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Reliability of Subsurface Safety Valves (SSSVs)– Cost/Benefit Analysis for SSSVs in Underground Gas Storage Wells

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Acronym List

AEEV – annualized estimated expected value

AGA – American Gas Association

ALARP – as low as reasonably practicable

AOF – absolute open flow

API – American Petroleum Institute

ASV – annulus safety valve

Bcf – billion cubic feet

BOP – blowout preventer

CBL – cement bond log

COFI – consequence of failure index

COS – Center of Offshore Safety

CSB – Chemical Safety Board

CTU – coiled tubing unit

DOE – Department of Energy

ID – inner diameter

INGAA – Intrastate Natural Gas Association of America

JITF - Joint Industry Task Force

LOC – loss of control

LOFI – likelihood of failure index

LOWC – loss of well control

MMcf – million cubic feet

MIT – mechanical integrity test

MMSCFD – million standard cubic feet per day

MSF – management system factor

NMA – near miss adjustment

OD – outer diameter

OEM – Original Equipment Manufacturer

PHMSA – Pipeline and Hazardous Materials Safety Administration

P&M – preventive and mitigation

ppf – pound per foot

psi – pound per square inch

PSM – process simulator model

RP – recommended practice

SME – subject matter expert

SV – safety valve

SSSV – subsurface safety valve

TA – temporary abandonment

T&P – tubing and packer

TSV – tubing safety valve

UGS – underground gas storage

USD – U.S. dollars

VBA – Visual Basic for Applications

WRSV – wireline retrievable safety valve

1. Executive Summary

The U.S. underground gas storage (UGS) industry has a good overall safety record and continuously improves its practices as part of its mission to enable a reliable and safe supply of natural gas for the nation. The U.S. UGS facilities are key components of the energy distribution network that supplies this affordable and clean energy source for all types of use, including residential heating, chemical feedstock and heating for industry, and year-round power generation. However, as with most chemical or petrochemical operations, the UGS industry experiences rare but significant safety events that endanger people and the environment [1]. The Aliso Canyon 2015 gas leak incident [2-6] is a primary example of a very significant loss of control (LOC) event that caused a large natural gas release. Fortunately, it did not cause fatalities. Costs of large-scale LOC events are enormous. Non-financial costs related to erosion of public confidence are equally considerable. Naturally, accidents of this scale attract new calls for regulations and improvements in safety practices. The Pipeline and Hazardous Materials Safety Administration (PHMSA) initiative to underwrite the Battelle/Sandia effort that resulted in this report is a part of the broader effort to learn from the Aliso Canyon and other events and to identify appropriate changes in safety practices.

The specific goal of the Battelle/Sandia project was to assess the role that subsurface safety valves (SSSVs) can have in improving UGS safety. In the offshore oil and gas production industry, subsea-floor SSSVs are a mandated part of the well safety system, as they are considered to provide a barrier between reservoir fluids, the sea and the surface in the event of certain catastrophic failure such as shearing or severe damage to the subsea wellhead and/or riser, thus mitigating environmental, safety, and financial consequences. However, the use of these devices in U.S. UGS operations is limited, as is typical of onshore oil and gas production wells, due to perceptions in risk of catastrophic failure and of net risk change – the impact of a catastrophic surface failure at any given onshore site and the protection supposedly afforded by a SSSV against the cost impact and operational reliability impact of installation, operation, and maintenance of the SSSV. In light of Aliso Canyon, it has been proposed that SSSVs could play an important role in natural gas storage safety [7]; however, there is a general question in the storage industry of their need as well as their reliability in mitigating hazardous conditions when needed [8]. The aim of Battelle/Sandia's effort was to resolve these questions in an unbiased and open-minded manner that would gain acceptance from all stakeholders.

The initial focus of this project was on a thorough review of relevant literature, examination of available accident statistics, and interviews with subject matter experts (SMEs). However, in pursuing available sources of UGS-related risk and failure data, it became apparent that the type and volume of well data needed to develop an evaluation criterion for SSSV failure rates is not available and/or is not statistically significant. With the paucity of data, the Battelle/Sandia team realized that the study must be based on a risk model which considers a broad range of UGS well designs and installation cases. The modeling approach that was adopted is based on the general American Petroleum Institute (API) 581 methodology [9] and the storage well-specific model created by the 2017 Joint Industry Task Force (JITF) [10]. The JITF model was modified to account for SSSV characteristics and SSSV-related workover safety risks. The model was used to evaluate risks for several common UGS well construction styles with and without SSSVs for wells with different reservoir rate potentials, feed volumes and pressures, and for locations with various population densities.

Any effective assessment of safety practices must include inputs from the affected industry and from SME knowledgeable on the subject. The Battelle/Sandia team adopted a two-prong approach to satisfy this criterion. First, Stephen Nowaczewski, a recognized expert in the field of UGS, was added to the project as a consultant, supporting the Battelle/Sandia team. Stephen has 37 years of experience working in the UGS industry and is recognized for contributing to joint industry efforts in the past, including with the API, the American Gas Association (AGA), and the Interstate Natural Gas Association of America (INGAA). Furthermore, Stephen, through his own Nova Northstar LLC, is an independent contractor, able to provide an informed and independent evaluation of the UGS industry practices and safety challenges. Second, as a part of the project, the UGS industry workshop was hosted by Battelle and Sandia on March 3-4, 2020 in Denver, Colorado. The workshop was attended by the entire Battelle/Sandia team and approximately 40 representatives from major U.S. UGS operators, PHMSA, and national laboratories. The Battelle/Sandia team used this opportunity to present the risk model, its initial predictions, and conclusions. The UGS industry provided its feedback, numerous comments and suggestions. The workshop presentations and summary of industry comments are available through the PHMSA website [11].

The main conclusion of the study is that an application of an SSSV can reduce risk in some, but not all, UGS wells. The applicability of SSSV depends on level of risk for given well:

- UGS wells with low risk (risk being defined as a product of likelihood of failure and consequence of failure) would generally not benefit from an SSSV application. In fact, the risk may be increased due to risks of more frequent and more complex SSSV-related workover operations.
- For wells with moderate risks – driven by moderate or moderately high likelihood of failure and combined with high to moderate consequence of failure – the application of an SSSV can be seen as a cost-beneficial option at reducing risk when considering the entirety of the net risk change.
- For UGS wells with inherently high risks, particularly when driven by high likelihood of failure, the application of SSSVs may reduce risk but since SSSVs are a consequence mitigation device, the reduction in risk does not treat such a well's initial, or inherent, high likelihood of failure and thus the net risk change, while substantial in high consequence cases, still may leave unacceptably high residual risks due to the persistent likelihood of failure – and in fact the increased workover frequency for SSSV reliability reasons could be seen as another reason to disfavor use of SSSV in such high risk cases.

The Battelle/Sandia team recommends that the applicability of a SSSV in UGS wells be assessed for each well instead of a broad regulation that mandates the use of SSSVs for all UGS wells. The most reliable way to assess SSSV applicability is to apply a quantitative risk model that accounts for these factors and evaluates risk before and after the SSSV installation. The Battelle/Sandia team recommends a broader adoption of quantitative risk models to assess and manage risks in UGS wells. Specifically, quantitative models that evaluate probabilities/likelihood and consequence of accidents should be advanced. Qualitative risk models that rank risks for wells without estimating accident probabilities and consequences provide information that is of partial value for risk management.

The Battelle/Sandia team simultaneously carried out two projects related to UGS well safety, one focusing on applicability of SSSV, and a second concentrating on the applicability of tubing and packers (T&Ps). Both projects used the same general risk modeling approach and analysis methods. The results of the T&P effort are described in the complementary report [12].

This report is organized into several sections. Section 2 of the report discusses limited availability of risk and reliability data in the UGS industry and proposes more structured data collection and sharing protocols for this industry. Section 3 presents the risk model developed by the Battelle/Sandia team which was the major part of this effort. The risk model was applied to a broad range of common UGS well types and installation scenarios and used to evaluate benefits of SSSV installation in these wells. Section 4 evaluates deliverability impairments for wells with T&P and SSSV installed. Section 5 provides information related to SSSV technology and its costs, as well as a record of an interview with two SMEs. Section 6 presents conclusions and recommendations of the Battelle/Sandia team. The appendix section includes additional results of the risk analyses and other supplemental information.

2. Collection and Sharing of Reliability Data

2.1 Examples of Safety Reliability Databases

The original intent of the project was to collect data through review of multiple venues that would qualify the performance of SSSVs across a range of deployments. It quickly became apparent that the type and volume of well data needed to develop a statistically meaningful criterion was not available. Operators' current data collection efforts are to focus on ensuring the well is functioning properly with no apparent safety risks. Future data collection efforts could include a compilation of data into searchable databases. These types of databases would assist industry, state, federal, and research organizations to better understand the real-world reliability of wells and their preventive and mitigative barrier mechanisms. It would help guide operational improvements and mitigate consequences.

There are known examples of industry voluntarily providing data related to safety performance for incorporation into databases that provide information for industry, the public, and regulators in order to continually learn and improve from their experiences. Two examples are 1. Center for Offshore Safety (COS) [13], which encompasses the offshore oil and gas industry and 2. U.S. Department of Transportation, Bureau of Transportation Statistics [14], which is known for its statistics on commercial aviation, but also encompasses all transportation classes.

The COS is an oil and gas example, which collects and publishes safety performance data from industry annually. The data provided are voluntary and confidential. An independent third party manages the collection from industry and provides the data annually to COS. Data collected cover wells, projects, production, decommissioning facilities and operations, encompassing both process safety and personal safety.

As is currently being done across several industry sectors, Battelle and Sandia recommend establishing a similar industry-wide approach for underground natural gas storage operators to enable and promote collection, storage, and sharing of reliability data. As shown in the examples above a data warehouse can be managed confidentially and will allow for collaborative data analysis which will lead to safety assessment and ultimate improvements, and advancement of risk management goals to protect people, protect the environment, and protect and optimize asset health. What follows is a guidance of what such a database framework may look like that would allow for a standard set of definitions, tools, and data formats for safety device reliability tracking within the UGS industry.

2.2 Proposed Framework for Reliability Data Assembly and Analysis

The Battelle/Sandia team proposes a data collection and analysis framework which can be used and act as a seed to be taken and developed by industry or industry associations (such as INGAA, AGA, etc.) to meet goals related to helping reduce the likelihood of well failure and reduce accompanying consequences by better managing risk with more informed statistics. The framework, presented in Appendix 2, follows a tiered approach that examines reliability by looking at the type of equipment installed, operations management, and influence by human factors. The framework goes beyond the barrier elements studied in this report and the T&P safety valve report [12], and includes types of other barrier element information operators could choose to report. Additionally, the framework described in Appendix 2 includes other risk management related information, again for the sake of suggesting how such a platform could be used holistically by the industry and its regulatory partners in gathering information related to storage safety.

Within this framework, the reliability data needed to help ensure adequate risk management are broken down into greater detail. Equipment installed considers such factors as wells, safety valves, tubing and packers, along with dates of installation, if a part failed, why it failed, had it been serviced, and when it was removed. Data related to operations include flow stream characteristics, workovers, equipment testing and inspections including pass/fail criteria, pass/fail rate, and if maintenance and intervention were deployed. Human factors encompass whether procedures are in place and training is performed, specifically in relation to maintenance, testing, and installation of safety valve and tubing and packer systems. Together this detail of data collection will help guide risk management and ultimately reduce the likelihood of well failure and accompanying consequences.

Reporting and communication aspects of data analysis could include assessment of industry safety goal achievement, long-term performance trend analysis, summary of issues, recommendations, or findings with respect to hazard/threat/risk identification, sensitivity of analyses, and risk reduction measures. Another component that should be implemented is effective tracking of leading and lagging indicators such as number and severity of unintended releases/leaks, “legacy” well failures, operator error events; encroachments, identification of unique threats to specific wells/fields, incidents and issues logged, closed-out, or ongoing/under management, and the means and timeliness of incident/issue resolution.

Collaborative data collection and analysis also could lead to periodic review or cost/benefit analysis of integrity management activities such as corrective actions implemented, preventive maintenance and monitoring, testing, inspection activities/methods, review or analysis of incidents and investigations to communicate lessons on failure modes, consequences, and correctives/improvements, evaluation of use of risk information in decision processes, and recommendations on enhancement of existing or implementation of new preventive and maintenance (P&M) measures spanning all areas of physical-technical and human and organizational barrier elements.

The Battelle/Sandia team recommends that industry and its regulatory agencies agree on what should be collected and can be collected and involve a 3rd party to warehouse and analyze and report on the data.

3. Battelle/Sandia Quantitative Risk Model

3.1 The API 581 Recommended Practice

The API 580 and API 581 Recommended Practices (RPs) [9] provide a consistent and quantitative method to evaluate and manage risks for systems that confine fluids including pressure vessels, piping, tanks, and other pressurized equipment. These RPs provide much in the way of reference material for various means of degradation mechanisms and mitigation methods that are based on an existing body of knowledge to assess likelihood of failure and consequence of failure. Also, the RPs provide a description of various levels of analysis starting from a basic mix of quantitative and semi-quantitative inputs made into an overall quantitative form, or a more fully quantitative level of analysis that can evolve into full quantitative/probabilistic modeling. Further, API 581 introduces the concept of the ‘management system factor’ which is a robust beginning treatment of, or look at, human and organizational issues and their impact, via the process safety management system, at an organization’s risk. Importantly, the API 581 method can be applied in situations where failure data are incomplete and/or not fully established. Most of the API 581 inputs are in the form of adjustment factors based on technical parameters such as pressures, corrosion rates, thickness of pressure vessels, and credits that account for safety and inspection procedures. API 581 is recommended for petrochemical plants, refineries, pipelines, and other chemical operations. The JITF recognized that API 580/581 concepts can be applied to the UGS well safety. The Battelle/Sandia team reached the same conclusion.

3.2 The JITF Model

The JITF, organized in response to the Aliso Canyon gas leak, developed a risk assessment model based on the API 581 method [10]. The model is specific to gas storage wells and provides risk estimates for catastrophic gas releases from these wells. The guidance model was not formally published but is known within the gas storage industry and its versions are used by some UGS operators. Appendix 6 of this report provides the 2018 guidance document created by the JITF team and is the most comprehensive description of the risk model available.

The JITF model included a very simplified method to account for the use of SSSVs; however, it did not account for any SSSV-related workover risks. The Battelle/Sandia team expanded this part of the model to consider the specific functionality of SSSVs and capture workover risks associated with the use of such devices.

3.3 The Risk Assessment Process Overview

The JITF model and the underlying API 581 method starts with estimations of two risk components: (1) the Likelihood of Failure Index (LOFI), and (2) the Consequence of Failure Index (COFI). Both components are estimated, usually within an order of magnitude or slightly better accuracy, and are not intended as precise failure probability or for cost predictions. Instead, the goal is to provide a reliable method to make risk decisions based on an assessment of risk change between options, select appropriate design alternatives, and implement risk-based inspection and maintenance procedures. The API 581 procedure develops LOFI and COFI estimations to evaluate risk. Risk can be quantified as the product of LOFI and COFI estimates, and the relative strength of the LOFI and/or COFI as drivers of risk can be visualized on a risk matrix, as shown in Figure 1. While the LOFI x COFI product can be used to rank risk, it may be important to understand whether risk is driven primarily by LOFI or by COFI, or by both. The understanding of what is driving risk is necessary for effective management of risk – for example, will it be more beneficial to reduce LOFI, reduce COFI, or reduce both LOFI and COFI – or is it necessary to reduce risk at all, if the risk is tolerable without further mitigation.

The interpretation of LOFI and COFI values evaluated by the JITF/adapted API 581 method depends on a specific system (in the sense of gas storage; here, a well) being evaluated and the risk tolerance limits of the organization managing the UGS facilities. Figure 2 presents a possible hypothetical picture of risk limits for a UGS well. In the example presented in Figure 2, the limits may be expressed as a maximum acceptable LOFI close to approximately 0.1 event per well-year, and a maximum acceptable annualized risk. Not all operator companies may quantify their limits explicitly or use the risk matrix for this purpose. The Battelle/Sandia team believes that quantification of risk limits is important for effective risk management because it sets clear safety goals and promotes quantification of risk in the context of such goals to drive cost-benefit based decisions. An operator can, of course, impose values based upon utility bases when making risk-based decisions; value bases frequently are applied in the areas of health and human safety and/or environmental stewardship. In the U.S, there is no agreement on the use of concepts such as ALARP ("as low as reasonably practicable") or on risk tolerance thresholds. However, the PHMSA Final Rule on Gas Storage Safety [15] requires operators to maintain and continually improve risk-based storage integrity management programs. Therefore, the Battelle-Sandia team used the more quantitative approach to analyze the efficacy of SSSV at reducing risk, and throughout this report presents figures such as those in Figures 1 and 2 to show results of analyses. The increased use of such figures in a standardized way might help the gas storage industry in ongoing investigation of well barrier element risk management and might be an important part of the independent analysis of safety and reliability warehouse data identified in Section 2 of this report.

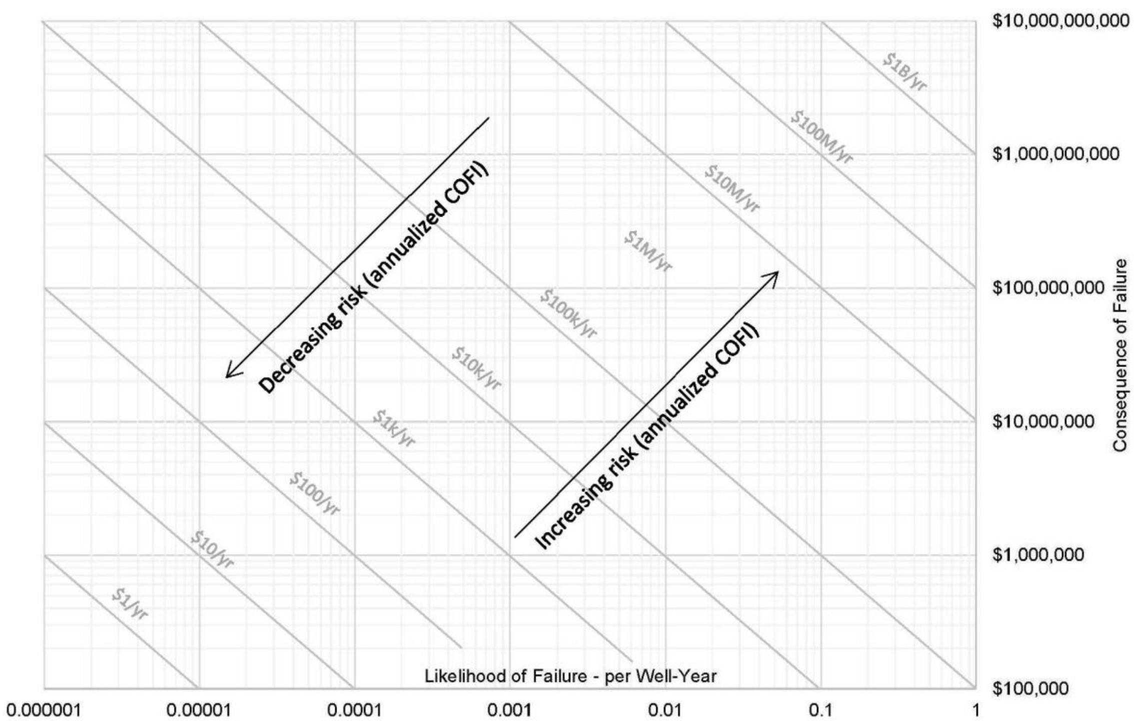

Figure 1: Example of a risk matrix.

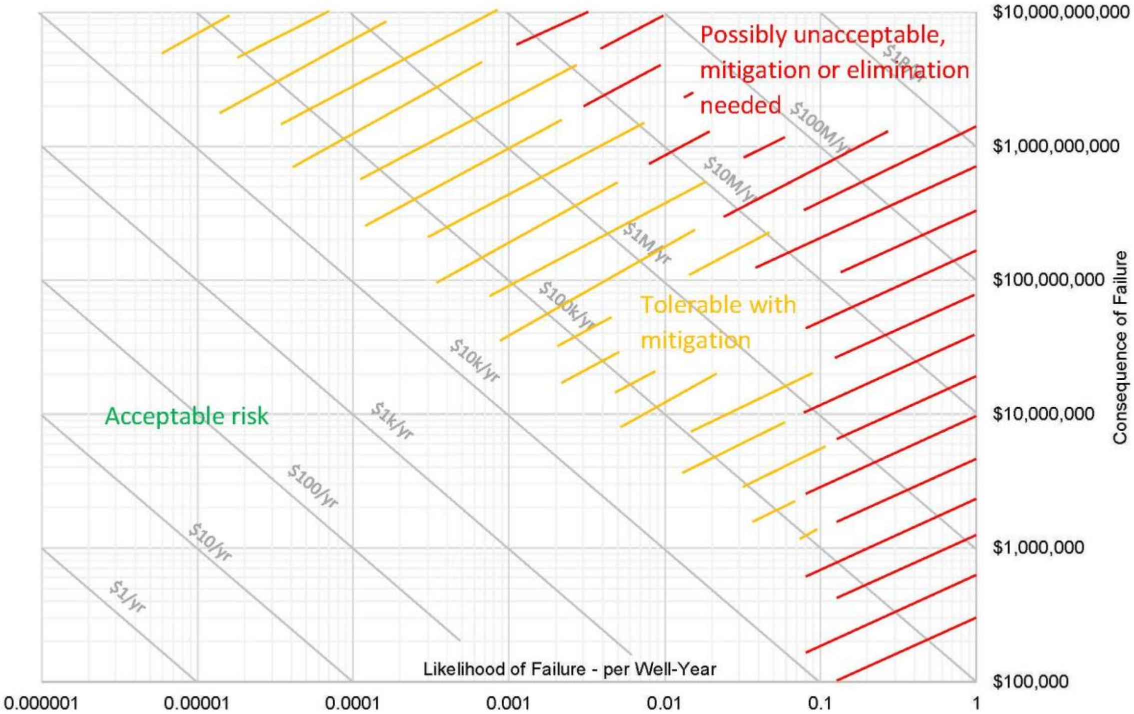

Figure 2: Range of acceptable risks for UGS wells.

3.4 The Likelihood of Failure Index (LOFI) Estimation

The JITF model used the following expression for LOFI, expressed as failure per well-year, during UGS well operations [10]:

$$LOFI_{Ops} = Gff \times \left[\left(Df_{thin} + Df_{mech} + Df_{impact}\right) + F_{whv} + F_{cmt} +\right] \times Credit_1 \quad (1)$$

where:

Gff is the generic failure frequency, per well-year

Df_{thin} is the damage/deterioration factor accounting for a wall thinning due to corrosion

Df_{mech} is the damage/deterioration factor accounting for a mechanical damage due to vibration, earth forces and stresses during well work

Df_{impact} is the damage/deterioration factor accounting for the possibility of a wellhead damage due to vehicular or object impact

F_{whv} is the factor accounting for a wellhead and valve design, condition, and functionality

F_{cmt} is the factor accounting for a cement sheath presence, condition, and functionality

$Credit_1$ is the management systems credit accounting for human and organizational factors.

Methods to estimate the above factors and credits are given in detail in the JITF model description [10].

The JITF model did not use the $Credit_1$ management system factor in recognition that the UGS industry was just starting its transition into the API 1170/1171 regulations issued in response to the Aliso Canyon incident. For this reason, the JITF model used the $Credit_1$ value of one. At the same time, the report outlining the model advocated use of this credit in future risk evaluations and outlined a detailed method to capture effects of human factors, safety management procedures, a degree of API 1170/1171 implementation, and maturity-robustness considerations. In the analysis, the Battelle/Sandia team will take full advantage of these parts of the JITF model to demonstrate that human and organizational factors are of paramount importance, including the question of SSSV applicability.

The Battelle/Sandia model used Equation 1, without modifications, to estimate the likelihood of failure for wells with and without SSSV during regular operations. This is consistent with the fact that an SSSV is a mitigation device and does not affect the likelihood of failure, only its consequences. However, the portion of the LOFI side of risk that is increased by SSSV installation but is not included in Equation 1, and not mentioned in the original JITF model, is the increased likelihood of loss of containment during workovers. The UGS industry points out that SSSVs require frequent workovers that are complex and may cause LOC type events. Furthermore, accidents during workovers endanger workers who work on a well, are in its vicinity, and have little chance to escape in case of the most serious events like wellhead fires; this part of risk must be accounted for in the COFI estimation. To account for total likelihood of failure with an SSSV in place due to increased workovers, the Battelle/Sandia team developed the following expression for annualized LOFI during these operations:

$$LOFI_{workover} = Frequency_{workover} \times FailureRate_{workover} \times Credit_2 \quad (2)$$

where:

$Frequency_{workover}$ is the net increase of workover frequency due to SSSV application

$FailureRate_{workover}$ is the failure rate during workover operations

$Credit_2$ is the management system credit accounting for human and organizational factors.

The values of annualized workover LOFI used in this study are described in Section 3.8.

3.5 The Consequence of Failure Index (COFI) Estimation

The JITF model used the following expression for consequence of failure during UGS well operations [10]:

$$COFI_{ops} = \left(COFI_{safety-surface} + COFI_{safety-subsurface} + COFI_{environmental} + COFI_{financial}\right) \times Credit_3 \quad (3)$$

where:

$COFI_{safety\text{-}surface}$ is the consequence of surface gas release, specifically consequence of injury or fatality caused by surface release with fire

$COFI_{safety\text{-}subsurface}$ is the consequence of subsurface gas release, specifically consequence of injury or fatality caused by subsurface release

$COFI_{environmental}$ is the consequence of gas and associated fluid release to environment

$COFI_{financial}$ is the overall financial consequence of gas release including items related to gas loss, repair and replacement, emergency response, service reliability, and other possible costs

$Credit_3$ is the credit due to use of isolation, detection, or mitigation measures.

Methods to estimate the above consequences are given in detail in the JITF model description [10]. All consequence components included in Equation 3 account for maximum well flowrate, volume of available gas, its pressure, well size, as well as population density around the well. For long-term and widespread area consequences, a duration of gas release is assumed to be 30 days, within which industry experience shows over 95% of loss-of-containment events are controlled.

The JIFT model includes a very simplified method to account for the use of SSSVs via the $Credit_3$. Specifically, if the SSSV is installed, the model sets the $Credit_3$ value to 0.85 times and reliability factor between 0.7 and 1. This study uses a more detailed description of SSSV's effect on COFI, which recognizes that these devices are effective in mitigation of surface releases but do not reduce consequences of subsurface releases. This characteristic of SSSVs necessitates that different types of consequences listed in Equation 3 should be multiplied by different credits, and that the overall COFI is expressed as a sum of multiple contributions:

$$COFI_{ops} = \sum COFI_i \times Credit_i \qquad (4)$$

where:

$COFI_i$ is the estimated consequence of specific type

$Credit_i$ is the credit applicable to this type of consequence

The values of credits used in this study are discussed in the next section.

3.6 Risk Reduction due to SSSVs

The COFI estimations outlined in Equations 3 and 4 include all types of consequences defined in the JITF model. Different safety devices, such as SSSVs, have a different effect on different consequence components that need to be captured in the model as COFI credits used in Equation 4. Table 1 presents values of credits used in this study to describe the effects of shallow- and deep-set SSSVs. A shallow-set SSSV has the largest effect on consequences that are caused by surface releases, specifically the safety consequence of fire at a well head. The appropriate value of credit in this case is $(1\text{-}R_{SSSV})\times C_{Del}$, where R_{SSSV} is the reliability of a SSSV and C_{Del} is the deliverability reduction factor. Several types of consequences in the JITF model are the effects of both surface and subsurface releases and these contributions cannot be easily separated. These include long-term gas releases due to subsurface release or surface release without fire, service and financial consequences, as well as releases of toxins and pollutants. For these consequences, the credit is $0.5+0.5\times C_{Del}\times(1\text{-}R_{SSSV})$, which assumes the subsurface consequences to be unchanged and the surface consequences scaled down with SSSV reliability and deliverability reduction. Consequence caused by the release of natural gas and its greenhouse effects are assumed to be caused by two types of events: (1) LOC events causing surface releases, and (2) leaks caused by SSSV operation and well interventions. The LOC release part of the credit is $(1\text{-}R_{SSSV})\times C_{Del}$. The leak credit is assumed to be 0.5% of the reservoir volume per year plus 0.1 MMcf per year. Several consequences are caused by subsurface releases that are not expected to be mitigated by a SSSV. This includes consequences related to soil stability and productivity, vegetation health, and water supply quality and security. The credit for these is *1*, meaning there is no consequence reduction.

Table 1: COFI credits for SSSVs during regular operations.

<table>
<tr><th rowspan="2">Type of consequence</th><th colspan="2">COFI Credit</th></tr>
<tr><th>Shallow-set SSSV</th><th>Deep-set SSSV</th></tr>
<tr><td>Surface release with fire</td><td>$(1-R_{SSSV}) \times C_{Del}$</td><td rowspan="4">$(1-R_{SSSV}) \times C_{Del}$</td></tr>
<tr><td>Long-term gas release due to subsurface and surface release without fire</td><td rowspan="3">$0.5+0.5 \times C_{Del} \times (1-R_{SSSV})$</td></tr>
<tr><td>Service and financial</td></tr>
<tr><td>Fluid flow, toxins and pollutants release</td></tr>
<tr><td>Greenhouse gases (GHG) emissions</td><td>$(1-R_{SSSV}) \times C_{Del} + C_{leakage}$</td><td>$(1-R_{SSSV}) \times C_{Del} + C_{leakage}$</td></tr>
<tr><td>Soil stability, vegetation health, soil productivity, water supply security</td><td>1</td><td>$(1-R_{SSSV}) \times C_{Del}$</td></tr>
<tr><td colspan="3">R_{SSSV} is reliability of SSSV
C_{Del} is a deliverability reduction factor for SSSV
$C_{leakage}$ is a leakage component of credit, assumed to be 0.5% of the reservoir volume per year plus 0.1 MMcf per year</td></tr>
</table>

A deep-set SSSV is more effective since it can mitigate both surface and subsurface gas releases. This effect can be described by the $(1\text{-}R_{SSSV}) \times C_{Del}$ credit applied to a broader set of consequences as shown in Table 1. The increased effectiveness of SSSVs is partly offset by lower reliability of deep-set valves, as well as by deliverability impairment and replacement that might attend to deep-set SSSVs on tubing. Table 2 presents SSSV reliabilities used in a model analysis. The reliabilities listed are based on the experience of the Battelle/Sandia team, industry input, and available reports. It should be pointed out that very low and low estimates do not reflect the baseline mechanical reliability of SSSV, but rather industry experiences in SSSV application in challenging environments with enhanced corrosion and erosion. As discussed in Section 5.7, SMEs believe that SSSVs have inherently very high mechanical reliability and most of the issues associated with their operation is caused by human factors.

Table 2. Reliability of SSSV.

Estimation	Reliability of SSSV	
	Shallow-set	Deep-set
Very low	0.60-0.67	0.36
Low	0.80	0.67
Medium	0.905	0.84
High	0.985	0.94

Selected U.S. UGS operators use wells with velocity string tubing in combination with two SSSVs, one in the tubing and one for the annulus space. The tubing of this type does not have a bottom packing as by design flow may be through the tubing, through the tubing-casing annulus, or both; therefore, the tubing does not act as a secondary barrier in such cases of tubing safety valves + annulus safety valves. The assessment of consequence reduction for this type of well can be described by credits listed in Table 1, provided modifications are made. Since volumes protected by both SSSVs are connected at the bottom of the tubing without a packer, both valves must simultaneously work to stop releases. This means that the single valve reliability R_{SSSV} should be replaced by a product of reliabilities of both valves, $R_{TSV} \times R_{ASV}$, the first value being reliability of tubing safety valve (TSV), and second value being reliability of an annulus safety valve (ASV).

The use of tubing-conveyed, tubing-set SSSVs in UGS wells could cause flow restrictions, depending on the strength of the well flow capability and the depth and diameter of tubing, among other aspects that also might reflect negatively on flow reliability. The net risk change attending to an SSSV application then also must account for the possibilities that deliverability impairment might affect gas storage operations and, in some cases, require additional wells to maintain the required production rate. Deliverability impairment may be present as a direct restriction in flow diameter and, as a result, a restriction in flow potential. Additionally, it may be present as a reduction in deliverability reliability, the available rate when needed, due to the same restriction or interruption of a smooth flow profile, causing increased turbulence and potential nucleation sites for the formation of hydrates or deposition of organic or inorganic solids, with the related decrease or loss of deliverability from the well. The delivery impairment effects are critical for the evaluation of applicability of these devices, since delivery rate is of primary importance for UGS operators. Section 4 of this report describes these effects in detail. Table 3 outlines the key aspect of the deliverability impairment effects: it is progressively more significant for wells with larger absolute open flow (AOF). Delivery effect on UGS fields depends largely on a combination of well sizes used. Fields that include wells with large AOF are affected more, fields that rely on wells with smaller AOF are affected less. The deliverability adjustment factor C_{Del}, defined as a fraction of the well's AOF available after SSSV or tubing is installed, is used in COFI estimates as shown in Table 1.

Table 3. Effects of deliverability impairment due to use of SSSVs and/or tubing.

AOF (MMSCFD)	Deliverability adjustment factor C_{Del} used in Tables 6 and 7		Replacement wells needed per well	
	Shallow set SSV	Deep set SSSV or Tubing	Shallow set SSV	Deep set SSSV or Tubing
300	0.95	0.55	0.05	0.45
100	0.965	0.68	0.035	0.32
60	0.98	0.72	0.02	0.28
10	0.995	0.93	0.005	0.07
1	1	0.99	0	0.01

Costs of adding new wells to maintain the overall production rate are added to the life cycle cost of a safety device. The full fractional cost of the needed (fractional) replacement wells was added back into COFI as a one-year cost. In a more robust investment valuation, such costs might be distributed over a multi-year period; however, in this analysis, the team was trying to show a directionality and maximal magnitude of risk change for other factors in SSSV risk management efficacy. As will be described later and depicted in Section 3.11, one can estimate risk change, due to implementation of an SSSV system, and then look at maximum-side adjustments to risk, including such maximum views of deliverability impairment.

The cost of a new well was assumed to be between $1M and $4M; while this does not cover all possible UGS new well costs, the team assumed this as a good range of approximately 90% of new well costs. The costs related to SSSV installation also include the effect of reliability of these devices, since there is the likelihood that the SSSV will fail in a way that will prevent use of the well. The question is how to estimate this type of SSSV reliability, specifically if the reliabilities listed in Table 2 apply. For example, a 300 MMSCFD well, which needs to be fitted with a shallow-set SSSV, might require the addition of 0.05 new wells. Assuming the SSSV is of medium reliability, the number of additional wells needs to be increased to 0.05/0.905=0.055. If the cost of a new well is $1M, the adjusted cost basis of additional wells in the net risk change calculation will be an additional $1M×0.055=$55k per new well.

Consequences of LOC events accruing during workover operations or “well intervention” (rig/downhole equipment on site and in the well) need to be estimated differently from LOC events accruing during regular operations. First, the SSSV is unlikely to provide any mitigation during workover because during well intervention the SSSV might be removed from a well, locked open or disabled. Second, the Battelle/Sandia team judged that LOC events during workover are unlikely to involve subsurface failure and release; only surface releases are expected. The potential for subsurface events during workover is ignored for cases both with and without SSSV. Third, the surface release with fire event during workover could be much more consequential than for failures during normal operation, due to workers being in the near vicinity of the well during the well intervention. Workers at the well are at the most danger for injuries since they are usually working in the immediate well vicinity and have little time to escape in case of well fire. Workover interventions are labor intensive and usually involve multiple people at a well and in immediate way of potential harm. The Battelle/Sandia model assumed that five workers are near the well during workovers. The COFI for human safety impact in the event of a surface release with fire was adjusted to add 5 people to each of the consequence cases. Therefore, the risk change impact is most noticeable for wells in low and very low population density areas or other areas where there are very few people in the critical heat radius of the well, where in the workover analysis, now there are five people in the way of immediate harm. The fourth difference for workover operations is the assessment of duration of a LOC event in the adjusted risk model. The team assumed that LOC events during interventions, while potentially more consequentially severe, could be of shorter duration than the LOC event during regular operations. The majority of LOC events during workover will be contained within 1 to 2 days according to industry statistics, and so as to not over-state both duration and severity of a workover LOC event, the risk assessment used statistics of blowout events for offshore wells, which indicates a weighted average duration of blowout in offshore events is approximately 4 days, or about 0.13 of the 30-day subsurface failure event period assumed in the JITF model for LOC events during regular operations. Table 4 summarizes the approach used for the workover COFI credits.

In addition to the COFI adjustments for workovers, two relatively minor adjustments were made to account for other safety risk to workers during workovers. The Battelle/Sandia team used industry statistics on drilling and service rig injury and severity and estimated other non-well failure and release related injuries. In summary, this resulted in increasing annualized safety-related consequence impacts in the range of $2K to $4K. Greenhouse gas effects of seeps, due to SSSV systems and well blowdowns, were included, and other gas use and loss while drilling and servicing were included, although the analysis of these sources of increased greenhouse gas emissions resulted in only several tens to several hundreds of dollars of consequence impact per year. Together, these additional safety and environmental consequence adjustments did not have a significant impact on the assessment of SSSV risk management efficacy. In the overall analysis, adjustments generally amounting to less than $10K in annualized expected risk make no change in the results of the assessment, and while these other safety and environmental adjustments fall into the zone of minimal significance, they were included in the analysis for the sake of completeness.

Table 4: COFI credits for workover operations.

Type of consequence	Credit	Comments
Surface release with fire	1	SSSV is likely to be removed or disabled during workover; therefore, there is no credit due to its use. The model procedure evaluating this risk assumes five workers at the well.
Soil stability, vegetation health, soil productivity, water supply security	0.13	Duration of LOC events during workovers is expected to be much shorter as compared to LOC events during regular operations. Subsurface release is very unlikely to occur during workovers but some environmental consequences occur during blowouts and can affect air, water, and soil qualities.
Service and financial		
Fluid flow, toxins and pollutants release		
Greenhouse gases emissions		
Subsurface release and extended subsurface spread of fluids	0	Subsurface release is less likely to occur during workovers – while such a likelihood is not zero, this was set to zero in each case in order to focus on the more typical surface event and its consequences to worker safety.

3.7 Types of UGS Wells Used in Analysis

The risk model outlined in Equations 1 through 6 provides meaningful methods to assess risk of UGS wells with and without SSSVs, and to quantify benefits of SSSV use. However, the model provides estimated values of LOFI and COFI that should not be interpreted as a "correct answer" for risk in any given well – that is for each UGS operator to assess and develop their own estimates. The Battelle/Sandia team applied the model to a broad range of hypothetical UGS wells that are not intended to represent any specific operator, UGS facility or well. The model was applied to four well construction styles, shown in Figure 3, representative for U.S. UGS facilities. These construction styles serve to represent the LOFI, modeling certain time-dependent characteristics such as corrosion rates, as well as design ("as-built")-dependent characteristics. In addition to the four well types, two bookend types were added: a near-ideal new well, and a problem well of poor construction type and at or near failure. This approach created six well styles for the LOFI estimation. Note that the depth references shown in Figure 3 are for schematic purposes only and do not imply actual depths; setting depths of any casing string in these styles can be at any depth in actual application.

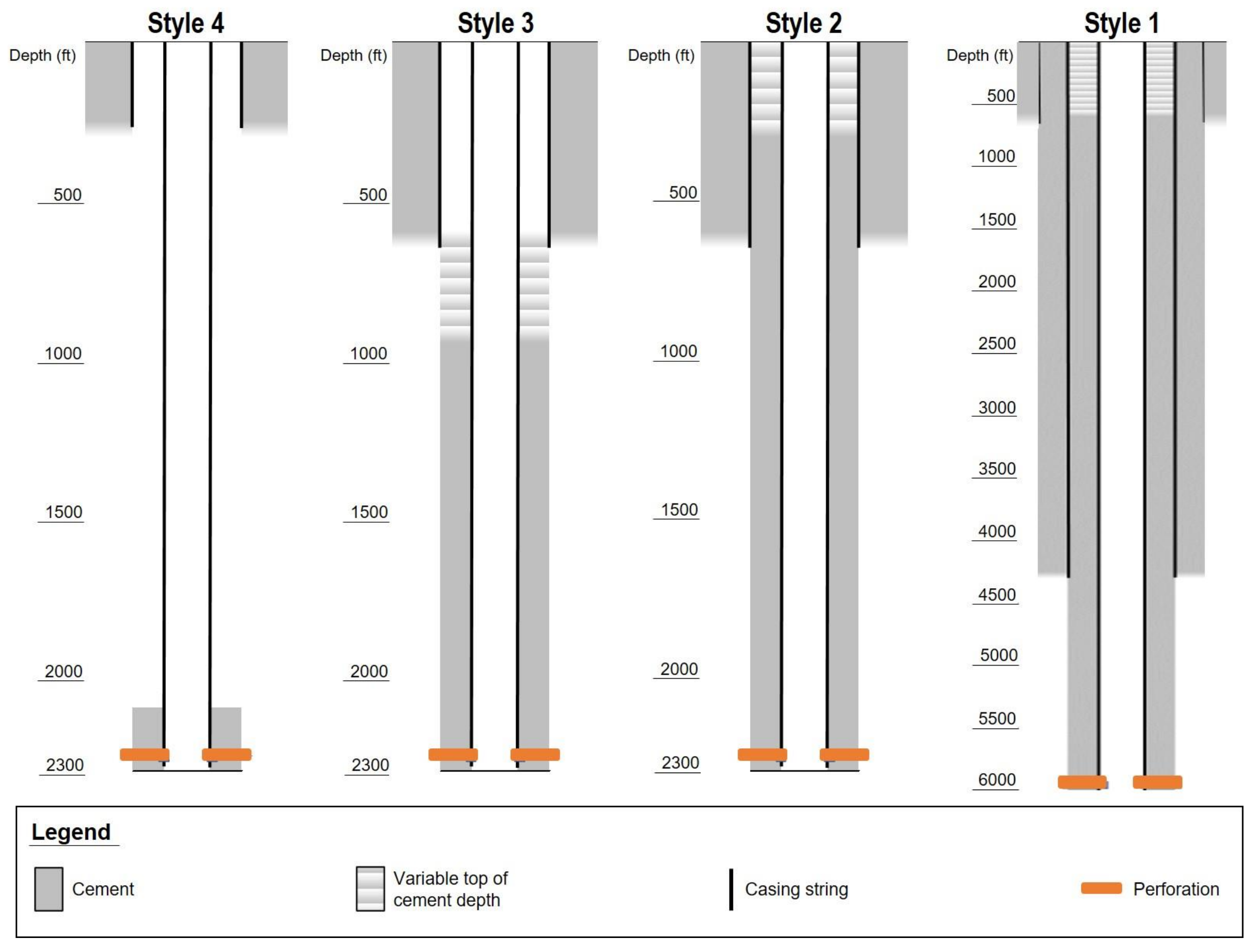

Figure 3: Four UGS well construction styles that were used for the model analysis.

Style 1 well has full protection of usable sources of drinking water by deep surface casing and cement, along with an intermediate casing and cement, to substantially inside the surface casing, in some cases to ground level. The intermediate casing is of mechanical strength and setting depth that can afford a full or partial secondary barrier to maximum gas storage pressure and may act together with impermeable rock formations, below the intermediate shoe, to provide a full passive secondary barrier. The production casing string in Style 1 is cemented nearly to surface and well inside of the intermediate casing string.

Style 2 well has adequate surface casing and cement to afford clear protection to usable sources of fresh water. It is set to today's state well construction standards below the base of fresh water, along with production casing and a near-full cement sheath, reaching well into the next outer string and, in some cases, with cement at or near the ground level.

Style 3 is a well with adequate surface casing and cement, generally affording acceptable protection to usable sources of fresh water. It has production casing with cement of variable height, but adequate to meet today's state well construction requirements with respect to zonal isolation. However, in some cases, the production casing cement might be well below the shoe of the next outer casing string, although in other cases it might be up to or inside of the next outer casing string.

Style 4 is a well with minimal surface casing depth and cement, and a production casing string and minimal cement. In some cases, the surface casing string might not be far enough below the base of usable sources of fresh water by today's standards, and/or the production casing cement may not provide a length of cement sheath meeting today's state well construction standards.

The reason for creating these well styles was to develop a set of hypothetical wells with LOFI estimated across five to six orders of magnitude that are representative of actual wells used for storage. The detailed well parameters used in the analysis are listed in Table 5. The well construction styles may be loosely representative of actual wells used for storage. Again, the team stresses that individual actual wells, if assessed in the JITF LOFI model, could have substantially varying LOFI depending on the inputs to the LOFI estimate.

All wells were assumed to use 5.5-inch outer diameter, 15.5 pound per foot (ppf) J/K-55 casing, simply to normalize a comparison fairly between well types and vary other parameters in the LOFI calculation. The maximum well pressure of 2,000 pounds per square inch (psi) was assumed. The analysis did not make variable assessments of site-specific factors that might occur in actual UGS wells – particularly for cases of earth forces, vibration, and other induced mechanical forces and impacts. Table 5 lists other well parameters assumed in the analysis.

The critical point to take as summary from this section of the report is that the team created the well styles represented in Table 5 and produced a range of LOFI that spanned from a maximum of 1 in the problem well case and 0.461212/well-yr in the Style 4 case to a minimum of 0.000003/well-yr in the ideal well case and 0.000022/well-yr in the Style 1 case. The 10 unique LOFI values in Table 5 were used in the risk analysis, combined with consequence environments that will be described in a following section.

Table 5. Assumed properties of the four styles plus two end-point styles of UGS wells used for the model analysis.

Well style	Generic Failure Frequency (failure/well-year)	Corrosion Rate Ranged (mm/yr)	Adjustment for Class 3 and 4 Joints	Df_{Work}	Df_{Impact}	F_{Whv}	F_{Cmt}	LOFI (failure/well-year)	
								Min	Max
Style 4	0.000100	0.018-0.045	1.6	5	2	0-100	90-4500	0.009742	0.461212
Style 3	0.000067	0.018-0.045	1.2	3	2	0	30-150	0.002363	0.010505
Style 2	0.000033	0.018-0.045	1.01-1.2	2	2	0	5-100	0.000302	0.003446
Style 1	0.000010	0.018-0.045	1-1.2	2	2	0	0.1-50	0.000022	0.000523
Ideal Well	0.000010	-	-	-	-	-	-	0.000003	0.000003
Problem Well	0.000100	-	-	-	-	-	-	1.000000	1.000000

3.8 Estimation of Annualized Workover LOFIs

Equation 2 includes a net increase of workover frequency caused by use of SSSVs over the baseline workover frequency for well interventions not related to SSSVs. Workover frequency is generally not easy to estimate since it depends on an operator's preference and regulatory environment. Workovers require significant resources, in both manpower and materials; therefore, workovers must be planned and managed carefully based on specific UGS facility's characteristics, location, and UGS operator workflow capabilities. The Battelle/Sandia team used its knowledge of UGS operations and estimated workover frequency rates for wells with and without SSSVs. Table 6 presents these estimates for the baseline workovers for UGS wells without SSSVs installed. To reflect the uncertainty of this parameter, the frequencies are estimated as low, medium, and high estimates. The well style is assumed to have an effect on workover requirements, mainly older wells might require more frequent interventions.

Table 6: Baseline frequency of workovers for UGS wells without SSSVs.

Estimate	Baseline frequency of workovers, per year			
	Style 4	**Style 3**	**Style 2**	**Style 1**
Low	0.067	0.056	0.045	0.033
Medium	0.100	0.100	0.073	0.058
High	0.200	0.125	0.100	0.083

Frequency of SV-related workovers is also dependent on the operator's preference, well design and reservoir characteristics, and regulatory mandates. Table 7 presents the estimated frequency range selected based on experience of the Battelle/Sandia team and on available literature. The state of California is a special case where regulatory rules could impact some wells such that re-entry must be performed at least every two years.

Table 7: Frequency of SSSVs-related interventions

Estimate	Frequency of SSSV interventions, per year
Low	0.04
Medium	0.125
High	0.2
California mandate	0.5

Combined re-entry frequency estimates are presented in Table 8. Depending on the type of well and its location, workover frequency ranges from approximately once per every 13.6 years up to once every two years.

Table 8: Combined workover frequency, baseline and SV-related interventions.

Estimate	Combined re-entry frequency		Method of estimation
	Interventions per year	Interval between re-entry (yr)	
Low	0.073	13.6	Low estimate for newer storage wells + low estimate for SV
Medium	0.225	4.4	Medium estimate for mid-age storage wells + medium estimate for SV
High	0.4	2.5	High estimate for old, converted wells + high estimate for SV
California mandate	0.5	2.0	California mandated SV inspection rate

The second factor in Equation 2 is the LOC rate during workovers. Although LOC workover data specific for USC wells are not available, offshore industry experience is documented and chosen to be representative as to basic equipment and work processes. LOC rate estimates averaged from reports, publications, and journal articles for offshore wells [16] are presented in Table 9 and discriminated by tubing-conveyed work string operations and wireline-conveyed tool operations. Because most SSSVs used in UGS wells are tubing-conveyed, this part of the data in Table 9 were used in the analysis. As with other parts of this analysis, the range of possibilities is presented so that other values can be calculated in the net risk change calculations. The Battelle-Sandia team again makes the point that it chose to go with a specific parameter or set of parameters for the sake of calculation efficiency and analysis of impact on the overall risk change.

The addition of an SSSV not only increases frequency of workovers but also significantly increases complexity of all workover operations. With this in mind, it appears that the most appropriate approach to calculate the annualized LOFI for UGS workovers is to use the LOC rates given in Table 9 and the total workover frequency values from Table 8. This conservative approximation was adopted by the Battelle/Sandia team.

Table 9: Workover LOC rates – approximate or estimated average from various sources.

Intervention Loss of Control (LOC) (per entry event)	
Tubing-conveyed entries, low estimate	0.0004
Tubing-conveyed entries, high estimate	0.0025
Wireline-conveyed entries, low estimate	0.00007
Wireline-conveyed entries, high estimate	0.00015

Table 10 shows the annualized workover LOFI estimations used in the model. Specifically, the team used average values between low and high estimates, using medium-range workover frequency, for tubing-conveyed entries. UGS operators may use values that describe their operations.

Table 10: Annualized increase of workover LOFI values used in the model.

Estimate	Frequency-workover: Due to SV alone, Re-entry rate per year (MTTR)	LOC change per year, SV issues ONLY, using tubing-conveyed entries, high estimate	LOC change per year, SV issues ONLY, using tubing-conveyed entries, low estimate	Frequency-workover: Critical-All Re-entry rate per year (MTTR)	LOC change per year, all entries, using tubing-conveyed entries, high estimate	LOC change per year, all entries, using tubing-conveyed entries, low estimate
V. High (CA)	0.5 (2)	0.00125	0.0002	0.5 (2)	0.00125	0.0002
High	0.2 (5)	0.0005	0.00008	0.4 (2.5)	0.001	0.00016
Medium	0.125 (8)	0.0003125	0.00005	0.225 (4.4)	0.0005625	0.00009
Low	0.04 (25)	0.0001	0.000016	0.073 (13.6)	0.0001833	0.0000293

3.9 Consequence Environments Used in Analysis

The Battelle/Sandia team created “consequence environments” – a total of 12 combinations of well flow potential, reservoir feed volume, local population density, and wide-area population density. The 12 combinations of primary COFI drivers were not intended to be an exhaustive construct of possibilities, but, as in the case of the LOFI well style construct, were intended to provide consequence environment combinations that provided a set of base case COFI that spanned several orders of magnitude. Table 11 provides the detail behind the consequence environments and lists the workover COFI and annualized workover risk attributed to each consequence environment.

Table 11: Consequence Environments used in the analysis.

Battelle-Sandia SSSV Study - Twelve Consequence Environments - Spanning 5 Orders of Magnitude												
	High Consequence Case Characteristics	**Intermediate Consequence Case Characteristics**	**Low Consequence Case Characteristics**	**Very low consequence case**	**High population - low rate, big volume Consequence Case Characteristics**	**Intermediate population - low rate, big volume Consequence Case Characteristics**	**moderately low population -high rate high volume Consequence Case Characteristics**	**very low population - high rate high volume consequence case**	**hi regional-mod local population, strong flow and volume consequence case**	**hi regional-lo local population strong flow and volume consequence case**	**Intermediate regional population - mod local population strong flow and volume consequence case characteristics**	**Intermediate regional population - low local population strong flow and volume consequence case characteristics**
AOF (MMcfd) at MOP (used MOP of 2000)	100+ (use 300)	25-99 (use 60)	30 or less (use 10)	<1 (use 1)	30 or less (use 10)	30 or less (use 10)	100+ (use 300)	100+ (use 300)	100	100	100	100
Applicable Critical Heat Radius (feet)	153-198' (api 581) or 153-310' CFER	73-89' (api 581) or 153-310' CFER	32-36' (api 581) or 153-310' CFER	<10'	32-36' (api 581) or 153-310' CFER	32-36' (api 581) or 153-310' CFER	153-198' (api 581) or 153-310' CFER	153-198' (api 581) or 153-310' CFER	92-115' (api 581) or 225-450' CFER	92-115' (api 581) or 225-450' CFER	92-115' (api 581) or 225-450' CFER	92-115' (api 581) or 225-450' CFER
safety factor	2.5 (2.5*198=485)	2.2 (2.2*89=196)	2 (2*36 = 72)	2 (2*10=20)	2 (2*36 = 72)	2 (2*36 = 72)	2.5 (2.5*198=485)	2.5 (2.5*198=485)	5 = 288); 2.5*225=563	5 = 288); 2.5*225=563	5 = 288); 2.5*225=563	5 = 288); 2.5*225=563
Use JITF COFI Tier	660	330	165	165	165	165	660	660	660	660	660	660
Nearby Population Density people/sq mi	1100	99	9	1	1100	99	9	1	99	1	99	1
Avg Pop inside radius of concern	54	1	0.03	0.002	3	1	1	0.002	5	0.002	5	0.002
30-day flow volume (MMcf)	over 1000 (use 3000)	301-1000 or less (use 600)	300 or less (use 90)	9	use 300	use 300	over 1000 (use 3000)	over 1000 (use 3000)	use 2400	use 2400	use 2400	use 2400
volume index	5	4	3	2	4	4	5	5	5	5	5	5
9-mile radius population density	1100	99	9	0.9	1100	99	9	0.9	120	120	99	99
population index	5449	54.5	5.4	0.5	5449	54.5	5.4	0.5	544.9	544.9	54.9	54.9
Total Consequences Est	**$1,954,711,323**	**$54,352,517**	**$4,964,519**	**$784,822**	**$1,188,331,148**	**$47,267,387**	**$143,642,850**	**$54,657,799**	**$373,530,042**	**$341,217,972**	**$184,141,112**	**$151,829,042**
Safety - surface fire	$349,110,000	$6,465,000	$193,950	$12,930	$19,395,000	$6,465,000	$6,465,000	$12,930	$32,325,000	$12,930	$32,325,000	$12,930
Environmental - Surface Fire	$6,360,650	$322,130	$45,820	$4,582	$636,065	$186,065	$6,360,650	$1,860,650	$6,088,520	$6,088,520	$6,088,520	$6,088,520
Financial - Surface Fire	$164,100,000	$18,020,000	$1,943,000	$355,800	$78,610,000	$14,760,000	$57,115,000	$25,105,000	$96,630,000	$96,630,000	$57,630,000	$57,630,000
Estimate - Surface Fire Cons	**$519,570,650**	**$24,807,130**	**$2,182,770**	**$373,312**	**$98,641,065**	**$21,411,065**	**$69,940,650**	**$26,978,580**	**$135,043,520**	**$102,731,450**	**$96,043,520**	**$63,731,450**
Safety Subsurf/Extend Surf	$1,237,680,023	$9,903,257	$735,930	$45,428	$990,144,018	$9,903,257	$1,226,550	$113,569	$123,768,002	$123,768,002	$12,379,072	$12,379,072
Enviro - Subsurf/Ext Surf	$33,360,650	$1,622,130	$102,820	$10,282	$20,936,065	$1,193,065	$15,360,650	$2,460,650	$18,088,520	$18,088,520	$18,088,520	$18,088,520
Financial - Subsurf/Ext Surf	$164,100,000	$18,020,000	$1,943,000	$355,800	$78,610,000	$14,760,000	$57,115,000	$25,105,000	$96,630,000	$96,630,000	$57,630,000	$57,630,000
Estimate - Subsurf/Ext Surf	**$1,435,140,673**	**$29,545,387**	**$2,781,750**	**$411,510**	**$1,089,690,083**	**$25,856,322**	**$73,702,200**	**$27,679,219**	**$238,486,522**	**$238,486,522**	**$88,097,592**	**$88,097,592**
Workover Loss of Control (LOC) - COFI Estimates	**$429,264,769**	**$43,727,954**	**$33,043,453**	**$32,432,370**	**$74,962,977**	**$42,806,887**	**$56,463,669**	**$39,426,999**	**$92,916,815**	**$60,604,745**	**$82,776,815**	**$50,464,745**
annualized estimated average mid-point value of workover LOFI x COFI - for net workover increase only	$54,463	$5,548	$4,192	$4,115	$9,511	$5,431	$7,164	$5,002	$11,789	$7,689	$10,502	$6,403

Table 12 provides a summary of the 12 consequence environments and the COFI estimate, as well as the percentage of the COFI estimate attributable to safety and environmental aspects of the COFI analysis, and the portion attributable to a downhole subsurface failure.

Table 12: Consequence environments summary.

Environment	Well flow (AOF)	30-day flow volume	Population density	COFI Estimate ($/event)	% Safety + environment	% Subsurface
Base	Very high rate well	High feed volume	High population density, even distribution	$1,954,711,323	83	73
	Modest high rate well	Moderate feed volume	Moderate population density, even distribution	$54,352,517	34	54
	Low rate well	Low feed volume	Low population density, even distribution	$4,964,519	22	56
	Very low rate well	Very low feed volume	Very low population density, even distribution	$784,822	9	52
Inverted	Low rate well	Moderate feed volume	High population density, even distribution	$1,188,331,148	87	92
	Low rate well	Moderate feed volume	Moderate population density, even distribution	$47,267,387	38	55
	Very high rate well	High feed volume	Low population density, even distribution	$143,642,850	20	51
	Very high rate well	High feed volume	Very low population density, even distribution	$54.657,799	8	51
Mixed	High rate well	High feed volume	Wider population density moderately high, nearby population density low	$373,530,042	48	64
	High rate well	High feed volume	Wider population density moderately high, nearby population density nil	$341,217,972	43	70
	High rate well	High feed volume	Wider population density moderate, nearby population density low	$184,141,112	37	48
	High rate well	High feed volume	Wider population density moderate, nearby population density nil	$151,829,042	24	58

The 12 consequence environments were evaluated across the 10 values of LOFI given in Table 5. The intent of the effort was to create well types representing a range of LOFI across six orders of magnitude, as reflected in Table 5, and a COFI across a range of five orders of magnitude in U.S. dollars (USD), from $100K-$1M to $1B-$10B. Within the consequence environment cases, population density ranged over five orders of magnitude (1000s to <1 persons/square mile), flow potential ranged over four orders of magnitude (>100 MMSCFD to <1 MMSCFD), and available 30-day feed volume ranged over four orders of magnitude (> 1 Bcf to <10 MMcf).

It is worth noting that Table 12 identifies consequence environments that range in character, where in some cases surface events dominate and in others subsurface events dominate and yet others where consequence potential is more evenly split between surface and subsurface events. In addition, Table 12 identifies that the Battelle/Sandia team created consequence environments where in some cases the safety and environmental consequences were dominant and other cases where the safety and environmental consequences were a minor to very minor part of total consequences.

3.10 Assessment of Human Factors Effects Related to Workover and SSSV System Management

Both Equations 1 and 2 include management system credit factors to include human factor effects on LOFI estimations for regular operations and workovers. The question is how to estimate these credits in a way that is quantitative, objective, and unbiased in context that typically involves strong opinions about human performance and corporate culture. As mentioned previously, the JITF model did not use the management system factor in recognition that the UGS industry in 2017 was only starting its transition into the API 1170/1171 regulations issued in response to the Aliso Canyon leak. For this reason, the JITF model used the $Credit_1$ value of one. At the same time, the JITF task force proposed a list of 52 questions designed to probe leadership quality, safety and hazard assessment procedures, management and operational procedures, safe work practices, training effectiveness, emergency response, incident reporting, and other factors.

Addressing human factors is an approach that seeks to account for differences in safety culture and human and organizational competency and experience when dealing with the possibility of more downhole work due to new safety devices retrofitted to wells. More widespread application of SSSV systems would impose an increase in complexity, both from the addition of devices and components requiring procedures for installation, testing, and maintenance, as well as troubleshooting reliability problems, along with increasing the complexity of well interventions.

Because of this, the Battelle/Sandia team reviewed several sources of information that reflect on human reliability [17, 18]. The Department of Energy (DOE) reference [17] embodies both mechanical component reliability information as well as human reliability information. For example, there is some information showing that error rates can range from 1/1000 to 1/10000 for simple tasks to 1/10 to 1/100 for increasingly complex tasks and complex tasks requiring detailed procedures, completed under stress. The well work environment, dealing with downhole devices and often indirectly sensing numerous signals and indicators, could be said to be moderately to highly complex. If upsets occur while following a plan, the way change is managed, the chances for deviation, miscommunication, and various stresses affecting decision making could tend to increase error rate. The Chemical Safety Board's (CSB) Pryor Trust report [18] provides one illustration of this and draws out a bowtie and event tree to show the many aspects of both technical failures and human and organizational failures that led to severe consequences. Many other well accident reports reveal the same inter-relationship of technical and human/organizational factors.

For purposes of the assessment of SSSV applications, when the team reviewed high-side risk change adjustments – particularly potential increases to risk attending to SSSV implementation – a high-side adjustment to workover loss of well control risk was proposed. A high-side approach emphasizes the importance of human factors, and plays to the management system maturity, or lack thereof, to account for the possibility that many "near-miss" occurrences may not be reported and luck and/or experience, as much as anything else, averts the near miss from developing into an actual LOC. Anecdotally, the team picked up on comments from the March 2020 workshop [11] that near misses and small, short-duration LOCs may not be reported in some corporate dynamics and cultures, may not be reported uniformly throughout the UGS systems, and may not be responded to in any consistent manner with root cause investigations and applications of lessons learned. What this suggests is that human factors cannot be ignored when evaluating risk change relating to the question of introducing technology that will increase complexity and frequency of well intervention.

The Battelle/Sandia team developed an adjustment for human factors using a three-tiered scoring system, based on the relative strength of operator personnel experience and the operator's maturity and effectiveness in a safety management system. The team attempted to describe behaviors with respect to reporting and learning culture – from generally ignoring or only locally handling near misses, to inconsistent and uncertain or uneven handling of near misses, to strong and consistent addresses of near misses with a broadcast learning culture developed from near miss and actual event investigative findings.

The result is a potential adjustment in workover LOC risk of as much as two orders of magnitude (~120x in Table 13 below) for weak systems, one order of magnitude (specifically, 15x as in Table 13) for early-developing, immature or average systems, to nil (no factor, or unity), to an actual potential reduction in risk (0.9x in Table 13) for strong, mature cultures and systems, reflecting that at present, the view is that a strong safety culture addressing events and near misses and seeking to learn from findings could reduce risk by nominally 10%. Perhaps in the future, it could be possible that advanced safety culture within an organization, combined with exceptional operational discipline, results in further risk reduction.

Support for this approach comes anecdotally from many literature reviews, process safety and safety incident triangles. The team found from such reviews and other casual sources of information (including personal conversations with various operators and process safety experts in other industries), that it is reasonable to assume that near miss incidents number 12 to 40x actual incidents, and could be even more in a range of 10 to 70+ times actual incidents.

In summary, for this study, a credit of 15 in Equation 2 was used for human factors to represent the gas storage industry at an early, developing stage of human factor management. Note that this credit is applied directly only to the workover risk estimate, which then feeds into the SSSV evaluation as a deduction from risk reduction benefit of the SSSV system itself.

Table 13: Proposed three-tiered scoring system for human factors.

Expertise and Management Systems	Management System Factor (MSF)	Behaviors	Near Miss Adjustment Factor (NMA)	MSF×NMA
Weak	3	Near misses ignored	40	120
Average	1	Inconsistent/uncertain handling of near misses	15	15
Better	0.3	Near misses addressed	3	0.9

3.11 Methods to Assess SSSV Utility

The Battelle/Sandia model outlined above is intended to be applied for specific UGS well designs and locations to assess their risk level and applicability of a SSSV to lower this risk. To illustrate this, three hypothetical wells were selected from the array of 10 values of LOFI and 12 consequence environments described above. In each case, several relevant model estimates are presented to demonstrate different types of outcomes. The main difference between the three examples is the overall risk level as described by their LOFI and COFI combination. Table 14 presents the assumptions and the model estimates for the three hypothetical wells. Figure 4 is the risk matrix-based diagram demonstrating the effects of a SSSV application in these examples.

Table 14: Model estimates for three hypothetical UGS wells.

Parameter	Example 1	Example 2	Example 3
Type of UGS well	Style 1	Style 3	Style 4
LOFI before SSSV application per year	0.000523 (a high-end estimate for this style well)	0.010505 (a high-end estimate for this style well)	0.461212 (a high-end estimate for this style well)
Consequence environment	Low rate well, moderate feed volume, moderate population density, even distribution	Very high rate well, high feed volume, Low population density, even distribution	Very high rate well, high feed volume, Low population density, even distribution
COFI without SSSV ($ per event)	$47,267,387	$143,642,850	$143,642,850
Annualized risk ($/yr)	$24,721/yr (low risk well)	$1,508,968/yr (moderate risk well)	$66,249,806/yr (very high risk well)
SSSV used	Shallow-set SSSV with high reliability of 0.985		
COFI with SSSV ($ per event)	$21,167,561	$72,820,691	$72,820,691
Reduction of annualized risk ($/yr)	-$2,462/yr (risk increase!)	$723,420/yr	$32,643,463/yr
Remaining annualized risk ($/yr)	$27,183/yr	$785,548/yr	$33,606,344/yr
Annualized risks due to workovers ($/yr)	$16,112/yr	$20,567/yr	$20,567/yr
Comments	Application of an SSSV in this type of well increases annualized risks – SSSV is not warranted	Application of an SSSV in this type of well decreases annualized risks by 48% – SSSV is warranted	Application of an SSSV in this type of well decreases annualized risks by 49%; however, the remaining LOFI is very high

A case of a low-level risk well is presented in example 1. The well is the most modern well, Style 1, with a minimum high-side estimate value of LOFI=0.000523 failures per well-year. The consequence environment includes low well rate, moderate feed volume, and moderate population density with even distribution. The model predicts COFI=$47,267,387 for this well. The product of LOFI and COFI, an annualized risk, is only $24,721/yr. The application of a SSSV in this well would lower the COFI to approximately $21,167,561, a 55% reduction. However, this benefit is more than erased once the workover risks are taken into account. The actual annualized risk increases by $2,462/yr. The use of a SSSV for this well is not warranted. Figure 4 shows the change of risk caused by the application of an SSSV in this well. The change can be represented by two effects, effectively two vectors, on the risk matrix. The initial COFI-LOFI position, prior to the SSSV application, is represented by the top blue point. The reduction of COFI (from $47,267,387 to $21,167,561 per event) is shown as a downward blue vector. This vector is vertical since an SSSV is a mitigation device, which has no effect of an

LOFI. The effect of workover is represented as a second blue vector, which is oriented diagonally, in the direction of increasing annualized risk. A length of this vector is approximately $16,112/yr – the estimated annual risk of workovers. The net sum of both effects is a slight (2.462/yr) increase of annualized risk. A comparison between Figures 2 and 4 indicates that the example 1 well was already in the acceptable risk part of the risk matrix and there is no need to lower risks for this well. The model analysis shows that the addition of a SSSV in this type of low risk UGS well is disadvantageous.

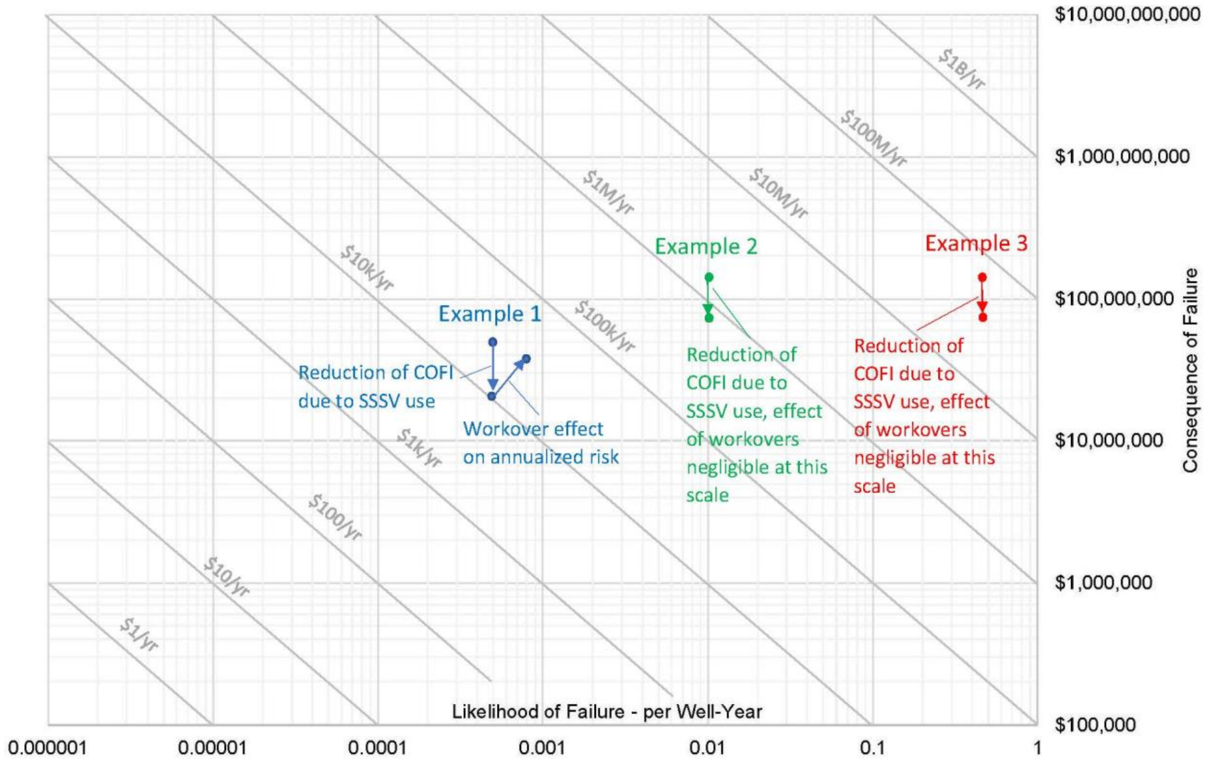

Figure 4: Schematic of the three examples from Table 14 shown on a risk matrix.

A case of a moderate risk well is represented in example 2. The well is a Style 3 well with an estimated LOFI=0.010505. This well has a very high rate and high feed volume, but is in an area with evenly distributed low population density. Estimated COFI for this well is approximately $143,642,850, resulting in an annualized COFI of $1,508,968/yr. The model predicts that the addition of a SSSV would lower the COFI to approximately $72,820,691 per event and the annualized COFI to approximately $785,548/yr, a 48% reduction for both quantities. The annualized risk due to workovers is $20,567/yr, which is relatively small in comparison with the annualized risk reduction or the annualized remaining risk. The effects of a SSSV are shown graphically on Figure 4, and due to its relatively small scale, the workover effect is negligible in comparison to the main COFI reduction effect. The application of a SSSV in this type of moderate risk UGS well is cost-beneficial as one mitigation to reduce risk.

A case of a high risk well is represented in example 3. This well has the same consequence environment as example 2 and the estimated COFI is $143,642,850 per event. However, this is a style 4 well, with a very large LOFI=0.461212. Such a large value of LOFI puts this well in the “mitigation required” part of Figure 2. The annualized risk is $66,249,806/yr, indicating that the drivers of risk in this well must be investigated and appropriately mitigated. The model predicts that the addition of an SSSV would lower the COFI to approximately $72,820,691 per event and the annualized COFI to approximately $32,643,463/yr, a 49% reduction for both values. Although this reduction is substantial, both in relative and absolute terms, the remaining risk is high and still driven by the obviously high LOFI. A graphical representation of this well is shown in Figure 4. The relatively modest annualized risks of workovers, estimated at $20,567/yr, are negligible in comparison with the risk reduction or remaining risk values. Example 3 is the case where an SSSV brings large risk reduction, but the drivers of likelihood of failure are not addressed and thus the remaining risks are high. Some other forms of risk mitigation, those driving down the likelihood of failure, are prudent for this well. If such options are not achievable, the risk might be best handled by elimination; in other words, the well could be properly plugged and abandoned. Appendix 5 lists additional ways to mitigate risks.

Examples 1 through 3 schematically illustrate the three classes of outcomes of simulations from the risk model developed by the Battelle/Sandia team. As will be demonstrated in the following sections of this report, these three types of classes can be generalized to the entire group of UGS wells analyzed. The existence of these classes signifies that SSSVs could have risk management cost-benefit efficacy in some but not all UGS wells.

A more comprehensive approach to evaluate SSSV applicability in UGS wells was carried out using the full set of hypothetical wells generated using 10 values of LOFI and 12 consequence environments described previously. For each well, the Battelle/Sandia team used two methods to present results of the risk model and to evaluate utility of SSSVs application:

1) net risk reduction due to various types of SSSV installation and
2) remaining, or residual, risk after installation of SSSV

The net risk reduction due to SSSV installation was calculated as:

$$Risk\ Reduction_{SSSV} = LOFI \times (COFI_{No\ SSSV} - COFI_{SSSV}) - LOFI_{Workover} \times COFI_{Workover} \quad (5)$$

where:

$Risk\ Reduction_{SSSV}$ is the annualized reduction of risk due to addition of SSSV ($/year)

$LOFI$ is the likelihood of failure index, the same value with and without SSSV, calculated using Equation 1 (event/year)

$COFI_{No\ SSSV}$ is the consequence of failure index before SSSV addition calculated using (Equation 3) ($/event)

$COFI_{SSSV}$ is the consequence of failure index after SSSV addition calculated using Equation 4 with credits from Table 1 ($/event)

$LOFI_{Workover}$ is the likelihood of failure index for workover operations calculated using Equation 2 and values from Table 5 (event/year)

$COFI_{Workover}$ is the consequence of failure index for workover operations calculated using Equation 1 and credits from Table 8 ($/event)

The residual risk remaining after SSSV installation:

$$Remaining\ Risk_{SSSV} = LOFI \times COFI_{SSSV} + LOFI_{Workover} \times COFI_{Workover} \quad \text{(eq.6)}$$

where:

$Remaining\ Risk_{SSSV}$ is the annualized remaining risk after SSSV addition ($/year)

Figure 5 is an example of model-estimated annualized risk reduction for UGS wells after the application of a shallow-set SSSV with a very high reliability of 0.985. Note that the bubble sizes are shown on a logarithmic scale, similarly as the values of LOFI and COFI. The bubble locations on the plot represent values of LOFI and COFI, obtained from Equations 1 and 3 before the addition of an SSSV. Values of risk reduction obtained from Equation 5 are represented as bubbles of different sizes. Figure 6 is the legend applicable to Figure 5 as well as to all bubble plots in this report.

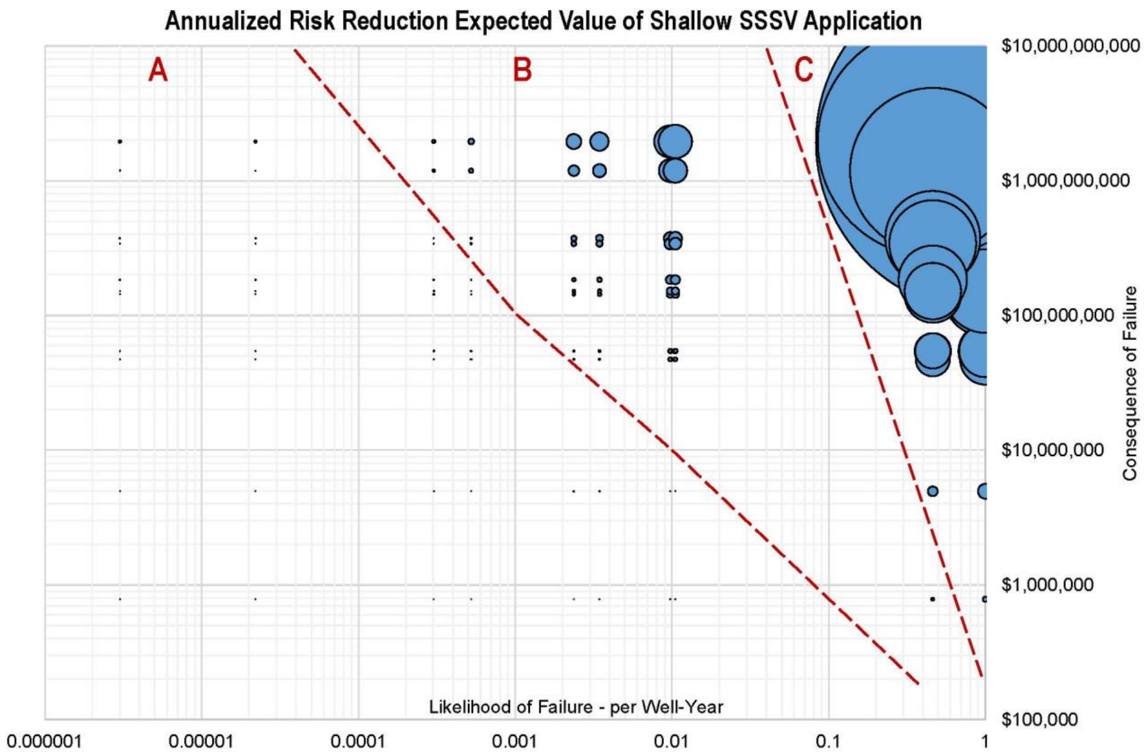

Figure 5: Annualized risk reduction due to shallow SSSV.

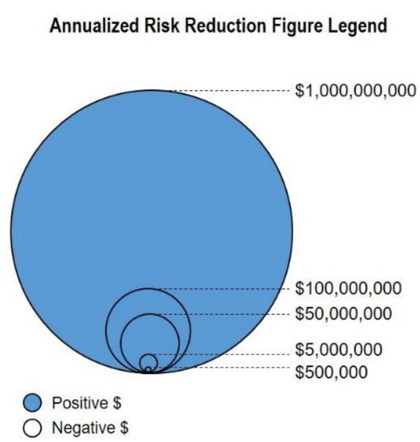

Figure 6: Legend applicable to all bubble plots in this report.

The main effect observed in Figure 5 is that the wells with higher initial risks have a larger risk reduction value; however, it does not mean that SSSVs bring significant benefits for all wells.

Specifically, the wells characterized by initial LOFI and COFI combinations located to the left of the left dashed line, part of the plot marked as “A”, have a risk reduction less than \$10,000 - \$40,000 per year, or, in some cases, the risk reduction is negative (risk increases). Note that the bubble size reduces significantly as the well LOFI decreases: this shows that low risk means low need for mitigation, and the cost-benefit of the mitigation likewise becomes vanishingly small as the inherent or initial risk decreases. Similarly, high risk situations benefit from many types of mitigation and any particular type can appear to have great cost-benefit; however, the choice of mitigations must align to the management of the most significant risk drivers. In other words, for wells with high LOFI and significant consequence potential, the high LOFI must be addressed, even if COFI mitigations are applied.

The second indicator of SSSV applicability, remaining or residual risk after mitigation treatment defined by Equation 6, calculated for the same set of cases, is shown in Figure 7. At first sight, Figures 5 and 7 appear remarkably similar with only minor differences in bubble sizes. As noted previously, this is due to the nature of the mitigation provided by an SSSV that reduces only consequences caused by surface releases and leaves the subsurface-based consequences unmitigated. In the case of surface-set SSSVs with high reliability, approximately half of the annualized risk is mitigated.

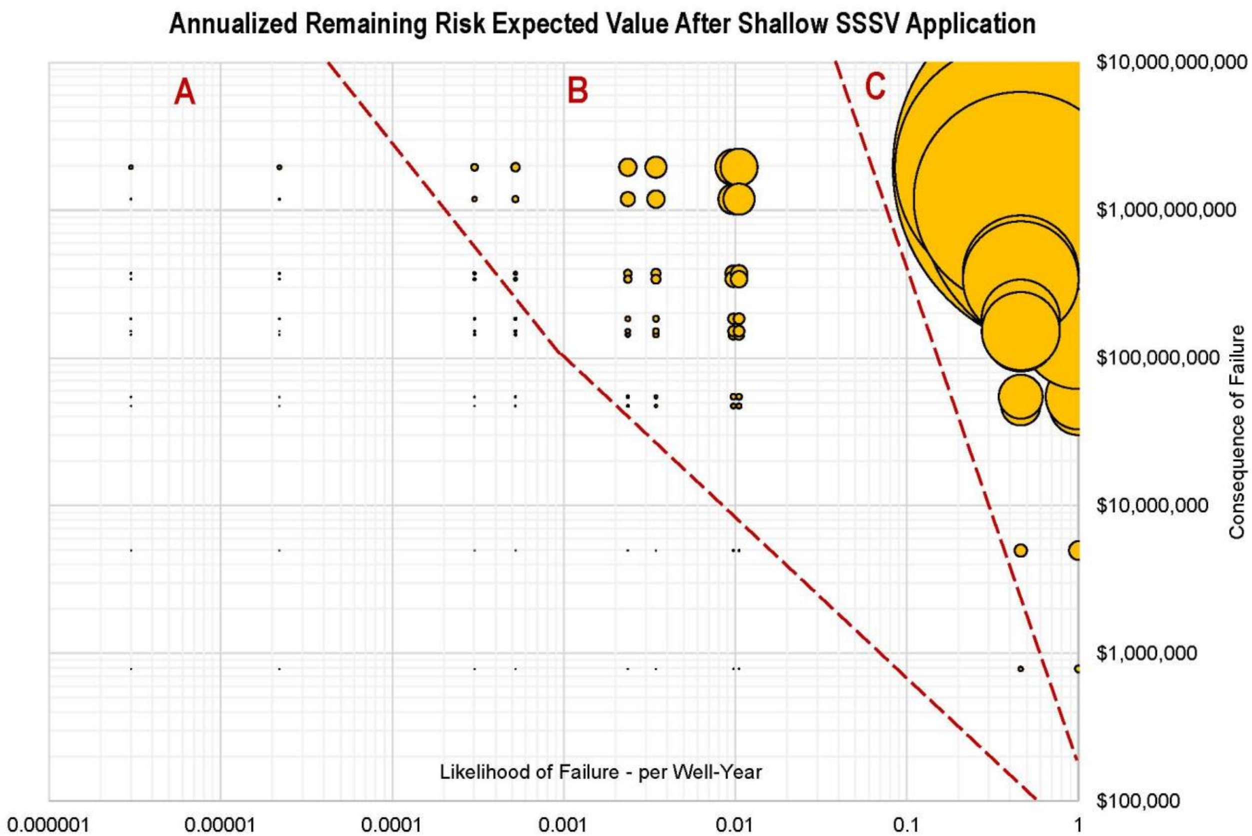

Figure 7: Annualized remaining risk after addition of shallow SSSV with all workover risk not including the assessment of human factors.

The key point of Figure 7 is that the remaining annualized risks can be substantial for the high-risk wells. In such cases, the application of an SSSV may need to be combined with another approach to lower the risk more immediately and permanently from the perspective of LOFI.

Note that cases of this type are marked as zone "C" and are characterized predominantly by high LOFI, generally around 0.1 failures per well-year or greater and, simultaneously, by substantial COFI, generally above $10,000,000. In risk analysis, a high failure potential, which is itself uncertain, should be treated as an imminent failure potential. The application of SSSVs in wells with such high failure potential would not provide sufficient mitigation, necessitating use of other approaches.

The general outcome emerging from Figures 5 and 7, as well as the examples listed in Table 14, are the three zones of SSSV applicability, outlined in Table 15. Since the zones represent very different recommendations for SSSV use, it is evident that the application of SSSVs can reduce risk for some but not all UGS wells. A reliable way to assess SSSV applicability is to apply a quantitative risk model that accounts for these factors and evaluates risk before and after SSSV installation.

Table 15. The three zones categorizing applicability of SSSV installation in UGS wells.

Zone	Criteria identifying this zone	Interpretation	SSSV applicable?	Example
A	The annualized risk reduction, estimated by the risk model, less than $10,000 -$40,000 per year, or even negative	Addition of SSSV increases risk or risk reduction in negligible	No	Example 1 in Table 14
B	Intermediate LOFI and COFI values	Addition of SSSV reduces risk in meaningful or significant ways	Yes, but compare to other possible risk treatments	Example 2 in Table 14
C	Very high LOFI approaching or exceeding 0.1 per year combined with COFI exceeding ~$10,000,000	Addition of SSSV reduces risk by substantial amounts, but substantial LOFI also remains	Yes, but remaining risk might be too high to tolerate and more immediate risk treatment might be necessary, particularly for reducing LOFI	Example 3 in Table 14

The modeling procedure described above was applied to four types of SSSV installations that are used in UGS wells:

- Shallow-set SSSV
- Deep-set SSSV
- Shallow-set combination of tubing safety valve and annulus safety valve (TSV + ASV) in wells that used tubing as a velocity string (no packer)
- Deep-set combination of TSV + ASV

These installation cases were modeled with and without two additional factors:

- Deliverability impairments introduced by SSSVs
- Human factors influence during workovers

The results indicated that the differences between the SSSV and TSV + ASV configurations, and between shallow-set and deep-set valve locations are relatively minor. These effects do not change the main conclusion of this work, that SSSVs are applicable to some but not all UGS wells. Since details of the results for different SSSV installations, delivery impairment, and human factors are not critical for the main message of this report, results of these simulations are presented in Appendix 1, where they can be accessed by readers interested in the details of this work. One important outcome of this study, discussed in Appendix 1, is the effect of deliverability impairment and human factors. Both factors have significant effect on applicability of SSSVs in UGS wells and must be included in the risk assessment evaluation.

4. Delivery Impairment

4.1 Introduction

This section summarizes a Sandia modeling study exploring the effects of hypothetical tubing and packer installations on available flowrates from representative natural gas storage configurations. Tubing and packer installations have the potential to provide an extra layer of protection against product loss in natural gas wells that connect a storage reservoir with surface piping, though their addition will reduce the effective internal diameter and, in turn, could reduce fluid flowrate for given pressure boundary conditions. A simple schematic of tubing and packers installed in a gas storage well is given in Figure 8 for illustration. The original cemented production casing is shown connecting the gas storage reservoir to the surface, with an inner diameter and resulting cross-sectional flow area that is determined principally by the production casing size at the time of installation. The tubing and packer may be added at a later time, and involves setting a packer deep in the original casing that stabilizes the end of the tubing and hydraulically isolates the resulting static annulus from reservoir pressure. This double-barrier configuration is more robust against casing leaks than a single barrier, and with pressure monitoring of the static annulus, can provide immediate notice of loss of primary containment from the tubing. A caveat of this configuration, however, is that the cross-sectional area available in the well to transport gas into or out of the reservoir is reduced relative to the original production casing, which was likely sized according to design calculations intended to optimize reservoir performance and economic considerations. The magnitude of flow reduction that may be realized is also affected by the deliverability of the reservoir into the given well. This study quantifies the magnitude of flowrate reductions associated with selected tubing configurations relative to base cases by applying basic numerical models for gas flow in pipes and reservoir deliverability. A more detailed report by Sandia on this study [19] will be made available on the DOE Office of Scientific and Technical Information public website (OSTI.gov) pending PHMSA/Battelle approval.

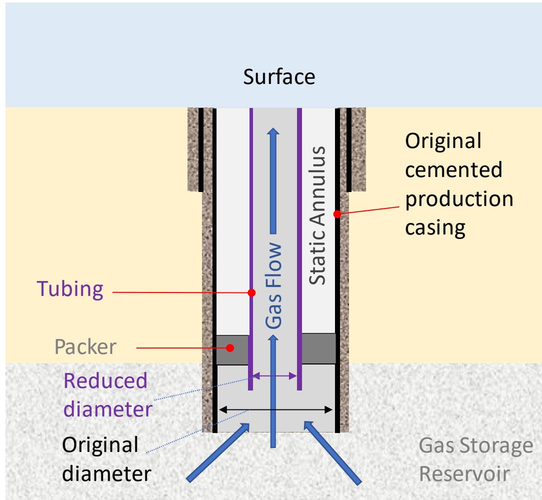

Figure 8: Schematic of tubing and packer configuration in a gas storage well indicating gas flow out of the reservoir during a drawdown.

4.1.1 Background

The impact of adding tubing and reducing cross-sectional area on natural gas flowrate in pipe is relatively straightforward, estimated by basic pipe flow equations. Generally speaking, the flowrate is proportional to the pipe inner diameter raised to the ~5/2 power. As such, a decrease in pipe inner diameter will decrease flowrate for given pressure boundary conditions. Implications for operators are less straightforward than this simple pipe flow equation, however. The properties of the storage reservoir and the well completion will affect this overall flow regime, and a coupled analysis accounting for both reservoir and well features must be included.

Industry concerns with the implications of tubing and packers have been documented in several publicly available reports [20-22]. One operator indicated that installing liners would result in a 40% reduction in deliverability with their current wells [22]. Another operator indicated that well flow on a peak day may be reduced by > 60% in some wells [21]. Part of the purpose of the current work is to conduct an independent analysis to see if these types of numbers can be reasonably expected in U.S. storage fields with the addition of tubing and packers.

4.2 Modeling Approach

4.2.1 Modeling Domain

The modeling domain includes a vertical (non-deviated) pipe that originates at reservoir depth z_1 and ends at the ground surface z_2 as shown in Figure 9. The well has a specified inner diameter *d,* absolute roughness *e,* and a length *L* equal to the elevation difference between z_2 and z_1. The wellhead flowing pressure, P_{WHF}, and bottomhole flowing pressure, P_{BHF}, are related through vertical gas well flow equations. The bottom of the well is coupled through a completion interval with a reservoir that exhibits a shut-in pressure P_{RSI}. P_{BHF} and P_{RSI} are related through a simple well deliverability equation with empirical constant *C* and exponent *n*. Only dry gas flow is simulated, with no condensation, particulates, or free liquids of any phase.

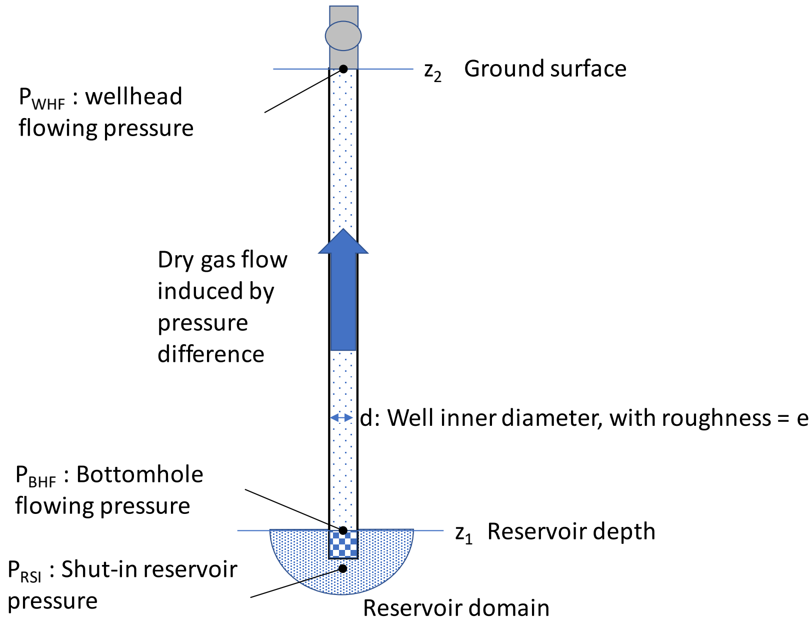

Figure 9: Conceptual sketch of modeling domain.

4.2.2 Flow Equations

4.2.2.1 Vertical Gas Well Equations

Through literature research and confirmation with industry experts, several basic equations were selected for use and comparison here. All derive from the fundamental principle of conservation of energy as expressed in the Bernoulli equation. These include the Darcy equation for pressure loss in a vertical pipe [23], the Weymouth equation for vertical gas well flow [24], and the Cullender Smith solution of a general equation for gas flow in wells and pipelines with large temperature gradients [25]. The Weymouth Equation is given here as an example in Equations 7 and 8, arranged to solve for volumetric flowrate *q* (SCF/day) across a tubing section [24]. "H_e" is a pressure correction to the horizontal pipe flow model to account for hydrostatic head resulting from elevation difference. Close inspection of Equation 7 shows the primary relationships between flowrate *q* and the controlling variables that this study is exploring, including tubing/well inner diameter (*d*), difference in driving pressures (P_1^2, P_2^2), and length of tubing/well (*L*). Equation 7 shows that flowrate *q* decreases with smaller well inner diameter, smaller driving pressure difference, and greater well or tubing length.

Weymouth Equation:

$$q = 433.5 \times E_{eff} d^{2.667} \left(\frac{T_{sc}}{P_{sc}}\right) \left\{\frac{5280 \times [P_1^2 - exp(H_e)P_2^2]}{GZTL}\right\}^{0.5} \qquad (7)$$

$$H_e = 0.375 \times G \left(\frac{z_1 - z_2}{TZ}\right) \qquad (8)$$

where:

- E_{eff} = efficiency (tuning) factor for the tubing section, dimensionless
- *d* = inner diameter of the tubing, in

- T_{sc} = standard temperature, °R
- P_{sc} = standard pressure, psia
- P_1 = pressure at point 1 in the tubing, psia
- P_2 = pressure at point 2 in the tubing, psia
- G = specific gravity of gas (=$\frac{MW_g}{MW_{air}}$), dimensionless
- Z = compressibility factor, dimensionless
- T = average temperature of the tubing section, °R
- L = length of the tubing section along its axis, ft
- z_1 = elevation at point 1 along the section of tubing, ft
- z_2 = elevation at point 2 along the section of tubing, ft
- MW_g= molecular weight of the natural gas, lb/lb-mole
- MW_{air} = molecular weight of air, 28.97 lb/lb-mole

4.2.2.2 Well and Reservoir Deliverability Equations

A simple well deliverability model was developed from a commonly-used formula in UGS facility design [26] as expressed in Equation 9:

$$Q_i = C_i[P_{RSI}^2 - P_{BHF}^2]^{n_i} \tag{9}$$

where:

- Q_i= gas flowrate for well *i*, MMSCFD
- C_i = Deliverability constant for well *i*
- P_{RSI} = Reservoir shut-in pressure, psia
- P_{BHF} = Bottom hole flowing pressure, psia
- n_i = deliverability exponent for well *i*
- *i* = subscript denoting an individual well number

Deliverability for an entire field comprising “N” wells may then be evaluated by taking the sum of the individual wells as shown in Equation 10:

$$Q_{field} = \sum_{i=1}^{N} Q_i \tag{10}$$

where:

- Q_{field}= gas flowrate for a given field with N wells, MMSCFD
- Q_i= gas flowrate for well *i*, MMSCFD
- *i* = subscript denoting an individual well number
- *N* = number of wells in a given field

Note this approach does not account for the features of the gathering system downstream of the wellhead(s) at an operator’s facility. As such, field-level deliverability here is defined at the wellhead(s), not at the outlet of the facility.

4.2.2.3 Gas Mixture Properties

The gas simulated in this study comprised a simple mixture with a majority of methane (CH_4) and an assortment of minority components. A representative gas mixture formulation was chosen for use here, with mole% as shown in Table 16.

Table 16. Representative natural gas component mixture used in this study.

Component name	Formula	Mole fraction
Nitrogen	N_2	0.010
Oxygen	O_2	0.000
Carbon Dioxide	CO_2	0.005
Water	H_2O	0.000
Methane	CH_4	0.905
Ethane	C_2H_6	0.050
Propane	C_3H_8	0.030

Representative gas mixture properties such as *MW*, *G*, critical pressure (P_c), and critical temperature, (T_c), were calculated using basic mole-weighted mixing rules as described in Guo and Ghalambor [27]. Table 17 lists the critical properties for each of the relevant gas mixture components from Frick and Taylor [28] as well as the mole-weighted mixture value (bottom row) calculated for further use in this analysis.

Table 17: Component critical properties and MW for natural gas components from Frick and Taylor [28]. Bottom row represents mixture value computed from simple mole-weighted mixing rule.

Component	Tc	Tc	Pc	MW
	[F]	[deg R]	[psia]	[lb/lb-mole]
Nitrogen	-232.8	227.2	492.4	28.02
Oxygen	-181.8	278.2	732	32.00
Carbon Dioxide	88	548	1071.6	44.01
Water	705.4	1165.4	3206	18.02
Methane	-117	343	673.3	16.04
Ethane	90	550	708	30.07
Propane	206.1	666.1	617.4	44.09
Mixture		362.9	673.5	17.84

Gas specific gravity (*G*) for the given mixture was calculated as shown in Equation 11, where the molecular weight of air was taken as 28.97 lb/lb-mole [27]:

$$G = \frac{MW_g}{MW_{air}} = \frac{17.84}{28.97} = 0.6159 \tag{11}$$

4.2.3 Numerical Models

4.2.3.1 Vertical Pipe Flow Models

Sandia coded Darcy, Weymouth, and Cullender-Smith equations for vertical pipe flow into Excel workbooks. Where necessary, Visual Basic for Applications (VBA) coding was used to enable iterative solutions for implicit equations. Sandia also utilized a commercial oil and gas process simulator model (PSM) to run comparison calculations on selected configurations for dry gas flow in vertical pipes. The purpose of these commercial model runs was to enable verification that the Sandia models were calculating output (gas flowrates, pressure drops, gas flow velocities, gas density, Z-factor) for vertical pipe flow scenarios that were mathematically correct and matched well with an established commercial simulator. The decision to use Sandia-developed models as opposed to the commercial model for the large matrix of runs ultimately executed in this study was based on two factors: (i) the commercial simulator did not have a pre-defined reservoir deliverability function, and (ii) setting up flexible, user-defined input and output was important for this work and easier for Sandia to implement using in-house codes rather than developing pre- and post-processors for the commercial PSM.

4.2.3.2 Combined Pipe and Well Flow Model

A combined pipe and well flow model was programmed into an Excel workbook that coupled the simple well deliverability model expressed in Equation 9 with the Cullender-Smith vertical pipe flow model. The model was configured to simulate a field of 20 wells with a range of individual well deliverability modeled after sample fields.

4.3 Model Verification and Validation

Model verification was performed to assure that the numerical models developed here solved the basic mathematical problems correctly. Model validation was performed to assess how well the numerical models simulated real-world systems.

4.3.1 Vertical Pipe Flow Model Verification

Several comparative modeling cases were run for the purpose of verifying performance of the Sandia in-house vertical pipe flow numerical models using Darcy, Weymouth, and Cullender-Smith equations against the commercial PSM. The base case was defined from the largest inner diameter simulated (8 inches), and subsequent cases were run with incrementally smaller inner diameter, expressed as fractions of the base case inner diameter. Model verification results are summarized in Figure 10 in terms of volumetric flowrate relative to the base case for a 2,000 ft long vertical pipe exposed to a 100 psi pressure difference carrying a natural gas mixture with specific gravity G = 0.62. The figure shows that all of the numerical models have nearly the same level of relative reduction in volumetric flowrate with tubing inner diameter and could potentially all be used moving forward, expecting nearly indistinguishable results as a function of model choice. The process was repeated for a 6,000 ft long vertical pipe with 500 psi pressure difference and the results were similar.

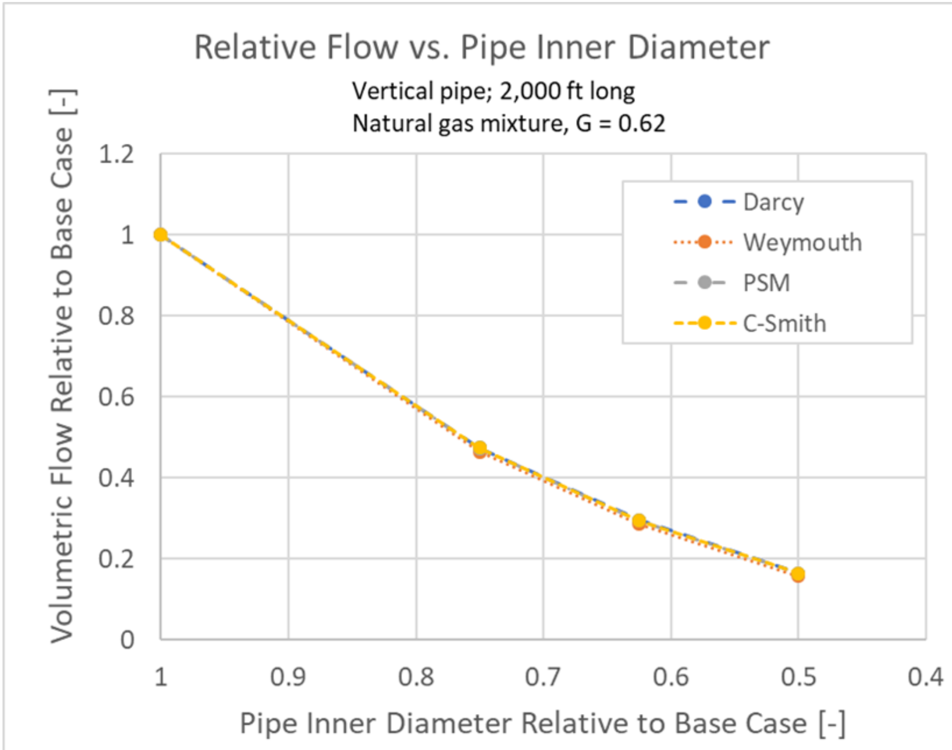

Figure 10: Vertical pipe flow model verification results, volumetric flowrate with pipe inner diameter.

4.3.2 Combined Pipe and Well Flow Validation

The combined pipe and well flow numerical model was run with field data (made available to Sandia) to validate the model's ability to predict flowrates and pressure drops against actual field results. This step is important to building confidence in the numerical model's ability to predict real system behavior due to operational changes such as reducing tubing diameter or changing wellhead or reservoir pressures. A comparison of the field data and model output is shown in Figure 11. Field data are shown in open symbols connected by dashed lines, while model results are shown in solid symbols connected by solid lines. The model-calculated volumetric gas flowrates compare to within 10% of the field data values for 10 of the 13 points compared, and within 10 to 30% for the other three points compared. The authors judge this as sufficient performance to meet the objectives of the work, which is to evaluate the effects of reduced tubing diameter on volumetric flowrate. The well depths, flowrates, and internal diameters in this example are consistent with the parameter range explored in this study. Additional model verification and validation details are given in Lord and Allen [19].

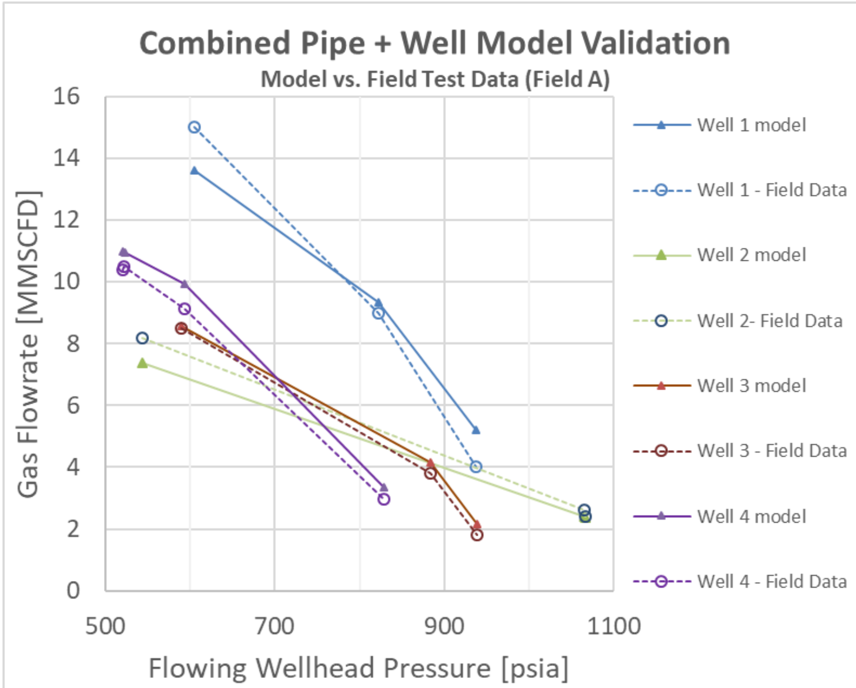

Figure 11: Model overlay with field data for four wells to validate combined pipe + well model performance.

4.4 Simulation Cases

Simulation cases here represent potential outcomes, in the form of deliverability reductions within a field, that result from reductions in tubing diameters. A field comprises a single UGS reservoir containing numerous wells under control of a single operator. The wells connect a reservoir to the surface piping, and deliverability of the field is ultimately determined by taking the sum of deliverability over all of the wells in the field as expressed in Equation 10. Reductions in tubing size will occur at the well level, so the realization of the change in tubing diameters appears in the well equations, creating a tubing effect on deliverability. In addition to the tubing effect, each well in a field can exhibit its own unique deliverability as controlled by the local porosity, permeability, formation thickness, and interface properties where the bottom of the well makes direct contact with the reservoir through the completion interval, quantified by parameters "C" and "n" from Equation 9.

4.4.1 Deliverability within a Field

Deliverability differences among wells within a field are possible in spite of sharing relatively uniform boundary conditions like reservoir shut-in pressure, wellhead flowing pressure, and well dimensions including depth and casing inner diameter. Examples of the well deliverability distributions in real depleted reservoir storage fields in the U.S. are shown in Figure 12 and Figure 13. Each figure shows the relationship between flowrate [MMSCFD] and well count, sorted in descending order, for a given difference in pressure squared. The field in Figure 12, identified as Field "C", has a few much higher than average-producing wells, with the remaining wells falling along a linear distribution much closer to the average 0.5 MMSCFD. This is referred to herein as a "hockey stick" distribution because its shape resembles a hockey stick. The field in Figure 13, identified as Field "G", has a linear distribution and lacks the high outliers exhibited by Field "C". The implications of these different distributions will come clearer as the analysis results are presented. Low-deliverability wells tend to be limted by local reservoir/well interface characteristics, and will tend to show less sensitivity to changes in tubing diameter. High-deliverability wells tend to be limited by tubing size, and can show more marked sensitivity to any new flow restrictions such as reduced tubing size.

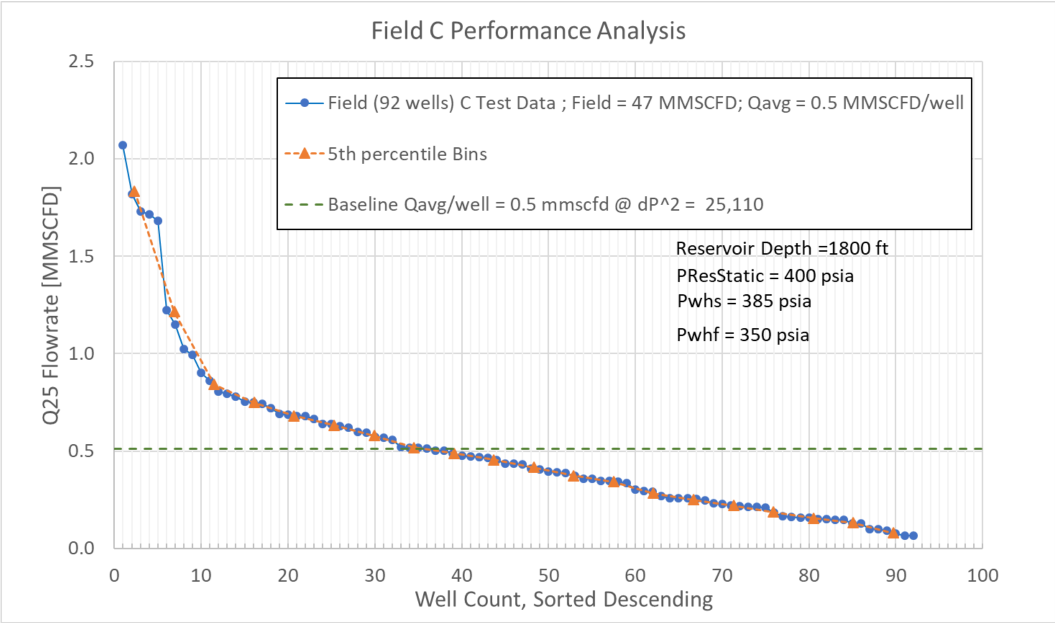

Figure 12: Deliverability distribution for field "C" comprising 92 wells based on field data, regrouped into 5th percentile bins, and scaled by the authors to yield a $Q_{avg/well}$ = 0.5 MMSCFD.

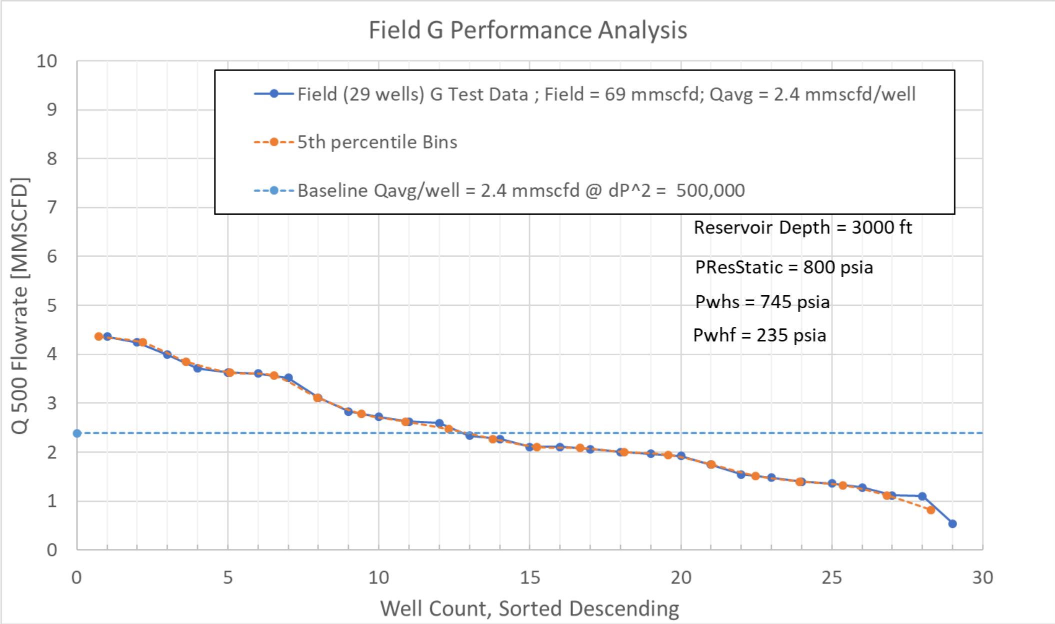

Figure 13: Deliverability distribution for field "G" comprising 29 wells based on field data, regrouped into 5th percentile bins, and scaled by the authors to yield a $Q_{avg/well}$ = 2.4 MMSCFD.

4.4.2 Fields, Wells, and Working Gas Capacities across the U.S.

The 2016-2017 Survey of Underground Storage of Natural Gas in the United States and Canada [29], published by the AGA, was used as background for this analysis. According to the AGA data, as of 2017, there were 359 aquifer and depleted reservoir storage fields in the U.S. comprising 13,909 wells and 4.13×10^6 MMSCF (4.13 TCF) of working gas capacity. The data were subdivided into average deliverability bins, denoted as $Q_{avg/well}$, computed by taking the stated working gas capacity for each field and dividing it by the number of wells in that field and then by 90 (days) for an estimate of average MMSCFD/well for a given field that would be required to deliver the working gas capacity of that field to a customer over a 90-day period, which is a typical duration of a peak demand contract for a facility operator. A graphical representation of these data is given in Figure 14, where the horizontal axis represents $Q_{avg/well}$ bins from 0.5 up to the maximum of 46.5 MMSCFD.

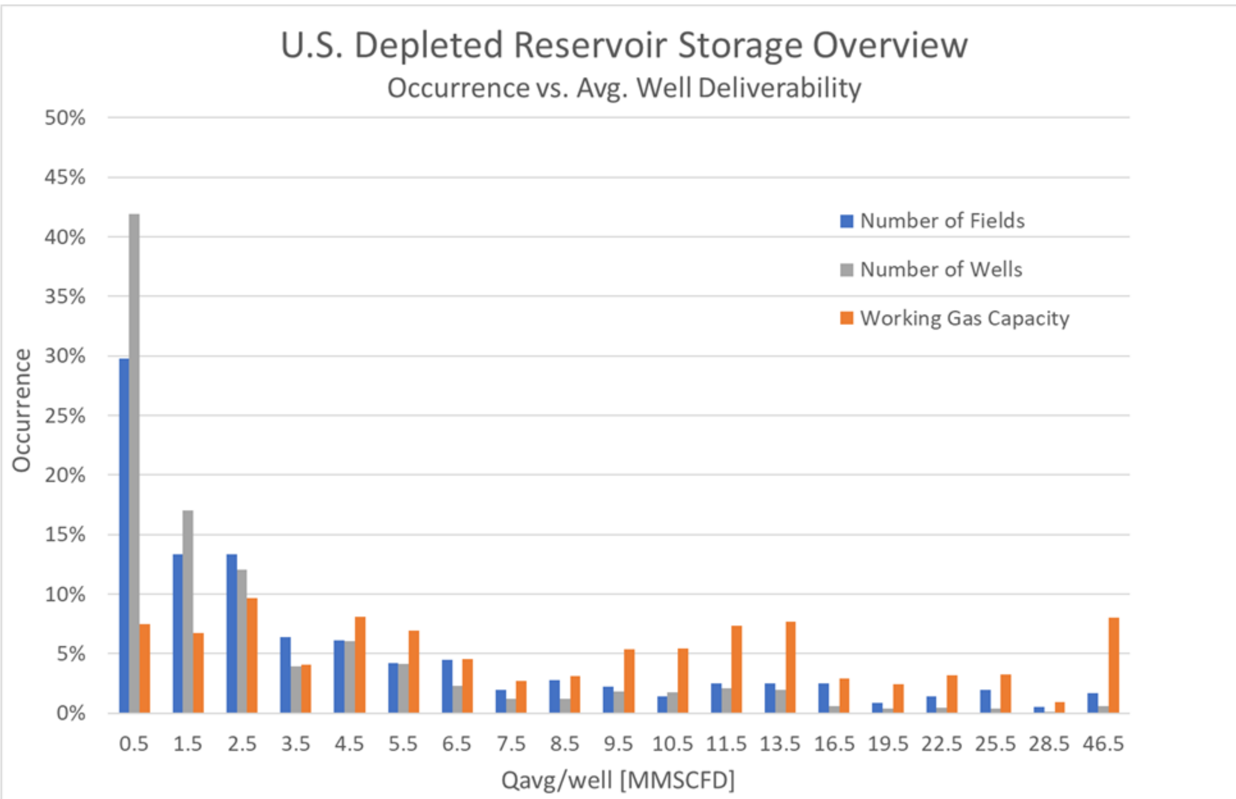

Figure 14: Overview of U.S. Depleted Reservoir Storage showing relative occurrence of number of fields, number of wells, and working gas capacity versus average deliverability per well for all reported fields in 2016-2017. Data from [29].

4.4.3 Simulation Cases

The scope of this study is to simulate possible outcomes for tubing reductions over most of the expected pressure, depth, and deliverability ranges observed in U.S. gas reservoir storage. There may be outlier cases, but this work is intended to give insight for the effects on most wells in most fields for most operators. As such, simulation cases were developed around the occurrence data defined from the AGA report and illustrated in Figure 14. Two fields, with deliverability distributions modeled after field “C” with a distribution shaped like a hockey stick, and field “G” with a nearly linear distribution, were simulated through a selected range of average deliverability bins, as illustrated in Figure 15. For a given deliverability bin, the average reservoir depth was determined from representative values out of the AGA data that corresponded to those bins. Maximum reservoir pressure, P_{max}, was determined from a linear correlation between depth and maximum pressure derived from the AGA data. Next, the reservoir shut-in pressure, P_{RSI}, that forms the boundary condition for the flow models, was determined as $P_{RSI} = P_{max} \times 0.53$, where 0.53 represents a conversion factor from the maximum reservoir pressure P_{max} to the more operationally relevant reservoir shut-in pressure P_{RSI} that would be observed when up to 80% of the working gas has been removed. The static wellhead pressure, P_{WHS}, another boundary condition for the flow models, was calculated by hydrostatic head difference from reservoir depth to wellhead depth. More details on these calculations and assumptions are given in Lord and Allen [19].

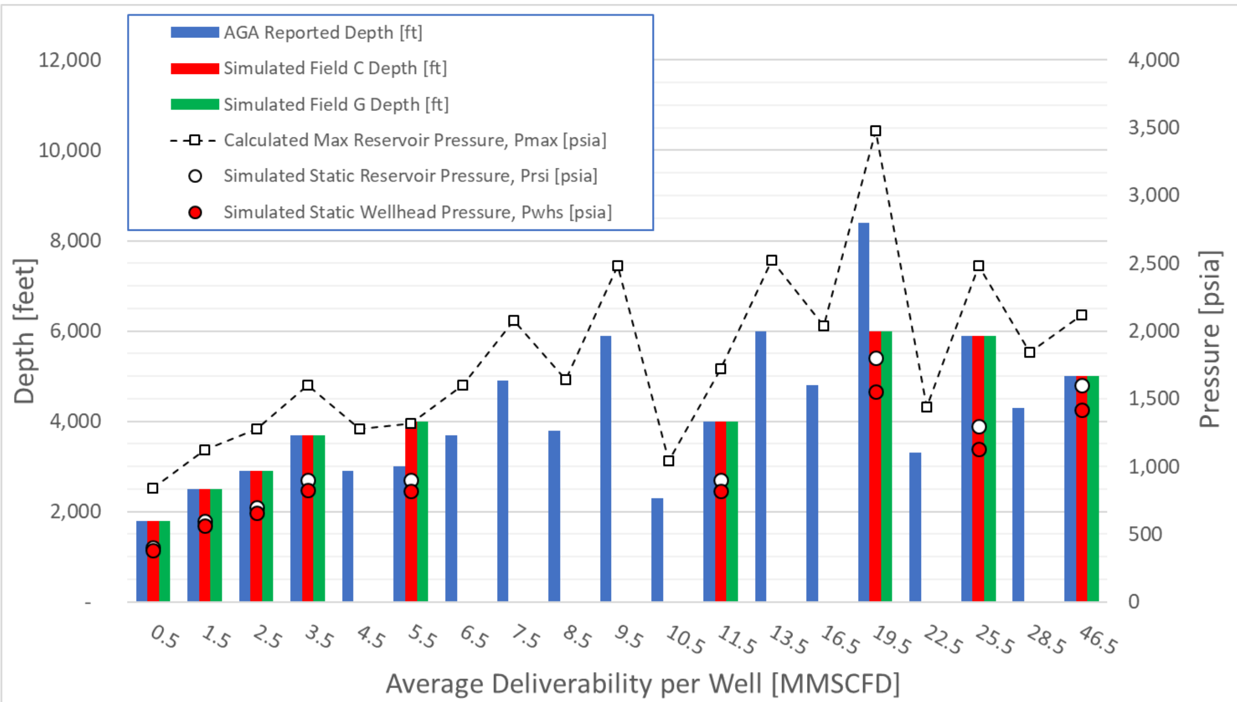

Figure 15: Overview of simulation cases (red and green columns) run in association with the AGA data (blue columns) on average deliverability per well in U.S. gas storage fields.

4.4.4 Run Matrices

The run matrices for this modeling study are given in Table 18 through Table 21. Taking Table 18 as a starting point, for a given field of wells, Field C (hockey stick distribution) in this case, the combined well and pipe flow model was run for a selected $Q_{avg/well}$ three times: once for the baseline well inner diameter (Base ID), and then two more times for liner sizes (Liner 1 ID, Liner 2 ID) that would potentially fit inside the baseline well. Liner sizes correspond to those listed in a readily-available commercial catalog [30]. While the largest liner that would fit into an existing production casing would be the logical choice for an operator, for a number of reasons a smaller diameter tubing might be applied. As such, there may be a practical need in the field to use a smaller liner size than anticipated simply by nominal diameter of the production casing. Additional model runs at a second liner size also provide a clearer picture of the relationships between well diameter and deliverability for relatively low effort once the model is running. Seven $Q_{avg/well}$ bins, from 0.5 through 19.5 MMSCFD, were modeled in this manner. For Field C, the maximum $Q_{avg/well}$ bin at Base ID = 4.95 inch that would be plausible given the likely operational conditions (Depth, P_{RSI}, P_{WHF}) was $Q_{avg/well}$ = 19.5 MMSCFD. From there, a larger baseline production casing size of Base ID = 6.276 inch was required to support the max flowrate in the highest deliverability wells. As such, another series of four $Q_{avg/well}$ bins was run with the larger Base ID of 6.276 inch, represented by the bottom four rows in Table 18. A similar process was followed using Field G (linear distribution), as summarized in Table 19.

An additional series was constructed to explore the effects of reservoir/well depth on well deliverability for a few selected configurations as summarized in Table 20. For the 5.5-inch outer diameter (OD) (4.95-inch ID) base case, two $Q_{avg/well}$ bins were simulated, namely 0.5 and 3.5 MMSCFD. For the 7-inch OD base case (6.276-inch ID), $Q_{avg/well}$ bins of 25.5 and 46.5 MMSCFD were simulated.

A final series was run to simulate effects of reservoir shut-in pressure (P_{RSI}) for selected configurations as summarized in Table 21. For the 5.5-inch OD (4.95-inch ID) base case, two $Q_{avg/well}$ bins were simulated, namely 3.5 and 11.5 MMSCFD. This distinction is relevant because a reservoir is potentially operated over a wide range of pressures from effectively full inventory at P_{max} to effectively empty at about half P_{max} with only cushion gas. Such pressure differences could, in turn, affect the sensitivity of the reservoir deliverability to liner additions. Modeling results for all of these cases are presented in the next section.

Table 18. Run matrix for Field C (hockey stick distribution) across $Q_{avg/well}$ bins for 5.5- and 7-inch OD base casing size.

Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Base OD	Base ID	Liner 1 OD	Liner 1 ID	Liner 2 OD	Liner 2 ID
[MMSCFD]	[ft]	[psia]	[psi²]	[in]	[in]	[in]	[in]	[in]	[in]
0.5	1,800	400	25,000	5.5	4.95	3.5	2.992	2.875	2.441
1.5	2,500	600	100,000	5.5	4.95	3.5	2.992	2.875	2.441
2.5	2,900	700	250,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	900	250,000	5.5	4.95	3.5	2.992	2.875	2.441
5.5	4,000	900	500,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	900	500,000	5.5	4.95	3.5	2.992	2.875	2.441
19.5	6,000	1,800	1,000,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	900	250,000	7.0	6.276	4.5	3.958	4.0	3.476
11.5	4,000	900	500,000	7.0	6.276	4.5	3.958	4.0	3.476
25.5	5,900	1,300	1,000,000	7.0	6.276	4.5	3.958	4.0	3.476
46.5	5,000	1,600	1,200,000	7.0	6.276	4.5	3.958	4.0	3.476

Table 19. Run matrix for field G (linear distribution) across $Q_{avg/well}$ bins for 5.5- and 7-inch OD base casing size.

Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Base OD	Base ID	Liner 1 OD	Liner 1 ID	Liner 2 OD	Liner 2 ID
[MMSCFD]	[ft]	[psia]	[psi^2]	[in]	[in]	[in]	[in]	[in]	[in]
0.5	1,800	400	25,000	5.5	4.95	3.5	2.992	2.875	2.441
1.5	2,500	600	100,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	900	500,000	5.5	4.95	3.5	2.992	2.875	2.441
19.5	6,000	1,800	1,000,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	900	250,000	7.0	6.276	4.5	3.958	4.0	3.476
11.5	4,000	900	500,000	7.0	6.276	4.5	3.958	4.0	3.476
25.5	5,900	1,300	1,000,000	7.0	6.276	4.5	3.958	4.0	3.476
46.6	5,000	1,600	1,200,000	7.0	6.276	4.5	3.958	4.0	3.476

Table 20. Run matrix for Field C (hockey stick distribution) across selected depths and $Q_{avg/well}$ bins for 5.5- and 7-inch OD base casing size.

Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Base OD	Base ID	Liner 1 OD	Liner 1 ID	Liner 2 OD	Liner 2 ID
[MMSCFD]	[ft]	[psia]	[psi^2]	[in]	[in]	[in]	[in]	[in]	[in]
0.5	1,800	400	25,000	5.5	4.95	3.5	2.992	2.875	2.441
0.5	4,000	400	25,000	5.5	4.95	3.5	2.992	2.875	2.441
0.5	6,000	400	25,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	2,000	900	250,000.0	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	900	250,000.0	5.5	4.95	3.5	2.992	2.875	2.441
3.5	6,000	900	250,000.0	5.5	4.95	3.5	2.992	2.875	2.441
25.5	4,000	1,300	500,000	7	6.276	4.5	3.958	4.0	3.476
25.5	5,900	1,300	500,000	7	6.276	4.5	3.958	4.0	3.476
25.5	7,000	1,300	500,000	7	6.276	4.5	3.958	4.0	3.476
46.5	4,000	1,600	1,200,000	7	6.276	4.5	3.958	4.0	3.476
46.5	5,000	1,600	1,200,000	7	6.276	4.5	3.958	4.0	3.476

Table 21. Run matrix for Field C (hockey stick distribution) across selected P_{RSI} and $Q_{avg/well}$ bins for 5.5-inch OD base casing size.

Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Base OD	Base ID	Liner 1 OD	Liner 1 ID	Liner 2 OD	Liner 2 ID
[MMSCFD]	[ft]	[psia]	[psi^2]	[in]	[in]	[in]	[in]	[in]	[in]
3.5	3,700	900	250,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	1,200	250,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	1,500	250,000	5.5	4.95	3.5	2.992	2.875	2.441
3.5	3,700	1,600	250,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	900	500,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	1,200	500,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	1,500	500,000	5.5	4.95	3.5	2.992	2.875	2.441
11.5	4,000	1,720	500,000	5.5	4.95	3.5	2.992	2.875	2.441

4.5 Modeling Results

Results from the combined pipe and well flow model runs for the simulation cases listed in Table 18 through Table 21 are summarized here. Each figure generally represents the results from 60 model realizations for a given field: 20 percentile bins × 3 well inner diameters (base ID, liner 1, liner 2).

4.5.1 Field C (Hockey Stick Distribution) Results across Selected $Q_{avg/well}$ Bins

Gas flowrate distributions for selected $Q_{avg/well}$ bins are illustrated below as modeled for Field C. Individual points on the figures represent the flowrates associated with each 5th percentile of wells in a given field, sorted in descending order. The values shown for the field in the figure legend represent the flowrates numerically integrated over a hypothetical field of 100 wells. Percent reductions in deliverability are thus compared against the baseline for the entire field. While selected results are shown here to illustrate important features of the analysis, detailed results for all simulation cases listed in Table 18 through Table 20 are given in Lord and Allen [19]. Representative model results for fields with baseline wells measuring 4.95-inch ID (5/5-inch OD) appear in Figure 16 and Figure 17. Representative results for fields with baseline wells measuring 6.276-inch ID (7-inch OD) appear in Figure 18 and Figure 19.

Figure 16 is described in detail as an example. Field C was simulated here using a "Q25" pressure difference. This Q25 shorthand denotes the difference in squares of the wellhead pressures at static and flowing conditions, shown in the P_{WHS}^2-P_{WHF}^2 column in Table 18. The thousands are dropped in the shorthand, so that if P_{WHS}^2-P_{WHF}^2 = 25,000 psi^2, the corresponding notation is Q25. Individual well deliverabilities for the given conditions are shown as points on the figure, sorted in descending order. Points under a given well diameter case (Base, Liner 1, Liner 2) are connected by simple straight line connectors. The $Q_{avg/well}$ for the baseline case is shown on each figure as a horizontal dashed green line. For Figure 16, the associated $Q_{avg/well}$ = 0.5 MMSCFD, and is visible in the placement of the dashed green line as well as listed in the figure legend.

With a baseline ID = 4.95 inches, the deliverability distribution of this field at Q25 is represented by the series of green points and solid green connectors. For a field with 100 wells, the simulated baseline deliverability for the entire field computed by numerical integration was 52.1 MMSCFD, as indicated in the legend. If a liner with ID = 2.992 inches is inserted in every well and the field is operated with the same Q25 pressure conditions, the deliverability distribution is represented by the series of blue points and connectors immediately below the green baseline series. The downward shift at the well level indicates the degree to which the individual well deliverability was affected by the reduction in ID by adding a liner of indicated size. The higher-deliverability wells are affected to a larger degree, both in absolute and relative terms, than the lower-deliverability wells. Numerically integrating across 100 wells with the 2.992-inch liner yields 50.6 MMSCFD, a 3% reduction from the baseline, as indicated in the figure legend. Repeating the process for a slightly smaller liner with ID = 2.441 inches yields the brown series and results in a 48.5 MMSCFD deliverability for the field for a 7% reduction against the baseline field at ID = 4.95 inches. Figure 17 shows a similar analysis, but with baseline $Q_{avg/well}$ = 19.5 MMSCFD and Q1,000 driving pressure for base well ID = 4.95 inches. The reductions in deliverability resulting from the addition of liners with ID = 2.992 and 2.41 inches are much more pronounced than in Figure 16 for the $Q_{avg/well}$ = 0.5 MMSCFD baseline. These liners lead to reductions of 42 and 58% deliverability, respectively, when applied across the entire field, as noted in the legend. Figure 18 and Figure 19 show the impacts of liner additions for a larger baseline well ID = 6.276 inches (OD = 7 inches). A similar pattern is observed here, with the higher-deliverability wells in the higher-deliverability bins affected more than the lower-deliverability wells by given reductions in liner inner diameter.

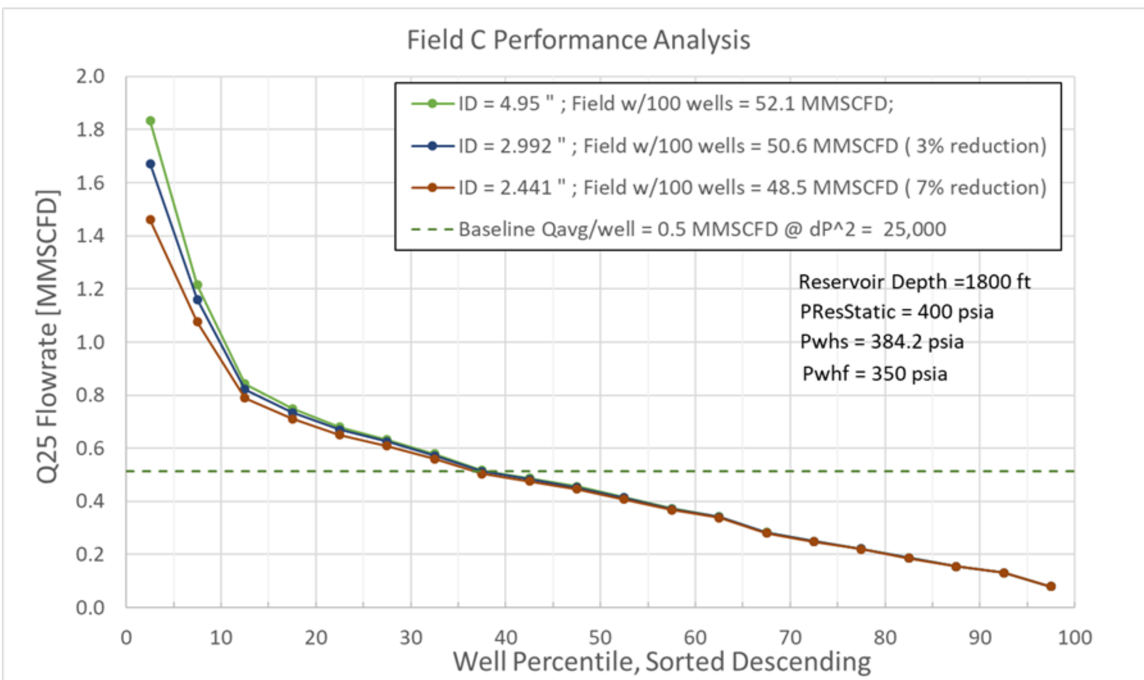

Figure 16: Q25 flowrates for Field C wells with baseline $Q_{avg/well}$ = 0.5 MMSCFD in 4.95-inch ID wells showing reductions at two liner sizes, 2.992 and 2.441 inches.

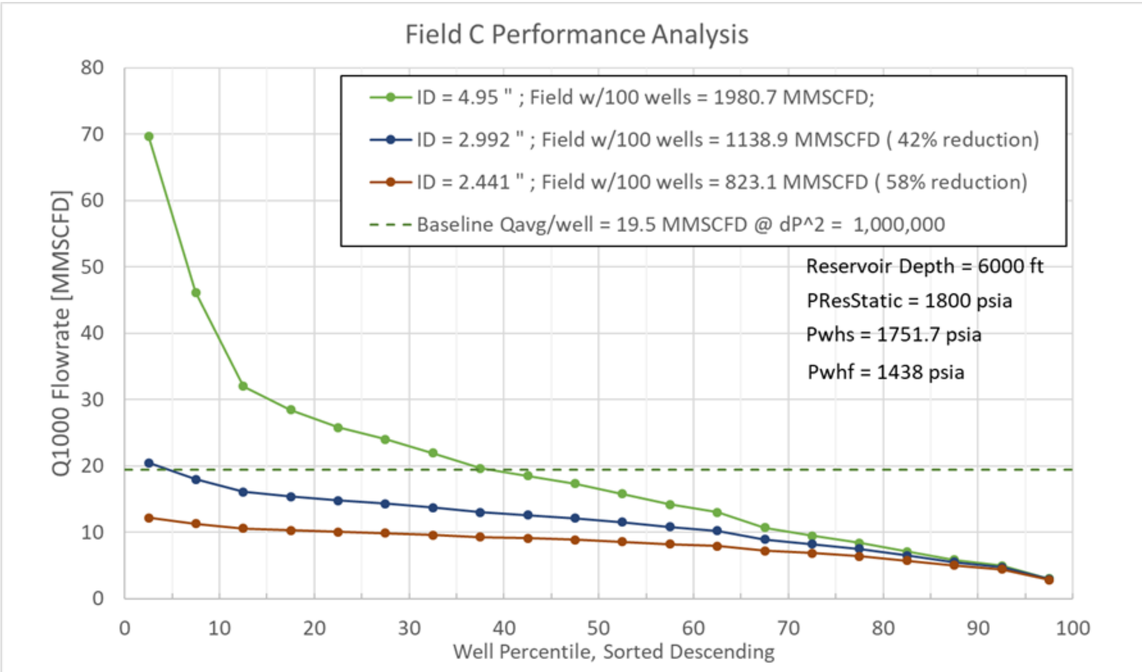

Figure 171: Q1000 flowrates for Field C wells with baseline $Q_{avg/well}$ = 19.5 MMSCFD in 4.95-inch ID wells showing reductions at two liner sizes, 2.992 and 2.441 inches.

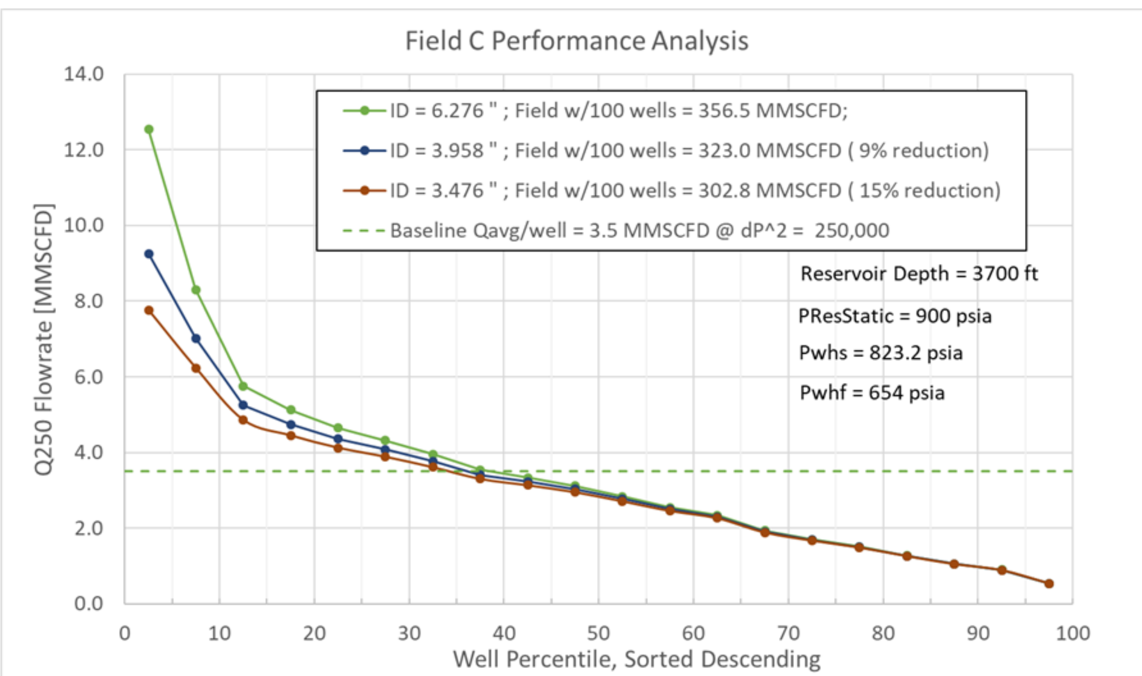

Figure 18: Q250 flowrates for Field C wells with baseline $Q_{avg/well}$ = 3.5 MMSCFD in 6.276-inch ID wells showing reductions at two liner sizes, 3.958 and 3.476 inches.

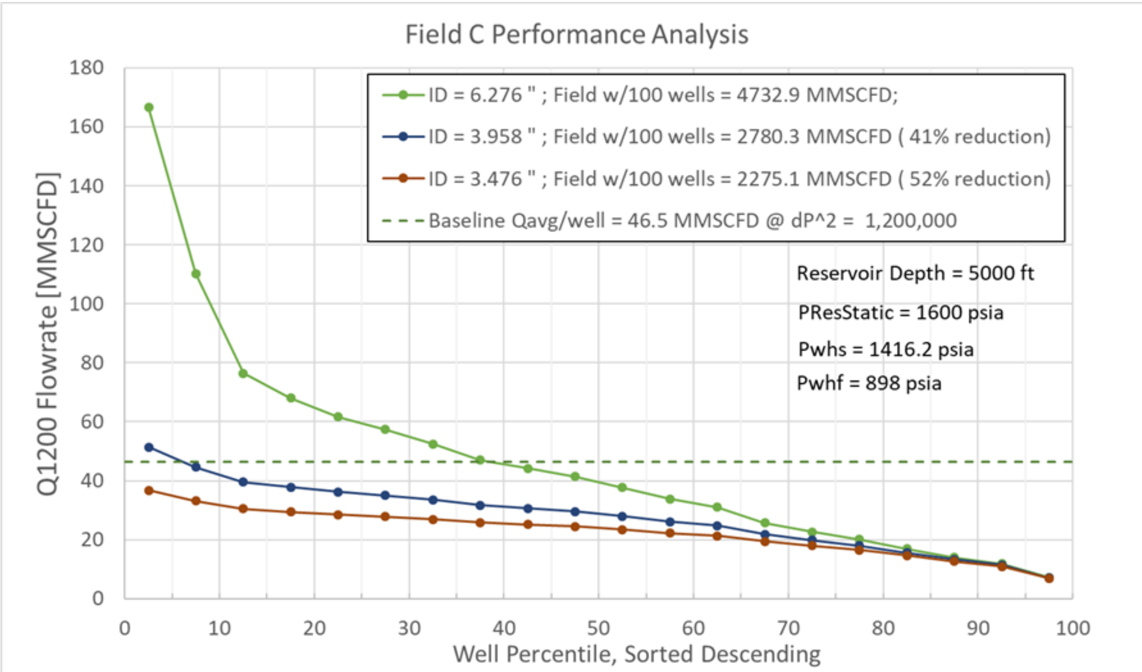

Figure 19: Q1200 flowrates for Field C wells with baseline $Q_{avg/well}$ = 46.5 MMSCFD in 6.276-inch ID wells showing reductions at two liner sizes, 3.958 and 3.476 inches.

A summary of liner effects on field-level reductions in deliverability for Field C (hockey-stick distribution) is given in Figure 20 based on the run matrix outlined in Table 18. Reviewing Figure 20, as field-level $Q_{avg/well}$ increased, the associated reductions in field-level deliverability also increased with incrementally smaller liners. For the base case ID = 4.95 inches (OD = 5.5 inches) represented by the yellow and blue series on the upper left section of the plot, field-level deliverability reductions ranged from 3% to 42% for Liner 1 (ID = 2.992 inches) and from 7% to 58% for Liner 2 (2.441 inches). When reviewing the results for the larger diameter wells with base case ID = 6.276 inches (OD = 7 inches) represented by the red and orange series, field-level deliverability reductions ranged from 5% to 41% for Liner 1 (ID = 3.958 inches) and from 8% to 52% for Liner 2 (ID =3.476 inches). At a given $Q_{avg/well}$, a smaller base ID was associated with more significant reductions in deliverability with liners. If $Q_{avg/well}$ = 3.5 MMSCFD is used as an example, the reductions due to liner for the base ID 4.95-inch case are 14 to 25%, while the reductions due to liner for the base ID = 6.276-inch case are 5 to 8%. Note the base case ID = 4.95 inches (OD = 5.5 inches) field-level simulations were not run for $Q_{avg/well}$ bins > 19.5 MMSCFD because the base configuration could not support the highest-delivery wells in the hockey stick distribution. The pipe friction pressure drops in these wells were simply too high to support those base flowrate levels.

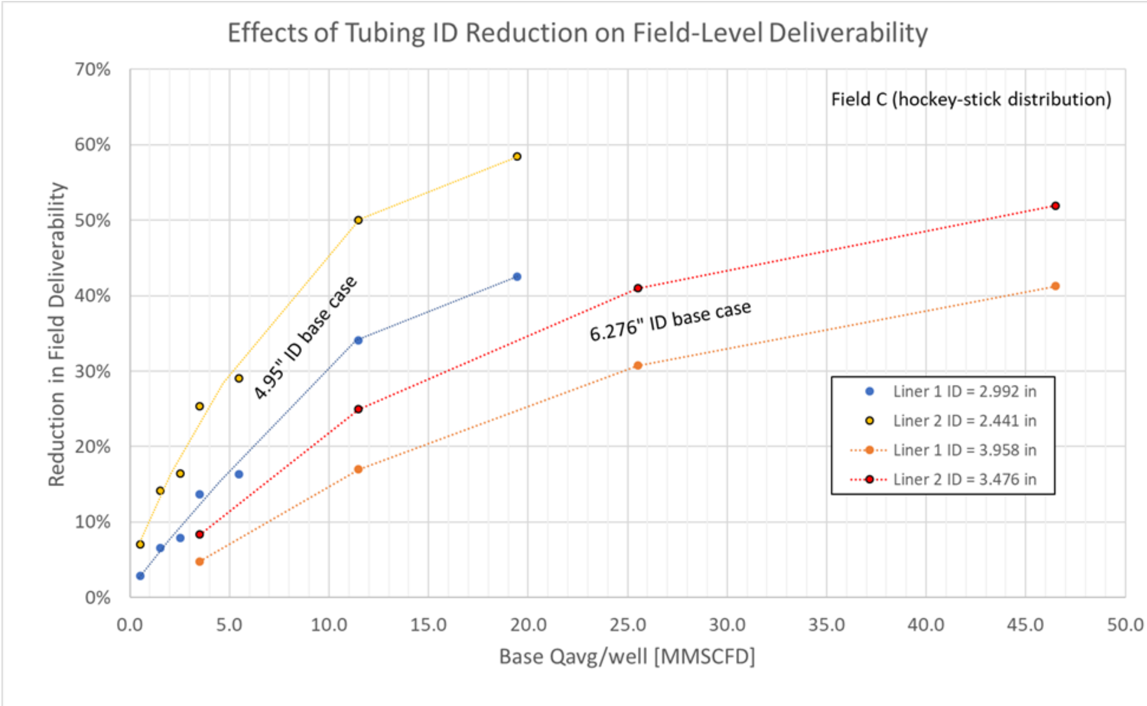

Figure 20: Summary results for Field C (hockey-stick distribution) for all $Q_{avg/well}$ and liners run against base case production casing ID = 4.95 and 6.276 inches.

4.5.2 Field G (Linear Distribution) Results across Selected $Q_{avg/well}$ Bins

Gas flowrate distributions for selected $Q_{avg/well}$ bins are illustrated below as modeled for Field G, which has a nearly linear distribution in well deliverability. The effects of decreasing well ID on deliverability follows the same general pattern as seen above for the Field C (hockey stick) distribution. Higher deliverability wells and higher deliverability bins are affected more than lower deliverability wells and bins, though the magnitude of tubing-induced reductions for the linear field is not as pronounced as for the hockey stick field. Some particular cases are discussed below.

The general effects of increasing $Q_{avg/well}$ in Field G is illustrated by comparing Figure 21and Figure 22 for a baseline well ID = 4.95 inches (OD = 5.5 inches). The $Q_{avg/well}$ = 0.5 MMSCFD case in Figure 21 only sees 1% and 4% reductions in deliverability at the field level with addition of 2.992-inch and 2.441-inch liners, while the $Q_{avg/well}$ = 11.5 MMSCFD case in Figure 22 sees 28% and 46% reductions for the same liner sizes. Moving up to larger initial casing size with baseline well ID = 6.276 inches at the same $Q_{avg/well}$ = 11.5 MMSCFD indicates that the effects of tubing size reductions are less severe at the field level, showing 11% and 19% reductions for liners with 3.958- and 3.476-inch ID, respectively, as shown in Figure 23. Increasing the flowrate to $Q_{avg/well}$ = 46.6 MMSCFD at the same casing sizes also increases the field-level reductions to 36% and 48%, respectively, as shown in Figure 24. The fields simulated in Figure 21 and to some extent Figure 23 can be characterized as reservoir-limited, with deliverability relatively insensitive to incremental reductions in tubing size. In contrast, the fields simulated in Figure 22 and 24 are more tubing-limited and show pronounced reductions in deliverability with tubing size reductions.

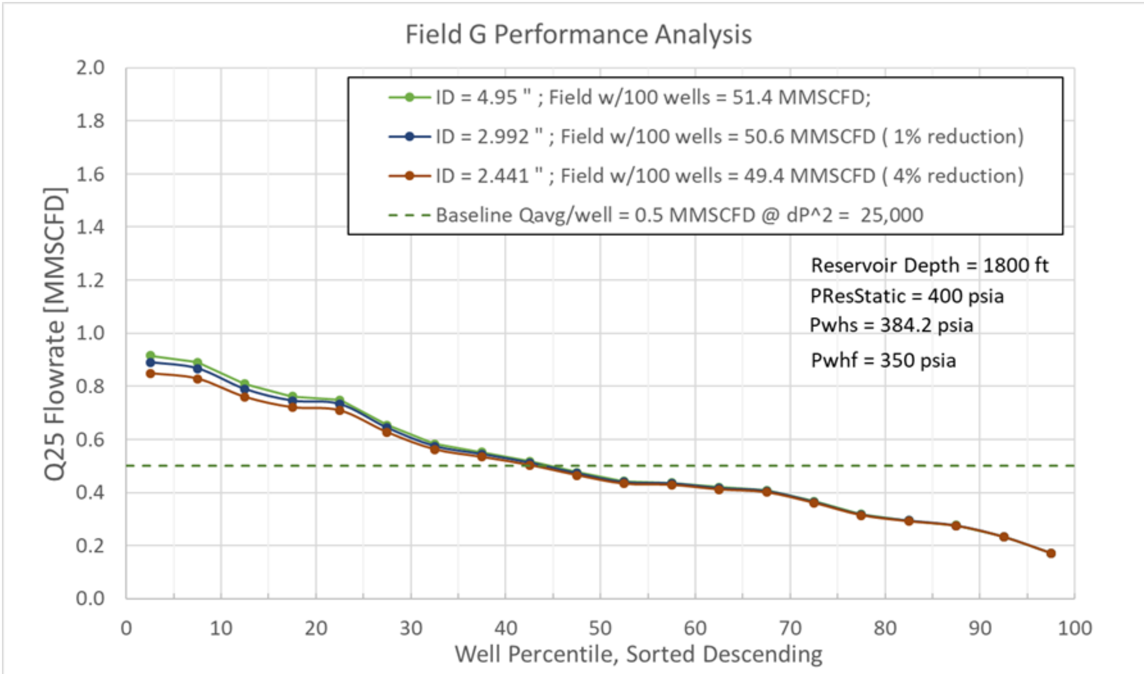

Figure 21: Q25 flowrates for Field G wells with baseline $Q_{avg/well}$ = 0.5 MMSCFD in 4.95-inch ID wells showing reductions at two liner sizes, 2.992 and 2.441 inches.

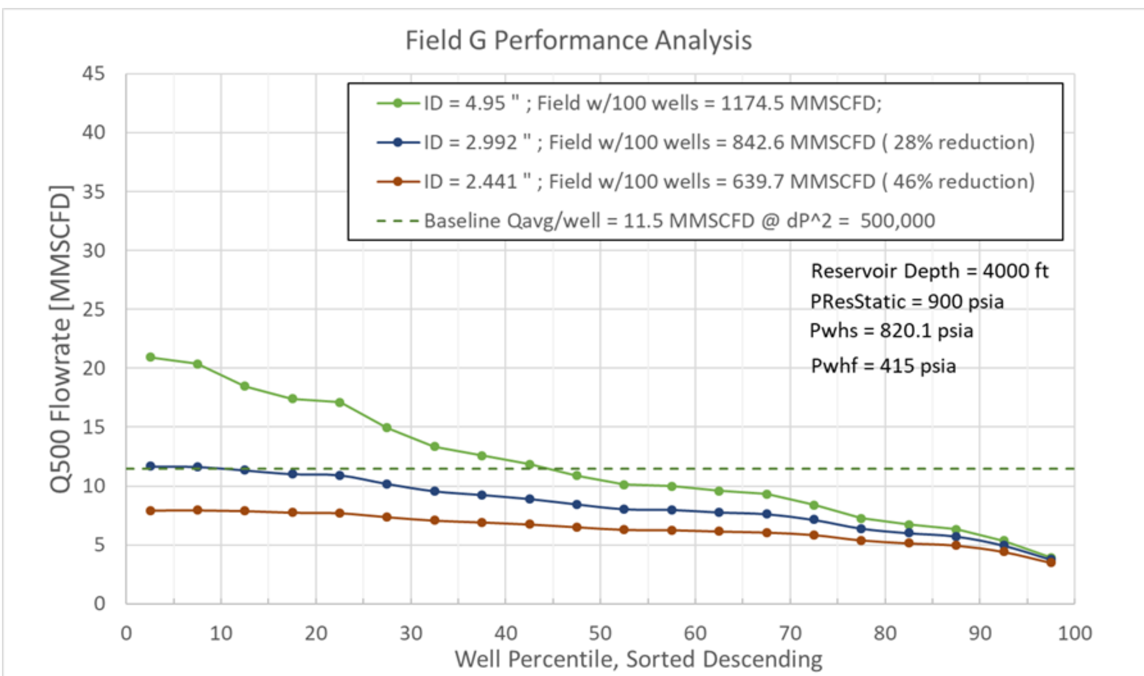

Figure 22: Q500 flowrates for Field G wells with baseline $Q_{avg/well}$ = 11.5 MMSCFD in 4.95-inch ID wells showing reductions at two liner sizes, 2.992 and 2.441 inches.

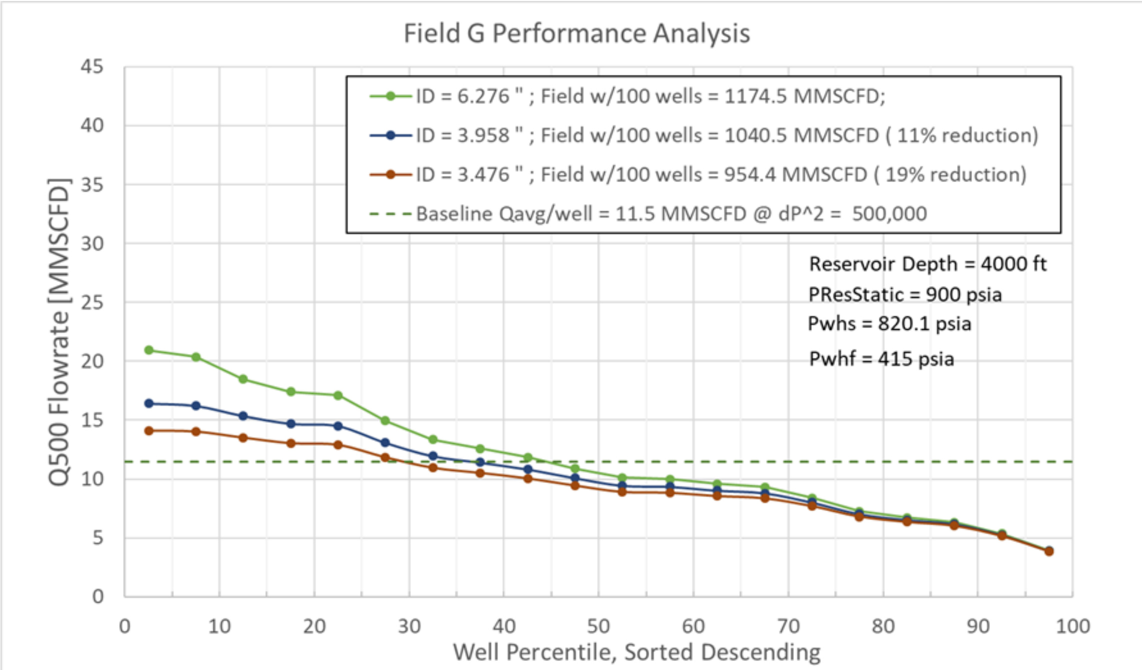

Figure 23: Q500 flowrates for Field G wells with baseline $Q_{avg/well}$ = 11.5 MMSCFD in 6.276-inch ID wells showing reductions at two liner sizes, 3.958 and 3.476 inches.

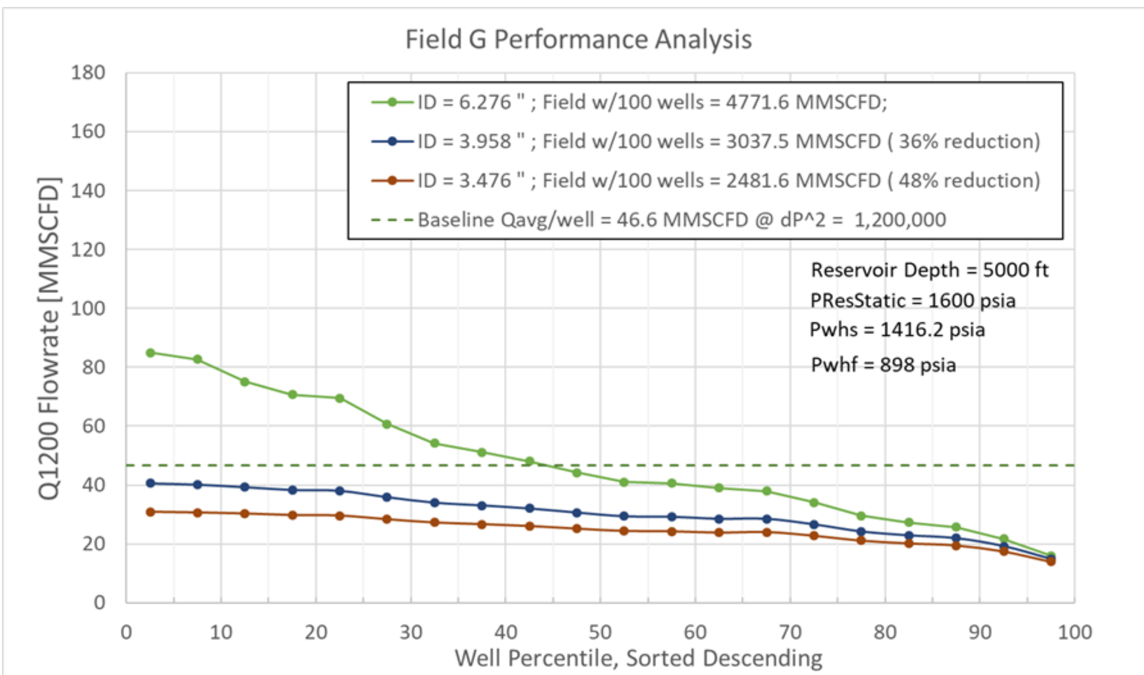

Figure 24: Q1200 flowrates for Field G wells with baseline $Q_{avg/well}$ = 46.5 MMSCFD in 6.276-inch ID wells showing reductions at two liner sizes, 3.958 and 3.476 inches.

A summary figure showing liner effects on field-level deliverability for Field G (linear distribution) is shown in Figure 25 based on the run matrix outlined in Table 19. As field-level $Q_{avg/well}$ increased, the associated reductions in field-level deliverability also increased with incrementally smaller liners. Assuming a base case ID = 4.95 inches (OD = 5.5 inches) represented by the green and purple series in the upper left of the plot, field-level deliverability reductions ranged from 1% to 38% for Liner 1 (ID = 2.441 inches) and from 4% to 55% for Liner 2 (2.441 inches). Moving to a larger base case ID = 6.276 inches (OD = 7 inches), field-level deliverability reductions ranged from 2% to 36% for Liner 1 (ID = 3.958 inches) and from 5% to 48% for Liner 2 (ID =3.476 inches). At a given $Q_{avg/well}$, a smaller base ID was associated with more significant reductions in deliverability with liners. If $Q_{avg/well}$ = 11.5 MMSCFD is used as an example, the reductions due to liner for the base ID 4.95-inch case are 28 to 46%, while the reductions due to liner for the base ID = 6.276-inch case are 11 to 19%.

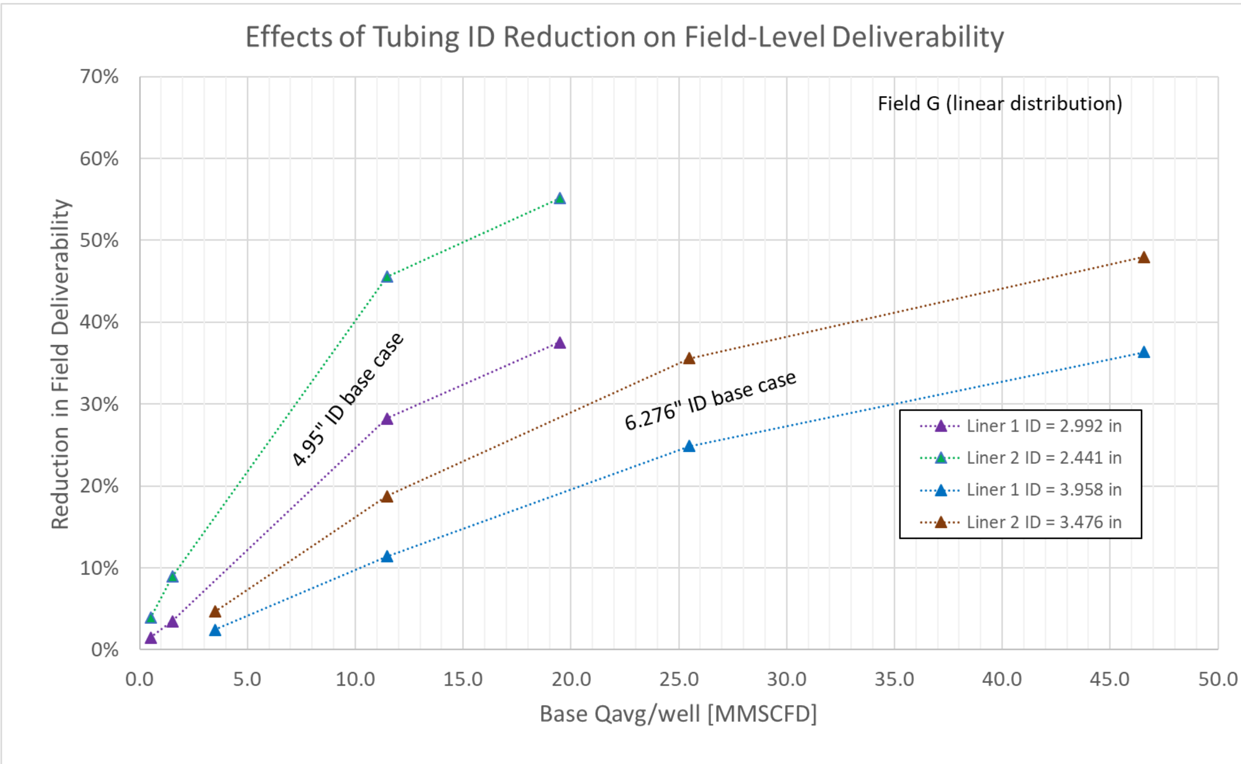

Figure 25: Summary results for Field G (linear distribution) for all $Q_{avg/well}$ and liners run against base case production casing ID = 4.95 and 6.276 inches.

4.5.3 Field C versus G Comparison

Several direct comparisons may be drawn to illustrate the effects of well deliverability distribution (i.e., hockey stick versus linear) on field-level deliverability in selected $Q_{avg/well}$ bins. Generally speaking, the high outlier wells, which form the “blade” of the hockey stick, are more susceptible to deliverability losses than the rest of the wells in the field with the addition of a liner. As such, when comparing fields that have the same $Q_{avg/well}$, those with the hockey stick shape shown in Field C exhibit greater reductions in field-level deliverability than the more linear Field G. Figure 26 provides a side-by-side view of deliverability reductions for Field C versus Field G across multiple $Q_{avg/well}$ bins and base ID = 4.95 inches and 6.276 inches for the addition of Liner 1. In every case, Field C saw slightly more reduction in field-level deliverability than Field G, indicated by a slight upward shift from each series “G” to each series “C”.

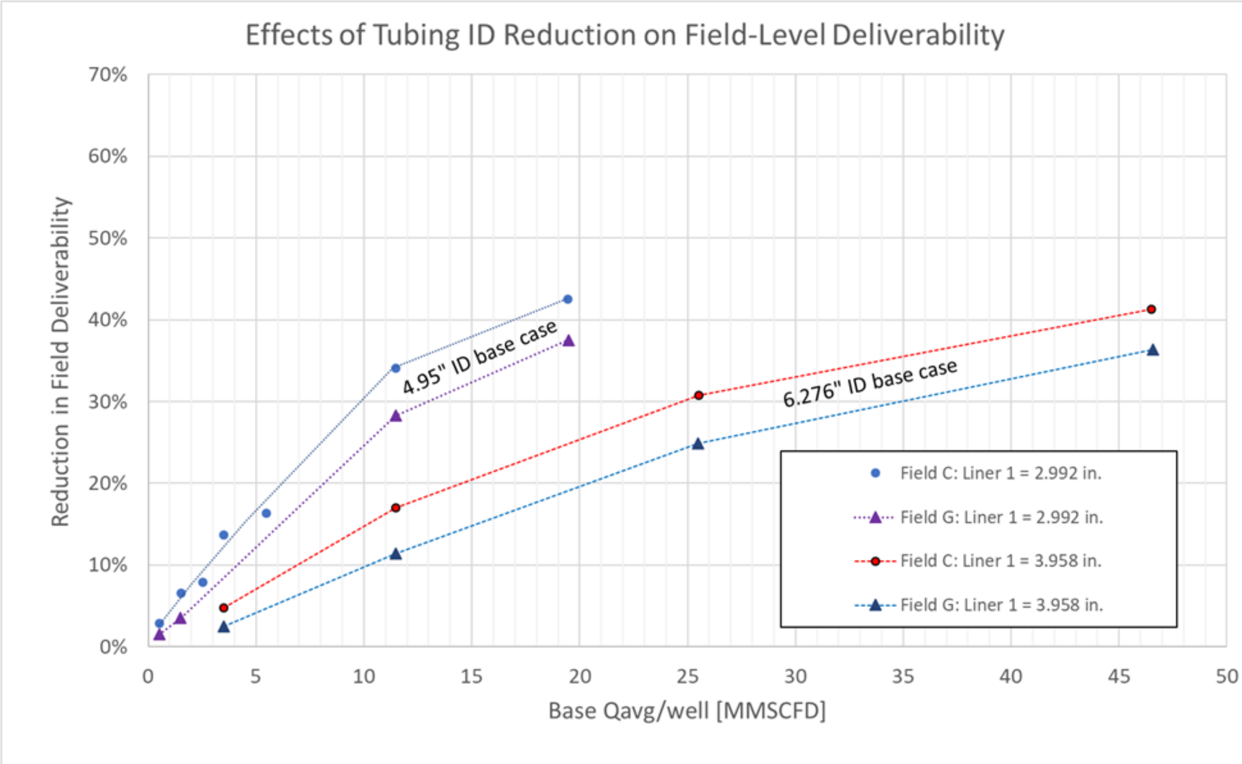

Figure 26: Summary results for Field C (hockey stick distribution) and Field G (linear distribution) for all $Q_{avg/well}$ bins and with Liner 1 run against base case production casing ID = 4.95 and 6.276 inches.

4.5.4 Effects of Depth and Reservoir Pressure on Deliverability for Field C

The effects of well depth coupled with tubing ID reductions were explored for selected cases in Field C according to the run matrix in Table 20, with the results summarized in Table 22 and Table 23. For each selected $Q_{avg/well}$ bin, three depth cases were run. The reservoir deliverability coefficients (C, n) were tuned to yield the given $Q_{avg/well}$ for the base case at each depth and then the effects of liners were computed. Deliverability reductions due to liners grow more pronounced with deeper wells. For example, for $Q_{avg/well}$ = 3.5 MMSCFD in Table 22, the effects of adding Liner 1 (ID = 2.992 inches) was a 9% field deliverability reduction for a 2,000 ft well, 14% for a 3,700 ft well, and 17% for a 6,000 ft well. This is conceptually consistent with the basic equations for steady pipe flow that indicate flowrate is inversely proportional to the square root of pipe length (recall Weymouth, Equation 7, such that an increase in pipe length, holding all other terms the same, will decrease the flowrate. While not explicitly modeled here, deliverability impacts of liners on directionally drilled wells could potentially be greater than shown in the current modeling because the length of tubing is greater than a vertical well for a given reservoir depth.

Table 22. Summary of field-level reductions in deliverability for Field C with liner size and well depth for base well ID = 4.95 inches.

Depth Series Field C				Base ID = 4.95 in	
Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Liner 1 ID = 2.992 in	Liner 2 ID = 2.441 in
[MMSCFD]	[ft]	[psia]	[psi^2]	% Reduction	% Reduction
0.5	1,800	400	25,000	3%	7%
0.5	4,000	400	25,000	5%	12%
0.5	6,000	400	25,000	7%	16%
3.5	2,000	900	250,000	9%	19%
3.5	3,700	900	250,000	14%	25%
3.5	6,000	900	250,000	17%	31%

Table 23. Summary of field-level reductions in deliverability for Field C with liner size and well depth for base well ID = 6.276 inches.

Depth Series Field C				Base ID = 6.276 in	
Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Liner 1 ID = 3.958 in	Liner 2 ID = 3.476 in
[MMSCFD]	[ft]	[psia]	[psi^2]	% Reduction	% Reduction
25.5	4,000	1300	500,000	34%	45%
25.5	5,900	1300	500,000	39%	50%
25.5	7,000	1300	500,000	41%	52%
46.5	4,000	1600	1,200,000	38%	49%
46.5	5,000	1600	1,200,000	41%	52%

The effects of reservoir shut-in pressure (P_{RSI}) coupled with tubing ID reductions were explored for selected cases in Field C according to the run matrix in Table 21, with the results summarized in Table 24. For each selected $Q_{avg/well}$ bin, four P_{RSI} cases were run to simulate the effects of adding liners to reservoirs that are operated at a range of reservoir shut-in pressures from full inventory condition where $P_{RSI} = P_{max}$ down to about 20% of working inventory, estimated here at 900 psia. Note the P_{WHS}^2-P_{WHF}^2 term that drives flowrate remains constant in this matrix. P_{RSI} has a slight effect on deliverability reductions from liners, causing greater deliverability reductions with lower P_{RSI}. For example, in the Q_{avg} = 3.5 MMSCFD series, adding Liner 1 results in deliverability reductions from base case by 14% for P_{RSI} = 900 psia as compared to 10% for P_{RSI} = 1,600 psia. Similar results are seen for Liner 2 with reductions ranging from 25% at P_{RSI} = 900 to 22% at P_{RSI} = 1,600 psia. A similar pattern is observed when looking at the Q_{avg} = 11.5 MMSCFD deliverability bin. While the dP^2 term and flowrates in these simulations are the same across the four P_{RSI} cases simulated, the lower flowing pressures associated with lower P_{RSI} cases induce higher velocities inside the well with resultant higher pressure drops due to friction that ultimately lead to greater losses in deliverability than at higher P_{RSI}.

Table 24. Summary of field-level reductions in deliverability for Field C with liner size and reservoir shut-in pressure for base well ID = 4.95 inches.

P_{RSI} Series Field C				Base ID = 4.95 in	
Qavg/well	Depth	P_{RSI}	P_{WHS}^2-P_{WHF}^2	Liner 1 ID = 2.992 in	Liner 2 ID = 2.441 in
[MMSCFD]	[ft]	[psia]	[psi^2]	% Reduction	% Reduction
3.5	3,700	900	250,000	14%	25%
3.5	3,700	1200	250,000	12%	24%
3.5	3,700	1500	250,000	11%	23%
3.5	3,700	1600	250,000	10%	22%
11.5	4,000	900	500,000	34%	50%
11.5	4,000	1200	500,000	33%	49%
11.5	4,000	1500	500,000	32%	48%
11.5	4,000	1720	500,000	31%	48%

4.5.5 Comparison across Multiple Bins, Fields

A summary plot that aggregates field deliverability results from all of the simulations listed in Table 18 and Table 19 is given in Figure 27. The x-axis represents $Q_{avg/well}$, and the y-axis represents the reduction in field deliverability due to liner additions as a percentage of the base deliverability. Each series on the plot represents a field, either C (hockey-stick) or G (linear), evaluated over multiple $Q_{avg/well}$ bins. The line segment connectors are notational, added to guide the eye to the next point in the series, and do not represent a mathematical curve fit.

One of the first general observations of the data presented in this way is that the reduction in field deliverability increases with $Q_{avg/well}$ for every series examined. This is a reflection of the fact that higher flowrate wells are more subject to tubing limitations, amplified as successively smaller liners are introduced. Conversely, lower flowrate wells are more typically reservoir-limited, and are consequently less sensitive to introduction of liners. Deliverability is also clearly affected by the base case well ID, as illustrated by the groupings visible in the figure with the 4.95-inch ID (5.5-inch OD) base case showing categorically greater reductions in deliverability with liners than the 6.276-inch ID (7-inch OD) base case.

Another observation consistent throughout this report is that the linear field G deliverability is less affected than the hockey-stick Field C for the same boundary conditions (P_{WHS}^2-P_{WHF}^2, P_{RSI}) with tubing size reductions: for every Field G series there is a corresponding Field C series that is shifted upward. The greater sensitivity of the highest deliverability wells (blade of the hockey stick) from Field C drive this effect at the well- and field-levels.

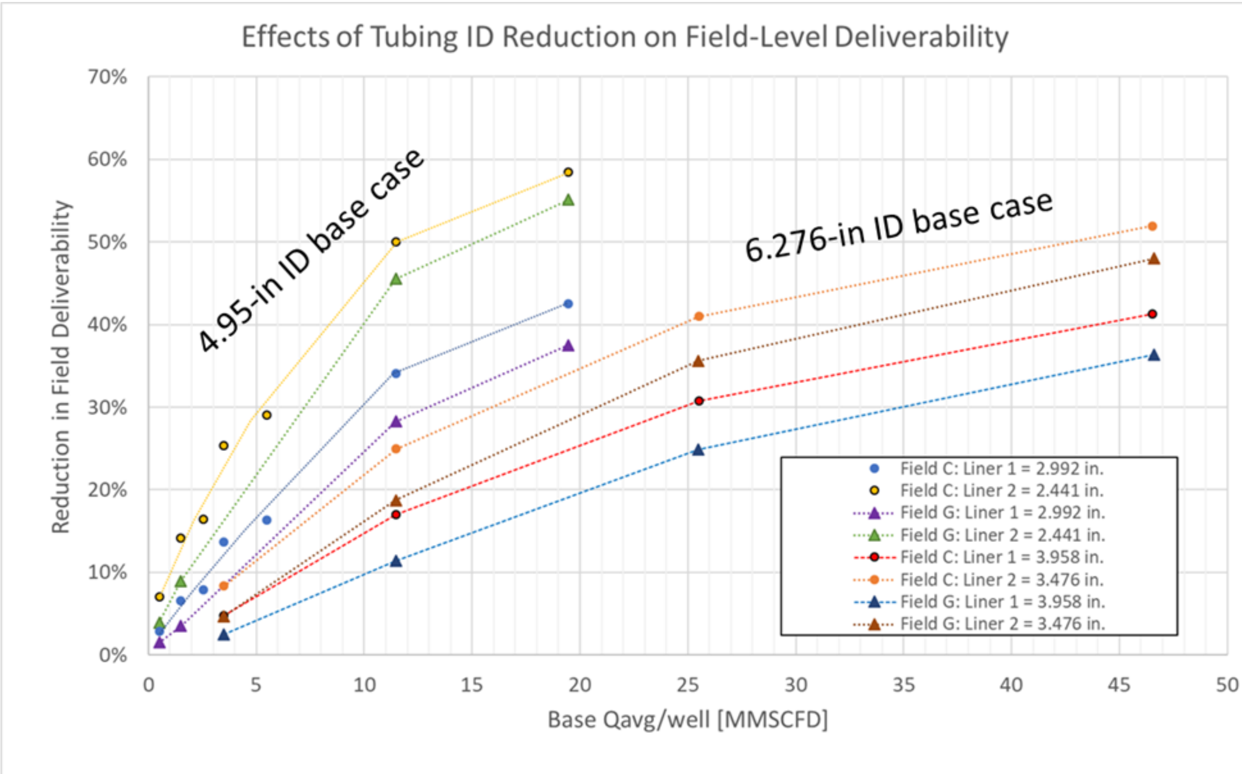

Figure 27: Summary plot of field deliverability across a broad range of $Q_{avg/well}$ bins for 4.95- and 6.276-inch ID base case wells with the addition of liners.

4.5.6 Interpretations for U.S. Depleted Reservoir Storage

The results of this modeling study illustrate several basic patterns:

- Higher-deliverability wells are subject to greater flowrate reductions as a result of tubing ID reductions than low-deliverability wells because high-flow wells are typically more tubing-limited than reservoir-limited.
- Higher-deliverability fields are similarly subject to greater flowrate reductions from tubing ID reductions, as some, if not all, of the wells are likely tubing-limited.
- Low-deliverability fields, which are constrained largely by reservoir conditions, can be relatively insensitive to tubing ID reductions.

How these factors could potentially affect access to the depleted reservoir storage inventory within the U.S. may be interpreted by reviewing the data obtained from the AGA report [29] introduced above in Section 4.4.2. Recall Figure 14, which organizes the AGA data into $Q_{avg/well}$ deliverability bins and reports occurrence of fields, wells, and working gas capacity across the U.S. by percentage. The AGA data indicate that the majority of fields and wells in the U.S. are associated with relatively low $Q_{avg/well}$, with 57% of fields containing 71% of wells associated with $Q_{avg/well}$ < 3 MMSCFD. Occurrences of fields and wells also decrease rapidly with an increase in $Q_{avg/well}$ so that medium- and high-deliverability fields are rare relative to the lower bins. While relatively low, the effects of liners on the low $Q_{avg/well}$ operators and fields are not necessarily zero, and some response is likely necessary to maintain their baseline field-level deliverability. An important consideration to overlay with this though is the working gas capacity associated with the range of deliverability bins shown in Figure 14. Working gas capacity is more evenly distributed across $Q_{avg/well}$ bins than the number of wells and fields, so while the number of fields and operators that would be significantly affected by tubing size reductions is low relative to the general population, their contribution to the overall capacity is significant.

An attempt to illustrate these combined effects of field/well/capacity occurrence with field-level reductions for varying $Q_{avg/well}$, base casing size, and liner additions is summarized in the hybrid plot in Figure 28. Here, the AGA occurrence data (column data, units on left vertical axis) from Figure 14 are co-plotted with the deliverability modeling results (points connected with lines, units on right vertical axis) from Figure 28. The plot shows that the highest occurrences of fields and wells at low $Q_{avg/well}$ are also associated with the relatively low field deliverability reductions. Moving left to right, as $Q_{avg/well}$ increases, occurrence of fields and well drops sharply, working gas capacity remains about the same, and reductions in field deliverability increase to their maxima for each series at highest $Q_{avg/well}$ cases simulated for each casing size. Looking back at some of the operator concerns expressed in public literature [20-22], the reductions in deliverability they cited, in the range 40 to 60%, are consistent with the highest-flowing wells and fields shown here.

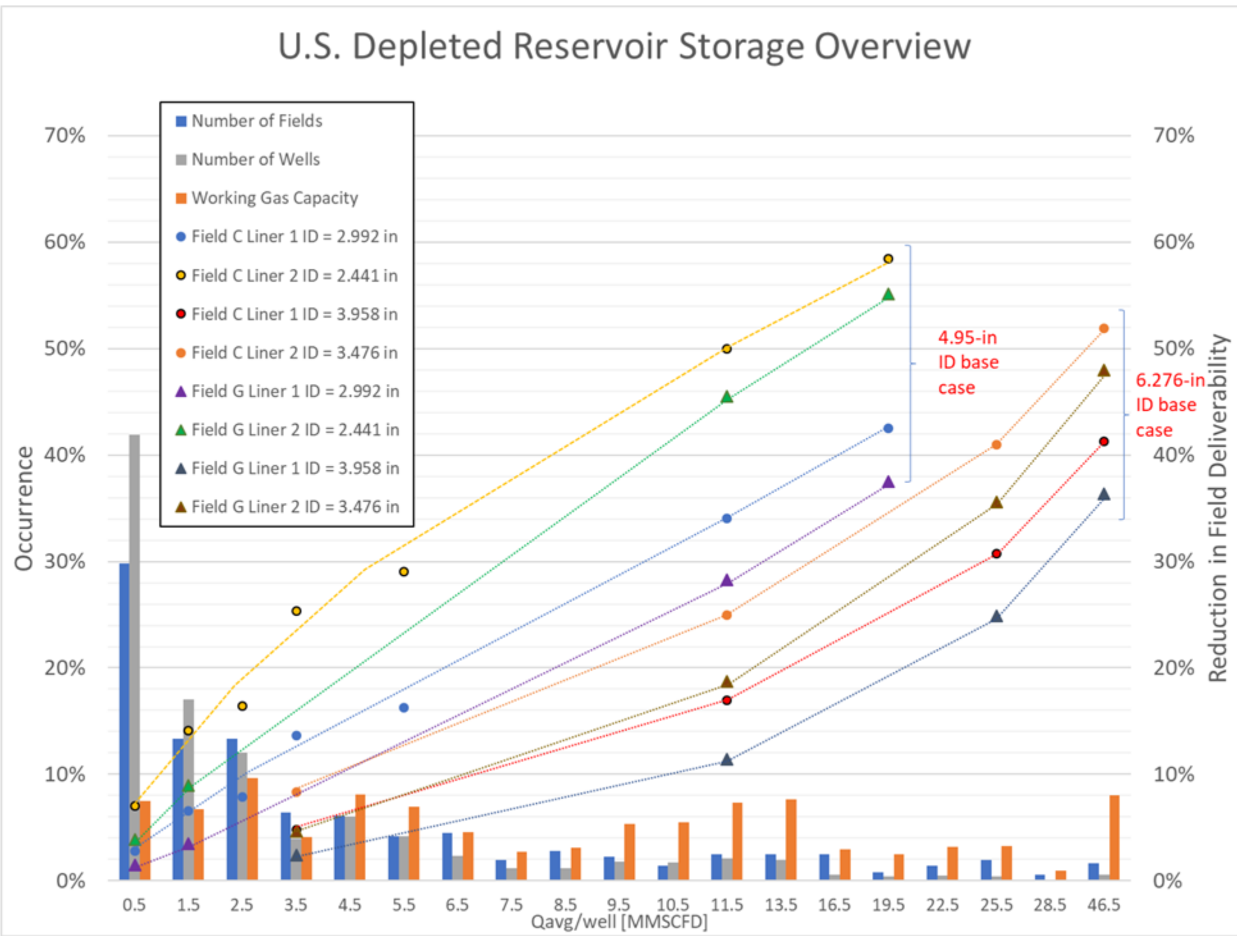

Figure 28: Hybrid graph showing overlay of field, well, and working gas capacity occurrence data from AGA [29] with field-level deliverability modeling results for selected tubing size reductions.

4.6 Summary

This analysis simulated well- and field-level reductions in deliverability from depleted reservoir underground storage as a function of tubing size reductions. The simulations were run with models developed at Sandia based on widely accepted pipe and reservoir flow equations, verified against commercial software, and validated against field test data.

The results can be summarized as follows:

- Adding tubing and packers has the potential to reduce deliverability at the field and well level due to the addition of flow restrictions in wells, though the extent of reduction is strongly dependent on whether the current wells are reservoir-limited or tubing-limited.
  - Tubing-limited wells will show notable reductions in flowrate with additional inner diameter restrictions.
  - Reservoir-limited wells will show small to no reductions in flowrate with additional inner diameter restrictions.
- All of the simulations presented here were based on examples of hypothetical fields whose parameters were derived from a large body of averaged field data obtained from a variety of sources, both public and private. The simulations are intended to give representative results across a range of possible fields and operating conditions in the U.S. The simulations are <u>not</u> intended to be predictive for a particular field or operator.
- Given that the current simulations use industry-accepted modeling techniques and typical data for reservoir and well deliverability, the general behavior of actual operator systems should be analogous to what is shown here.
- Individual operators will have the actual well performance data and calibrated models that will best predict the response of their own fields to changes in configuration.
- Operator concerns noted from the public record stating that reductions in deliverability could reach 40% [22] for their current wells or even exceed 60% in some wells on the peak day [21] appear to be validated by the current work for the highest-deliverability wells and fields. These 40 to 60% reductions do not represent the majority of wells or fields in the U.S. but are possible under the right conditions for the highest-flowing wells and fields.
- While the effects of liners on low deliverability fields are small, they are not necessarily zero, and some response from operators may be necessary to maintain their baseline field deliverability.
- The modeling indicates that deeper wells experience greater reductions in deliverability than shallower wells with the introduction of liners, and all other factors held equal.
- While not explicitly modeled here, deliverability impacts of liners on directionally drilled wells (i.e., non-vertical) could potentially be greater than shown in the current work because the length of tubing, and therefore tubing effects on deliverability, is greater for a deviated and/or horizontal well than a vertical well for a given reservoir depth.
- The modeling indicates that drawdowns at lower reservoir shut-in pressure (i.e., when inventory is at a relatively low level) are subject to slightly greater losses in deliverability than higher shut-in pressure (i.e., when inventory is at or near maximum capacity).

5. SSSV Implementation and Technology

5.1 Well Workover Interventions - General

Operators of underground natural gas storage wells must often perform workovers (any kind of well intervention involving invasive techniques) for monitoring well integrity, maintenance, repair, or changing reservoir conditions. Workovers fall into two general categories (light and heavy) and can range from simple and relatively low risk, inexpensive operations to major, complex projects with high risk and cost. Some workovers are routine operations and might be required by regulation for monitoring well integrity. Other workovers might be in response to a well barrier element or component failure and/or replacement, or an unknown problem with a storage well, or a need to restore or improve deliverability. Well integrity evaluation can include review of well design, drilling and completion records, workover records, wellhead inspections, casing inspections, pressure monitoring, and gas and fluid sampling.

5.2 Workover Types and Associated Risks

Well service personnel typically perform light interventions using slickline, wireline or coiled tubing. These systems allow operators to clear the well of sand, paraffin, hydrates or other substances that form blockages and reduce or completely halt productivity. Operators also use light interventions to change or adjust downhole equipment such as valves or pumps and to gather downhole pressure, temperature, and flow data. In many cases, because light interventions are relatively inexpensive and require minimal equipment, they are included in routine well maintenance programs.

Some examples of light workovers for monitoring well integrity include running wireline logs for checking casing integrity or performing mechanical integrity tests (MITs), or running slickline tools for pressure or temperature or fluid data gathering or other investigative purposes.

An MIT is a pressure test to determine the integrity of the tubing and packer. The tubing annulus is pressured up to a pre-determined amount and monitored for a specified period, from 15 to 30 minutes. If the pressure decreases more than 15%, or some other specified pass/fail criteria during the specified period, the well fails the MIT and remedial action is required. The well must pass the MIT prior to being placed back into operation.

Electric line logging operations generally do not require a service rig but may be run at the time of service rig operations. Electric line tools are run into the well with wireline lubricators assembled onto the wellhead; the lubricator, along with wireline blow-out preventers, provide the well control in the absence of the wellhead components and valves removed to perform the well entry.

Casing inspection logs can detect corrosion or erosion of the casing which reduces the thickness of the casing wall from either the inside wall or outside wall of the casing. Both monitoring techniques can be performed without a service rig, which limits the risk and keeps the cost relatively low.

Cement bond logs (CBLs) or cement evaluation logs are used to determine the amount of cement behind the casing and the quality of the cement bond to the casing and the formation. Other integrity monitoring logs include noise, temperature, tracer, or flow logs run on electric wireline systems.

Some workovers can be performed very economically by slickline units with minimal risks. A slickline is a single strand of thin wire that conveys tools and sensors into and out of the well. Slickline-based interventions include removing sand and paraffin, running or retrieving subsurface control valves and running sensors into a well to record bottom hole temperatures and pressures. Slickline is reeled on and off a hydraulically driven drum. A heavier cable may be deployed when the tensile strength required to complete an operation exceeds the rating of the slickline cable. The slickline can perform light-weight mechanical operations that do not require an electric power source or a data telemetry system. Many slickline operations can be performed without shutting the well in. The pressure lubricator installs on the wellhead to allow work to be performed under pressure; in addition to the lubricator, wireline blowout preventers can be used to seal off and/or cut the line in the hole and assist the lubricator in pressure control. Some examples of slickline unit operations are fishing, memory logging, setting and/or retrieving blanking plugs, gauges and wireline retrievable safety valves (WRSVs).

Some workovers require the use of a service rig, a coiled tubing unit (CTU) or a snubbing unit, which usually increases the cost and risks of the operation. CTUs and snubbing units generally come with their own pressure-control systems. Other work-string tubing-conveyed work from a service rig require installations of blowout preventer (BOP) systems.

Service rig workovers usually have more risk but less cost than CTU or snubbing unit workovers. Some service rig workovers require the well to be “killed” by loading the hole with a fluid. The hydrostatic weight of the fluid column is calculated to be equal to or slightly greater than the formation pressure (also called pore pressure) which controls the flow of the well. However, using kill fluid to control the well can cause damage to the storage formation. Many operators prefer not to risk damage to their storage reservoir, so they perform their workovers with CTU or snubbing units which can reduce the risk but increase the cost of the workover. One risk of using kill fluid to control pressure is the possibility of “swabbing” the kill fluid during workover operations. For instance, pulling tubing and packers can cause a swabbing effect on the well which can decrease the hydrostatic pressure exerted by the fluid column and allow a kick to enter the casing. If a kick goes unnoticed by the rig crew, or is not properly addressed, it can lead to an uncontrolled flow of gas and well fluids, even with a BOP system in place, since the BOP must be actuated to perform its closure functions. The reliability of BOP systems has been studied in depth, particularly after blowout events in which failure of the BOP system or failure of crews to test and operate the systems has been indicated as a contributing or leading cause of failure. It is worth noting the strong interdependence of human factors and technical factors in the operation of safety devices such as BOP systems.

A CTU has a continuous length of steel or composite tubing that is flexible enough to be wound on a large reel for transportation. The CTU is composed of a reel with the coiled tubing, as injector, control console, power supply, and well control stack (Figure 29). The coiled tubing can be injected into the well under pressure without having to kill the well. Advantages to using a CTU over a service rig or a snubbing unit is the speed at which the tubing can be injected into and pulled back out of the well. This can be very beneficial when several trips of the tubing are required to complete the workover. However, due to relative lack of rigidity of the coiled tubing and due to limitations in mechanical properties, lengths available, and other service capability aspects, the applicability of CTU can be limited.

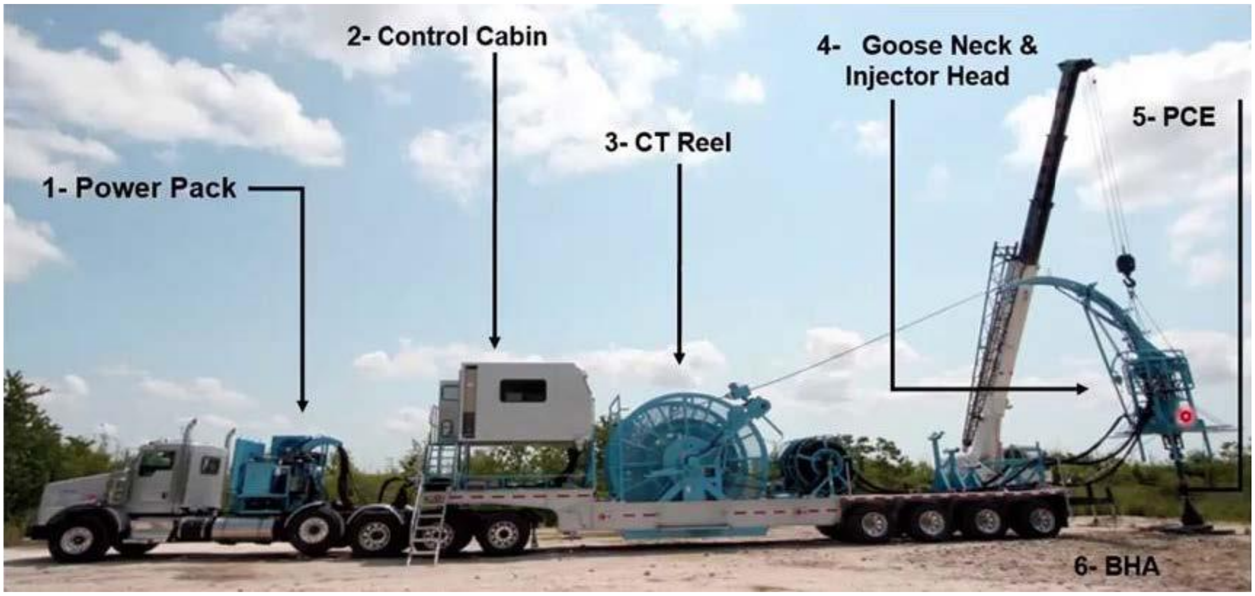

Figure 29: A Coiled Tubing Unit (CTU) with components labeled.

A snubbing unit is equipped with stationary slips, traveling slips and BOPs which allows the workover to be performed under normal well pressure without the need to kill the well (Figure 30). Snubbing units take many hours to rig up and the process of running tubing in the well or pulling tubing out of the well is much slower than with a CTU or a service rig. However, the snubbing unit mitigates the risk of formation damage from kill fluid and thus can be more economical in the long run. There is some methane venting during snubbing unit operations, but the total volume is minimal.

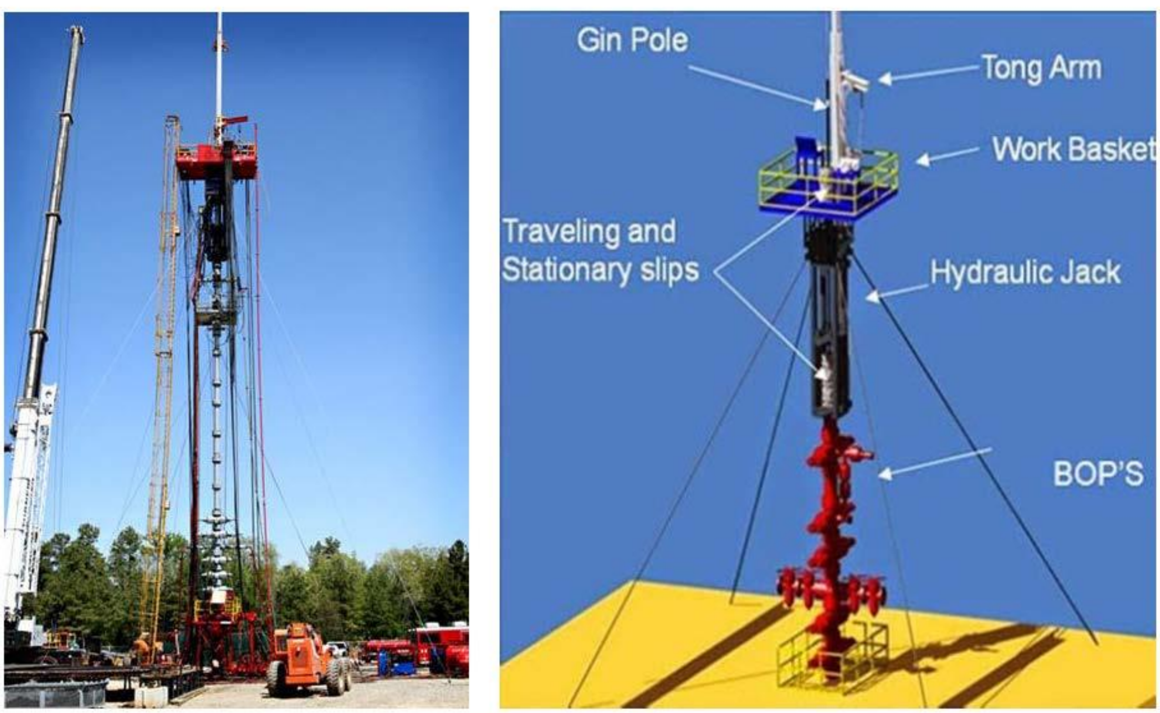

Figure 30: Snubbing unit in operation (left) Major components of a snubbing unit (right).

5.3 Workover Costs

Workovers vary so widely by type, complexity, location, well depth and cost for replacement and/or repair parts that it is very difficult to compare costs of one workover to another. However, costs tend to increase based on the type of equipment needed to perform the workover.

For example, workovers that can be performed with a slickline unit would tend to cost less than those that require an electric wireline (logging) truck. Workovers requiring a service rig would tend to cost more than those that can be done with a slickline unit or electric wireline truck. Those workovers requiring a snubbing unit will tend to cost more than those that can be done with a service rig. Finally, workovers requiring a CTU will tend to cost more than those that can be done with a snubbing unit.

Another consideration is how long a workover takes using one type of equipment versus another. For instance, even though a CTU costs more per day than a snubbing unit, the CTU might save the operator enough time that the total cost of the workover is less when performed with a CTU. No matter which type of equipment is used to perform a workover, the longer it takes to complete it, the more it will cost.

Safety and well control are always a consideration of what type of equipment is employed for a storage well workover and operators must decide how much risk they are willing to accept and how much additional cost they can afford to reduce the risk. For instance, even though a snubbing unit might cost more than a service rig, the snubbing unit might offer the least risk for a loss of well control incident or damage to the storage formation. Therefore, the operator might decide to employ the snubbing unit for the added safety and well control.

5.4 SSSV Types and Installation

An SSSV is a part of a flow shutdown system installed within a natural gas storage well to prevent uncontrolled flow. Most SSSVs are installed in the upper wellbore to provide emergency closure in the event of a critical failure at the wellhead or pipeline. SSSVs are sometimes used in underground natural gas storage operations, depending on several differing circumstances. It is estimated that up to 5% of onshore underground natural gas storage wells in the U.S. are currently equipped with SSSVs [31].

The SSSV can be in-line with the production tubing (tubing-retrievable) or installed within the production casing (wireline-retrievable). The SSSV setting depth is a function of what the operator is trying to protect and the potential consequences the operator is trying to reduce.

There are two types of SSSVs: surface-controlled and subsurface-controlled. In each case, the SSSV is designed to isolate the wellbore in case of emergency. A surface-controlled SSSV has control equipment installed above ground with a control line to the SSSV. The control system operates on hydraulic fluid and pressure. Reliability of the total system includes mechanical functionality of the safety valve mechanisms for open, close, or lockout (temporary abandonment), as well as the mechanical integrity and functional performance of the control system control line, fluid, fluid reservoir, valves, sensors and controls. A subsurface-controlled SSSV is a self-controlling valve. It is configured to close based on the differential pressure through the valve (where differential pressure can be associated with gas flow/velocity) or by pressure in the tubing (pressure type).

There are advantages and disadvantages associated with SSSVs. The advantages include risk reduction related to consequence mitigation by limiting the magnitude and duration of an event that occurs downstream of the valve. The SSSV system provides a means of automatic or controllable shut-off of flow and thus could have a protective effect to places of habitation, roads, human gathering places, environmentally sensitive areas, and other industrial infrastructure, including inter-related gas storage facilities, or other sensitive receptors. The automatic functionality of the SSSV can protect against consequences of catastrophic well failure due to natural hazards such as earth movements, seismic events, floods, severe weather and other events or human-induced hazards that could cause an uncontrolled flow of gas [31].

Some disadvantages of SSSVs are the additional cost of installation and maintenance, reliability of the SSSV and the control system, need of increased well entry for repair or replacement of the SSSV, and resulting risk of uncontrolled flow during well intervention. In addition, SSSVs do not activate for small leaks, only those severe enough to activate the valve. Also, high velocity flow of gas, liquid, sand and particulate through the SSSV can cause erosion of the seal, causing leakage when the valve is closed.

Installing tubing and an SSSV within the well reduces the cross-sectional flowing area significantly. For example, if the tubing is half the diameter of the casing, the flowing area is reduced ~75 percent. The reduction in flowing area causes a pressure drop which could reduce deliverability during critical periods from a negligible range to more than 50 percent, depending on the well flow capability, operating pressure range, length of the tubing, and other factors. If the flow deliverability requirements remain the same for a gas storage field, then new gas storage wells must be drilled to make up for the lost capacity. Even when deliverability impairment due to tubing-set SSSV is minimal, the SSSV system reliability might cause a deliverability reliability need for backup, via well stimulation or new drilling – again dependent on criticality of field demand, well demand, and site-specific well factors. Each storage well operator must evaluate the deliverability impact of tubing and SSSVs to verify that their fields can deliver the gas to serve market demand, including residential heating and power needs on a peak or high-demand day, as well as on the last day of withdrawal, when storage field pressures are much less due to low end seasonal inventory.

An SSSV can fail and/or function improperly due to circumstances such as hydraulic leaks and contamination by solids, which impair the function of valve components. Surface controlled SSSVs have experienced control failures, seal and tubing leaks and malfunctions that cause the valve to close. A tubing retrievable SSSV is connected to the tubing and lowered in the well with a drilling or service rig. If a leak develops in the hydraulic control line or any of the seals, a drilling or service rig must be brought in to retrieve the SSSV from the well. Until a rig can be brought in, the well remains closed and unable to deliver gas [31].

5.5 Risk Related to SSSV Systems

Additional risk can be introduced to a well associated with SSSV, including risk related to the installation, malfunction and/or failure of the SSSV components and need to intervene and repair or suffer other risk related to impairment of deliverability potential and/or reliability. Adding SSSVs to existing wells requires shutting in the well, killing the well (unless conducting the operations by snubbing), usually by installing plugs and adding water to control well pressure, replacing the wellhead and installing the SSSV, often on a tubing/packer string. These steps, while manageable, expose the operator and environment to risks of uncontrolled releases. Well servicing exposes workers and nearby public to safety risks. Loss of well control can cause noise disturbance in the case of blowout without fire and heat impact in the case of blowout with fire. Well servicing can also result in the loss of service for the downtime of the well, which depending on many other factors, could impair storage service to customers.

SSSV systems have expected reliability ranges, based on industry reliability tracking; however, reliability in U.S. gas storage applications has not been diligently tracked. The Battelle/Sandia studies make use of world-wide industry data to supplement U.S. gas storage data on SSSV reliability.

The Battelle/Sandia study also included evaluation of other consequences of SSSV applications, beyond the risk of loss of control during workover, as described in Section 3 and including 1) potential for increased methane emissions from leakage as well as from increased workover frequency; 2) increased safety risk to rig workers and others on-site during well work, attending to any well drilling and servicing work and not related to loss of control events.

As SSSVs have some well-established reliability ranges, the increased well interventions to pull the valve for well casing inspection or to service and repair the valve also increase methane emissions.

Because SSSVs and tubing are installed inside the well casing, they impede the use of downhole analytical tools, such as well profile calipers, and full-bore, casing-contact-necessary casing integrity logging tools, and cement integrity logging tools. This impedes an operator's ability to proactively assess the integrity of the well via casing inspection and flow logging/detection programs. In order to maintain surveillance of the condition of the casing, casing inspection tools and flow detection devices can be run inside a "casing" completion, and follow-up surveys can be directed at various frequencies depending on the findings of a survey or depending on a combination of other factors that recommend inspection. An SSSV/tubing string installation increases the cost (often two or three times or more) and complexity of casing condition monitoring.

SSSVs prevent the installation of a full-size plug in the well, impeding resolution of a potentially hazardous situation or significant leak event. However, some installations can make use of a lower packer with smaller diameter plug profile than the upper packer on the safety valve string. The lower packer affords the operator the ability to wireline set the lower plug, blow down the well, monitor the seal of the plug against the well pressure, then commit work to the upper packer and safety valve assembly, reinstall the upper assembly and test it, and return the well to service by pulling the lower plug.

SSSVs, regardless of where they are installed, are only partly effective, to the extent of the SSSV system functional reliability, in limiting a leak that is located above the SSSV. However, if a downhole leak occurs below the SSSV, the SSSV could reduce the operator's ability to deliver an effective treatment because repair tools must be small enough to fit through the SSSV without getting caught in the length of the SSSV profile.

Generally, for efficient well intervention and isolation in a leak event, restrictions inside the casing could and often do need removal. Deep set subsurface safety valves increase risk of problems and prevent the operator from setting a plug to control a well unless an additional packer is set beneath the point where the SSSV is set; such an arrangement retains a risk due to time and complexity for extraction of the tubing string and SSSV, relying on the lower packer plug to hold for a long period of time and hoping that no problems occur with the extraction or re-insertion [31].

5.6 Costs Related to SSSV Systems

The cost of installing a tubing and SSSV system varies from well to well depending on the type and size of the SSSV being installed, the depth of installation, pressure rating of the well, tubing size, and the method of installation. Installation of a SSSV system on tubing is usually most cost efficient when using a service rig. However, using a service rig normally requires isolating the reservoir pressure from the well work, which increases the safety and efficiency risk as previously discussed in this summary.

In the absence of lower packers and plug setting options, and in the cases where an operator might not want to kill the well due to formation sensitivity to kill fluids and the related reliability impairments of restoring the well to full deliverability, one option of installing a SSSV on tubing without having to kill the well is to use a snubbing unit. A snubbing unit allows installation and/or removal of tubing and packer without the need to kill the well (see Section 5.2). The cost of the snubbing unit installation can be significantly more than a service rig installation but the mitigation of possible permanent formation damage from killing the well can ultimately save the operator money over the long term.

The Battelle-Sandia team developed general cost estimates for installation of shallow-set SSSV on tubing for underground natural gas storage wells of different depths. The estimates are based on assumptions and ranges for: service rig or snubbing unit day rates and associated daily rental equipment; materials cost for tubing, packers, safety valve systems, and wellhead adapters and valves; logging costs for casing and cement integrity logs; high pressure pumping services; specialty labor including welding, packer and safety valve tool experts; well work supervision; miscellaneous trucking/hauling, site preparation and restoration, and waste management costs; administrative and project management costs; and, as applicable, overheads and contingencies.

The estimates given in Tables 25 and 26 are best considered as a "rule-of-thumb" midpoint with a probable range including ~90% of most real-world cases, and with a range of at least -15%/+20%, but which could be more or less, depending on the geographic location and complexity of the work. Without electric-line logging costs, the installations might decrease by tens of thousands of dollars depending on the number and type of logs run, and daily costs including contingencies for other equipment on site during logging.

The estimates for snubbing costs are similarly mid-point estimates in a probable -15%/+20% range, again more or less depending on many site-specific factors.

The point of these estimates is to note that the cost per well is not trivial and a more widespread implementation of SSSV systems, beyond the current <5% of UGS wells with SSSV, would have a measurable and significant financial impact. This order of magnitude cost perspective also forms part of the risk assessment in this study, as it is included in the adjustment of risk change: it is, effectively, added back into the net of risk reduction benefits of a SSSV, since the cost of implementation is a risk modifier.

Table 25. Estimated costs of service rig installation.

Type of well	2,000 ft well	4,500 ft well	7,000 ft well
Estimated cost	$120,000	$150,000	$190,000
Estimated mid-range typical costs – Range could be -15%/+20%, depending on location and complexity			

Table 26. Estimated costs of snubbing unit installation.

Type of well	2,000 ft well	4,500 ft well	7,000 ft well
Estimated cost	$150,000	$210,000	$240,000
Estimated mid-range typical costs – Range could be -15%/+20%, depending on location and complexity			

The cost for deep-set SSSV on tubing increases as the primary cost increase relates to the length of new tubing and the time for installing longer strings: for the 2000 ft well, mid-point cost might be $130,0000 to $135,000 as compared to the $110,000 to $120,000 for shallow-set SSSV. The 4500 ft well cost mid-point might range is $195,000 to $205,000, and the 7000 ft well cost mid-point might range is $275,000 to $290,000. These costs similarly might range at least -15%/+20%, depending on location, site specifics, and complexity.

5.7 Interview with SMEs on SSSV Technology, Maintenance, and Servicing

The Battelle/Sandia team interviewed two UGS industry experts with extensive hands-on experience with installation and maintenance of SSSV. The goal of the interview was to get an overall assessment of SSSVs as risk mitigation devices in the UGS wells, to identify common issues with the use of these devices, and to develop recommendations that may improve use of SSSVs. The interview was organized as an open discussion with the experts sharing their experience and recommendations and the Battelle/Sandia team asking questions and taking notes. Following the interview, both experts had the opportunity to review and edit the report shown below.

This interview should not be considered as a comprehensive and unbiased review of SV use in the UGS industry, especially since only two experts participated. However, the interview identified a few issues and recommendations that, in the opinion of the Battelle/Sandia team, are significant, unbiased, and practical to implement. Some of the observations made by the SMEs describe poor practices and areas that need significant improvement. By no means should these statements be considered as applying to the entire UGS industry or specific operators. The Battelle/Sandia team decided to include these observations out of respect for the interviewed SMEs, their experiences, and in recognition that the technical points raised are both valid and informative.

The interview identified several observations and recommendations that are described below.

Observations and recommendations related to mechanical construction of SSSVs:

- SSSVs are relatively simple mechanical devices that have inherently high mechanical reliability, likely in the 95 to 98% range. Most of the issues with SVs are related to human factors, not their mechanical construction.
- Newer SSSV designs are not necessarily better than older ones. Design goals that reduce SSSV overall size and/or reduce the number of moving parts may not produce a better SSSV. Reduced size may reduce cost of manufacturing but there is no evidence that smaller SVs are more reliable. Elimination of some moving parts may be detrimental to SSSV reliability. The specific example which illustrates this is the elimination of the temporary abandonment (TA) feature, which prevents damage to the SSSV sealing surfaces when a wireline passes through the SV during logging operations. The TA feature includes extra moving parts; however, these parts are very useful.
- One of the experts provided the following comment related to the TA feature of a particular SSSV make and model: The Camco Alpha 1 safety valve has a temporary abandon (TA) option, that when a wireline tool is run through the tubing from surface, it connects with a collet-type profile that, once engaged with downward pressure using jars, will drive a tube through the flapper part (the pressure holding part of the safety

valve). This protects the flapper from the stainless-steel wireline that is used to set profile plugs and other mechanical operations of the well. Once the valve is TA'd it pushes the flapper completely open and wireline work can be completed. Once the internal work is done, the wireline can run in with the tools to close the collet and re-establish the flappers' operation. There had been a history of wire cut grooves that ruined the flapper seal area causing the shut in of the safety valve to fail (to isolate adequately).

- Several specific SSSV models were discussed during the interview. The Battelle/Sandia team has no intention to either endorse or criticize any SSSV model or manufacturer. Instead, it is recommended that the selection of a specific SSSV model be left to experienced engineers employed by UGS operators. When selecting an SSSV model, lifetime cost and safety features should be considered. The lifetime cost includes cost of a new valve, costs of maintenance and spare parts, as well as anticipated costs of introducing new equipment. Introduction of an SSSV makes other downhole interventions more expensive and can increase safety risk. At the least, the SSSV needs to be extracted and re-set for work such as casing inspection logging, certain other logging, and most jointed tubing-conveyed tools and interventions.
- It appears there is very little need for the design of new SSSVs applicable to UGS wells since existing SSSVs can have excellent reliability records. It appears existing SSSV designs in use could experience higher reliability if human factor management was improved to match the inherent mechanical reliability. While various improvements in SSSV design might be possible, the next section focuses on the aspects of human factors related to SSSV.

Observations and recommendations related to human factors connected to SSSV use:

- The majority of issues associated with the use of SSSVs in UGS wells are caused by human factors, including decisions made during installation, monitoring and maintenance procedures, and training of the personnel handling these devices.
- Complacency is an important factor affecting views and attitudes related to SSSVs. It could be commonly concluded that since failures of UGS wells and SSSVs installed on them are rare, these accidents will never happen; therefore, rigorous safety procedures are not necessary, or that from lack of institutional attention over time, the view of importance and/or need of a SSSV, even if installed, becomes low priority. This complacency should be appropriately handled by UGS operators as well as state and federal regulators. UGS operators should evaluate SSSV use on a rational basis and implement their installation and timely maintenance for UGS wells that can benefit from this device. Regulatory agencies should work with industry to develop rules related to risk-informed decisions related to SSSV applicability, as minimally provided in API 1171 recommendations (see API 1171 Clause 6.2.5), and where SSSVs are in use, develop rules related to management of mechanical reliability and human and organizational reliability through application of procedures, training, monitoring, inspections, and testing, as well as recording of reliability information for continual learning. Minimum testing intervals of SSSVs are identified in API 1171 and further design, maintenance, testing, and inspection practices are recommended in API 14A and API 14B.
- Installation practices of SSSVs in UGS wells should include some basic principles:

- Installation of a fire-sensitive melting connector on an SSSV control system. This connector, if installed near the wellhead, melts in an event of surface fire and triggers automatic closing of the SSSV, which stops the fire. Considering the low cost of this connector and its significant benefits in case of fire, use of this connector should be universal.
- Installation of a manual SSSV closure actuator, and design review of installation location to assure reliable access in time of need. Each UGS well with the SSSV installed should include a manual closure actuator installed at an appropriate distance and at an easily accessible and identifiable location in the event of an emergency. An actuator installed too close to the well may be unreachable in an event of fire, and therefore not useful. An actuator installed too far from a well, or at a location which is not obvious, may take too long to reach. Installation of an actuator at a close, but fire-safe distance, from a well is a reasonable practice.
- Many SSSV installations are at relatively shallow depths due to decrease in reliability of control line and hydraulic pressure with increasing depths, as well as potential adverse impacts to well deliverability potential for SSSV set on tubing strings. Depth of placement is usually the operator's choice but is limited to an operator's confidence of the control line reliability per depth, pressure, temperature, fluid composition, susceptibility to solids deposits/build-ups, and other factors. SSSV placement in a tubing string in tandem with a wireline set wireline retrievable packer allows good retrievability and serviceability, with safety increased if a lower packer is set to the permit plug setting to isolate the well pressure from the upper packer and SSSV assembly when the upper assembly needs servicing.
- Wireline-set safety valves permit servicing with a slick line. Wireline set valve use should be considered against size, depth, and safety issues in the application.
- The operation of the hydraulic control of the safety valve is usually a very precise operation. Control systems require testing as well, and a hydraulic pump (often a hand pump) is used to apply pressure to the control line to open the flapper. The hydraulic system might be located fairly close to the well head and consists of a reservoir tank, with a spring-loaded bladder that acts as a variable to keep the pressure constant during the flow-back operation. This system can be added to a fire-safe system that requires a simple jump line and a tool that can hold operation pressures, but if fire reaches it, it will melt, causing the hydraulic pressure to drop and closing the flapper to a shut-in position. This is positioned by the hydraulic control box (using a flexible control line) to a position usually 1 ft above the top of the well head system used.
- SSSVs and their control systems can be inherently reliable if their design and operation are well-communicated during training. Hands-on demonstration with the mechanical parts and functions of the systems and a prompted question and answer session can be effective elements of a training and competency program.

- There is lack of knowledge and experience, in general, with respect to testing SSSVs, being aware of their function and need for inspection and maintenance, and need to fix versus remediate; this can be covered in training and reinforced with mentored hands-on/in-field execution of tasks. Part of the training should include review of applicable standards for how to apply known good practices as well as original equipment manufacturer (OEM) instructions to site-specific conditions (recognizing that weather, terrain, and other factors can create need to modify known good practices and adapt them to specific sites). Training should include annual question-and-answer safety meetings, which could help to make sure new employees are shown the proper operations as well as providing a review for experienced field personnel. Annual refresher training could include having the operation field technician at the well while a third party performs another step-by-step operational test during an interactive period that would allow for any questions and/or explanation of the valve and of the hydraulics. An "operations" class to instruct and answer any questions from the field technicians is needed to provide knowledge for them to keep the system operational. The field test of the valve is not complicated and should be in a written form that is easily accessible and can be done in a step-by-step operation.

- Training also could include discussion of what types of records should be kept on valve operation and malfunctions. Valve test records should be kept. "Safe failures" (false closures) should be recorded along with the conditions of pressure and flow at the time of failure. Functional failures should be recorded. Failures of valve operation, which were restored after routine maintenance, such as washing or repeat "exercising" of the valve, should be recorded. Functional failures, which could not be remedied and resulted in valve removal, repair or replacement, and reinstallation should be recorded. Conditions during the time of failure should be recorded. Whenever valves are pulled, the presence of any foreign materials, signs of damage or wear or corrosion should be recorded. Control system failures, leaks, and component causes should also be recorded.
- Training of personnel involved in SSSV installation and maintenance is important. Since SSSVs are frequently installed underground, it is likely that people working on these devices may not have seen these devices and may not fully understand SSSV components, dimensions, and functionality. Training using pictures or animations of SSSVs is less effective than seeing and examining an actual SSSV. It is recommended that old SSSVs that were removed from UGS wells be used for training purposes.
- Experience indicates occasional problems with tool sticking or "hang-up" when pulling or re-installing the safety valve string. The causes of sticking can include factors such as poor vertical alignment of the string and wellhead, buildup of solids in the casing and SSSV string, pack-off device slips not retracted or broken and dragging, or insufficient valve opening at the surface.
- All mechanical devices require periodic testing, inspection, and maintenance. SSSVs are no exception to this rule. The API 1171 regulation states that operators must test installed SSSVs once per year. This level of regulation is appropriate since it does not mandate use of SSSVs in all UGS wells, which would not be appropriate, but requires frequent SSSV inspection and maintenance.
- Redressing an SSSV is a common procedure that should be done every few years. For a shallow-set SSSV, it costs several thousand dollars to redress a valve, approximately ten thousand dollars, or more, depending on site-specific conditions, to pull, redress, and put it back in a well. The costs would be greater if the SSSV is deep-set. Spare parts needed for redressing may have a long delivery time; therefore, adequate spare parts should be purchased in advance and stored at readily accessible locations.
- Exercising of a valve, which is essentially a test of its function, not only confirms its operation but also improves its reliability (as reported by PG&E during the Denver workshop). Precautions should be taken to make sure a SSSV is not slammed (slammed closed), as it is known that slamming can easily damage SSSVs.

- One of the SMEs prepared an example check list for pulling and re-running SSSVs. This checklist is given in Appendix 3.

6. Conclusions and Recommendations

The work carried out by the Battelle/Sandia team led to several conclusions and recommendations:

- Application of SSSVs can reduce risk in some but not all UGS wells.
    - UGS wells with low risk (risk being defined as a product of likelihood of failure and consequence of failure) would generally not benefit from SSSV application, in fact the risk may be increased due to risks of more frequent and more complex SSSV-related workover operations.
    - For wells with moderate risks – driven by moderate or moderately high likelihood of failure and combined with high to moderate consequence of failure – the application of an SSSV can be seen as a cost-beneficial option at reducing risk when considering the entirety of the net risk change.
    - For UGS wells with inherently high risks, particularly when driven by high likelihood of failure, the application of SSSVs may reduce risk but since SSSVs are a consequence mitigation device, the reduction in risk does not treat such a well's initial, or inherent, high likelihood of failure and thus the net risk change, while substantial in high consequence cases, still may leave unacceptably high residual risks due to the persistent likelihood of failure; the increased workover frequency for SSSV reliability reasons could be seen as another reason to disfavor use of SSSVs in such high risk cases.

The Battelle/Sandia team recommends that the applicability of SSSVs in UGS wells be assessed for each well instead of a broad regulation that mandates the use of SSSVs for all UGS wells.

- Applicability of an SSSV in a UGS well depends on multiple factors including well design, reservoir pressure, total amount of stored gas, and nearby population density. The only reliable way to assess SSSV applicability is to apply a quantitative risk model that accounts for these factors and evaluates risk before and after SSSV installation. The Battelle/Sandia team recommends a broader adoption of quantitative risk models to assess and manage risks in UGS wells. Specifically, quantitative models that evaluate probabilities/likelihood and consequence of accidents should be adopted. Qualitative risk models that rank risks for wells without estimating accident probabilities and consequences provide information that is of partial value for risk management.
- The API 580/581 methodology offers a practical and sound method to assess risks for systems that confine pressurized fluids, including the UGS systems. This approach was recognized by the JITF team, which was assembled following the Aliso Canyon accident, and further developed by the Battelle/Sandia team. The Battelle/Sandia team recommends that UGS operators adopt some type of quantitative risk model, for example the model developed in this work, or an equivalent. Each UGS operator could adopt an approach most suitable for their systems, organization, available reliability data, and risk management procedures.

- Application of SSSVs in UGS wells increases frequency and complexity of workover operations, which must be included in the overall SSSV risk assessment. Each workover introduces risks of worker injury, of LOC events, and environmental damage. These risks must be weighed against benefits of SSSV use. A significant component of workover risks is related to an exposure of workers to safety consequences, up to and including death, that could result from an LOC event.
- Application of SSSVs in UGS wells might introduce gas deliverability restrictions that must be included in the overall risk assessment. Deep-set SSSVs introduce greater deliverability restrictions, especially if the SSSV is tubing-mounted. Effects of deliverability restrictions affect especially high-flow UGS wells and facilities that deliver gas product at rates near their capacity. If an application of SSSVs is mandated for these wells, an operator may be forced to build additional wells that would carry additional risks and costs.
- Human factors such as quality of management, safety training, and safety culture have significant effect on well risks. Although they are difficult to quantify, the impact of human factors can be as significant to the net risk change as the effects of safety devices such as SSSVs on net risk change. The Battelle/Sandia team recommends that regulators encourage and sponsor more studies evaluating human factor effects on risks, and development of objective methods to measure human and organizational performance. This area of research is very challenging but potentially very beneficial towards safety improvements.
- Failure rate data and safety data specific to UGS systems are very scarce in literature with the exception of reports of very large and publicized accidents like the Aliso Canyon incident. Information about less significant incidents, their frequency and outcomes, and frequency and types of near misses is almost unobtainable. The Battelle/Sandia team believes such lack of data prevents evaluation of the safety record of the UGS industry and inhibits possible safety improvements that were achieved by other industries with more open practices. The team recommends development of a standardized data collection and sharing procedures that address the needs and concerns of the UGS industry. Appropriate procedures will foster safety improvements, better collaboration between industry and regulators, and highlight industry accomplishments. The Battelle/Sandia team recommends that industry and its regulatory agencies agree on what should be collected and can be collected and involve a 3rd party to warehouse and analyze and report on the data.

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Appendix 1 – Predictions of the Battelle/Sandia Risk Model for UGS Wells with Different SSSV Configurations

The modeling procedure described in Section 3 was applied to four types of SSSV installations that are used in UGS wells:

- Shallow-set SSSV
- Deep-set SSSV
- Shallow-set combination of tubing safety valve and annulus safety valve (TSV + ASV) in wells that used tubing as a velocity string (no packer)
- Deep-set combination of TSV + ASV

Differences in SSSV placement for these installations are shown schematically in Figure 31. Each installation type was modeled with and without deliverability restrictions, as well as with and without human factor impact during workovers. The values of SSSV reliabilities, deliverability impairment and human factor credits used in these estimations are listed in Table 27.

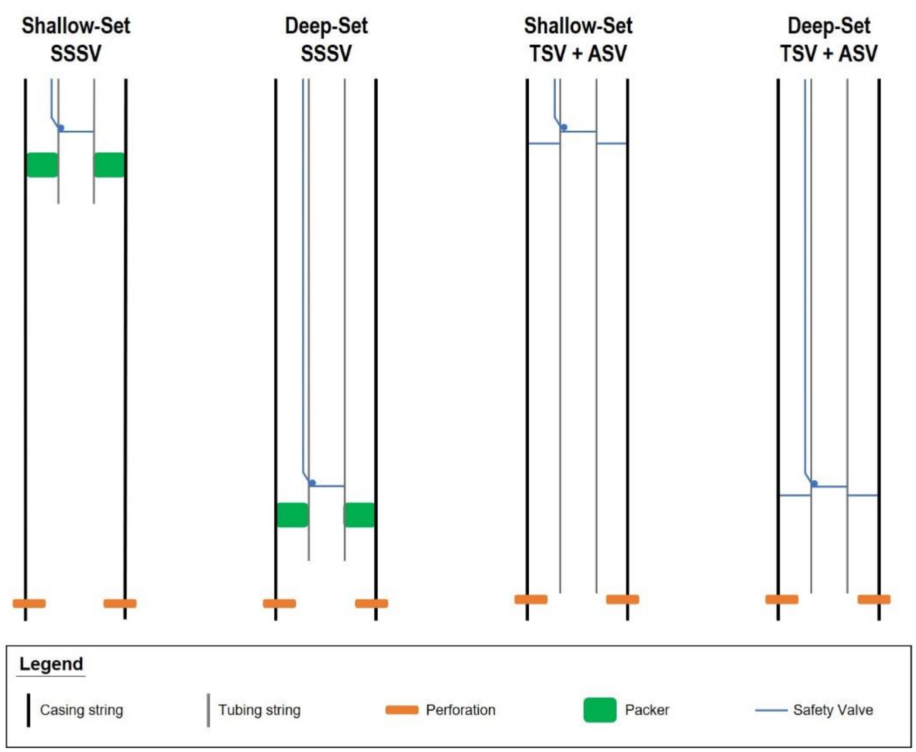

Figure 31: SSSV configurations used for analysis.

Table 27. Parameters used in simulations of different SSSV configurations.

T&P/SSSV configuration	Reliabilities of SSSV R_{SSSV}, R_{TSV}, R_{ASV}	Deliverability impairment factor C_{Del}	Human factors credit in workover LOFI	Figure
Shallow-set SSSV w/o delivery impairment or HF	.60 - .67 - .8 –.905 – .985	NA	1	32
Shallow-set SSSV with delivery impairment or HF	.67 - .8 – .905 – .985	Depends on initial deliverability – see Table 3	15	33
Deep-set SSSV w/o delivery impairment or HF	.36 - .67 - .84 - .94	NA	1	34
Deep-set SSSV with delivery impairment or HF	.36 - .67 - .84 - .94	Depends on initial deliverability – see Table 3	15	35
Shallow-set TSV + ASV w/o delivery impairment or HF	.67 - .8 - .905 - .985 Note that this is reliability for each valve	NA	1	37
Shallow-set TSV + ASV with delivery impairment or HF	.67 - .8 - .905 - .985 Note that this is reliability for each valve	Depends on initial deliverability – see Table 3	15	38
Deep-set TSV + ASV w/o delivery impairment or HF	.5 -.7 - .85 - .95 Note that this is reliability for each valve	NA	1	39
Deep-set TSV + ASV with delivery impairment or HF	.5 -.7 - .85 - .95 Note that this is reliability for each valve	Depends on initial deliverability – see Table 3	15	40

SSSV Configurations, Shallow- and Deep-set

The estimated reduction of annualized risk for a shallow-set SSSV application is shown in Figure 32. Recall that for a shallow-set SSSV, that is in the upper few hundred feet of a well, downhole failures occurring below the SV are not mitigated. Therefore, in the analysis, only surface failures with fire and extended releases without fire are mitigated, and the risk reduction is substantial in high consequence areas but minimal in low consequence areas. High consequence, again, is driven primarily by population density and secondly by well rate and feed volume. Thus, in low population density areas, even high rate/high volume wells have relatively low safety risk but higher workover risk, which act together to reduce cost/benefit of SSSV installations.

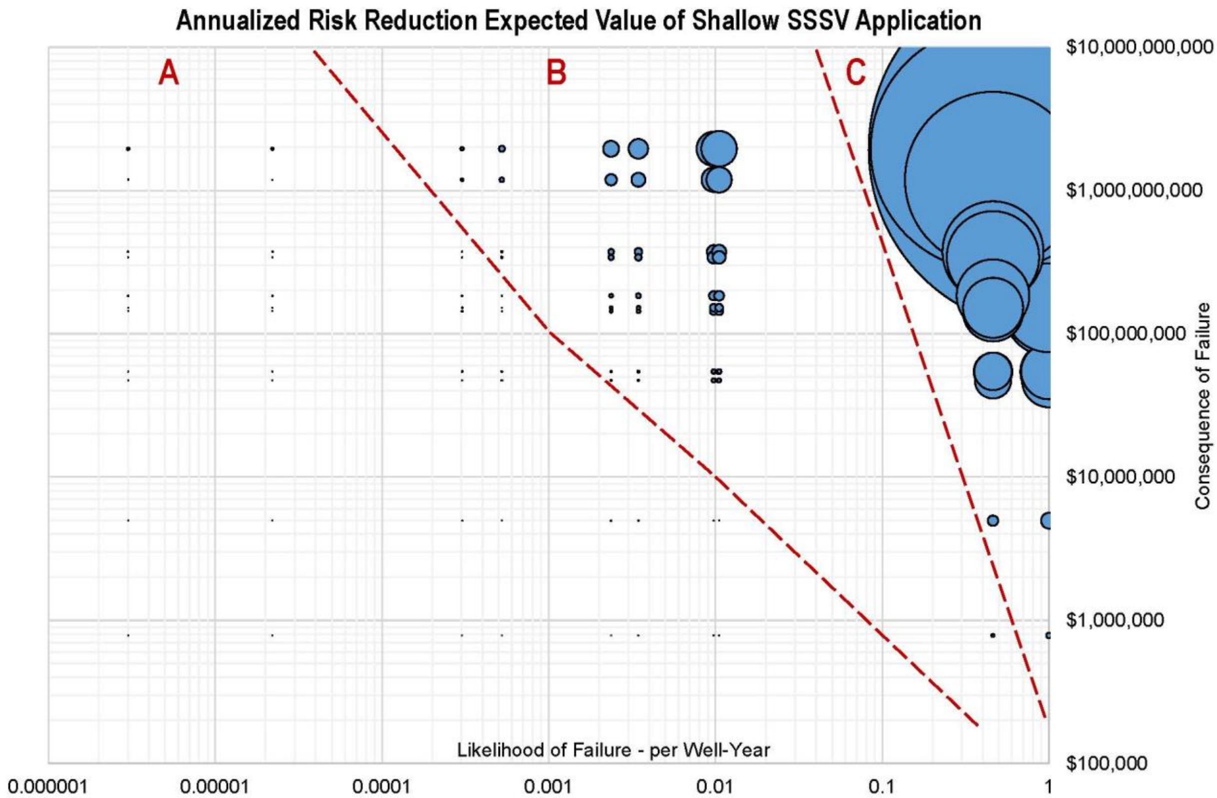

Figure 32: Annualized risk reduction of shallow-set SSSV application with all workover risks but without delivery impairment nor human factors effects.

The results obtained after inclusion of the deliverability impairment and human factors are presented in Figure 33. With shallow-set SSSV, the effects of deliverability impairment generally are not significant, but the Battelle/Sandia team attributed some deliverability potential and reliability impairment to shallow-set systems, with the amount of impairment related to flowrate (see Tables 3 and 27). Depending on the depth and pressure of the well, the installation cost for the SSSV system, as well as the new well replacement cost, can vary. When multiplying the workover costs by the human factor adjustment (15x) and adjusting the net risk change for deliverability impairment and human factors, the results in terms of the A-B range dividing line shifts rightward incrementally, generally by only a quarter-order of magnitude at low COFI but up to 0.7 to 1 order of magnitude at high COFI, effectively narrowing the range of wells within zone B.

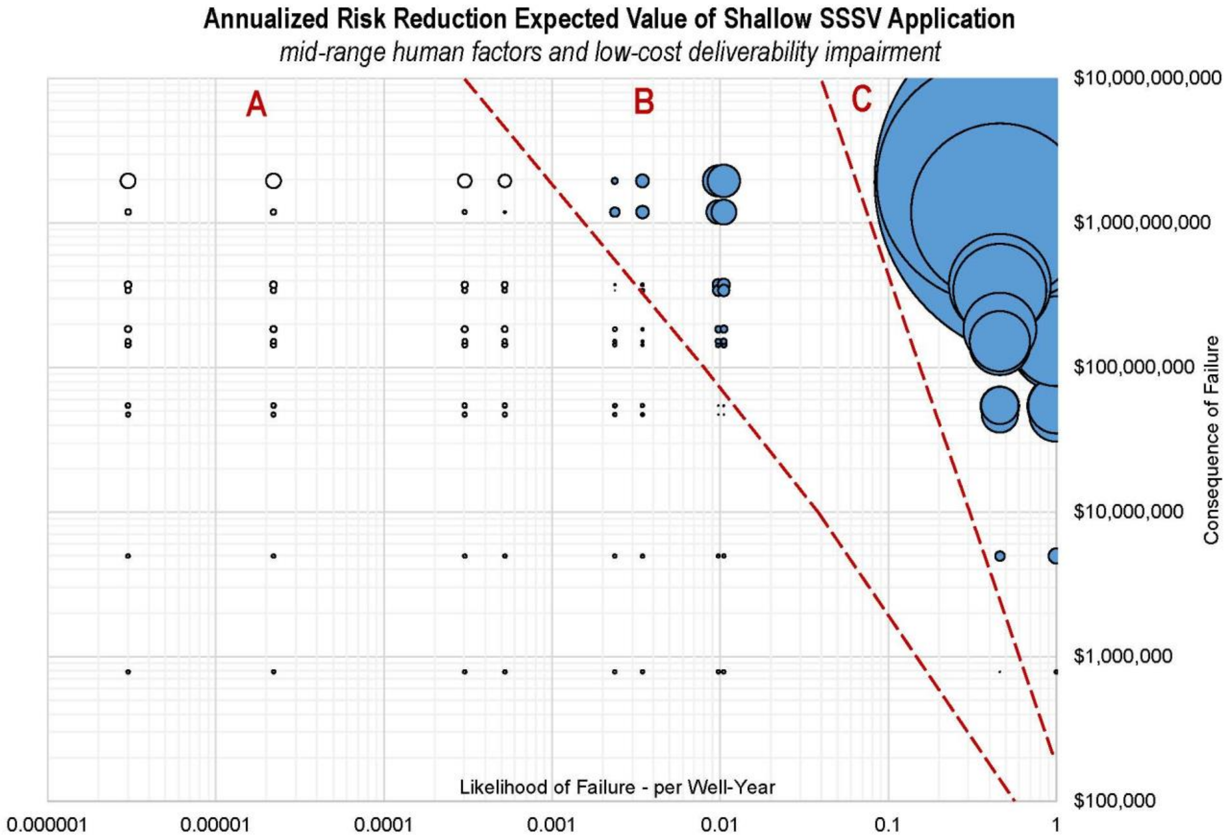

Figure 33: Annualized risk reduction of shallow-set SSSV application with all workover risks, with delivery impairment and human factors effects.

This group of simulations assumes a deep-set SSSV near the bottom of the production casing inside a tubing string. Reliability of deep-set SSSVs is judged to be less than the reliability of shallow-set SSSVs due to greater difficulties with the control system function and with keeping the valve mechanism clean and functional. Figure 34 presents the estimated annualized risk reduction without deliverability impairment and without human factors effects. Relative to the shallow-set SSSV, the deep-set SSSV configuration pushes the boundary between regions A and B to the left in the risk matrix, to lower LOFI, but incrementally, by 0.1 to 0.5 order of magnitude. This shift is due to the more effective mitigation of a deep-set SSSV, that reduces both surface and subsurface consequences. However, this improved effectiveness is partially offset by a lower reliability of deep-set SSSVs.

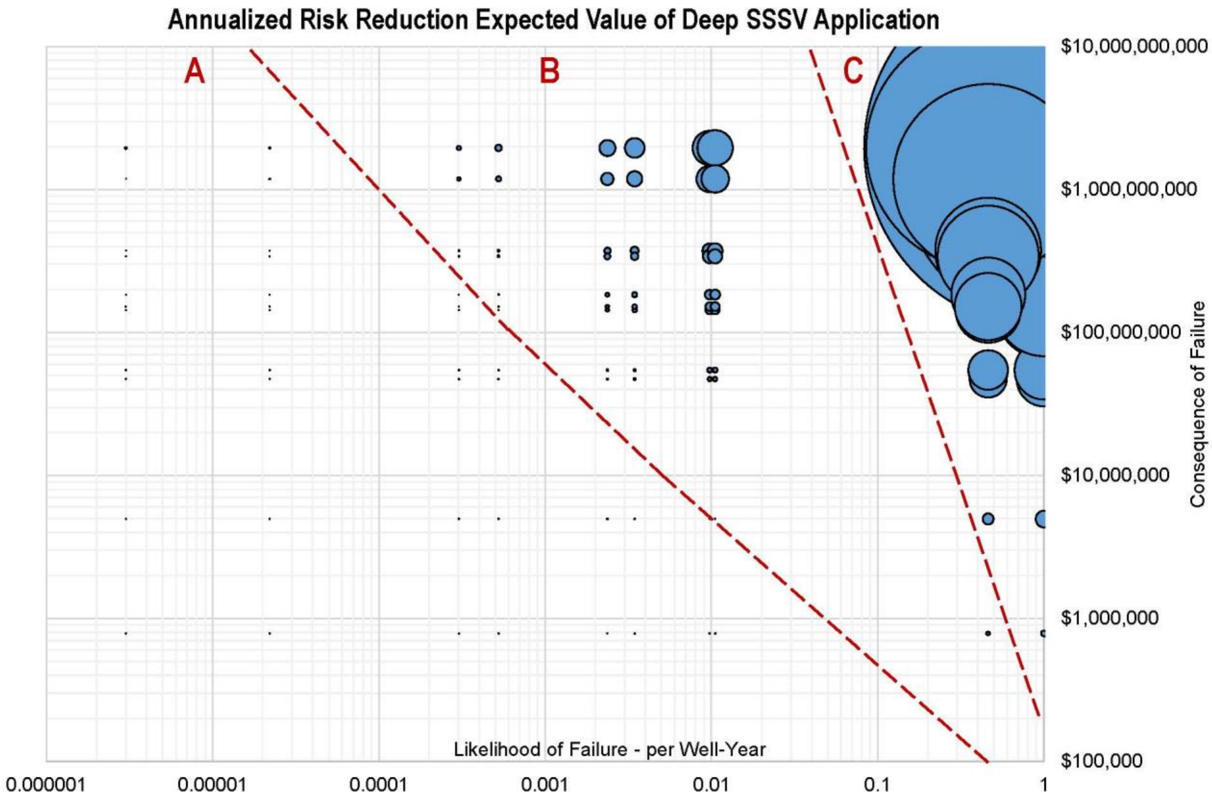

Figure 34: Annualized risk reduction of deep-set SSSV application with all workover risks but without delivery impairment nor human factors effects.

The results obtained after the inclusion of the deliverability impairment and human factors are presented in Figure 35. With deep-set SSSV, the effects of deliverability impairment are significant (see Tables 3 and 22). Depending on the depth and pressure of the well, the installation cost for the SSSV system, as well as the new well replacement cost, can vary. The Battelle/Sandia team used a range of new well costs of $1M to $4M, adjusting the cost by dividing by the deep-set reliability factor to account for annualized SSSV installation and maintenance costs. When also multiplying the workover costs by the human factor adjustment (15x) and adjusting the net risk change for deliverability impairment and human factors, the results in terms of the A-B range dividing line shift rightward by about one order of magnitude.

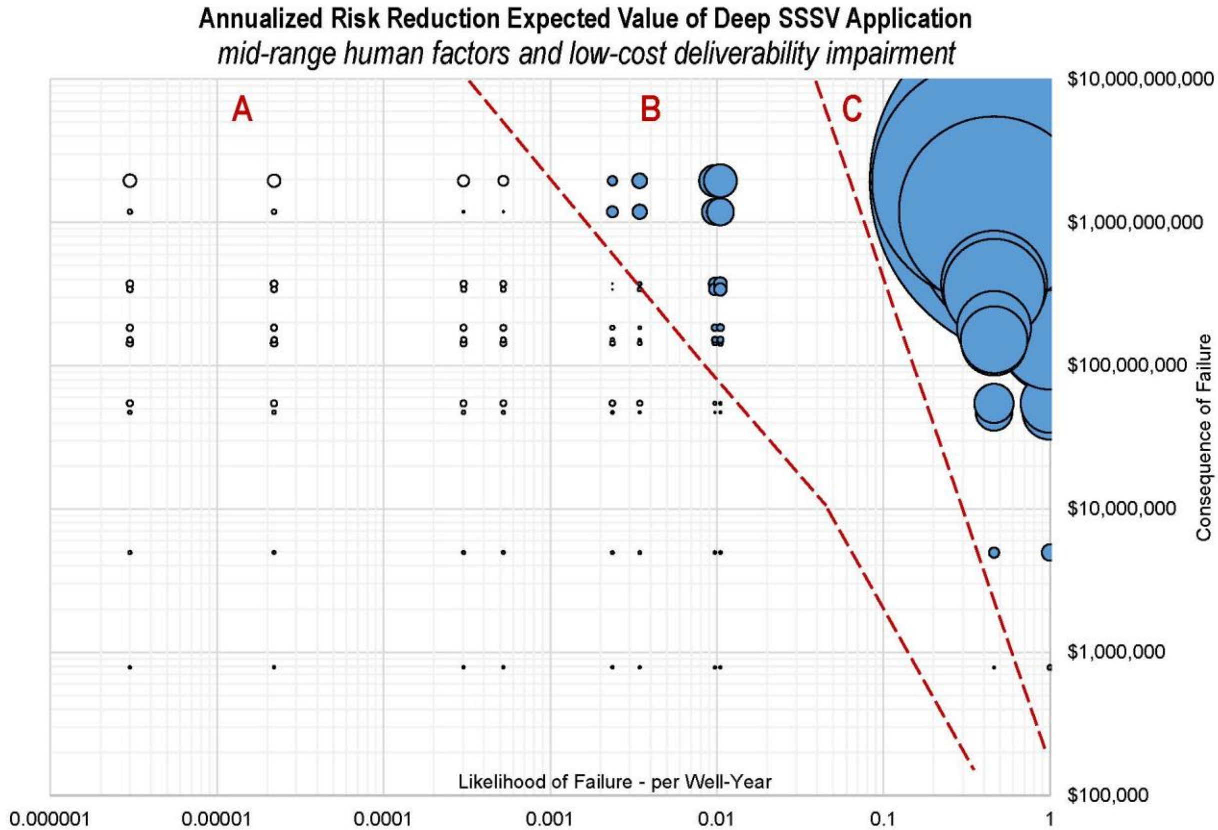

Figure 35: Annualized risk reduction of deep-set SSSV application with all workover risks, with delivery impairment and human factors effects.

The boundary lines separating zones A-C for all simulations involving shallow- and deep-set SSSVs are presented in Figure 36. As it was discussed above, the deep-set SSSVs have the broadest zone of applicability prior to accounting for the effects of deliverability impairment and human factors. The shallow-set SSSVs have the boundary line separating zones A and B shifted towards larger LOFIs by approximately 0.1 to 0.5 orders of magnitude. Inclusion of deliverability impairment and human factors shifts this boundary by up to an additional order of magnitude for both shallow- and deep-set SSSVs.

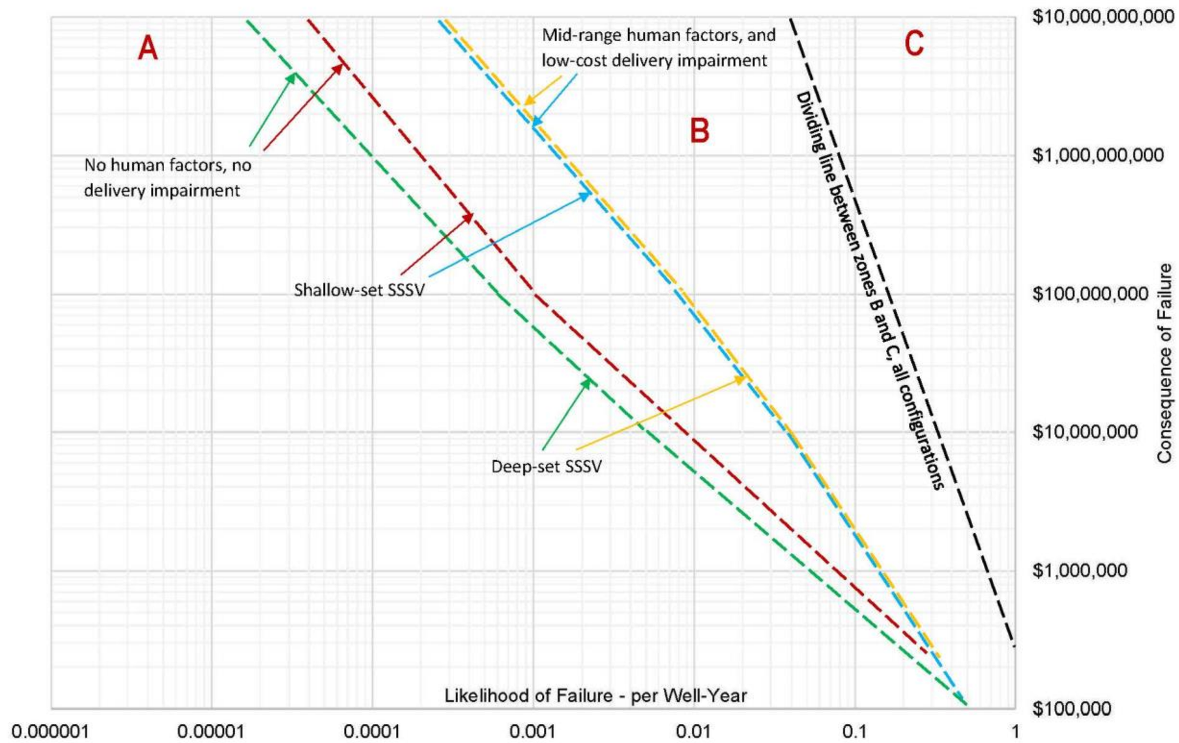

Figure 36: Effect of deliverability impairment and human factors on the boundary line separating zones A and B – results for shallow- and deep-set SSSVs.

Table 28 defines the boundary between zones A and B, shown in Figure 36, in terms of COFI and LOFI points that are intersected by these boundaries.

Table 28. Approximate position of the dividing line between zones A-B for SSSV installations.

Installation type	Workover adjustments only, no inclusion of human factors or deliverability impairment			Workover adjustments with human factors and deliverability impairment			
	COFI insertion point	**LOFI insertion point**	**COFI×LOFI insertion value**	**COFI insertion point**	**LOFI insertion point**	**Shift (orders of magnitude)**	**COFI×LOFI insertion value**
Shallow-set SSSV	$1 Billion	0.0002	$200,000	$1 Billion	0.0015	0.9	$1,500,000
	$100 Million	0.001	$100,000	$100 Million	0.008	0.9	$800,000
	$10 Million	0.01	$100,000	$10 Million	0.04	0.6	$400,000
	$1 Million	0.08	$80,000	$1 Million	0.15	0.3	$150,000
Deep-set SSSV	$1 Billion	0.0001	$100,000	$1 Billion	0.0018	1.3	$1,800,000
	$100 Million	0.0006	$60,000	$100 Million	0.0085	1.2	$850,000
	$10 Million	0.005	$50,000	$10 Million	0.045	1.0	$450,000
	$1 Million	0.05	$50,000	$1 Million	0.15	0.5	$150,000

TSV + ASV Configurations, Shallow- and Deep-set

In this section the Battelle/Sandia team addresses the configuration where a UGS well is configured to flow either through tubing, the tubing-casing annulus, or both, and both a tubing safety valve (TSV) and annulus safety valve (ASV) are installed. The tubing is not set on a packer and, therefore, does not act as an independent barrier system since it has no bottom closure. The team modeled systems where the TSV/ASV combination is set high in the well (shallow-set) and where the TSV/ASV is set low in the well (deep-set). The TSV and ASV must act together for total protection, but each is an independent consequence mitigation barrier.

Reliability of the TSV/ASV was set as indicated in Table 27. The flow potential of the well was adjusted for the flow restriction going to each side of the flow stream (the tubing or the annulus) since the analysis must address the partial mitigation afforded by either the TSV or the ASV.

Figures 37 and 39 show the net risk change for the shallow and deep configurations. Relative to the shallow-set SSSV, the shallow-set TSV-ASV combination is shifted leftward only slightly, by 0 to 0.3 orders of magnitude. However, for the deep-set TSV-ASV relative to the single deep-set SSSV configuration, the results are nearly the same.

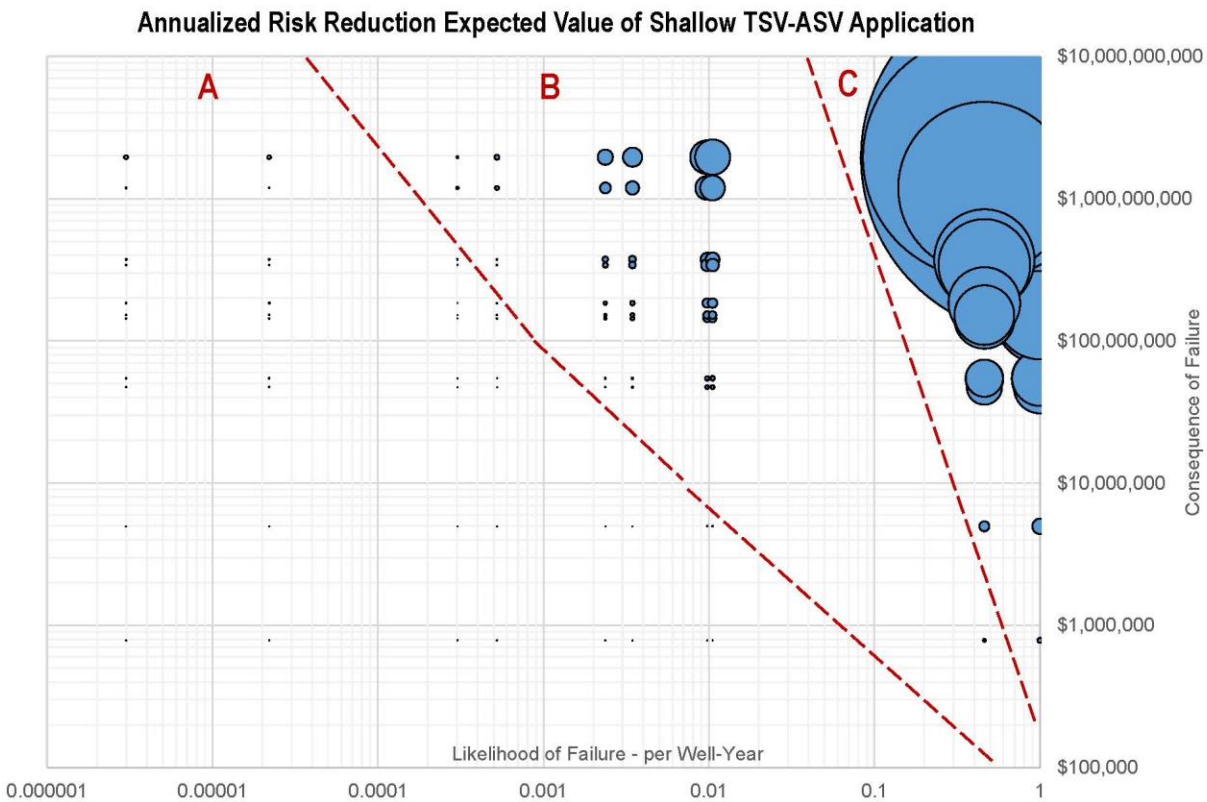

Figure 37: Annualized risk reduction of shallow-set TSV + ASV application with all workover risks but without delivery impairment nor human factor effects.

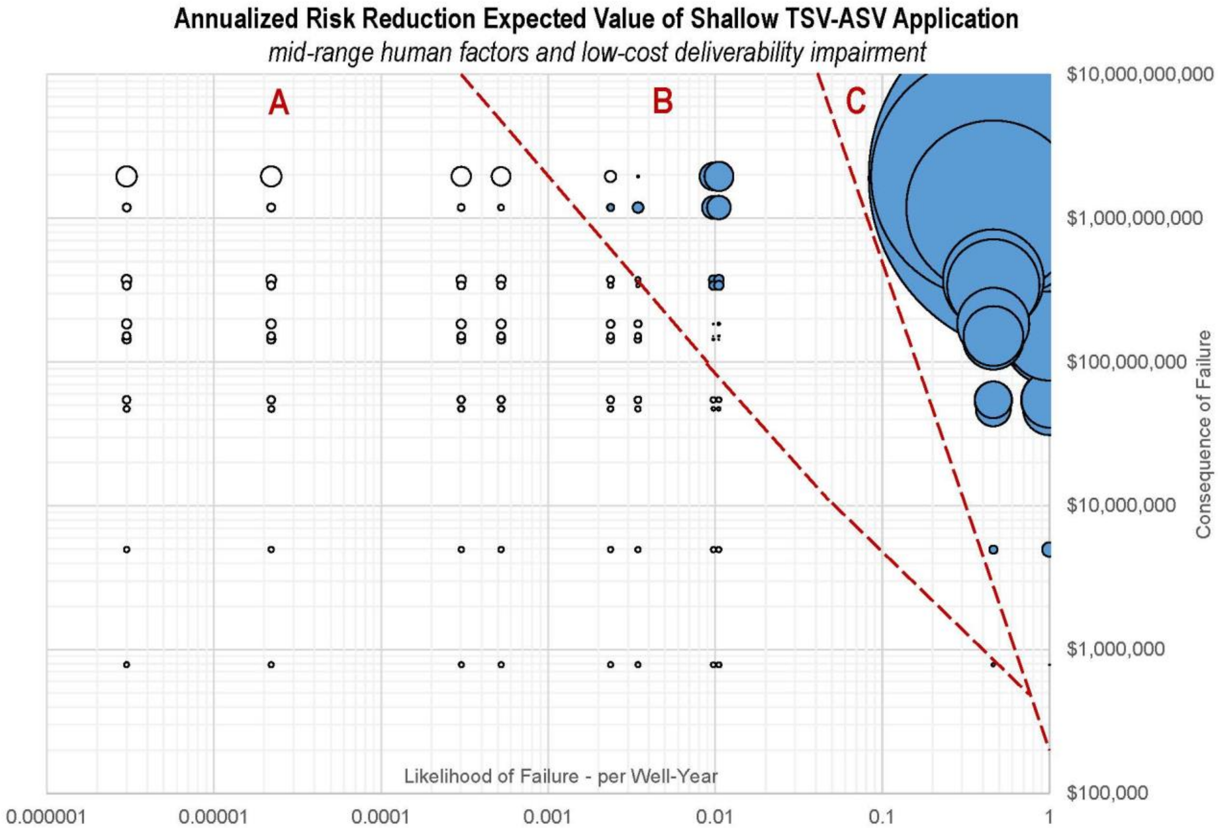

Figure 38: Annualized risk reduction of shallow-set TSV + ASV application with all workover risks, with delivery impairment and human factor effects.

Figures 38 and 40 show the risk change for the TSV-ASV configurations adjusted for the effects of deliverability impairment and human factors. The results, in terms of the A-B range dividing line, shift rightward by approximately one order of magnitude and the A-B dividing line position is nearly indistinguishable from the shallow-set or deep-set SSSV deliverability and human factors adjusted risk change.

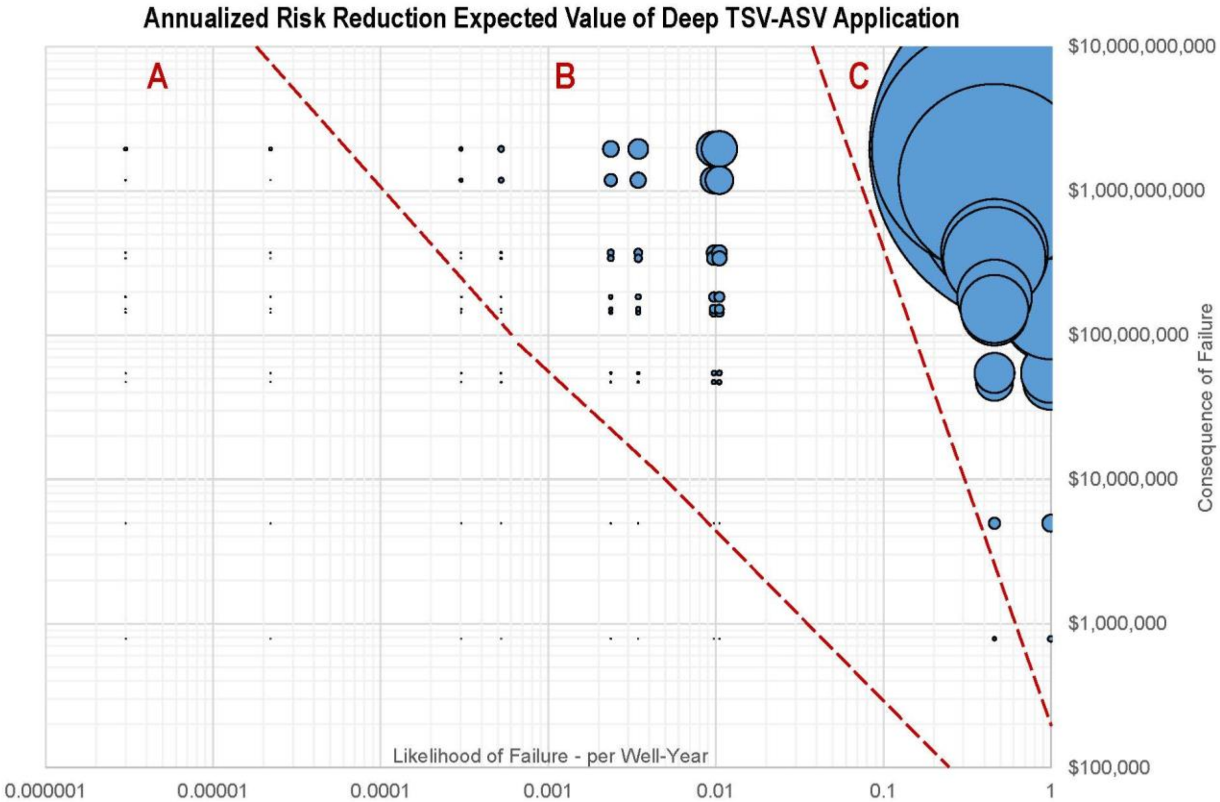

Figure 39: Annualized risk reduction of deep-set TSV + ASV application with all workover risks but without with delivery impairment nor human factor effects.

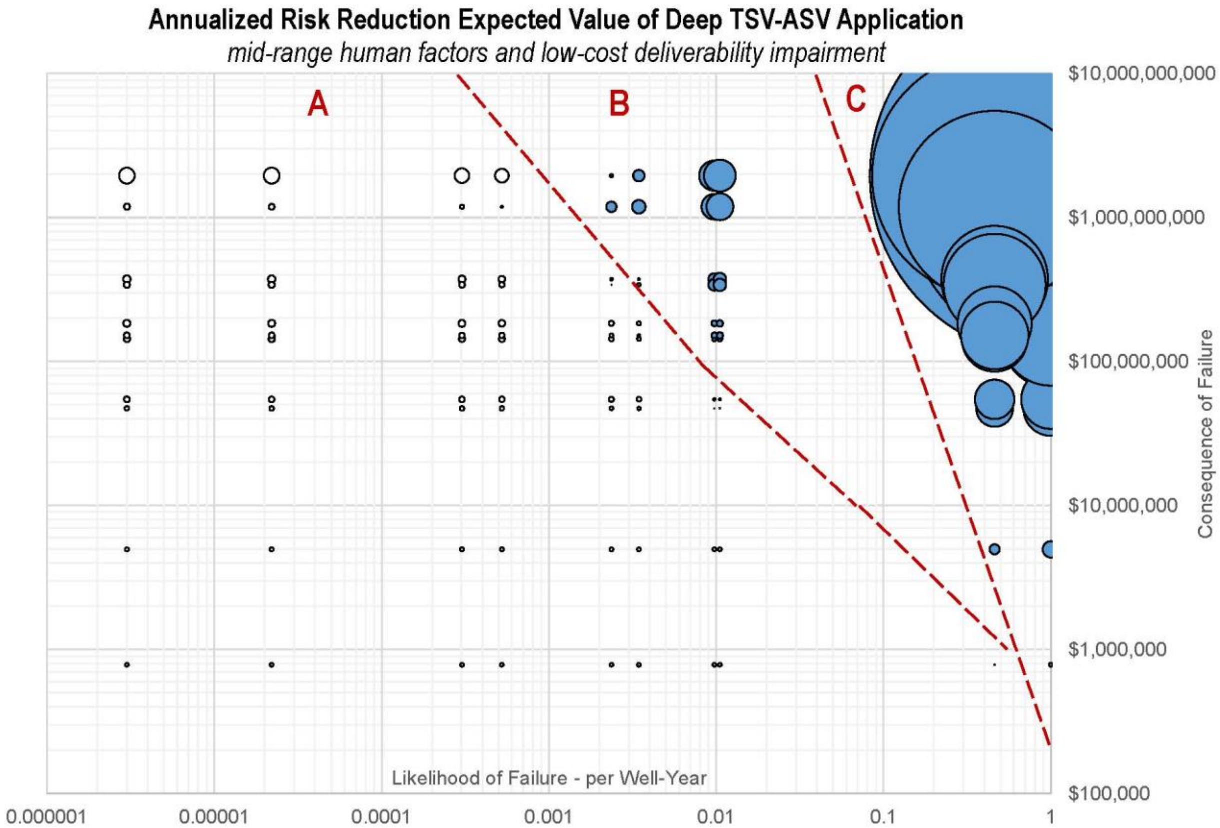

Figure 40: Annualized risk reduction of deep-set TSV + ASV application with all workover risks, with delivery impairment and human factor effects.

The boundary lines separating zones A-C for all simulations involving shallow- and deep-set TSV+ASV are presented in Figure 41. Similarly, as with SSSV configurations, the deep-set TSV+ASV systems have the broadest zone of applicability prior to accounting for the effects of deliverability impairment and human factors. The shallow-set TSV+ASVs have the boundary line separating zones A and B shifted towards larger LOFIs by approximately 0.1 to 0.4 orders of magnitude. Inclusion of deliverability impairment and human factors shifts this boundary by an additional order of magnitude for both shallow- and deep-set TSV+ASV configurations.

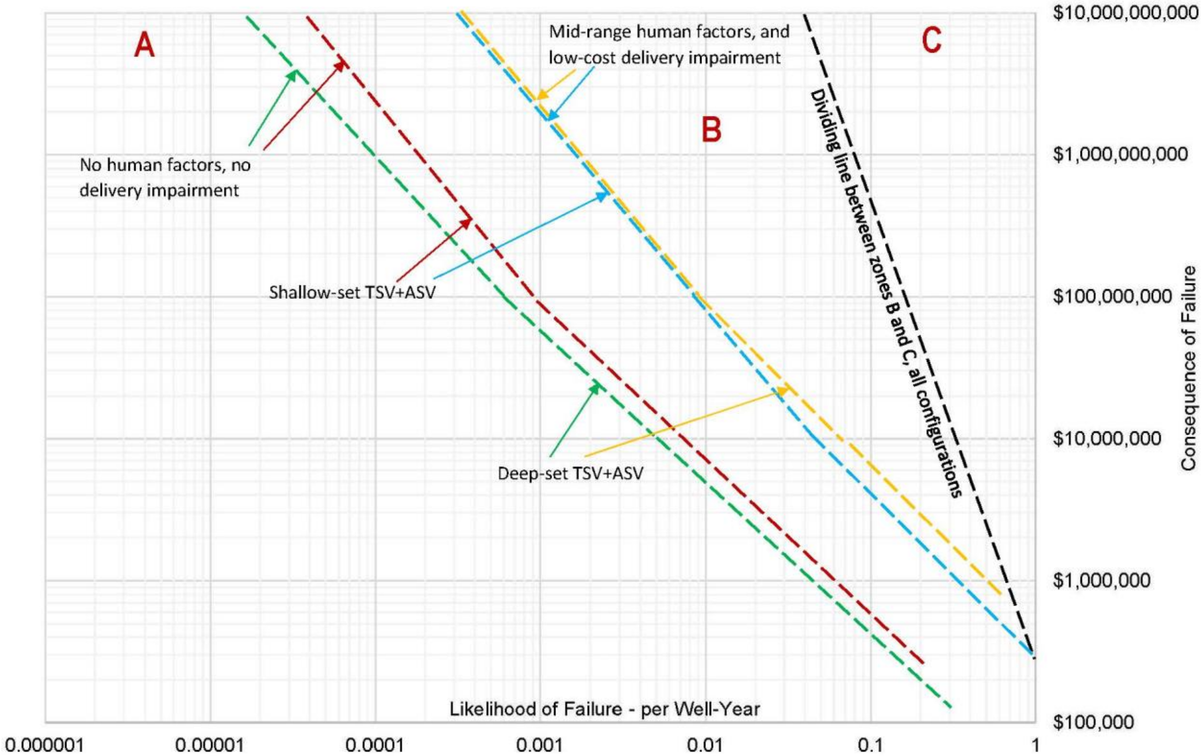

Figure 41: Effect of deliverability impairment and human factors on the boundary line separating zones A and B – results for shallow- and deep-set TSV + ASV.

Table 29 defines the boundary between zones A and B, shown in Figure 41, in terms of COFI and LOFI points that are intersected by these boundaries.

Table 29. Approximate position of the dividing line between zones A-B for TSV + ASV installations.

Installation type	Workover adjustments only, no inclusion of human factors or deliverability impairment			Workover adjustments with human factors and deliverability impairment			
	COFI insertion point	LOFI insertion point	COFI×LOFI insertion value	COFI insertion point	LOFI insertion point	Shift (orders of magnitude)	COFI×LOFI insertion value
Shallow set TSV + ASV	$1 Billion	0.00018	$180,000	$1 Billion	0.0018	1.0	$1,800,000
	$100 Million	0.0009	$90,000	$100 Million	0.009	1.0	$900,000
	$10 Million	0.007	$70,000	$10 Million	0.055	0.9	$550,000
	$1 Million	0.06	$60,000	$1 Million	0.4	0.8	$400,000
Deep-set TSV + ASV	$1 Billion	0.0001	$100,000	$1 Billion	0.0014	1.1	$1,400,000
	$100 Million	0.0006	$60,000	$100 Million	0.008	1.1	$800,000
	$10 Million	0.005	$50,000	$10 Million	0.07	1.1	$700,000
	$1 Million	0.045	$45,000	$1 Million	0.55	1.1	$550,000

Appendix 2 – Framework for Reliability Data Assembly and Analysis

The data collection and analysis framework provided here is meant to act as a seed to be taken and developed by industry or industry associations (such as INGAA, AGA, etc.) to meet goals related to helping reduce the likelihood of well failure and reduce accompanying consequences by better managing risk with more informed statistics. The framework presented here follows a tiered approach which examines reliability by looking at the type of equipment installed, operations management, and influence by human factors.

Equipment

<u>Well</u>

- Wellhead, pressure seals, gaskets, valves
- Casing, number and sizes
- Annulus, tubing/casing, casing/casing

<u>Safety valves</u>

- Number of installations
- Date, years of service, active, inactive, set depth & location, conveyance (wireline, casing, or tubing)
- Number of installations removed, reason
- Failure mode, safe, critical
- Safety valve components
    - Mechanical valve /type
    - Control system – pneumatic or hydraulic,

<u>Tubing and Packer</u>

- Number of installations
- Date, years of service, active, inactive, depth, type (packer: permanent, retrievable)
- Number of installations removed, reason
    - Failure mode, safe, critical
- Tubing & Packer Components
    - Tubing
    - Seals
    - Nipples
    - Packer elements
    - Tubing hanger

Operation Management

<u>Flow stream Characterization</u>

- Pressure
- Max flowrate
- Min flowrate
- Velocity
- Controls in place?

- Particulates
    - Type -sand, etc.
- Build-ups
    - Type – hydrates, precipitates, organic/inorganic solids

<u>Equipment Inspection/Testing</u>

- Wells
    - Site inspection
    - Mechanical Integrity monitoring
        - Operation limits/thresholds test
            - Pass
            - Fail
    - Logs – numbers of wells
        - Casing inspection
        - Cement integrity
    - Annulus surveys
    - Gas leak surveys
- Safety valves
    - Control system test
        - Frequency
        - Mode of testing
        - Pass/fail criteria
        - Was maintenance required to perform retest to acceptable pass?
        - Pass/fail rate
    - Annual/periodic valve test
        - Type of test (describe test for functionality [open/close])
            - Fully functional? Yes, no, if not why?
        - Type of test for leakage/sealing
            - Leakage or sealing pass/fail criteria
        - Was maintenance required to retest valve to "pass" condition? If so, what maintenance was performed? What occurred during re-test?
        - Pass/fail rate
- Tubing & Packer
    - Pressure test
        - Mechanical integrity test
            - Fluid used (gas, liquid)
            - Maximum pressure applied
            - Permissible leak off or other pass/fail criteria
            - Pass/fail rate
            - Maintenance performed to attempt retest, if applicable
            - Retest results

Tubing inspection/tubing leak inspection logging

Type of log (caliper, flux leakage, sonic/ultrasonic, noise/temperature, other)

Pass/fail criteria for logs, follow-up investigation frequency

Pass rate and/or additional investigation (follow-up investigation) rate

Plug in tubing and/or plug in packer tests

Reason for isolation plug test

Pass/fail criteria

Pass/fail rate

Tubing head, hanger, and valve seal tests and inspections

Leakage or other pass/fail criteria

Repairs or minor maintenance performed to do retest

Retest pass/fail rate

Other tubing and packer system integrity tests

Describe type of test

Describe pass/fail criteria

Describe minor repair or maintenance activity for retest

Pass/fail rate

<u>Equipment Intervention</u>

Wells

Remediations without repair

Remediations requiring repair or replacement

New wells drilled

Added/upgraded barriers

Safety valves

Remediate valve

Replace valve

Control system repair/upgrade

<u>Work overs</u>

Number of workovers

Incidents when trying to pull equipment, type

Human Factors

<u>Procedures</u>

Training of procedures

Specifications for design

Maintenance

Testing

Service

Repair

Procedures specific to:

Safety valve system maintenance (valve mechanism and control system)

- Safety valve system testing and inspection (valve mechanism and control system)
- Safety valve system installation and removal (valve mechanism and control system)
- Tubing and packer system maintenance (including all barrier elements of the system: wellhead parts [tubing head and hanger and seals, tubing valve], tubing string, packer, tubing/packer connection/interface)
- Tubing/packer system testing and inspection (including mechanical integrity [pressure] testing, logging, etc.)
- Tubing/packer system installation, removal

Definition of normal operating windows for barrier systems (safety valve systems, tubing/packer systems) including pass/fail criteria, leakage allowances, and other pressure, fluid, rate, temperature or criteria

Identification of AOC (related to conditions found outside of the above-defined ‘normal operating windows)

Management of Change instances when well barrier elements have been changed, or operating windows have been changed

Management of non-conformances: backlog list of items needing replacement or repair or changeout due to non-conformance to regulatory rules and/or a company’s design, operation, and maintenance standards

Appendix 3 – Example Checklist for Pulling and Re-running SSSV

This appendix provides an example minimum stepwise checklist for pulling and re-running safety valves. This checklist was compiled by one of the SMEs interviewed by the Battelle/Sandia team.

When a valve is pulled due to functional failure, the reason for failure should be identified. If a valve has failed in a field test before the valve is pulled, a complete startup of the system should be done. If the failed valve doesn't pass inspection, once the valve is pulled and before the complete redress of the valve, the shop should provide another step-by-step operation of valve. Noting the circumstances of the failure during the disassembly of the valve, a visual inspection of all O-rings and mechanical parts will be performed before assembly will start.

The well owner/operator must provide a down-hole schematic of the well-bore information and the equipment and depths of the equipment and casing, with entry diameters, plug make and diameter, and packer make and activation and release/setting mechanism.

Step 1) Before pulling the safety valve from the well bore, provide a visual and mechanical check of the control system of the safety valve by operating a closed valve safety test.

A) Did the valve hold and above pressure was ___________ PSI
B) Did the valve fail and above pressure was ___________ PSI

List any abnormalities of the test

Step 2) Identify how the well pressure is or will be isolated and how isolation will be assured during safety valve retrieval. Complete steps to isolate well pressure from the safety valve and implement steps to control well pressure during safety valve retrieval and reinstallation procedures.

Step 3) Open up the safety valve and start the retrieving process

Step 4) Once the valve is at the surface, inspect the valve for any of the below listed items:

A) If the safety valve did not pass operational test, perform visual inspection and record signs of:
- A-1) Any type of paraffin, scale, salt etc.
- A-2) Metal fatigue, and/or distress on the valve or any of the materials
- A-3) If possible, collect a sample of the material for testing.

B) If the safety valve did pass operational test, perform visual inspection and record signs of:

- B-1) Any type of visual inspection of paraffin, scale, salt etc...
- B-2) Any metal fatigue, and/or distress on the valve

Step 5) Inspections and tests at the repair shop:

A-1) Before the valve is repaired, a bench/vise test of operation should be performed.

Test opening and closing pressures and mark accordingly
Opening pressure _____ PSI   Closing pressure _____PSI

1) Valve opened as per operation/manufacturer guidelines   Yes __   No__
2) Any visual distress in any of the valves parts   Yes__   No__
3) Begin dissembling of the valve make notes on any parts that seem out of context

____

____

4) Once the valve has been disassembled, inspect seals and O-rings noting any disparities

____

____ _

5) Once parts have been cleaned and buffed, inspect all parts for distress and condition of the threads (all of the components will be cleaned and inspected, including all threaded components. The seal assembly will be cleaned and inspected.)

6) Install all seals and O-rings and proceed to assemble safety valve. Note any disparities during assembly and note what part, etc. The seal assembly will be cleaned and inspected. All O-rings and hard seals will be replaced, and the flapper will be visually inspected before the valve is re-assembled.

____

____ ___

7) Once assembly is complete, a pressure test will be performed on the case (body of valve) and also a closure and bleed off test will be performed and documented. Once the valve has been assembled, proceed to test it with both a water test and a gas or air test.

Make note of the pressures and results of test.
Valve tested ___   At what pressures Water ____ PSI
Air or Gas   ____ PSI did the valve open and close.

Opening Pressure ______ PSI
Holding Pressure _______PSI Pressure beneath the flapper

Notes: When a valve is pulled for other work and not because the valve function has failed or been impaired, routine maintenance service should be performed - inspection, cleaning, redressing or refurbishing/rebuilding. Tests should apply the pressure rating for the valve, usually $5-10K for a hydraulic test of the body of the valve. Next a gas test of the ID of the valve, with both ends capped, and pressure will be applied. During the test, if everything holds, bleed off the hydraulic line to the flapper and allow the flapper to close. While holding the gas pressure on the valve from the bottom, slowly bleed down the ID of the valve from the top. If the gas pressure holds and the ID is completely bled down, the test is complete and the valve is ready for re-install.

For false closures, even if a field test was performed and a redress is needed, before the redress, a system step-by-step operation would be done to double check whether or not the failure was a false closure.

Appendix 4 – Description of Steps in Battelle-Sandia Analysis of Risk and Risk Reduction for SSSV, T&P, and Other Combinations

Description of steps in Battelle-Sandia analysis of risk and risk reduction for SSSV, Tubing/Packer, and other combinations

Step No.	Description
1	Prepare information for estimates of Likelihood of Failure Index (LOFI)
2	Input information and determine estimate and ranges for Likelihood of Failure Index
3	Prepare information for estimates of Consequence of Failure Index (COFI)
4	Input information and determine estimate and ranges for Consequence of Failure Index
5	Estimate the change in COFI with the introduction of a safety device and its location (shallow-set SSSV, deep-set SSSV, Tubing/Packer, Tubing with SSSV, etc.)
5a	Adjust the safety (surface event), safety (subsurface event), environmental VECs, and various service-reliability-financial aspect consequences according to several estimates of safety device reliability (generally, low, mid, high reliability based on industry information or anecdote, as available)
5a Note1	Note that some consequence line items are not affected depending on the type and location of the safety device. For example, subsurface event consequences related to a casing failure deeper than the setting of a SSSV are not affected by the SSSV presence
5a Note2	Note that the equations used for each consequence adjustment are specific to the device, its location in the well, and the reliability ranges. COFI adjustments also were made for restrictions in AOF when safety devices such as tubing and packer were analyzed.
5b	Sum the residual risk remaining after introduction of the safety device and calculate the risk reduction of the safety device
5c	Calculate the percentage of consequences reduced in the categories of safety, environment, and service/reliability/financial consequence areas
6	Estimate Workover Risk of Loss of Well Control (LOWC) - using general industry ranges for LOWC
6a	Estimate consequences of LOWC from base COFI in Step 4, using multipliers as follows:
6b	Range annualized estimated LOWC risk using high and low industry rates of LOWC, multiplied by workover entry per well year, multiplied by the adjusted COFI for LOWC; range for all workovers being more risky due to SSSV or other safety features, or only incremental additional workovers due to SSSV reliability or other components
6c	Estimate additional safety risk due to rig work injury potentials, using industry data (this generally works out to an expected annualized value of ~$2K-$4+K)
6d	Calculate total annualized expected value of LOWC + safety risk by adding results of 6c to results of 6b
7	Calculate annualized estimated expected value (AEEV) for risk before introduction of a safety device, multiplying LOFI and COFI
8	Calculate the annualized estimated expected value of residual risk with the safety device by multiplying LOFI by the after-safety-device installation residual risk determined in Step 5. The calculation is performed for each safety device reliability (low, mid, high)
Step No.	**Description**

9	Calculate the annualized estimated expected value of risk reduction by subtracting the annualized expected residual risk from the original or base expected risk
10	Adjust the annualized estimated expected risk reduction for the following:
10a	Subtract the annualized estimated expected value of workover risk (+additional rig worker safety risk), assuming only incremental additional workovers contribute (results of Step 6)
10b	Subtract the annualized estimated expected value of workover risk (+ additional rig worker safety risk), assuming all workovers are more complex and contribute increased workover risk (results of Step 6)
10 Note1	Note1: the workover risk adjusted AEEV of risk reduction due to the safety device is the minimum net risk reduction
11	Additional adjustments to AEEV of risk reduction are considered in the next evaluation, and these include: 1) deliverability impairment due to flow tubular diameter restrictions; 2) deliverability reliability uncertainty due to reliability of safety device <100%; 3) added risk due to fractional added wells to make up for deliverability and deliverability reliability estimated from 1 and 2 above; and including adjustment, with 2 above, for life-cycle safety device costs; 4) additional weighting for less than adequate management of human and organizational factors affecting safety in a more complex environment caused by introduction of new and unfamiliar equipment such as SSSV, increased time pressure and cost pressure due to an increase in downhole work required because of the safety device and need for other monitoring of casing and cement or other downhole conditions
11a	deliverability impairment for flow tubular restriction was based on results of Sandia studies - a table approximating values used in the analysis is attached
11b	deliverability reliability uncertainty, along with life-cycle cost of safety device, was estimated by dividing an estimated new well cost by the mid-range reliability factor for the device. For example, if a new well cost is ~$4 million, then for a shallow-set SSSV, $4 million divided by mid-range reliability of .905 yields an adjusted cost basis for new replacement wells and life cycle costs of safety device installations of $4.42 million, while for a $1 million new well, the adjusted cost basis is $1.1 million.
11c	the fractional new well cost plus life-cycle safety device installation cost adjustment is added to the AEEV of risk reduction for a new well assumed to be robust/near-ideal in construction and also includes annualized workover risk costs for the fractional new well
11d	the costs in 11b are multiplied by the deliverability impairment estimate in Step 11a
11e	Inadequate address of human factors is estimated to be in the range of 5-15 times the annualized mid-range workover risk (see Step 6). We used a multiplier of 15 to provide a high-side estimate as an example
11f	Add the results of 11e to the results of steps 11b, c, d
12	Subtract from the AEEV of risk reduction (workover risk adjusted) the additional, high-side adjustment for deliverability and human factors
13	Analyze results of adjusted annualized expected value of risk reduction: 1) AEEV >$1 million are color-coded red 2) AEEV <$1 million but >$100,000 are color coded orange 3) AEEV <$100,000 but >$10,000 are color coded yellow 4) AEEV <$10,000, including negative AEEV, are color coded green
Step No.	**Description**

14	When a range of LOFI have been estimated for a well, the process is repeated for each LOFI. In the example scenarios, for each well type the project team estimated a max LOFI and a min LOFI, so results are presented for the range of LOFI.
15	Using the percentage of risk reduction attending to safety and environmental consequences derived in Step 5c, additional matrices of AEEV were generated for the range of LOFI and showing only safety risk reduction, and showing only safety+environmental risk reduction
16	Operators will have site-specific information that might cause other adjustments to AEEV; for this reason, the project team rationalized that AEEV<\$10,000 did not present a clear enough case of risk reduction value of the safety device. Further, the project team rationalized that AEEV in the yellow range (<\$100,000 but >\$10,000 might be in the range of questionable value of risk reduction, and inside a range where other risk mitigations could reduce the base LOFI and COFI to the point where the AEEV might fall close to or inside the green range
17	The project team rationalizes that cases where AEEV fall in the orange and red categories are prime candidates for application of the safety device; however, alternative risk mitigation measures should be compared. In many cases where analysis suggests cost/benefit efficacy of the safety device, the reason is primarily driven by high LOFI, and in such cases an operator should question why the well risk is not mitigated by replacement of all or some of the barriers driving the high LOFI, or a plug/abandonment of the well and replacement, if necessary, by a new and more robustly completed well.
18	Outside of the high-LOFI cases that almost always suggest efficacy of a safety device but might be more reasonably treated by other mitigations, as discussed in Step 15, the conditions suggesting implementation of an additional safety device generally include a sliding scale of log-scale increases in COFI with log-scale reductions in LOFI.
19	In addition to the color-coded matrices of calculated AEEV for each reliability range, the high reliability row was chosen to plot in 2-d log-log COFI risk reduction x LOFI. Two plots are shown for comparison: one with AEEV adjusted for workover risk only, and one with AEEV adjusted for deliverability and human factors and workover risk.

Appendix 5 – Other Methods to Lower LOFI and/or COFI

The installation of a SSSV is only one of the possible ways to reduce risk in UGS wells. Other methods should be considered since they may further reduce risks, with or without SSSV application. Generally, the safety of UGS wells should be approached holistically, considering all possible risk mitigation devices and procedures. Examples of methods that may lower well risks include:

- Tubing and packer (T&P) systems are applicable in some UGS wells. T&P may provide a secondary barrier, which reduces COFI, specifically the consequences caused by subsurface releases. The Battelle/Sandia team carried out a comprehensive evaluation of T&P systems in UGS wells [12].
- Surface protection barriers installed around a wellhead can effectively prevent impact events causing well damage and possibly LOC events (per API 1171 Clauses 10.2, 10.3). Perform regular inspection/condition assessment of these barriers.
- Eliminate knowable unknowns describing well design and as-built or as-found condition. Unknowns introduce significant risks both in operation and during LOC mitigation operations.
- Identify and eliminate well characteristics that, due to their initial design or due to modifications, would make the LOC mitigation challenging. The Aliso Canyon event is an example of a well with a complicated flow path that caused difficulty in killing despite numerous attempts. The consequences of this accident could have been significantly reduced if this well was more amenable to the well kill methods.
- Construct new wells, perform well repairs and replacements to robust safety standards/ high safety factors
- If possible, construct new wells in less populated areas
- Employ rigorous technical and human factors management standards and training procedures

Appendix 6 – The JITF Risk Model Guidance Document

This appendix contains the latest available version of the JITF model guidance document [10]. The Battelle/Sandia team obtained this document, and a permission to publish it, from its authors. The document is provided in its original form and was not edited by the Battelle/Sandia team.

PREPARED FOR **AMERICAN PETROLEUM INSTITUTE**
THE AMERICAN GAS ASSOCIATION
THE INTERSTATE NATURAL GAS ASSOCIATION OF AMERIC2018

UNDERGROUND NATURAL GAS STORAGE

RISK ASSESSMENT AND TREATMENT

STORAGE WELL METHODOLOGY

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This document is the result of the hard work of experienced and highly-skilled engineers and operators in the underground natural gas storage industry. We appreciate their efforts to share their knowledge and help increase the safety of storage. Special thanks to the committee who developed this document:

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DISCLAIMER

This document is solely intended to provide an example of risk assessment and treatment; however, it is not the only available approach. It is meant to be an aid to operators intending to implement portions of API Recommended Practices 1170 and 1171 and should not be read to supersede any applicable laws or regulations. It should also not be read as creating new legal requirements or amending or creating additional elements to the API Recommended Practices.

Table of Contents

A. Executive Summary and Conclusion

In the July 2016 industry white paper *Integrity and Safe Operations*, in part 1 "Natural Gas Storage Well Integrity Management Process & Risk-Based Approach (API 1171 Section 8)" reviewed the basic steps in a risk management process. This Guidance expands upon the July 2016 paper and develops a framework for quantitative and semi-quantitative assessment of the likelihood of failure of primary well barrier elements and the consequence of that failure, in order to derive an estimate of risk, rank wells in risk using a consistent quantitative to semi-quantitative process, and guide rationale to decision making about risk treatments. This Guidance was developed by incorporating the risk assessment and treatment methodology in standards such as API 580, API 581, API 1171 and ISO 16530-1.

The scope of this Guidance is to do relative ranking of risk for reservoir and aquifer natural gas storage wells, including their wellheads. The scope does not include the risk for salt cavern wells, geological containers (reservoirs, aquifers or salt caverns), plugged and abandoned wells, disposal wells, well interventions (e.g. drilling, reconditioning, logging, etc.), mining or other threats.

The Guidance provides a consistent method and rationale for ranking risk. It also provides templates for visualizing hazard management with various barriers and controls, for setting up event trees and fault trees, and a tool for reviewing risk treatment options to enhance reliability and safety. The Guidance drives toward:

- Standardization of a risk management framework,
- Standardization of risk analysis, focusing on loss of containment due to failure of a component of the primary barrier envelope,
- Standardization of quantitative to semi-quantitative approaches to risk estimates; and
- Standardization in approaches to risk treatment decision making, effectiveness review, and continual improvement.
- Standardization of methods to identify success paths and corrective actions for responding to barrier degradation or failure.

It is important to note that this Guidance is not a probabilistic quantitative modeling of risk. Hence, the risk ranking generated by this analysis is a relative ranking of storage well risk utilizing a multitude of factors impacting the likelihood of a well component failing (Likelihood of Failure Index- LOFI) with the resultant potential consequence(s) of the component failing (Consequence of Failure Index- COFI). All of the damage/decay mechanisms are summed and multiplied by the generic failure frequency. The result is that the LOFI is likely conservative.

The risk assessment includes a 5-step process- identify risk objectives, risk assessment, risk treatment, risk management plan and process review and reassessment for continual improvement. Some of the processes and tools utilized by the Guidance include process safety indicators (leading and lagging indicators), bow-tie diagrams, risk treatment library.

There is are associated Microsoft Excel spreadsheets ("Risk Guidance workbook LOFI.xlsm" and "Risk Guidance workbook COFI.xlsx") with this Guidance that provides the template for the analysis and relative risk ranking of wells. Operators will have the ability to tailor the worksheets to fit their specific assets. The model was tested by a group of operators and found to be useful in comparing the relative risk of their diverse asset bases.

This model is a useful tool to determine where to prioritize and expend resources based on what is driving risk (i.e. LOFI, COFI or both)

1. If LOFI drives risk, mitigations might go toward more inspection/repair/replacement, as well as to inherently safer designs for new or replacement components.
2. If COFI drives risk, mitigations might go toward detection/isolation/containment systems as well as to engineering/management methods in regard to awareness of and response to abnormal conditions. Also, the higher the potential consequence, the mitigative actions will be more driven toward precautionary measures due to uncertainty of actual outcome of an event
3. If risk is driven both by LOFI and COFI, then combinations of inspection/repair /replacement and engineering/management methods could be employed.

When operators make decisions on precautionary basis to protect life and environment, they also are making themselves increasingly robust against severe or catastrophic financial loss – thus the focus on the safety and environmental value drivers is the essence of the business case for process safety management. In preventing loss of containment, in protecting people and the environment, operators are protecting their property and their financial values as well.

While this Guidance closely follows the risk assessment and treatment methodology in API 580-581, one notable deviation is the exclusion of API 581's extensive review of the maturity of an operator's integrity management practices (management system factor). Due to the recent development and publishing of API 1170 and 1171 and associated implementation by operators, it was viewed as premature to incorporate API 581's detailed review of process maturity in this Guidance at this time. An abridged version, with editing to be more specific with respect to storage fields and wells, is included in this Guidance's Appendix 4 for future consideration.

While the risk analysis equations presented in this Guidance are very specific as to equation structure and values for ranges for the variables, it is the intention of the Guidance that individual operators can modify both the variables and range values to best fit their specific storage assets[1]. The 5 risk management steps presented herein (identifying objectives and risk tolerance, risk assessment, risk treatment, risk management plan components, and continual improvement and reassessment) are to be rigorously followed for all applicable storage assets – it is the detailed structure and components of the associated equations presented in this Guidance that are subject to site specificity. As long as any modifications are done on a logical, fact driven and consistent basis, the result will likely make the industry's management of risk more effective.

[1] Note that if operators change one set of criteria, they should review what happens to the LOFI and its limits overall to verify the continued logical analysis of the data.

Finally, it should be noted that this Guidance is intended and structured for an audience that is intimately familiar with the design, operations and technology associated with natural gas storage wells.

B. Introduction

This Guidance outlines risk assessment and risk treatment methodology for wells that can be adapted by most natural gas storage operators of depleted reservoirs and aquifers. The guidance expands on the API 1171 Section 8 risk management process outline. The July 2016 industry white paper *Integrity and Safe Operations*, in part 1 "Natural Gas Storage Well Integrity Management Process & Risk-Based Approach (API 1171 Section 8)", pp. 6-9 of the subject report, reviewed the basic steps in a risk management process.

This Guidance expands upon the July 2016 paper and develops a framework for quantitative and semi-quantitative assessment of probability of failure of primary well barrier elements and the consequence of failure, in order to derive an estimate of risk, rank wells in risk using a consistent quantitative to semi-quantitative process, and guide rationale to decision making about risk treatments.

This Guidance provides a consistent method and rationale for ranking risk. The Guidance provides templates for visualizing hazard management with various barriers and controls, for setting up event trees and fault trees, and a tool for reviewing risk treatment options to enhance reliability and safety. The risk assessment and treatment methodology leverages standards such as API 580, API 581, API 1171, and ISO 16530-1, 2.

The Guidance drives toward:

- Standardization of a risk management framework;
- Standardization of risk analysis, focused on loss of containment due to failure of a component of the primary barrier envelope;
- Standardization of quantitative to semi-quantitative approaches to risk estimates; and
- Standardization in approaches to risk treatment decision making, effectiveness review, and continual improvement.
- Standardization of methods to identify success paths and corrective actions for responding to barrier degradation or failure.

The effort towards quantitative or semi-quantitative methods derives from the importance of determining risk reduction of applied risk treatments, along with an estimate of the cost-effectiveness of the treatments.

The effort towards standardization of frameworks, particularly in the quantitative and semi-quantitative approaches to risk analysis, to risk treatment decision making, and to checking on the effectiveness of risk treatments, derives from the importance of improving safety by creating means for the industry to collaborate, share information, and continually improve by establishing and applying best practices.

Additional value of standardization and a plan-do-check-act continual improvement process is clarity for regulatory agencies, as representatives of the public good, in how the industry is managing risk to improve safety, service reliability, and environmental stewardship. Standardization of a risk management process can allow for good order in regulatory rule-making, implementation, and audit. This process will enable the development of a common risk-informed language for communication and consensus between industry groups and regulatory bodies. This industry wide standardization, subject to site specific differences, will result in the public being able to expect that any storage field in any state will have similar rigorous risk analysis and integrity management.

Standardization of a framework and its processes brings value by providing an organized way to achieve gas storage industry goals of protecting people, environment, service reliability, and property.

Standardization does not mean inflexibility. Throughout this Guidance, any operator can employ creative means of adapting the suggestions as best fit the operator's facilities, organizational capabilities, and institutional history. However, operators electing to follow this Guidance will be able to present a plan-do-check-act risk management process with recognizable steps, consistent means of estimating a quantitative or semi-quantitative estimate for risk, a consistent means of driving risk treatment decisions, and a consistent means of showing the value of risk reduction efforts.

The decision-making aspect of the risk management process, coming in light of the risk evaluation step and the choice of risk treatment, focuses on the principles of a tolerable risk framework. The tolerable risk framework simplifies decisions in light of an understanding of what is unacceptable risk, what is tolerable risk, and what types of risk should be reduced as low as reasonably practicable. What is unacceptable is any immediate threat or actual situation of loss of containment in a primary barrier element resulting in potentially significant consequences to human health and safety or environmental damage. The tolerable risk framework contains a broad area of "tolerable risk", an area in which most storage operations occur, but inside which risk must be evaluated in order to make risk treatment decisions in the spirit of ALARP – as low as reasonably practicable – decisions that are made on a cost-benefit basis. However, some decisions might be based on some bounded constraint placed by an operator's, or societal, values in regard to safety, environmental stewardship, or other parameters. The approach will also enable consistent application of risk informed decision making during operations and throughout the system life cycle.

The Guidance provides a library of generic risk treatment options, including inspection and monitoring, equipment repair, replacement, rehabilitation, or removal, and/or equipment additions. Additional information can be found in the 2016 document "Underground Gas Storage- Integrity & Safe Operations" also published by API, AGA and INGAA. The Guidance defines risk treatment to include technical/physical barrier elements of various types – passive, active, and control – as well as fundamental and human/organizational barriers and procedural controls that comprise a process safety management system. The Guidance provides a means for crediting additional preventive, mitigation (detection and isolation systems), and inspection and monitoring programs with reductions in probability or reductions in consequence potential related to primary barrier element failure. Use of the framework and methods in this Guidance allows an estimate of risk reduction for the treatments employed.

C. **Definitions**

This Guidance adopts definitions from existing standards as noted, for the following terms:

abnormal operating condition API 1171, 3.1.1

Condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

(a) indicate a condition exceeding design limits; or
(b) result in a hazard(s) to persons, property, or the environment; or
(c) indicate a potential downhole problem not related to design or hazard(s) but which may risk the integrity of the well and/or the reservoir.

Barrier (barrier element) API 65-2, 3.1.7

A component or practice that contributes to the total system reliability by preventing liquid or gas flow if properly installed

NOTE: The Guidance defines the barrier types and roles – technical/physical barriers serving in passive, active, or control functions, as well as fundamental and human/organizational barriers and procedural controls comprising a process safety management system – in order to account for technical, human and organizational reliability roles in process safety.

Physical barrier element API 65-2, 3.1.45

A physical means of preventing flow; can be classified as hydrostatic, mechanical, or solidified chemical materials (usually cement)

Well barrier ISO 16530-1, 2.62

System of one or several well barrier elements that contain fluids within a well to prevent uncontrolled flow of fluids within or out of the well

Primary well barrier ISO 16530-1, 2.39

First set of well barrier(s) that prevent flow from a source

Well barrier element (WBE) ISO 16530-1, 2.63

One or several dependent components that are combined to form a well barrier

Well barrier envelope ISO 16530-2, 3.53

Combination of one or several well barrier elements that together constitute a method of containment of fluids within a well that prevent uncontrolled flow of fluids within, or out of, a well

Well barrier system API 65-2, 3.1.63

One or more barriers that act in series to prevent flow. Barriers not acting in series are not considered part of a single well barrier system, as they do not act together to increase total system reliability.

Breaking of Containment ISO 16530-1, 2.8

The failure of one or more physical or procedural barrier elements such that release occurs either instantaneously or at a later time when additional barrier failure(s) occur (modified)

collector formation API 1171, 3.1.11
Formation, usually vertically above the gas storage reservoir, capable of trapping and accumulating gas

communication API 1171, 3.1.12
Fluid movement influence, which may be detected by pressure observation, fluid physical and chemical composition analysis techniques, or other means

containment API 1171, 3.1.13
Ability of a reservoir to confine stored gas and prevent migration either laterally or vertically out of the reservoir

functional integrity API 1171, 3.1.16
Total reliability of the storage system, including the physical integrity of the reservoir and well components and the performance reliability assurance established by management systems employed by the storage operator

Loss of Primary Containment (LOPC) = Failure [contains a functional definition of containment] **API 580, 3.1.18**
Termination of the ability of a system, structure, equipment, or component to perform its required function of containment of fluid (i.e. loss of containment). Failures may be unannounced and undetected at the instant of occurrence (unannounced failure).

plan API 1171, 3.1.29
Documented explanation of the mechanisms or procedures used to implement a program and to achieve compliance with standards

NOTE: A specific well work plan for drilling, completion, servicing, or workover operations can be written step-by-step instructions and associated information (cautions, notes, warnings) that describe how to safely perform a task.

procedure API 1171, 3.1.33
Documented explanation of action taken to achieve the steps of a process

NOTE: Procedures can be a description of the execution of tasks in a method or linked set of methods that will enable the activity to be accomplished according to a set of guidelines and standards.

process API 1171, 3.1.34
Systematic, ordered series of events directed to some end that comprise an approach or methodology to achieve an objective

NOTE: A process can describe work flow activity and quality standards for a wide range of procedures. Example: The risk management process is a systematic application of management policies, procedures and practices to the activities of communicating, consulting, establishing the context, and identifying, evaluating, monitoring and reviewing risk.

program API 1171, 3.1.35
Overall approach to manage a functional activity or physical part of an asset

NOTE: A program can be a defined outline of work activities that are designed to address specific objectives. Programs identify what to do and why it needs to be done. The program can define important aspects such as purpose and scope, roles and responsibilities, tasks and procedures, and anticipated results and work products.

Risk Tolerance terms (ISO Guide 73:2009)
risk appetite: amount and type of risk that an organization is willing to pursue or retain

risk tolerance: organization's or stakeholder's readiness to bear the risk after risk treatment in order to achieve its objectives

NOTE: Risk tolerance can be influenced by legal or regulatory requirements.

risk acceptance: informed decision to take a particular risk

NOTE 1: Risk acceptance can occur without risk treatment or during the process of risk treatment.

NOTE 2: Accepted risks are subject to monitoring and review

risk criteria: terms of reference against which the significance of a risk is evaluated

NOTE 1: Risk criteria are based on organizational objectives, and external and internal context

NOTE 2: Risk criteria can be derived from standards, laws, policies and other requirements

Well integrity ISO 16530-2, 3.54
Containment and the prevention of the escape of fluids (liquids or gases) to subterranean formations or surface

zonal isolation API 1171, 3.1.39
Condition of no communication between the gas storage formation and other formations in a wellbore or between the wellbore and any formation intended to be isolated

D. The Risk Management Process Overview

Integrity management programs incorporate a risk management process that includes system or facility definition, data gathering and documentation, gap identification and closure plans, risk analysis, evaluation, treatment decisions and treatment evaluation, design standards and design assurance, management of change, quality control and continual improvement actions. Risk management is a multi-step process, as outlined below.

Step 1: Identify objectives, define risk appetite and intolerable/tolerable risk, define current remaining risk after current risk treatments or mitigations ("residual risk") and improvement targets, and evaluation/decision criteria for risk management amid internal and external contexts affecting the storage asset;

Step 2: Risk assessment, composed of:

a. Risk source identification
b. Barrier identification, barrier decay modes, and event scenario development
c. Risk analysis
    1) Likelihood of failure index (LOFI)
    2) Consequence of failure index (COFI)
    3) Uncertainty ranging and sensitivity testing [2]

d. Risk evaluation and preliminary decisions against tolerable risk, targets and criteria determined in Step 1

Step 3: Risk treatment

a. Identification of success criteria for barrier performance and success paths that describe corrective actions for barrier degradation or failure
b. Treatment options /alternatives evaluation
c. Development of risk management plans
~~d.~~ Evaluation of treatment effectiveness versus performance targets

Step 4: Risk management plan

a. Development of a risk management plan, describing the steps in the risk management process, with specific actions and targets for tolerable risk for identifiable parts of the storage asset (field, well)
b. Identification, tracking, and treatment of integrity management occurrences, including loss of containment events and issues which if not treated could be become loss of containment events

[2] This is an important part of standard risk management process/risk analysis. However, if the operator is going to concentrate on worst-case situations, then it may be less of an issue than if the operator is going to work a probability-weighted analysis of risk. This paper utilizes the latter scenario.

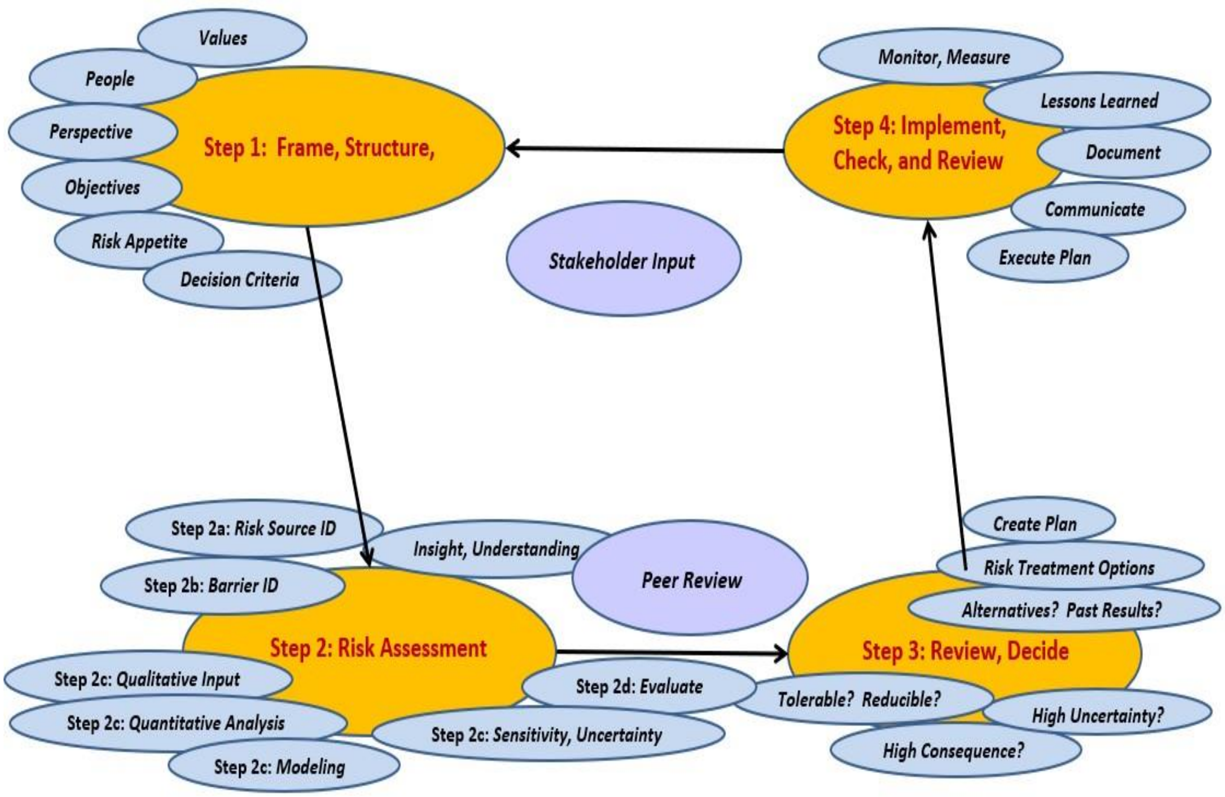
c. Management review of risk management plans and issues handling

Step 5: Continual improvement- review and reassessment

a. Periodic review of goals/objectives/targets achievement
b. Risk reassessment intervals
c. Self-audit
d. Personnel training and risk management / integrity management skills development
e. Adaptation of lessons learned

The flow of a robust risk management process creates a values-based, risk-informed decision process and continual feedback/improvement loop, as depicted in Figure 1.

Figure 1



E. Risk Management Process Steps

Step 1- Identifying Objectives, Tolerable Risk and Targets, and Evaluation/Decision Criteria amid Internal and External Contexts

Guidance: operators can develop their own process for accomplishing Step 1 as best fits their respective assets. To add in that effort, the following discussion reviews objectives, tools and other aids that may assist the operator in completing Step 1.

General Industry Objectives

Storage operators' objectives are to be stated in a risk management plan. The risk management plan includes a description of the steps in the risk management process. Objectives setting within Step 1 of the operator's risk management process outline targets for leading and lagging indicators of process maturity. An example outline follows of what operators could define in Step 1 of the risk management plan process description.

a. Develop risk management processes to improve safety by:

- i. defining overall mission and objectives of the project, process, or system
- ii. providing a robust, holistic identification of risk sources
- iii. demonstrating how barriers are used to manage risk
- iv. estimating risk in quantitative, semi-quantitative or qualitative ways[3]
- v. ranking wells by risk estimates
- vi. prioritizing resources to reduce risk among highest-risk wells, and
- vii. evaluating risk reduction;

b. Avoid loss of containment and its consequences;

c. Meet service obligations, increase reliability, and increase flexibility;

d. Prevent or minimize capital and operating costs related to unnecessary, ineffective, or inefficient inspections, and focus resource efforts on most needed inspections and mitigations;

e. Meet or exceed safety and environmental requirements; and

f. Evaluate the integrity management program effectiveness and evaluate the application of alternative risk treatments

g. Establish and maintain records management as necessary to support the integrity management program for the life of the storage asset

[3] Note that different receptors (e.g. humans, environment and property) have different criteria for assessing tolerance. This is handled in the consequence of failure index analysis, as presented later in this paper.

The risk management plan would include establishment of operating limits and thresholds for response action. Step 1 of the risk management process includes a review of current contexts of the operator's systems and components and how the design/as-built operating limits compare to the capabilities of the current state; risk management planning includes actions to:

1) Identify current remaining risk
2) Identify risk acceptability and a tolerable risk range
3) Set criteria for evaluating risk reduction and set performance targets
4) Identify success paths and identify actions necessary if risk is unacceptable
5) Develop a risk-informed decision process
6) Identify internal and external contexts amid which risk management decisions will be made, and
7) Solicit subject matter experts and management on objectives, tolerable risk and targets

<u>Step 1 Tools and Other Aids</u>

Step 1 requires a review of the internal and external factors affecting the operating company. The "socio-technical" pyramid of five foundational reliability blocks, from UK HSE RR-637, Figure 2, is a useful tool for operators to contemplate the impacts to their ability to manage risk and achieve the objectives. The five reliability building blocks include:

1) Company internal reliability and external reliability of the socio-political environment in which the company does business;
2) Organization and management system reliability
3) Communication and feedback systems reliability
4) Operations reliability
5) Engineering reliability

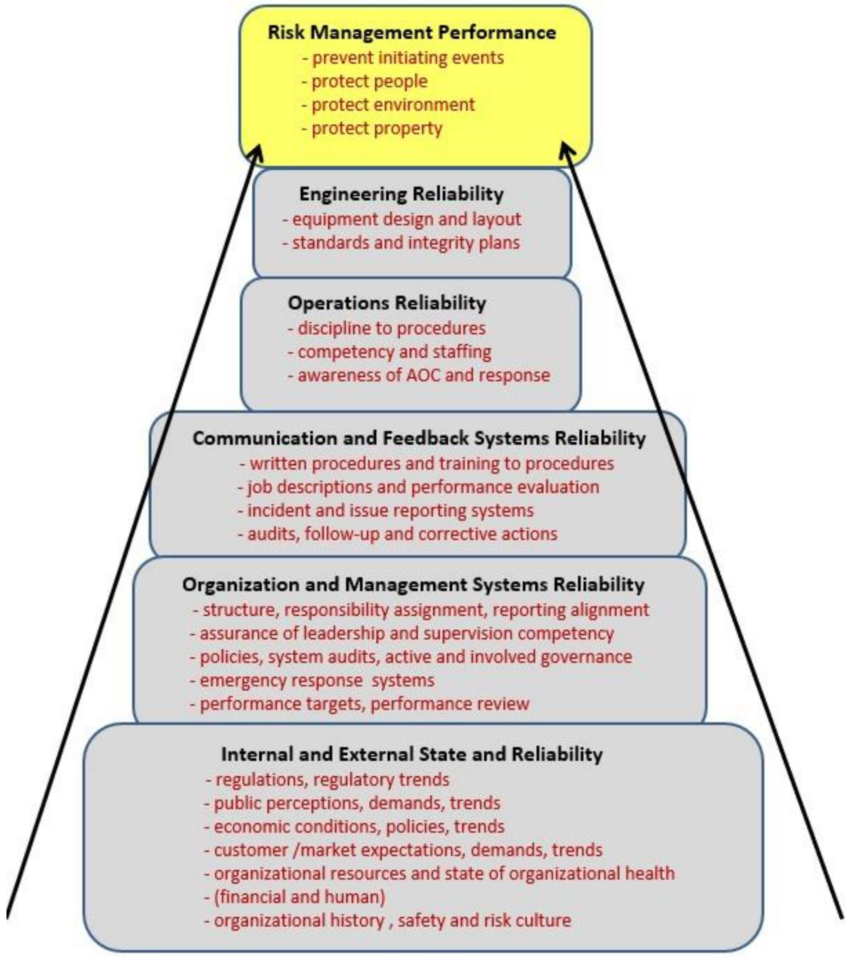
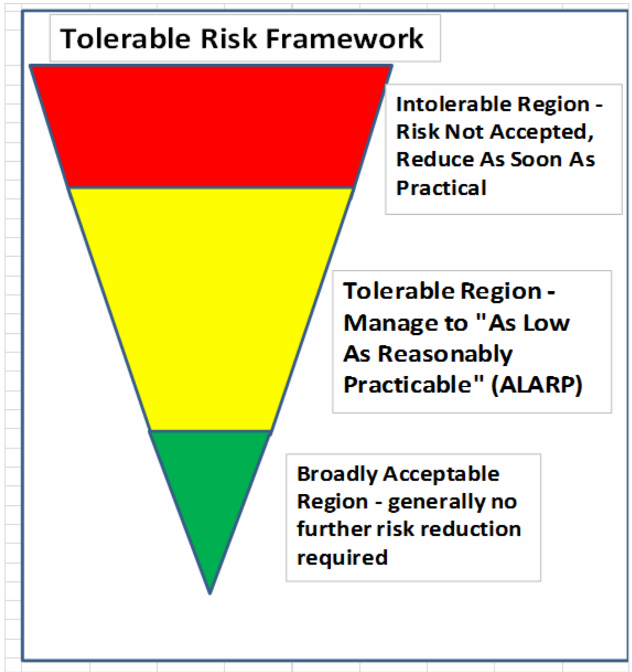


Figure 2

Operators can employ a tolerable risk framework approach, depicted in Figure 3, to understand that risk can exist in three regions: unacceptable, tolerable, and generally acceptable. For all three regions, effectively managing the risk must be linked to parameters that the operator can directly control. Operators also need to be cognizant that while there are risks they cannot control, they nevertheless need to incorporate recognition and flexibility in their risk management analysis and treatment programs to attempt to address such events if they occur. See Tolerable Risk Framework (refer to RFF DP-10-67) listed in the Bibliography.

Figure 3



The operator can establish a tolerable risk framework by setting the thresholds, or limits, between the three regions, expressly for certain consequence categories such as safety, environmental, and service quality, but perhaps also for financial, or other operator-selected categories. Some category limits might be set by regulation, or by world or regional consensus, or by industry associations and standards bodies.

The operator can set rules of conduct for their operations when or if risk is estimated to be in the unacceptable region. The operator also could set rules for when no further risk reduction efforts are necessary, as for example when risk is estimated to be in the broadly acceptable region.

An operator could find most or all of their facilities in the tolerable risk region, whereupon the operator can determine which categories of risk require further risk reduction. Operators can agree that safety and environmental risk should be driven "as low as reasonably practicable" (ALARP), a risk reduction philosophy that employs utilitarian (cost/benefit) analysis to compare options for risk reduction in terms of the options' resource burden vs. net risk reduction benefit. Net risk reduction is a measure of the gross risk reduction in the target category, such as safety, along with attendant risk reductions or risk increases in other significant categories.

Step 1 is a preparatory step that precedes risk assessment, but it is critical to the success of the risk management process because it defines the mission, sets the plan, the goals, objectives, and targets for continual improvement, the means of execution, and the means of evaluating progress towards goals achievement. Thus, an additional Step 1 task is development of the risk management decision process, and how the operator will evaluate risk and risk reduction quantitatively in order to apply

ALARP. Operators can set annual or multi-year targets for risk reduction and then evaluate reductions using the quantitative measures employed in the risk assessment process.

Operators might identify leading and lagging indicators of their risk management process effectiveness, and within those indicators operators could identify specific targeted measures. Possible indicators are identified in Appendix 1.

<u>Setting targets for lagging indicators of risk management process effectiveness:</u>

Lagging indicators are a measure of process safety incidents, near misses or unsafe conditions which activated one or more layers of protection. Lagging indicator metrics are retrospective and describe events that already occurred. Because near misses or unsafe conditions are actual events, their true value is in the identification of potential future more serious events. Evaluation of risk reduction is a lagging indicator of an operator's risk management process effectiveness. For example, objectives and targets in risk reduction for an operator's fleet of storage wells might include:

- Reductions in likelihood of failure index by work remedying, replacing, or removing ineffective or deficient materials or units;
- Reductions in likelihood of failure index by increasing frequency of inspections, tests, or monitoring or types of tests, inspections, and monitoring, in order to reduce uncertainty in the "current" state;
- Reductions in likelihood of failure index by revising operating limits to increase safety factors;
- Reductions in likelihood of failure index by installing/maintaining/restoring preventive barriers;
- Reductions in likelihood of failure index by increasing reliability and reducing well interventions;
- Reductions in consequence of failure by installing mitigation barriers;
- Reductions in consequence of failure by reducing footprint;
- Reductions in consequence of failure by increasing monitoring and improving event recognition and response time; and
- Reductions in consequence of failure by improving emergency preparedness.

<u>Setting targets for leading indicators of risk management process effectiveness:</u>

Leading indicators are a measure of items that can identify potential issues. Leading indicator metrics are forward looking intended to help drive performance improvement and lead to a reduction in the number and severity of process safety incidents. Data collected from leading indicators can give early indication of deterioration in the effectiveness of key safety systems and enable corrective actions to be taken in a timely manner. Objectives and targets for risk management leading indicators can focus on the state and condition of the plan-do-check-act processes. Leading indicators might include:

- Leader engagement and participation in safety reviews and integrity management program reviews;
- Procedures and standards development;

- Self-audits;
- Training program development and training completions; and
- Employee engagement, communication, and feedback opportunities.

<u>Development of Risk Management Decision Methodology</u>

Decision science can be applied in the risk management process to form a consistent method to determine and manage risk tolerance and acceptance levels and select the type and extent of controls.

A decision is a choice among alternatives that could yield uncertain outcomes, but an operator might have preferences among possible outcomes. Good decisions are defined not by outcome, since the actual outcome is uncertain, but by whether the decisions are made through a structured process using the best available information. The information required to make good risk-informed decisions should be identified using a systematic process.

Uncertainty might be underestimated or improperly assessed due to overconfidence, a narrow and/or biased (usually optimistic) view of possible outcomes, and leaving too large a zone of ignorance, failing to broaden knowledge through shortcomings in the breadth of inputs and perspectives from stakeholders in the decision-making process. The decision process is robust if it includes communication to decision makers in regard to characterization of uncertainty, its sources, and the sensitivity of the analysis to critical parameters.

Additional guidance on decision making methodology is presented in Appendix 2.

Step 2- Risk Source Identification

Step 2a- Risk Source Identification – Alignment to API 1171

Risk assessment begins with identification of risk sources affecting probability of failure and barriers/controls to failure and their related barrier decay modes. API 1171 and API 581 are useful references to find threats/hazards acting as potential contributors to likelihood of failure index (LOFI). LOFI is a function of:

1. Deterioration and damage types, mechanisms, and causative agents
2. Rate of deterioration/damage (time-dependent or time-independent)
3. Probability of identifying and detecting deterioration and predicting future states with inspection techniques
4. Tolerance of equipment to the deterioration and damage types, often related to design, especially with respect to safety factors and metallurgical properties of equipment

Damage, usually time-independent, can occur due to:

Outside force- Natural causes (earth forces, land and water movements)

3rd party actions including:

Transport/vehicular

Foreign well drilling and production operations

Construction and industrial activities, such as mining, logging, etc.

Sabotage/vandalism

Deterioration mechanisms, usually time-dependent, relate to:

Thinning due to internal and/or external corrosion

Thinning due to mechanical/chemical erosion

Mechanical fatigue, vibration

Stress induced in any manner by tension, compression, axial torsion/shear

Mechanical wear

API 1171, Section 8, Table 1, specifically addresses a number of risk sources:

Well Integrity deterioration:

- ~~P~~*otential loss of containment due to* Corrosion, Material Defects, Erosion, Equipment Failure, Annular Flow, cement bond failure, cathodic protection system interference, valve failure, gasket failure, thread leaks, mechanical fatigue/vibration, etc.

Design - casing and cement:

- *Potential loss of containment due to* inadequately completed wells, sealed plugged well(s), failure of cement squeeze job perforations or stage tool, pressure rating of components, etc.

Human/Organizational Reliability/Operation and Maintenance Activities:

- *Potential loss of containment due to* inadequate procedures, failure to follow procedures, inadequate training, inexperienced personnel and/or supervision

Well Intervention:

- *Potential loss of containment due to* loss of control of a storage well while drilling, reconditioning, stimulation, logging, working on downhole safety valves, etc.

Third Party Damage (Intentional/Unintentional Damage):

- *Potential loss of containment due to* foreign drilling and production activities, vandalism, terrorism, vehicular impact, subsurface impact, general construction, mining, etc.

Outside Force - Natural Cause, Weather-related, Ground Movement:

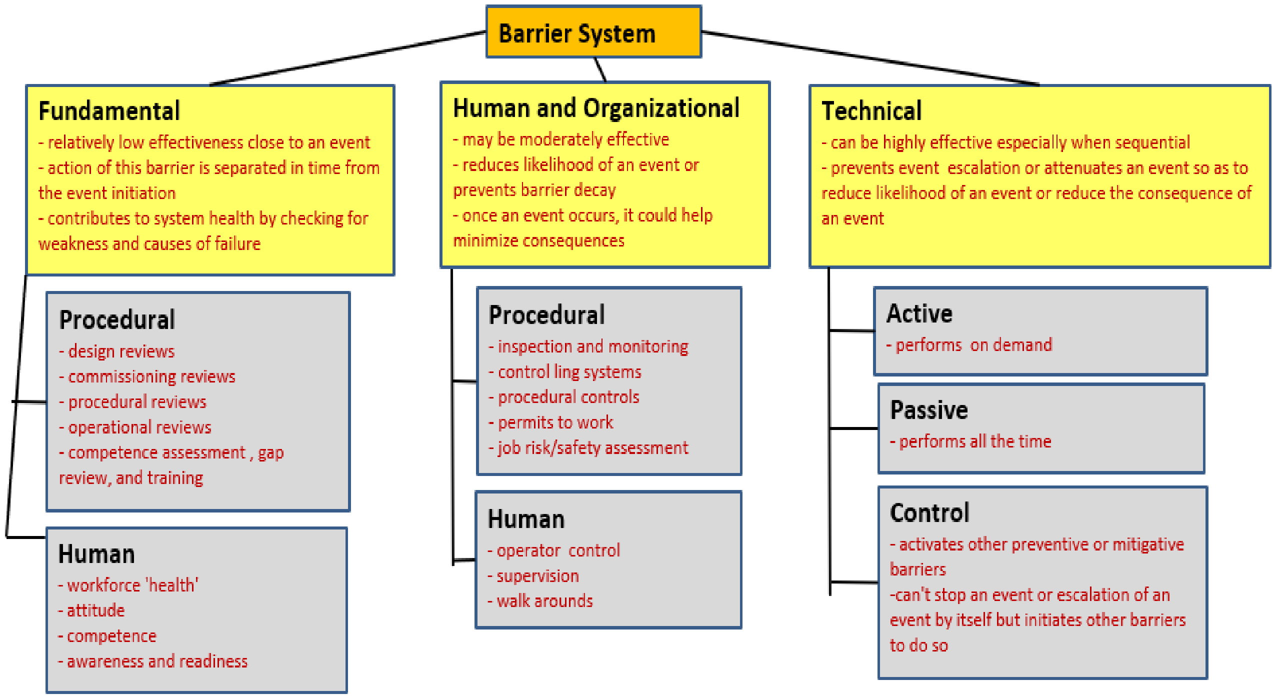
- *Potential loss of containment due to* floods, landslides, earthquakes, earth mass movements, subsidence/compaction, other earth forces inducing shear, compression, tension or impact, struck by objects such as trees, rockfalls, etc.

Step 2b: Barrier Identification, Barrier Decay Modes, and Event Scenario Development

Integrity management relies on assurance of barrier effectiveness. Operators can identify barriers, decay modes affecting barriers, and monitoring, inspection, and testing activities that provide information on barrier capability and effectiveness.

There are several classes of barriers: physical/technical barriers, including active, passive, and control sub-classes, human and organizational barriers, and fundamental barriers. All types of barriers work together to provide for safety assurance. Figure 4 summarizes a barrier system approach that includes assessment of the three types of barriers.

Figure 4



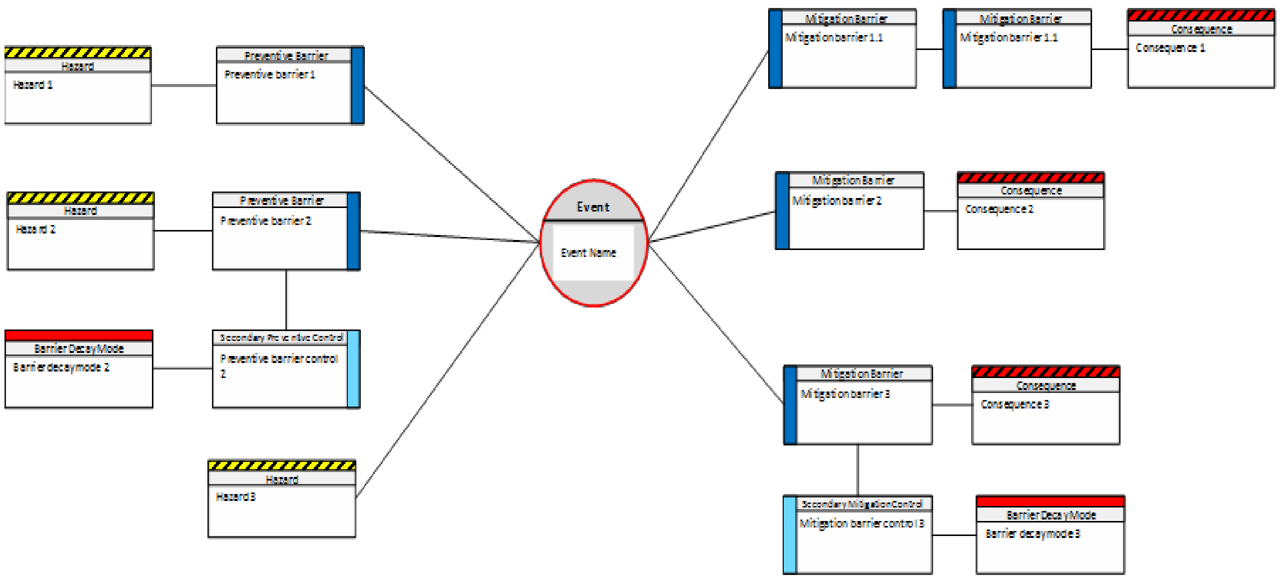
A threat/hazard – barrier matrix (see Appendix 3) is one qualitative way to view how risk is handled. API 1171 Section 8, Tables 1 and 2, provides a start to matching threats/hazards with various types of barriers that can address those threats. ISO 16530 provides additional examples of hazard-barrier matrices.

Bowtie diagrams provide a visual summary of the hazard-barrier interaction to prevent or mitigate a loss of containment event. An example is shown below in Figure 7. In this example, various hazards (on the left) can lead to a loss of containment event (center) resulting a variety of potential consequences (on the right). Blocking the hazards from initiating an event are preventative barriers. Similarly, potentially blocking an event from leading to serious consequences are mitigation barriers. There can be multiple barriers employed for each potential hazard or consequence.

Bowties additionally can show barrier decay/degradation modes (escalation factors), or threats to barrier capability and effectiveness as well as barrier support mechanisms, i.e. elements that support barrier effectiveness. The diagram fosters identification of secondary barriers (or “escalation controls”) that support primary barriers, arrest or alert to degradation, is helpful for focusing monitoring, inspection, and testing, and can help set up more quantitative risk analysis. Additional review and discussion of bowtie applications can be found in Pitaldo, et. al., in Society of Petroleum Engineers paper

127201-MS “Integrated Risk Management: Using Intranet-Based Tools to Effectively Communicate Critical Risk Information from Bow Ties and hazard and Risk Registers”, 2010.

Figure 5



Some common barrier decay/degradation modes (escalation factors) for storage wells and wellheads are listed in Table 1.

Table 1

Barrier Decay Modes

Blockage	Inadequate plan / criteria
Corrosion (external)	Inadequate procedures
Corrosion (internal)	Inadequate safety culture
Decrease in vigilance	Inadequate supervision
Defective equipment	Inadequate task specification
Design changes / original damaged / add-ons	Inadequate testing
Erosion	Incorrect equipment or material specification / usage
Error during maintenance	Incorrect installation
Excessive workload	Insufficient training or competence
External loading	Material defect/degradation
External pressures of time, resources, other	Operator error
Failure to operate on demand	Outdated information, data, or procedure
Impact	Overpressure
Inadequate commissioning	Procedural violation
Inadequate communication	Procedure not followed
Inadequate compliance monitoring	Structural defect
Inadequate design	Staff shortage / staff turnover
Inadequate inspection	Temperature
Inadequate isolation	Vibration / Fatigue
Inadequate maintenance	Wrong equipment

Fault Tree/Event Scenario Development

Bowties or hazard-barrier matrices can be turned into fault trees and event trees. For purposes of this Guidance, the focus is on loss of primary well barrier containment, thus a failure in wellheads and valves, casing and cement, and any other aspect of the primary barrier envelope, which could result in a large surface release with or without fire, or a subsurface release that could migrate through well or geologic pathways and impact various areas around a well.

During hazard-matrix, bowtie, or fault/event tree development, the levels of incidents that could occur are likely to be noted. PHMSA's storage Interim Final Rule compels reporting for incidents exceeding certain thresholds and for safety-related conditions discovered by operators, where safe operating limits are impacted. In addition to reportable events, operators can define four levels of incident, adapting from API 754. In API 754, incident tiers 1 and 2 involve loss of primary containment:

Tier 1 – unplanned or uncontrolled release resulting in at least one of these consequences: "days away from work" injury and/or fatality; or hospital admission and/or fatality of a third party; or officially declared community evacuation or shelter-in-place ; or fire or explosion (resulting in greater than or equal to $x ($25,000) of direct cost to the Company; or pressure relief device (PRD) discharge to atmosphere with liquid carryover, discharge to a potentially unsafe location, on-site shelter-in-place, or public protective measures (e.g., road closure); or release rate greater than 1000 lbs. of Flammable Gases with IBP < 35 °C & FP < 23 °C.

Tier 2 -- unplanned or uncontrolled release resulting in at least one of these consequences (below the levels of Tier 1): recordable injury; or fire or explosion resulting in greater than or equal to $x ($2,500) of direct cost to the Company; or pressure relief device (PRD) discharge to atmosphere with liquid carryover, discharge to a potentially unsafe location, or on-site shelter-in-place or public protective measures (e.g., road closure); or release rate greater than 100 lbs. but less than 1000 lbs.

API 754 Tiers 3 and 4 indicators address the strength and operational effectiveness of barrier/control systems. Tier 3 can be viewed as similar to PHMSA's requirement for reporting of safety-related conditions.

Tier 3 indicators are challenges to the barrier system that might progress along a path to harm, but stop short of Tier 1 or Tier 2. Examples include:

- Safe Operating Limit Excursions
- Primary Containment Inspection or Testing Results Outside Acceptable Limits – indication that primary containment equipment has been operated outside acceptable limits, with actions triggered including replacement, repairs, increased inspection/testing, or de-rating of process equipment.
- Demands on Safety System, such as activation of a safety-instrumented or safety shut-down systems, relief devices, or other loss of protective containment events
- Other LOPC with consequences reflecting process safety hazards rather than personal safety/health or environmental issues such as fugitive emissions.

Tier 4 indicators relate to operating discipline and management system performance and represent the performance of individual components of the barrier system. Tier 4 indicators can be indicative of process safety system effectiveness; weaknesses in these indicators could lead to Tier 1, 2 or 3 events. Examples of safety system effectiveness include:

- Process Hazards Evaluation Completion
- Process Safety Action Item Closure
- Training Completed on Schedule
- Procedures Current and Accurate
- Work Permit Compliance
- Safety Critical Equipment Inspection
- Safety Critical Equipment Deficiency Management
- MOC and PSSR Compliance
- Completion of Emergency Response Drills
- Fatigue Risk Management

Additional reading on safety incidents and development of actions to improve safety performance can be found in Martland, ""Investigation of Process Safety Incidents & Implementing Effective Corrective & Preventive Actions", SPE paper 140246.

Threat interactions

Threat interactions are handled in this Guidance's risk model by simultaneously considering numerous damage and deterioration mechanisms that could attack a primary barrier element in the likelihood of failure and/or consequence of failure model equations. While this is not a true probabilistic modeling effort, it does, in a simplistic manner, take many damage mechanisms and assume they are acting at once on a well, thereby most likely giving a more conservative analysis. The interaction matrix, Table 2, shows three categories of interaction.

Table 2

API 1171 Threat Matrix
Identifying Threats Handled in the Risk Management Probability of Failure Guidance

Category 1	Category 2	Category 3
Handled in probability of failure estimation	Handled as a credit-management system effectiveness and maturity	Not handled in the probability of failure
corrosion	inadequate procedures	loss of control while drilling
material defects	failure to follow procedures	loss of control during service/ intervention
erosion	inadequate training	exceeding pressure or volume limits
equipment failure	inexperienced personnel	geological issues
annular flow	inexperienced supervision	
cement bond failure		
cathodic protection system interference		
valve failure		
gasket failure		
thread leaks		
mechanical fatigue/vibration		
inadequate design/completion		
inadequate seal plugged well(s)		
failure of cement squeze job perfs /stage tool		
inadequate pressure rating of components		
earthquakes		
floods, landslides, earth/water mass movements		
subsidence/ compaction		
other earth forces/ events inducing shear, compression, tension or impact		
struck by objects such as trees, rockfalls, etc.		
vehicular impact		
subsurface impact		
drilling/mining		
vandalism, terrorism		
general construction		

Figure 6 is another representation of the API 1171 threat matrix identifying which threats and interactions are classified as Category 1, 2 or 3.

Figure 6

API 1171 Threat Matrix Identifying Threats Handled in the Risk Management Probability of Failure Guidance

	Corrosion	Material Defects	Erosion	Equipment Failure	Annular Flow	cement bond failure	cathodic protection system interference	valve failure	gasket failure	thread leaks	mechanical fatigue/vibration	inadequate design/completion	inadequate seal plugged well(s)	failure of cement sqz job perfs /stage tool	inadequate pressure rating of components	inadequate procedures	failure to follow procedures	inadequate training	inexperienced personnel	inexperienced supervision	earthquakes	floods, landslides, earth/water mass movements	subsidence/ compaction	other earth forces induced shear, compression, tension or impact	struck by objects such as trees, rockfalls, etc.	vehicular impact	subsurface impact	drilling/mining	vandalism, terrorism	general construction	loss of control while drilling	loss of control during service/ intervention
Corrosion																																
Material Defects	1																															
Erosion	1	1																														
Equipment Failure	1	1	1																													
Annular Flow	1	1	1	1																												
cement bond failure	1	1	1	1	1																											
cathodic protection system interference	1	1	1	1	1	1																										
valve failure	1	1	1	1	1	1	1																									
gasket failure	1	1	1	1	1	1	1	1																								
thread leaks	1	1	1	1	1	1	1	1	1																							
mechanical fatigue/vibration	1	1	1	1	1	1	1	1	1	1																						
inadequate design/completion	1	1	1	1	1	1	1	1	1	1	1																					
inadequate seal plugged well(s)	1	1	1	1	1	1	1	1	1	1	1	1																				
failure of cement sqz job perfs /stage tool	1	1	1	1	1	1	1	1	1	1	1	1	1																			
inadequate pressure rating of components	1	1	1	1	1	1	1	1	1	1	1	1	1	1																		
inadequate procedures	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2																	
failure to follow procedures	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2																
inadequate training	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2															
inexperienced personnel	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2														
inexperienced supervision	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2													
earthquakes	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1												
floods, landslides, earth/water mass movements	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1											
subsidence/ compaction	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1										
other earth forces/ events inducing shear, compression, tension or impact	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1									
struck by objects such as trees, rockfalls, etc.	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1								
vehicular impact	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1							
subsurface impact	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1						
drilling/mining	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1					
vandalism, terrorism	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1				
general construction	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1			
loss of control while drilling	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3		
loss of control during service/ intervention	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	

1 handled specifically or generally in the probability of failure estimation routine
2 handled as a credit potential - management system effectiveness and maturity
3 not handled in the probability of failure: well intervention activity through new drilling, redrilling, or reconditioning or servicing is a separate effort covered by the range of safety procedures demanded by API 1171 and other good practices

Category 1 interaction is incorporated in the risk model through the total likelihood of failure, conservatively, such that the sum of the likelihood of failure index is associated with all of the individual threats shown in Figure 6. The total likelihood of failure index is used to calculate the individual and/or societal risk for each well. The total likelihood can be used to rank wells to make integrity management decisions that decrease likelihood of failure and thus reduce risk.

Category 2 threats in the matrix can be handled by credits in the likelihood of failure estimates. The credit available in the model in this Guidance is a simple approach defining robustness and maturity of integrity management program implementation. In the future, these threats could be handled by a more rigorous credit review similar to the management system factor assessment in API 581. For informational purposes, this Guidance has adapted the API 581 philosophical approach and included a management systems factor assessment in Appendix 4. The assessment in Appendix 4 illustrates one means of driving continual improvement in their process safety / integrity management systems.

Category 3 threats relate to loss of control when drilling or servicing. The Guidance does not handle these failures in the model, because these are specific threats that should be treated by equipment, procedures, and other parts of a process safety management system covering well drilling and intervention.

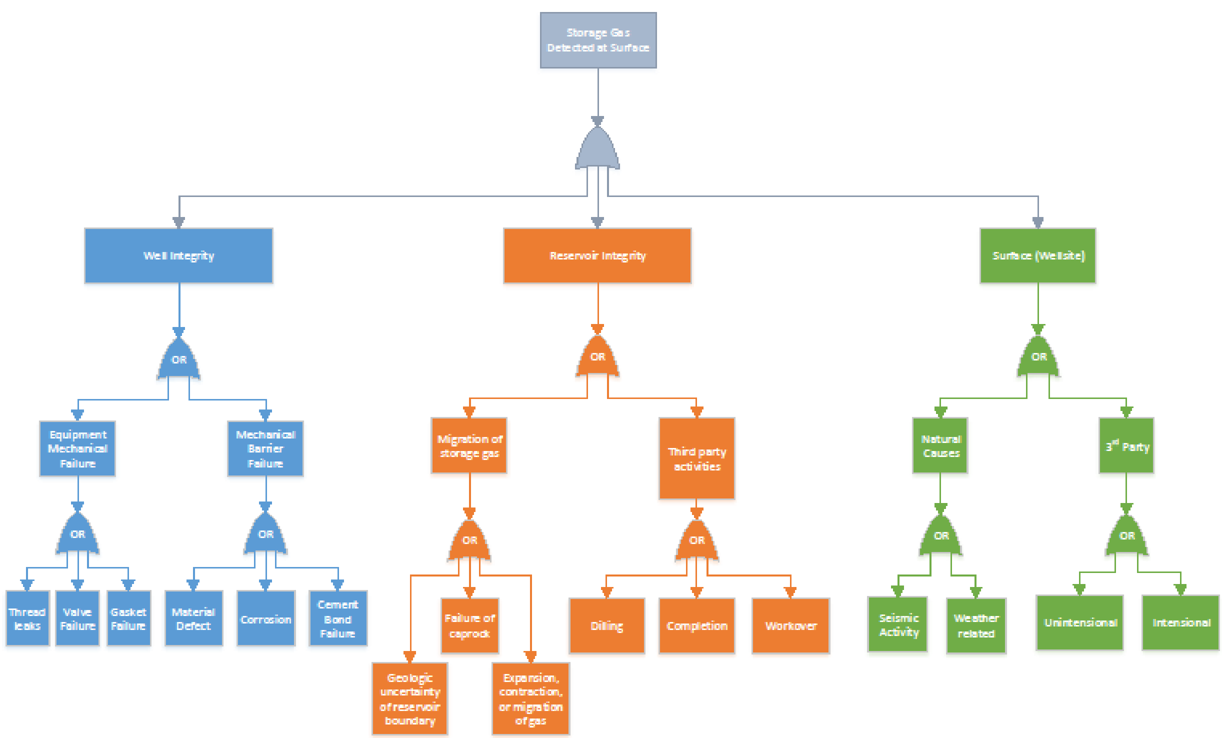
<u>Event Scenario Development - Failure Modes</u>

In this Guidance, the event scenarios envisioned are failure of well casing, wellhead, and valves causing open flow to the surface, with or without fire, and prolonged flow downhole through a sizable aperture in the casing/cement such that a widespread area could be impacted.

NOTE: The operator should be aware that considering only large and catastrophic events might skew the total risk toward lower frequency events and, hence, comparing the total risk with the risk criteria might not be valid. This Guidance is flexible enough to include smaller leaks, also. Regulatory agencies and the public will expect operators, as a precautionary principle, to consider a variety of sizes of leaks that could impact public safety and/or impact the environment. Tolerance to smaller events can be addressed by operators in their risk management objectives (Step 1)

Failure modes and effects include leak apertures from pinholes to large ruptures. The corrosion pinhole to small hole failure mode leads to mostly small to moderate leaks. Larger leaks can result from brittle or ductile failure of casing which opens a wider aperture. Stress corrosion cracking can lead to larger leaks or to small through-wall cracks. Metallurgical and mechanical damage can lead to failures ranging from small holes to ruptures. Localized corrosion can lead to small to medium sized leaks and ruptures, depending on location, while general thinning due to corrosion or erosion generally leads to larger leaks and ruptures.

The risk analysis probability of failure and consequence of failure follow from the large or catastrophic



Step 2c: Risk Analysis

The risk analysis in this Guidance provides routines for quantifying likelihood of failure index (LOFI) and Consequence of Failure Index (COFI).

LOFI depends on generic failure frequency and deterioration rates and other damage factors for casing, cement, and wellhead components.

Consequence of Failure Index (COFI) depends on release rate, volume available for release over an extended period of time, population in the near-well and widespread areas of potential impact, presence of valued environmental components in areas of potential impact, and impacts related to overall service, reliability and other financial consequences of a particular incident.

Step 2c.1: Likelihood of Failure Index (LOFI)

LOFI is a function of the asset/component condition – design/as-built and current; deterioration/damage type and mechanism; rate of deterioration and exposure to time-independent damage mechanisms; probability of identifying and detecting deterioration and predicting future states with inspection techniques; tolerance of equipment to the deterioration types; and human and organizational factors.

For a single well, likelihood of failure index (LOFI) = Failures/Operating Yrs For

a group of wells, likelihood of failure index (LOFI) = Failures/Well-Yr Industry,

likelihood of failure index (LOFI) = Total Failures/Total Operating Yrs

For a situation where there have been no failures in a component or piece of equipment, i.e. Failures equal zero in the above equations, API 581 cautions the evaluator that even with no failures to date, it is known from experience the true failure probability is greater than zero. Simply given more time, a failure will occur~~.~~

This Guidance treats probability of failure of storage well primary barrier elements by providing quantitative and semi-quantitative (indices) means of assessing conditions and factors that could lead to failure. The root equation is:

LOFI = LOFI (casing) + LOFI (wellhead & valves) + LOFI (cement)

…specifically,

LOFI = Gff * [(Dfthin + Dfmech + Dfimpact + Dfother...) + Fwhv + Fcmt]

The following is a brief description of the individual variables in the equation above. Considerable additional discussion is presented in Appendix 5.

Gff = generic failure frequency

> Based on the available data, as discussed in Appendix 5, the generic well failure frequency (failure per well year) is in the range of N x E-05 per well year. The recommended ranges of N come from data supplied to the referenced studies in Appendix 5. In this Guidance, for production wells converted to storage, N is approximately equal to 9.3 E-05. For new storage wells or wells reconditioned for storage with the current design standards, N may be as low as 2 E-05. Operators have the latitude to use different values.

Df = damage/deterioration factors Dfthin, Dfmech, Dfimpact and Dfother

The damage/deterioration factors for the well and wellhead include wall thinning (Dfthin), mechanical damage (Dfmech), casing or wellhead impact (Dfimpact) and other factors as determined by the operator (Dfother). The Df factors are further defined as:

Dfthin = [(WTorig/WTcurrent) * ((1000^(MOP/Burstadj) /(1000^.8))* Icond + FLOCOMP]

WTcurrent = WTlast – (CR * YRS); if no last inspection or no inspection, then
WTcurrent = WTorig – CRdefault*AGE

Where:

WTorig = wall thickness- original

WTcurrent = wall thickness- current state

Burstadj = burst strength, adjusted for current condition of casing

YRS = years since last casing inspection

AGE = casing age

Icond = factor describing totality of casing inspection findings

FLOCOMP = factor for fluid composition, including sand/particulates, acid gases, and water; where FLOCOMP = (V*sand) + acid gas + water

Dfmech = Dfprev + Dfvib*Fb + Dfearth*Fbearth + Dfwork

Where:

Dfprev = whether there have been previous failures related to vibration

Dfvib = factor for mechanical fatigue due to vibration, shaking, or other repeating stress

Fb = factor for annual frequency

Dfearth = factor for earth forces

Fbearth = factor for physical controls or barriers

Dfwork = factor for number of stresses that might have occurred during well work

Dfimpact = (Dfveh-const + Dffallobj) * Fbimpact

Where:

Dfveh-const = factor for potential for vehicular strike (e.g. car, truck, train, farm equipment, etc.)

Dffallobj = factor for impact form large falling object (e.g. tress, rocks, etc.)

Fbimpact = factor for a preventative control

Fwhv = wellhead and/or valve failure factor

The damage and deterioration factor for the wellhead include considerations for individual wellhead component condition and functionality with respect to containing pressure and isolating flow. Similar to casing and tubing, the wellhead design factor is important in the evaluation of condition and functionality. The wellhead failure factor is assessed by:

Fwhv = Fapi * Dwhc + Fapi * Dvseal

Where:

Fapi = design (API, non-API) and pressure rating (pressure rating vs. MOP)

Dwhc = condition of the wellhead

Dvseal = functionality testing of valves and seals

Fcmt = cement sheath factor

The cement sheath factor addresses the sheath's sealing and zonal isolation verification and certainty. Fcmt depends on condition and functionality. An additional consideration for the annular flow/pressure factor (Fann), the operator will need to determine if observed flow/pressure is from the storage zone or a different formation. The cement sheath factor is assessed by:

Fcmt = Dcondition * Fann * Ffunction

Where:

Dcondition = cement condition factor (electric log based)

Fann = annular flow factor

Ffunction = cement functionality factor

All of the above factors are discussed in much more detail in Appendix 5. Criteria for suggested numerical ranges for individual factors is also presented. Note that operators can develop their own ranges for one or more factors in addition to incorporating additional factors if that would better represent their individual storage assets.

If the pipe is susceptible to other forms of attack, refer to API 581 methods for estimating influence on probability of failure.

An example of how the LOFI estimate could be calculated is facilitated by a companion workbook to this Guidance in a Microsoft Excel-based LOFI rationale and estimation spreadsheet (see "Risk Guidance workbook LOFI.xlsm"). The LOFI estimation spreadsheet includes a tab explaining rationale and range of scaling of LOFI factors as developed by the authors of this Guidance. Storage operators are able to adjust the scaling factors to best suit a particular asset. The rationale sheet identifies that operators can do something about probability of failure by assessing for each item included in this Guidance's LOFI equation:

- does it relate to a barrier element or to the containment capability of a barrier element? Does it relate to a barrier degradation/decay mechanism?
- can it be assessed? what information would operators have or could obtain in order to choose an index?
- is the range/scale of indices aligned with expectation of failure likelihood given the cause?
- does it make sense that operators could change a condition and use the index values to show a risk reduction (due to decrease in LOFI)? (in other words - do the range and scaling of indices permit operators to credit a reduction in LOFI when upgrading a condition?), and

- if not attending to a physical condition, would an increase in monitoring frequency, type of inspection, effectiveness of inspection, or other aspect of inspections, monitoring, and testing, allow operators to credit risk reduction (by LOFI reduction)?

The LOFI estimation spreadsheet provides a calculation tab that allows operators to input values for each well and the sheet will calculate the LOFI; this gives operators the ability to look at the effects of their judgment of relative scaling of index use for many of the factors that require a scaling across a range of index values.

NOTE: It is important to bear in mind that there is no "right" answer for risk, thus there is no "right" answer for the probability of failure. The LOFI *is an estimate, and it can be ranged an order of magnitude plus/minus to get an idea of relative risk. Risk estimates are most valuable in a relative sense by comparing relative risk of alternatives. It is important to make maximum use of qualitative understanding of risk relationships to support decision making in preference to overreliance on quantitative estimates. This can be accomplished through testing of sources of uncertainty as well as testing sensitivity. Since various index-scaled factors, such as wellhead/valve factors and cement integrity factors (a qualitative and semi-quantitative mix), can be subject to bias and/or lack of consistency, the index-scaled factors should be ranged and sensitivity tested.*

NOTE: It is important that an operator use a consistent assessment of factors for cement, wellheads, impact, and mechanical conditions that could abet probability of failure. The goal is a relative assessment of probability of failure, the primary causes in a particular well, and a ranking of wells by risk and a lead-in to decisions on risk management where probability of failure could be reduced. In any risk assessment it is good practice to start with generic failure frequencies by equipment to obtain the baseline risk. The operator then moves on to more detailed sensitivities based on the initial risk profile. This could usually benefit any assessment in two ways by, first, not giving too much credit in the beginning to safety critical systems and, second, by not being overly conservative by using too many deterioration factors.

NOTE: Throughout the LOFI *analysis, operators using this format might choose to alter the formulas, ranges, or other numeric criteria, or add other factors that might better fit their storage assets, and explanation of the rationale/basis for alterations or creation of new criteria could be helpful for lessons to the entire industry. Also, whatever methods are used by operators, those methods ought to be used as consistently as practical within an operator's own asset base.*

LOFI Credits:

CREDITS: At the end of the LOFI calculation estimate in the Excel workbook associated with this Guidance, operators may apply credits for robustness, effectiveness, and maturity of their integrity management systems, subject to the cautionary notes below. In the workbook, the resultant likelihood of failure index for a given well is multiplied by the LOFI credit to yield a credit adjusted failure frequency for a well.

NOTE: Operators cannot and should not think deterministically: credits do not necessarily change LOFI for a single well. The evaluation of the credit provides operators with a way to test the value of integrity management with respect to risk reduction.

NOTE: Application of any "credits" should be evidence-based and conservative. Operators might place too much confidence in their management systems to reduce risk - they fail spectacularly more often than desired, resulting in near misses and major accidents. Therefore, the initial implementation of an integrity management system, similar to the broad requirements of API RP 1171, should minimize or even exclude any management system factor "credits" based solely on an evaluation of the maturity of the operator's integrity management system.

NOTE: Operators should review the importance of human factors as outlined in Society of Petroleum Engineers (SPE) Technical Report "The Human Factor: Process Safety and Culture", March 2014, Society of Petroleum Engineers.

NOTE: Sklet, et al, in "Monitoring of Human and Organizational Factors Influencing the Risk of Major Accidents", (SPE 126530, 2010, Society of Petroleum Engineers) identify seven elements, or areas, of an operational safety barrier system, and advocate means of verification of those elements. The seven elemental performance areas are: 1) work practice, 2) competence, 3) procedures and documentation, 4) communication, 5) workload and physical working environment, 6) management, and 7) management of change.

The equation with the approximate measures of management system implementation and maturity include:

CREDIT = (Yrs IMP Program factor) * (Test Completion factor) * (Maturity-Robustness factor)

Where:

> Yrs IMP Program factor = number of years employing an integrity management program aligning to API 1170-1171
>
> Test Completion factor = completion of asset information on primary well barrier elements – percentage of wells with casing inspection surveys, wellhead and valve assessments, and cement integrity and functionality assessments (includes verification/documentation of materials and design and estimated current mechanical strength)
>
> Maturity-Robustness factor = maturity and robustness of inspection program, including repeat casing inspections, frequency of pressure and fluid flow monitoring, and other testing

Appendix 6 contains additional details and potential ranges for the three factors.

A more robust management systems factor can be developed over the next few years as the storage industry matures in applying API 1170-1171 concepts as well as the concepts of this Guidance. See Appendix 4.

Total LOFI Estimate and Probability Levels – Range, Descriptors:

The total likelihood of failure index (LOFI) can be estimated using the spreadsheet tool provided with this Guidance ("Risk Guidance workbook LOFI.xlsm"). Operators will see the main drivers for increasing

LOFI and be able to direct risk management plans at those actions that help reduce risk by reducing the LOFI side of the likelihood x consequence risk estimate. The importance of developing tools to screen and prioritize wells for treatment and monitoring is illustrated in the 2011 SPE paper 145428 by Powell and Van Scyoc, "Well Site Risk Screening: The Critical Few"; the authors note in their abstract "…a small proportion of the total well inventory has the greatest risk; these wells warrant the most detailed analysis and application of resources to assure that well integrity is maintained…".

The mathematics of the LOFI calculation permit some equations to "blow-up" and in extreme cases provide values that would drive total LOFI >1.0. Therefore, the equations are capped at maximum values in Excel – first at the term in the Dfthin that uses an adjusted burst pressure (the term is capped at a value of 350), and then at the total LOFI calculation, which is capped at 1.0. In many cases where these caps occur, the LOFI will be 1.0 or generally high in the range of 0.1 to 1.0, a range in which an operator should be taking nearly immediate action to mitigate likelihood of failure.

Power-law (logarithmic) categorization of LOFI allows operators to differentiate more likely probability of failure from less likely probability of failure. Within ranges of inputs due to uncertainty and sensitivity and within a particular log-range of probability, there can be enough spread for an operator to rank one well as higher risk than another. For example, a well with LOFI of .0015 is better characterized as unlikely to fail, whereas a well with LOFI of .0089 is better characterized towards more likely to fail. The qualitative descriptors in the Table 3 below are to be viewed as fuzzy-boundaries that range across the orders-of-magnitude of the probability ranges.

Table 3

Likelihood Categories

Qualitative descriptor	**Probability Range**	**Minimum of Range**
Very Likely	P>0.1 to 1	1 in 10
Likely	P>0.01 to 0.1	1 in 100
Unlikely	P>0.001 to 0.01	1 in 1000
Very Unlikely	P>0.0001 to 0.001	1 in 10,000
Extremely unlikely	P>0.00001 to 0.0001	1 in 100,000
Remote	P>0.000001 to 0.00001	1 in 1,000,000
Unforeseeable?	P>0.0000001 to 0.000001	1 in 10,000,000

A credible event is within the realm of possibility - generally a likelihood higher than 1 x 10-6/yr

Uncertainty Ranging / Modeling, and Sensitivity Testing:

The effects of uncertainty in LOFI (and COFI) can be tested prior to finalizing the LOFI analysis. In the COFI estimate, this Guidance provides for the uncertainty ranging as part of the estimation process. In the LOFI estimates, an operator can iterate the LOFI estimate using different values for those factors that are more subjective. The operator might be quite certain of some aspects of the LOFI estimate. For example, an operator might be highly confident of the Dfthin analysis because of high-quality casing inspections; the operator might be highly confident of Dfmechanical and even of Dfimpact, based on site-specific knowledge. However, the operator might be uncertain of the effect of human-induced workover stress, and/or on wellhead and valve condition, and/or on cement condition. For those factors where uncertainty is greater, the operator can range the input values to test the effect on LOFI.

Likewise, within the LOFI and COFI analyses, operators can identify those factors to which the analysis of risk (estimates of LOFI and COFI) is most sensitive, such that changes in aspects of such 'sensitive' variables drive the greater or greatest changes in risk level.

NOTE: For further reading, see DNV GL STRATEGIC RESEARCH & INNOVATION POSITION PAPER: Enabling Confidence: Addressing uncertainty in risk assessments.

Step 2.c.2 Consequence of Failure Index (COFI):

This Guidance provides a means of estimating a range of consequence impacts for the following event types:
Surface release and fire
Surface release and no fire
Subsurface release and migration

Generally, loss of containment events leads to consequences in three main areas: human safety and health, environmental (valued environmental components (VEC)), and service quality (interruption/reliability/remediation and repair - financial). The potential severity of consequences depends on fluid properties, fluid rate and the mass available to feed the loss over the period of time that the leak is not controlled. The fluid properties can depend on composition, physical state, pressure, temperature, and inherent hazardous properties such as flammability, toxicity, ignitability, and ability to spread.

The failure mode can affect the release rate characteristics. For purposes of this Guidance, the focus is on failure/event modes that tend to the worst-case conditions. Where practical, the approach that is taken advises ranging of consequences in each of the significant areas along some scalable, power-law basis. The power-law scalable recommendation helps to dampen natural biases humans have toward narrow and optimistic views and helps to increase awareness and sensitivity to high-consequence potential, thus promoting a precautionary approach.

For example, in this Guidance, Consequence of Failure Index (COFI) is converted to cost equivalents, with order-of-magnitude levels in seven tiers. Along with the seven tiers of probability of failure in this Guidance, the seven-fold consequence tiering provides for a balanced 7 x7 risk matrix. Suggested qualitative descriptors and ranges for the consequence tiers are:

Insignificant	<$10K
Minor	$10K to <$100K
Significant	$100K to <$1M
Serious	$1M to <$10M
Major	$10M to <$100M
Critical	$100M to <$1B
Catastrophic	>$1B

Throughout the COFI part of this Guidance, it is emphasized that consequences have a probability-severity pairing. For example, should a driving accident occur, the probability of a fatality is X, while the probability of property damage only is Y, etc. The consequence is thus X*$equiv + Y*$equiv + … (other consequence probability-severity pairs), where $equiv is the cost-equivalent effect of the consequence and the sum of the probabilities X, Y, …n = 1.0.

A focus only on worst-case outcomes could result in over-estimate of risk, by assuming that the probability of that particular outcome, Xworstcase, is Xworstcase=1.0.

This Guidance treats the total COFI as the sum of all the COFI – safety and health, environmental, and service/reliability/financial. The scalable ranging of consequences will help operators to test the sensitivity of event outcomes to values-based consequences (safety, health, environmental) as opposed to financially-based consequences. An important aspect of this Guidance is the evaluation within the COFI, and in the combined LOFI x COFI, of where safety consequence potential dominates.

NOTE: In this Guidance, even though the consequences are converted to a cost equivalent, the emphasize is on the preeminence of human health and safety.

<u>Failure event types and their effects</u>

Pinhole leaks, casing/tubing collar leaks, flanged connection leaks, seal and valve stem leaks are generally characterized by relatively low flow rates and isolated impact areas. While these types of leaks are more common than rupture-type failures, the common leaks mostly should be identified through robust, holistic inspection, testing, and monitoring programs.

In this Guidance, worst-case type failures are assumed – a wellhead decapitated or a near-well severance between the flowline and the well; a downhole leak through an aperture sufficient to permit a large multi-day release volume (later defined herein). This Guidance does not treat well drilling and workover blowouts/loss of control incidents; however, the more typical event in such work is a surface leak with or without fire, so the Guidance considers that the consequences of such an event can be handled within the framework of this Guidance.

The COFI analysis requires estimates and ranging of consequence impact area. The impact areas for “subsurface release” and “surface release and no fire” could be more widespread than “surface release and fire”, but impact type and severity could be different.

Risk management decisions for specific wells will be driven by the estimates for the LOFI and COFI. Preventive and mitigation actions might be the same, even if COFIsurfacefire is insignificant but COFIsurfacenofire is significant, or vice versa, or if both are high. If COFIsurfacenofire is high it might be likely that COFIsubsurface also is high. The consequence of failure, in other words, if high for any particular event type, likely drives an operator to make certain risk management decisions. The COFI will be adjusted by credits for any effective isolation, detection, or mitigation systems already employed by the operator. The final COFI equation is:

COFI = (COFIsafety-surface + COFIsafety-subsurface + COFIenvironment + COFIfinancial)*credit

A spreadsheet is provided that contains the COFI estimation routines.

While adding the COFI for each event type can tend to magnify the total COFI in this Guidance, the likely reality is that a failure will consist of only a single event type. The magnification of COFI in this Guidance will help drive an operator to inspect significant consequence potential even if probability of failure is lower, thus this approach imposes the precautionary principle upon gas storage operators.

The precautionary approach is the reason that API 1171 prescribes, at 6.2.5:

"…the operator shall evaluate the need for any type of emergency shutdown valve by reviewing the following:

- distance from dwellings, other buildings intended for human occupancy, or other well-defined outside areas where people assemble such as campgrounds, recreational areas, or playgrounds;
- gas composition, total fluid flow, and maximum flow potential;
- distance between wellheads or between a wellhead and other facilities, and access availability for drilling and service rigs and emergency services;
- added risks created by installation and servicing requirements of safety valves;
- risk to and from the well related to roadways, rights of way, railways, airports, and industrial facilities;
- alternative protection measures which could be afforded by barricades or distance or other measures; and
- present and predicted development of the surrounding area, topography and regional drainage systems and environmental considerations."

COFIsafety-surface

The approach to evaluation impacts to human health and safety for a surface release and fire address the scenario: "...if a well is flowing at AOF at MOP at surface, and there are humans inside the heat impact radius, what is the probability of various injuries up to and including fatalities, and what is the equivalent cost in "value of a statistical life…"

The evaluation of COFI related to impacts to human health and safety related to a surface release and fire depend on:

- The number of potential persons in harm's way for surface release and fire
- The well's absolute open flow capacity (AOF) at MOP
- The estimated heat impact radius

The severity of the impact to people is converted to an equivalent dollar value using the "value of a statistical life" (VSL) indexed to US Government VSL (DOT) guidance (see *Notes on VSL* below). While the use VSL in this Guidance only to put the consequences on an equivalent scale (that is, in dollars) for purposes of economic analyses and furtherance of the path to a philosophy of "As Low As Reasonably Practicable", this Guidance emphasizes that storage operators prioritize the protection of human life, which is beyond discrete intrinsic value, and on the health of valued environmental components, which also can be beyond good understanding of intrinsic value. Therefore, the operator will find that at the end of the consequence discussion, this Guidance emphasizes the priority on protecting life and environment and that the risk evaluation must treat the adequacy of protections to human life and valued environmental components.

Assumptions on accident safety effects distributions are ranged from PHMSA pipeline event statistics. The safety severity profiles are given three or four distributions: a "very low" distribution coming from vehicular accident severity distribution and then "low", "mid", and "high" distributions coming from 20-year pipeline industry event statistics reported to PHMSA (lowest 5 years, all years, and highest 5 years). PHMSA reported events include fatalities and significant injuries so within this Guidance the distribution across various severities of injuries other than fatality were assumed. This Guidance assumes that within this range of distributions is an estimated ranging based on known storage well incidents and the impact probability-severity.

Each of the injury severity distributions is given a weighting, then the weighted VSL-based cost equivalence is calculated. Tables 4 below illustrate the development of the VSL-based cost equivalence.

Table 4

consequence:

number of persons potentially within heat impact radius tier

consequence potential range, high-low

based on rates of fatalities-injuries-non-injuries in traffic accidents and pipeline incidents

	v. low (traffic accidents)	low (pipe incidents avg lowest 5 yrs)	mid (pipeline incidents avg)	max (pipeline incidents avg of max five years)	per person VSL-basis 2017, millions USD
insignif	0.68	0.7961	0.69	0.54	0.001
Minor	0.2	0.12	0.15	0.122	0.029
Moderate	0.056	0.0281	0.032	0.12	0.451

Serious	0.03	0.018	0.032	0.08	1.008
Severe	0.018	0.011	0.032	0.03	2.553
Critical	0.01	0.011	0.032	0.029	5.691
Fatal	0.006	0.0158	0.032	0.079	9.597

multiply number of people potentially inside a threshold radius zone based on well AOF at MOP by the hi-med-low VSL basis and frequencies

Sum the values to get impact.

Examples:

One person inside heat impact radius

Zero people, safety risk given surface fire = 0.002 times output below minimum one worker/week for one person 50 wks/yr, 20 min/visit

0.001884

Table below multiplies the vlow-low-mid-max distributions by the VSL-based cost for the injury severity level indicated

One person: equivalent dollars	v low	low	mid	max			
insignif	0.001	0.001	0.001	0.001			
Minor	0.006	0.003	0.004	0.004			
Moderate	0.025	0.013	0.014	0.054			
Serious	0.030	0.018	0.032	0.081			
Severe	0.046	0.028	0.082	0.077			
Critical	0.057	0.063	0.182	0.165			
Fatal	0.058	0.152	0.307	0.758			
distribution	0.030	0.240	0.500	0.230	1.000		
Sum	0.222	0.277	0.623	1.139		consequence equivalence per person	minimum value P=0 (allowance for temp. visitation)
10*	2.224	2.774	6.226	11.386		6.465 million	0.013
						wtd avg $ equivalence (VSL-based) per person	

max occurs 23% of the time

low occurs 24% of the time

mid occurs 50% of the time v

low occurs 3% of the time

For ten persons, multiply the above by 10 to get a weighted consequence equivalence of $65 million

Summary - within area of impact, calculate per person consequence

NOTE: Operators can choose to revise the weighting of the distributions.

The final estimated weighted safety consequence per person is upgraded by a factor of 10 to place emphasis on uncertainty and preeminence of safety. The method sets a minimum human safety impact by assuming a minimum time weighted human on site at 0.002 persons per year, even when permanent population is "zero", in order to allow for the presence of people during worker visits for routine inspection and maintenance.

The calculation routine with the estimated weightings of the distributions and the ranging of the distributions themselves returns a VSL-weighted number of $6.465 million per person.

Operators may adjust the range of safety consequence distributions to obtain a different weighted average VSL-based consequence index – this framework gives a methodology but allows operators to develop their own numeric values for safety index for each person inside a critical heat-impacted radius. Operators must use their own numeric values derived from this methodology consistently.

Additional information on VSL is included in Appendix 7 and pertains to the ranging recommended by the US Government Guidance.

Heat Impact Radius

GRI-00/0189, "A MODEL FOR SIZING HIGH CONSEQUENCE AREAS ASSOCIATED WITH NATURAL GAS; PIPELINESGAS RESEARCH INSTITUTE", Contract No. 8174, October 2000, by C-FER Technologies, Inc. ("GRI C-FER Study") gives a simplified equation that assumes a guillotine cut of a natural gas pipeline with flow from both ends and certain heat flux decay factors. For methane combustion with threshold heat intensity of 5,000 Btu/hr ft2, the hazard area equation is given by: r = 0.685*(p*d^2)^0.5 where r is the hazard area radius (ft), d is the line diameter (in), and p is the maximum operating pressure (psi).

Operators can calculate the absolute open flow (AOF) from a storage well at maximum operating pressure (MOP) when the failure occurs. Assume:

- maximum operating pressure
- wellhead vertical jet
- appropriate rate limitations due to tubing/casing inner diameter

This Guidance assumes that this AOF at MOP is P95+ (inclusive of most known possible rate capacity). For conservative analysis in a storage well case, to test the potential for "consequence-dominated" risk, it is assumed a maximum case of release at AOF through flow-tubing restricted ID.

For heat impact radius and adverse effects on human safety, this Guidance uses heat flux equations to estimate the radius of impact at 5000 BTU/hr-ft2 / unshielded 30 second escapability developed for natural gas pipelines, and compares that radius value to those derived from API 581 radius of impact at

4000 BTU/hr-ft2 and "spontaneous ignition". This is similar to the methodology presented in the C-FER report.

Additional safety factors can be placed on top of the basic equation for all the operator's wells or for specific wells as warranted by the circumstances.

Not all occurrences result in a two-ended flow or a circular impact area. One-ended flow such as might come out of a well with no pipeline connection or from a well after the well's pipeline has been shut off. Conservatism in the radius of impact formula allows for error in assumption of a circular heat impact zone – possibly for an elliptically shaped area with a/b ratio to 0.25.

API 581 consequence area analysis assumes that the release rate is continuous, probability of ignition is constant and a function of the fluid release and the temperature relative to auto-ignition. In most gas storage wells, for conservative analysis this Guidance assumes a continuous release.

NOTE: Refer to API 581, Part 3, Table 4.9 for harm to people and Table 4.8 for damage to components.

The API 581 equation for the consequence area wherein significant impacts to human safety occur is:

consequence area (sq ft) = a*X^b, where X=mass rate in lb/sec and a and b are constants for gas components, with methane-ethane a=745, b=.92; propane-butane a=837, b=1.0.

NOTE: Operators can check their calculations from emergency response / blowout plans against this analysis and use the greater of the heat impact analyses.

*NOTE: For heat impact radius effects on equipment, use API 581 consequence area (sq ft) = a*X^b; for methane-ethane a=280, b=.95; propane-butane a=313.6, b=1.0.*

This Guidance recommends a number of set radial distances which operators can use to evaluate dwelling structure counts in the vicinity of each of their wells. Upscaling the calculated heat impact radius to the next largest standard radius "tier" can add another level of conservations. To be clear, operators can find the heat impact radius and then compare that value to the default radius tiers (165', 330', 660', 1320', 2640'). Operators select the radius that encompasses the 1%L30sec heat impact radius, and count the potential people in that radius. Examples:

X=85', count within 165'
X=225', count within 330'
X=400', count within 660'

Even if there are no residents in the area, this Guidance sets a non-zero minimum based on visits to the well site by operator representatives.

The number of people inside the impact radius is multiplied by the per-person VSL-based impact described above. The default weighted average probability-severity VSL-based safety impact averages to ~$0.6465 million per person ($6.465 million per person when multiplied by 10) inside the heat impact radius. Using only the "max" distribution (which comes from the worst five years of PHMSA data for pipeline incidents), would have $1.139 million per person per event ($11.386 million per person per event when multiplied by 10).

Additional information on the GRI-00/0189 study is included in Appendix 8.

Summary – Safety Consequence for a Surface Release and Fire:

Since any people living within the threshold heat-impacted radius will have a chance of fatality that exceeds 1 in 10,000 per storage well surface release and fire event, operators should provide mitigations to reduce the risk.

Conceptual example:

When estimating risk from LOFI *COFI, since the weighted ranged chance of fatality is ~4 in 100 (.038), if people are in the heat-impacted radius, then unless LOFI <.0026 per well-year, risk of fatality will be unacceptable (given an unacceptable fatality threshold of 1 in 10,000 per capita per year).

GUIDANCE PRINCIPLE:

Using the ALARP principle, the LOFI *COFI for fatality should be reduced toward/less than 1 in 100,000 per capita per year. Well design, knowledge of well condition, and other preventive measures will reduce LOFI. In addition, COFI can be reduced by various mitigation measures – adding barriers, adding detection and isolation devices, and so on.

COFIsafety-subsurface - Subsurface Release or Extended Surface Release with No Fire

The extended release of gas could occur in the subsurface, where a release due to loss of primary barrier element containment does not come to surface but moves through geologic strata and natural or human conduits. A subsurface event as described could go on for a period of time without detection, but risk analysis of this event potential can help operators to see value in employing inspections, monitoring and mitigation schemes when consequence potential is great.

This Guidance treats a subsurface event and its impacts on safety in a manner such that widespread health and safety effects from an extended surface release with no fire also could be assessed from the same methodology.

The factors involved in assessing the subsurface and extended surface release are 30-day release volume potential and population density of a wider radius than the consequence impact radius assessed for the surface release and fire event.

This Guidance assumes that operators can estimate 30-day release volume given a starting point of the reservoir at full levels, or maximum operating pressure, and a rate decay related to volume-per-pound, or material balance with pressure support from drive mechanisms as known by the operator. Further, this Guidance imposes precaution by recommending that operators estimate the 30-day release volume using AOF starting from MOP. Certainly, in a potential surface release, this rate and volume can be much more likely than the same rate and volume flowing through a subsurface failure. This Guidance treats the 30-day release volume as a P90-P95 case – in other words, 90%-95% of all release cases would be identified and stopped or, at the least, substantially mitigated, within 30 days.

NOTE: There can be "long tails" on extended surface or subsurface release events. The Aliso Canyon well incident went on for over 90 days, and the Macondo Deepwater Horizon blowout lasted over 45 days. However, wider-scope industry literature as well as storage-specific incident surveys suggests that many are brought under control in a matter of a few hours while a 15-day release duration encompass 75-90% events, and 30-day durations encompass 90-95% of all events.

The conservative, precautionary application of release volume in the subsurface case is appropriate insofar as there is great uncertainty in where migrating gas might go and what and who it might impact.

This Guidance uses power-law (logarithm) based scaling of 30-day release volume; the Guidance also uses power-law scaling of population density.

The methodology in this Guidance requires operators to determine a 30-day release volume and a population density in a 9-mile zone radially around the storage well. Since this Guidance sets a power-law scaling to the consequence estimation, it is not necessary to know a precise population count. The population density can be estimated, fairly, based on latest census information regarding population density of the county, town, or township; or if the operator has more specific local knowledge, the operator can provide an estimate.

The Guidance methodology uses VSL-based safety consequences in a manner similar to that used for the surface leakage-fire event.

The distribution of harmful effects along the consequence severity scale is a very difficult estimate, but this Guidance provides a lower severity rate effect based on the authors' knowledge and experience. Operators can choose to use the distribution set in the Guidance or use their own.

Further, the spatially-weighted distribution of effects to an increasingly wider area is a difficult estimate, but this Guidance assumes most impact occurs within a 1-2 mile radius of the well – 98% within 2 miles and 99.9% in 3 miles. In the supermajority of subsurface events, the impacts from subsurface leaks are contained within a 1-2 mile radius. Events such as Hutchinson, Kansas, represent the "long tail" end of such subsurface occurrences. Aliso Canyon also represents a "long tail" end of a surface release. PHMSA's Storage IFR and supporting documents note incidents that had impacts of 6-8 miles or more. The COFI spreadsheet attached/linked to this Guidance allows operators to change the spatially –weighted distribution, as well as the VSL-based safety consequence severity distribution.

Operators can use the COFI spreadsheet in this Guidance; the estimate involved the multiplication of:

volume index * population index * safety consequence distribution

The consequence estimate can be scaled further to provide a scalable (power law based) range of low-mid-high consequence estimates.

The detail of the estimation methodology can be followed in the spreadsheet, but it is briefly described here:

The local population density is estimated to log-based ranges and given an index number fixed to the lower end of the range. The number of people inside the impact radii is calculated and weighted by the impact radius weighting. A safety impact severity distribution range is estimated across a range of lo-med-hi distributions and then multiplied by the VSL-basis for each injury severity type.

The 30-day release volume range is given an index number 1-6, based on power-law scaling. The weighted-indexed people per sq. mi is multiplied by the 30-day volume index then multiplied by VSL-ranged injury severity. The sum of the injury-severity for the (population index, 30-day volume index) pair is the estimated safety-based consequence of a subsurface release.

Operators may change the distributions and weightings on impact injury severity, but whatever the operator chooses should be used consistently within a field, or across an operator's assets.

The consequence analysis includes estimating population density or total population in a defined radius, with a weighted average over 1 - 9 miles; note probabilities in the table below:

Table 5

COFI Safety - SubSurface Release:							
30-day volume	radius of impact		tiers (miles)				
			1	2	3	6	9
	probability of impact		0.8	0.18	0.0189	0.001	0.0001
	determine potential human population within each tier						
	simplify using county, town, or township population density per sq mile						

The impact area likelihood can depend on geologic and well integrity factors: geo-pathways, old well pathways; the well under evaluation will already have LOFI based on its own integrity conditions, but the wider analysis will evaluate other pathways.

The consequence analysis proceeds to calculate a release volume index and a population index, based on the area impact likelihood distribution in the Table 5. The population index is characterized as per Table 6:

Table 6

population density per sq mi	initial population index	r=1	r=2	r=3	r=6	r=9	population index
0.1-1	0.1	0.3	1.3	2.8	11.3	25.5	0.5
1-10	1	3.1	12.6	28.3	113.1	254.5	5.4
10-100	10	31.4	125.7	282.8	1131.1	2545.0	54.5
100-1000	100	314.2	1256.8	2827.8	11311.2	25450.2	544.9
1000-10,000	1000	3142.0	12568.0	28278.0	113112.0	254502.0	5448.9
>10,000	10000	31420.0	125680.0	282780.0	1131120.0	2545020.0	54488.6

The 30-day release volume index is characterized in Table 7:

Table 7

30-day volume mmcf	volume index
<1	1
1-10	2
10-100	3
100-1000	4
1000-10,000	5
>10,000	6

The spreadsheet then calculates an estimate for:

consequence = volume index * population index *safety consequence severity-probability

This is based on VSL distribution, estimates of v. low, low, mid, and high impact severity distributions, in Tables 6 and 7, resulting in Table 8:

Table 8

	v. low	low	mid	hi	2017 VSL-based $	lo$	hi$	wtd
insignif	0.94889	0.93297	0.894	0.869	0.001	0.00095	0.00087	0.00091
Minor	0.022	0.024	0.028	0.03	0.029	0.00064	0.00087	0.00076
Moderate	0.018	0.02	0.024	0.025	0.451	0.00812	0.01128	0.00999
Serious	0.01	0.012	0.02	0.022	1.008	0.01008	0.02218	0.01663
Severe	0.001	0.01	0.016	0.02	2.553	0.00255	0.05106	0.03319
Critical	0.0001	0.001	0.012	0.018	5.691	0.00057	0.10244	0.04473
Fatal	0.00001	0.00003	0.006	0.016	9.597	0.00010	0.15355	0.04618
any injury	0.0511	0.067	0.1	0.115	sum	0.023	0.342	0.152
	1	1	1	1				
distribution	0.1	0.35	0.4	0.15				

Operators can use the weighted range; use of the "max" basically doubles the consequence potential

Calculate: consequence = volume index * population index *safety consequence severity-probability.

In Table 9: Consequence Estimate – Final Estimates, the volume index is multiplied by the population index and then each pair is multiplied by the weighted/ranged injury potential value from Table 8.

Table 9

vol index	6	5	4	4	3	2	1
pop index	55000	5500	550	55	55	5.5	0.5
insignif	300.095	25.008	2.001	0.200	0.150	0.010	0.000455
Minor	251.691	20.974	1.678	0.168	0.126	0.008	0.000381
Moderate	3296.585	274.715	21.977	2.198	1.648	0.110	0.004995
Serious	5488.560	457.380	36.590	3.659	2.744	0.183	0.008316
Severe	10952.370	912.698	73.016	7.302	5.476	0.365	0.016595
Critical	14761.316	1230.110	98.409	9.841	7.381	0.492	0.022366
Fatal	15238.069	1269.839	101.587	10.159	7.619	0.508	0.023088
Sum	50288.685	4190.724	335.258	33.526	25.144	1.676	0.076

Equivalence of over $50B to $4B to several hundred $million to several tens of $millions to single millions or much less

From Table 9, note that the power-law basis escalates consequences: when population index is high, the consequence equivalence can "explode" to greater values. While some might think a $50B exposure is untenable, the value occurs in the extreme case of very high-volume index and very high population index. Few places in the world hold such a combination, so the lack of comfort with such a high estimate is to be expected, but lack of comfort does not invalidate the methodology, which for more typical population densities and release volume potentials, provides estimates in the potential millions to tens of millions of dollars equivalence range, or into several hundreds of millions for more densely populated areas.

Summary: Safety – subsurface release, or surface release/no fire:

Subsurface release and surface release with no fire are similar in that their consequence areas can be large and the health and safety impacts are difficult to estimate. The framework in this Guidance assumes a 30-day release volume as indicative of an approximate P95 event – that is, 95% of all releases would be contained within 30 days or less. The framework asks that a population in a potential impact area up to 9 miles in radius be estimated. The framework provides an injury-severity distribution that can be used to estimate impact. Operators could range these estimates quite widely and employ measures to reduce risk as revealed by the analysis.

Societal Risk: As the number of people potentially impacted by an event grows with the larger radii potentially impacted by subsurface leaks/migrations and/or pervasive surface leaks, the uncertainty around impact grows. Operators should use increasingly precautionary measures when storage facilities (wells) are proximal to larger densities of population. The use of ALARP should be employed to review those wells with greater probability of failure when the LOFI *COFI estimate exceeds 1 in 10,000 fatalities per capita per year; operators should employ mitigations to reduce the risk. Since the weighted ranged chance of fatality is ~5 in 1000 (.0048) per event, then unless LOFI <.0207 per well-year, risk of fatality will be unacceptable (given an unacceptable fatality threshold of 1 in 10,000 per capita per year).

Using the ALARP principle, the LOFI *COFI for fatality should be reduced toward/less than 1 in 100,000 per capita per year. Well design, knowledge of well condition, and other preventive measures will reduce LOFI. In addition, COFI can be reduced by various mitigation measures – adding barriers, adding detection and isolation devices, and so on.

Consequence of Failure – Environmental: COFIenvironment

This Guidance provides for a ranged estimate of widespread impact from surface (non-fire) or subsurface release, using the same 30-day release volume assumption, on the valued environmental components (VEC) of soil stability, soil productivity and vegetation, water supply, air and water quality (mobility enhancement of toxins and pollutants), and air (greenhouse gases). The Guidance recommends that environmental impacts estimated to order of magnitude cost and that $ value further converted to an index number (logarithmically aligned to cost). The Guidance provides some base cost ranges but no particular methodology to assess impacts in detail, as an operator must evaluate the wider area around the storage facilities for the state of the VEC and the local/regional perception of value. Nonetheless, without a great level of study, promoting a scalable range of environmental consequence estimates allows an operator to assess potential environmental impacts relatively quickly.

The COFIenvironment estimate includes the effects of incident duration and duration of effects after the incident is controlled, water quality restoration such as spill clean-up and habitat reconstruction, land and water reclamation, emissions penalties, and temporary environmental degradation, loss of habitat, and loss of enjoyment (loss of environmental quality).

For most natural gas well leaks, operators could assume that the air impact is the most significant; the soil and water impact might be relatively localized depending on soil or rock type in the substrate. Disruption of the subsurface by high pressure gas moving through materials of lower compressive strength could open pathways for movements of other fluids, which could contain chlorides, BTEX, or other contaminants. Surface disruptions could include pits, cracks, craters, and liquefaction, which significantly degrade soil stability and could degrade soil productivity. Local water wells could be impacted and groundwater supplies adversely impacted by gas bubbles or contamination by associated fluids traveling with the gas or through pathways opened or enhanced by the gas flow.

The evaluation of environmental consequences in the event of a well leak can be difficult, but can best be ranged with some confidence according to power-law, order-of-magnitude estimates, based on well 30-day release potential and sensitivity of several valued environmental components in the area of potential impact.

The VEC and value ranges used as a starting point recommendation in this Guidance are given in Appendix 9.

Summary- Environmental:

Operators can estimate the environmental consequences using tables in Appendix 9. Operators can test the consequence ranges for sensitivity using area of impact likelihoods and release volume indices found in Appendix 9.

If potential exists for toxic fluids to migrate with the gas flow, operators should test the sensitivity of that part of the environmental consequence analysis ("Fluid Flow/Transport of Toxins/Pollutants") and take an increasingly precautionary approach as population density increases and release volume potential increases.

Consequence of Failure - Service-reliability-financial: COFIfinancial

Most values-based consequences can be addressed separately and specifically in the COFI for safety and COFI for environmental described in preceding sections. Other consequences to the operator's service capability, reliability, and financial and reputational well-being as well as financial consequences to neighboring 3rd party activities / facilities can be estimated in this section.

Operators can use this section to estimate such consequences for several types of events, including the surface release and fire event, the 30-day surface release and no fire event, or the 30-day subsurface release and migration event. This Guidance provides a simple spreadsheet with pre-filled line items, to which operators can supplement with other site or facility specific items. This Guidance recommends that operators range the estimates along a power-law scaled P5 – P 50 – P95 range to test sensitivity to the magnitude of potential events and their impacts.

COFIfinancial evaluation includes:

- production loss (time); product lost during leak (depends on pressure, volume available and isolation potential, leak point geometry, detection and response/isolation time)
- deployment costs for emergency response personnel, degradation of product quality
- equipment repair and restoration [incl. analysis of eqpt lead time], on-site and off-site property damage [incl. damage to adjacent eqpt and further business/service impacts]
- cost of cascading business risk [interruption of flow/feed to the next point curtails that activity as well], ability to compensate for flow/service loss, business interruption/service interruption cost, loss of market share/loss of customers
- relocation/reimbursement, loss of goodwill/public reputation
- increased cost of insurance, litigation costs
- regulatory actions/fines/cost of new regs
- and other items as identified by the operator.

Guidance: The lo-mid-hi ranging should be the operator's estimate of P95 (low) P50 (mid) and P5 (high) - in other words, a cost consequence experienced in 95% or 5% of events.

Operators may skew the distribution and add columns for identifying the P-values. For example, an operator may choose to indicate the mid-range P-value is something between P30 and P70.

The idea is to widely bracket potential consequence values, using a logarithmic or related power-law basis. For example, by doing this, the operator might estimate that the potential consequence, say, for equipment repair and restoration is, in probably 95% of cases, at least $1,000,000 and at most (in 95% of cases) no more than $10,000,000, with an estimated most likely value of around $3,000,000.

Even for minor impacts, operators should be sensitive to the cost of events. API 581 notes that any failure (loss of containment) has financial consequences associated with it, even if there is no damage.

The example below represents how an operator might choose to fill in Table 10:

Table 10

Cost Category	low estimate	mid-range est	high estimate	P distribution if not default
emergency response and incident management cost	$100,000	$1,000,000	$10,000,000	
product lost during leak	$100,000	$1,000,000	$10,000,000	
degradation of product/service quality	$1,000	$10,000	$100,000	
business interruption/service interruption cost, loss of market share/loss of customers	$1,000	$10,000	$100,000	
ability to compensate for flow/service loss	$100	$1,000	$10,000	
deployment costs for emergency response personnel	$10,000	$100,000	$1,000,000	
equipment repair and restoration	$1,000,000	$3,000,000	$10,000,000	
on-site and off-site property damage [incl. damage to adjacent eqpt and further business/service impacts]	$1,000,000	$3,000,000	$10,000,000	
relocation/reimbursement	$10,000	$100,000	$1,000,000	
cost of cascading business risk [interruption of flow/feed to the next point curtails that activity as well]	$10,000	$100,000	$1,000,000	
loss of goodwill/public reputation	$10,000	$100,000	$1,000,000	
increased cost of insurance	$100,000	$1,000,000	$10,000,000	
litigation costs	$100,000	$1,000,000	$10,000,000	
regulatory actions/fines/cost of new regs	$100,000	$1,000,000	$10,000,000	
other (list and estimate)	$100,000	$1,000,000	$10,000,000	
Cost of lost/damaged homes	$1,000,000	$10,000,000	$100,000,000	
Home air/local water source monitoring	$1,000	$10,000	$100,000	
Clean up of toxic release/clean up of pollution	$100,000	$1,000,000	$10,000,000	
Wildlife/endangered species impact	$10,000	$100,000	$1,000,000	
total estimate low/high	$3,753,100	$23,531,000	$195,310,000	

The recommendation to use power-law scaling when estimating consequences again serves several purposes:

- It allows relative quick entry of information without need for exhaustive analysis
- It allows testing by peer review, wherein an operator can test for internal consistency
- It allows for industry cooperative peer review, lessons learned sharing, and consistency
- It increases sensitivity to the consequential magnitude of infrequent events

Consequence of Failure – Total Summary:

This Guidance, in its COFI estimation workbook ("Risk Guidance workbook COFI.xlsx"), provides a tab for a COFI summary, which takes the ranged values for the safety, environmental, and financial tabs. An example is given in Table 11, below.

Table 11

Summary of Consequence Potentials

Consequence Category	P95 low estimate	P50 mid-range est	P5 high estimate	P distribution if not default
Safety - Surface Release and Fire	$13,870,490	$32,322,796	$56,931,500	
Safety - Subsurface Release	$3,300,000	$33,500,000	$335,000,000	
Environmental - Surface/Subsurface Release	$761,000	$11,600,000	$135,500,000	
Service Reliability and Financial	$3,753,100	$23,531,000	$195,310,000	
total estimate low/high	$21,684,590	$100,953,796	$722,741,500	

Guidance: lo-mid-hi come from the individual calculation sheets

The operator can identify the type of consequence dominating the total estimate at each level of probability. The low and mid-range estimates can be highlighted in particular for the main drivers (safety, environmental, or service reliability/financial). It is important to focus on the low-mid-range estimates, since it is the case that in the more extreme, catastrophic events, financial consequences might dominate. Values-driven decisions – those that serve to protect safety and environment – get greater focus in the low-mid range estimates. What is noteworthy is that when operators make decisions on precautionary bases to protect life and environment, they also are making themselves increasingly robust against severe or catastrophic financial loss – thus the focus on the safety and environmental value drivers is the essence of the business case for process safety management. In preventing loss of containment, in protecting people and the environment, operators are protecting their property and their financial values as well.

Table 12 gives an example where an operator can flag the dominance of safety consequences in this case for P95 to P50 events. Note that safety and environmental consequences also are high in the P5 event, but as a single line item the financial consequence dominates.

Table 12

Example:				
Consequence Category	**P95** **low estimate**	**P50** **mid-range est**	**P5** **high estimate**	**P distribution** **if not default**
Safety - Surface Release and Fire	$14,000,000	$32,500,000	$57,000,000	
Safety - Subsurface Release	$3,300,000	$33,500,000	$100,500,000	
Environmental - Surface/Subsurface Release	$761,000	$11,600,000	$135,500,000	
Service Reliability and Financial	$3,753,100	$23,531,000	$195,310,000	
total estimate low/high	$21,814,100	$101,131,000	$488,310,000	
main consequence driver(s):	safety	safety		

In this way, safety (and possibly environmental) are "sticky" categories, meaning that at "low" and "mid"-estimates, they can dominate and show that they should be treated accordingly in risk management plans. At the high estimates, other service-reliability-financial impacts can become dominant, even though safety impacts remain critical - but safety could appear to become dominated by other concerns.

This Guidance recommends that operators use the COFI Summary table in the COFI estimation workbook and flag the aspects driving or dominating the consequences at the range of outcome probability levels, and structure risk management plans accordingly.

Consequence of Failure – Credits:

This Guidance recommends that at the end of COFI analysis, operators evaluate the current isolation, detection, and mitigation systems in place and estimate a credit. The credit can be used as a multiplier in the COFI equation:

COFI = (COFIsafety-surface + COFIsafety-subsurface + COFIenvironment + COFIfinancial)*credit

The methods to calculate credits for each detection, isolation/containment, or mitigation system employed are described further below; the total credit is the product of the individual credits. The COFI total can be adjusted by the total credit as a factor, as noted in the equation.

Operators can use the credit factor methodology to estimate risk reduction when making risk treatment decisions concerning alternatives to deploy isolation, detection, or mitigation measures. Operators can build into their qualitative bowtie diagrams, fault/event trees the use of such systems to test the robustness of the risk management plans for their facilities. Two event tree examples are presented in Appendix 10.

COFI – Credits for Detection and Isolation:

Detection and Isolation/Containment Systems can detect, isolate, or temporarily contain a leak to reduce release magnitude and duration or both. Mitigation systems are designed to reduce the consequences of a leak.

A secondary passive technical/physical barrier can act to isolate a failure but outside of the primary barrier (containment). Even though operators might not be able to know or test the condition of this secondary barrier, this Guidance permits a credit based on the operator's cautious evaluation of the barrier's effectiveness. The reasoning is that if there is loss of containment on a primary barrier element, and if failure were "immediately" stopped or confined by a passive second barrier in a coupled/multiple passive barrier system, this Guidance treats that barrier as an effective passive mitigation barrier. The secondary barrier cannot be considered as a preventive barrier unless the operator can know and test the condition of the barrier.

This Guidance assigns classifications to detection and isolation systems as noted in the Appendix 11 in Table 11 - 1.

For each Detection and Isolation/Containment System, operators can use Table 11 -2 in Appendix 11 to evaluate the reliability and multiply the reliability credit subfactor by the detection/isolation class subfactor to get the credit.

If there are multiple systems, the total credit is the product of all the systems: credit1*credit2*credit3*credit(n)…

COFI – Credits for Mitigation:

Operators might employ mitigation systems such as inventory blowdown devices, fire suppression systems, heat shielding capabilities, in-situ vent wells, and enhanced emergency response technologies. The mitigation system must have a technical/physical basis (not human or procedural) in order to take the credit.

Operators can calculate a credit for each identified mitigation system based on the estimated level of effectiveness of the mitigation system in reducing consequence potential. Table 13 shows the mitigation credit subfactors:

Table 13

Effectiveness/Reliability	Credit Subfactor, Cme1
Very Low	1
Low	0.98
Moderate	0.85
Moderately High	0.75
Very High	0.6

Risk Analysis – Summary

LOFI = Gff * (Sum(Df) + Fwhv + Fcmt) * credit

COFI = (COFIsafety-surface + COFIsafety-subsurface + COFIenvironment + COFIfinancial)*credit

Risk estimate = LOFI * COFI

This Guidance recommends:

- Operators evaluate risk using the LOFI and COFI framework methodology in this Guidance
- Operators test sensitivity by ranging LOFI and COFI within the LOFI and COFI frameworks
- Operators use peer review to gauge consistency, robustness, and reasonability in the use of the LOFI, COFI, and credit estimation methods
- Operators think in power-law scalable terms rather than in deterministic and/or non-scalable likelihood and consequence values
- Operators test the consequence potential for sensitivity to values-driven consequences such as safety and environmental impacts
- Operators evaluate risk reduction on both LOFI and COFI using the framework methodology in this guidance

Industry literature offers additional views on qualitative and semi-quantitative risk models and applications of concepts similar to those developed in this Guidance. For example, interested operators can review Dethlefs and Chastain "Assessing Well Integrity Risk: A Qualitative Model", SPE paper 142854, 2012.

Step 2.d Risk Evaluation

The risk management process continues after risk analysis with decision making stages of risk evaluation and risk treatment options analysis. During risk evaluation, the operator should relate back to the first step of the risk management process, where objectives, targets, and evaluation methods were to be set, and where the operator was to describe its risk tolerance and the criteria to be used for measuring risk and risk reduction.

In risk evaluation, the operator should recall the tolerable risk framework, precautionary principles and the application of "As Low As Reasonably Practicable" (ALARP), and a structured decision process. Additional discussion of ALARP and using risk concepts to create increasingly fail-safe systems and avoid major accidents can be found in the 2012 SPE paper 156910 (Martland and Mann, "Examining the Suitability of E&P Major Accident Prevention Design Principles in a Changing Global Environment and Comparison with the Rail, Nuclear, and Aviation Industries").

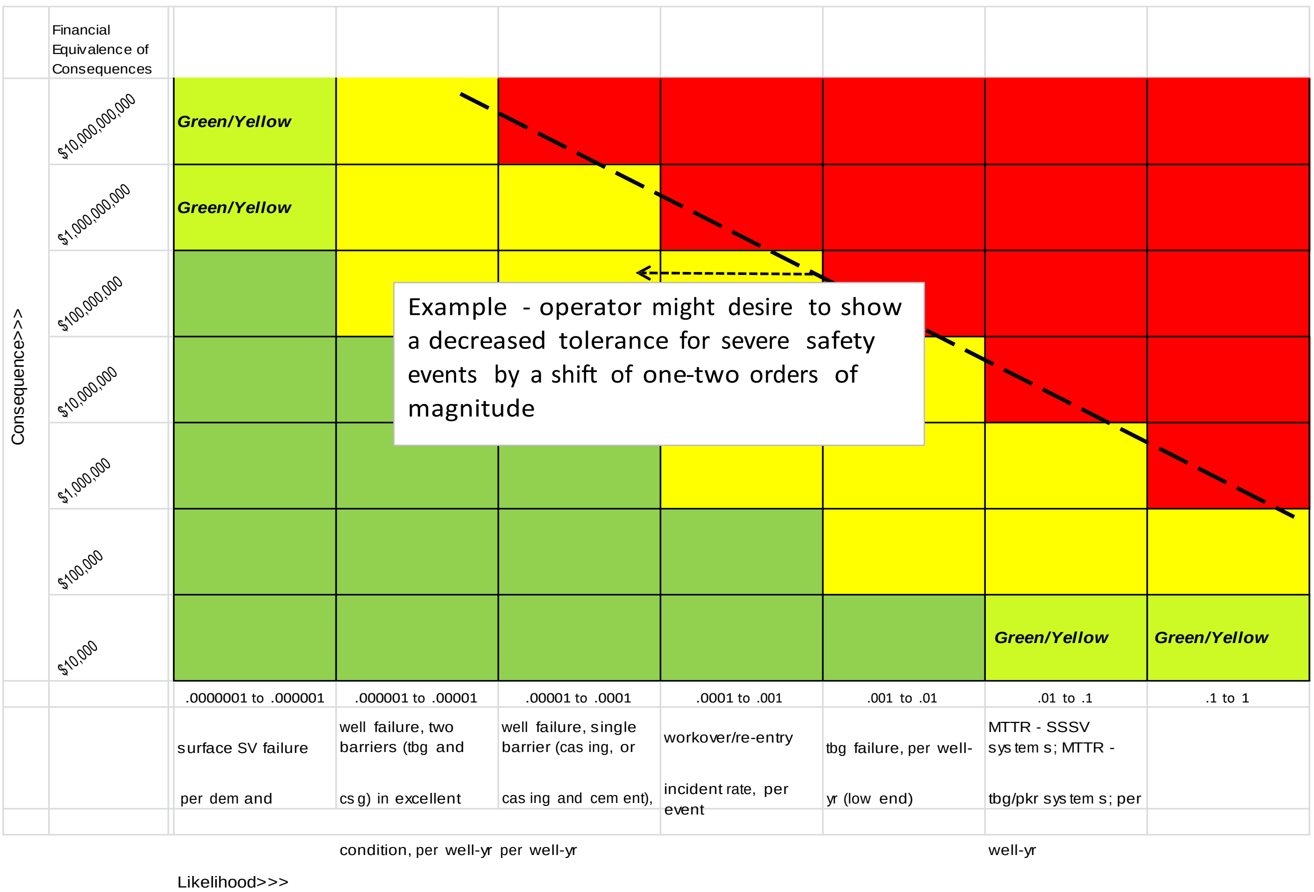
This Guidance provides a 7x7 log-scalable likelihood-consequence risk matrix (Table 14), with value tiers as noted in Table 14 below. Operators can use the risk matrix in this Guidance to assess relative risk at components in and across their storage assets.

Table 14

Likelihood Categories			Consequence Categories	
Qualitative descriptor	Probability Range	Minimum of Range	Qualitative descriptor	Equivalent USD
Very Likely	P>0.1 to 1	1 in 10	Insignificant	<$10K
Likely	P>0.01 to 0.1	1 in 100	Minor	$10K to <$100K
Unlikely	P>0.001 to 0.01	1 in 1000	Significant	$100K to <$1M
Very Unlikely	P>0.0001 to 0.001	1 in 10,000	Serious	$1M to <$10M
Extremely unlikely	P>0.00001 to 0.0001	1 in 100,000	Major	$10M to <$100M
Remote	P>0.000001 to 0.00001	1 in 1,000,000	Critical	$100M to <$1B
Unforeseeable?	P>0.0000001 to 0.000001	1 in 10,000,000	Catastrophic	>$1B

Risk matrices can be used to assess risk for single events and not cumulative risk assessments. Risk tolerance for safety or for environmental consequence is determined separately, as for example when using an individual risk / societal risk criterion to evaluate safety risk tolerability. For many risk-informed decisions with respect to equipment testing, monitoring, and maintenance, operators could use the risk matrix in this Guidance to assess relative risk in and across their storage assets. The risk matrix could be divided by thresholds into unacceptable and acceptable regions, according to an operator's criteria in step 1 of the risk management process, as shown in the following figure:

Figure 8



Operators might use different matrices to note acceptable thresholds for different consequences: for example, operator tolerance of financial cost consequence might be greater than operator tolerance for safety or environmental consequence. In this way, multiple risk matrices might be necessary for operators to evaluate risk against safety, environmental, and financial consequences, or, one matrix can be used but a shift in tolerance thresholds is noted for different consequence types.

Where tolerance thresholds are not set by regulation, industry standards, or company tolerance policies, ALARP can be used to determine the cost/benefit of risk reduction measures. For any threshold, whether mandated or voluntarily set, further risk reduction options can be assessed by ALARP.

During risk evaluation and using the proposed LOFI and COFI framework methodology, operators can determine if the risk is driven primarily by LOFI or COFI, or by a combination, as this realization will help set up risk treatment decisions.

- If LOFI drives risk, mitigations might go toward more inspection/repair/replacement, as well as to inherently safer designs for new or replacement components.

- If COFI drives risk, mitigations might go toward detection/isolation/containment systems as well as to engineering/management methods in regard to awareness of and response to abnormal conditions.
- If risk is driven both by LOFI and COFI, then combinations of inspection/repair /replacement and engineering/management methods could be employed.

Engineering methods might include installation of additional preventive barriers, installation of consequence mitigation barriers such as safety valves, and alarms, and identification of additional success paths for supporting the performance of the preventive and mitigation barriers. Management methods might include increasing the robustness of the operator's human and organizational barriers through strengthening its overall process safety management system (see Appendix 4).

Step 3: Risk Treatment

Risk treatment decisions are set up by the risk evaluation stage. Risk treatment decision-making includes the review of current risk treatments in place and a review of alternatives for risk reduction by employing options from among categories such as:

- Isolation/Removal from service
- Repair, replace, rehabilitate
- Inspection, testing, maintenance program/frequency changes
- Consequence potential reductions – operational design changes, isolation-relief-safeguard and/or real-time monitoring, detection-alarm systems installations
- Probability of loss of containment reduction – equipment changes for new material safety factors and metallurgical properties, safeguards/barrier installation, changes in operating limits, etc.

The risk treatment stage of the risk management process should involve a review of the effectiveness of existing risk treatments. Operators can evaluate any new or increased risk of the chosen risk treatment alternative during the assessment of change in risk after risk treatment. Some treatments involve installation of additional equipment and material in a well, and those items have lifetimes and reliability issues that might demand additional well interventions. The potential increase in safety of a new risk treatment, offset by any potential increase in risk due to additional well interventions or potential equipment malfunction, needs to be analyzed so as to ascertain a more accurate impact to overall system reliability and safety. Therefore, both reliability issues and well interventions are to be considered in evaluating the change in risk after a risk treatment is applied. This Guidance has been structured such that operators can evaluate the effectiveness of existing risk treatments through direct LOFI and COFI or through credits evaluations. The LOFI and COFI frameworks are set up so that operators can evaluate the effectiveness of proposed risk treatments at reducing risk.

Operators can also use a cost/benefit basis of treatments in specific wells in order to move toward an ALARP philosophy if they wish to do so. The costs for applications of risk treatments can vary greatly due to site- and well-specific conditions, and the risk reduction value of a specific treatment also will vary with the particular conditions of any well. However, application of the methods outlined in this

Guidance and the LOFI and COFI tools can help an operator set up evaluation schemes for moving toward an ALARP approach.

Additional review of reliability engineering concepts and available well component reliability information can be found in SPE paper 178557-MS (Jenssen and McPherson, “Applying the Concept of Systematic Reliability Management and Analysis to Achieve Better Well Equipment Performance Through Less Failures and Reduced Down Time Due to Work-Overs”, SPE paper 178557-MS, Society of Petroleum Engineers, 2015).

This Guidance provides an example risk treatment options library. A risk treatment option library should provide a range of options for categories such as

- Isolation/Removal from service
- Repair, replace, rehabilitate
- Inspection, testing, maintenance program/frequency changes
- Operations and/or design changes
- Isolation-relief-safeguards
- Real-time monitoring or detection-alarm systems
- Equipment changes for new material safety factors and metallurgical properties
- Additions of barriers
- Addition of alternative success paths to support barrier performance
- Changes in operating limits
- Other

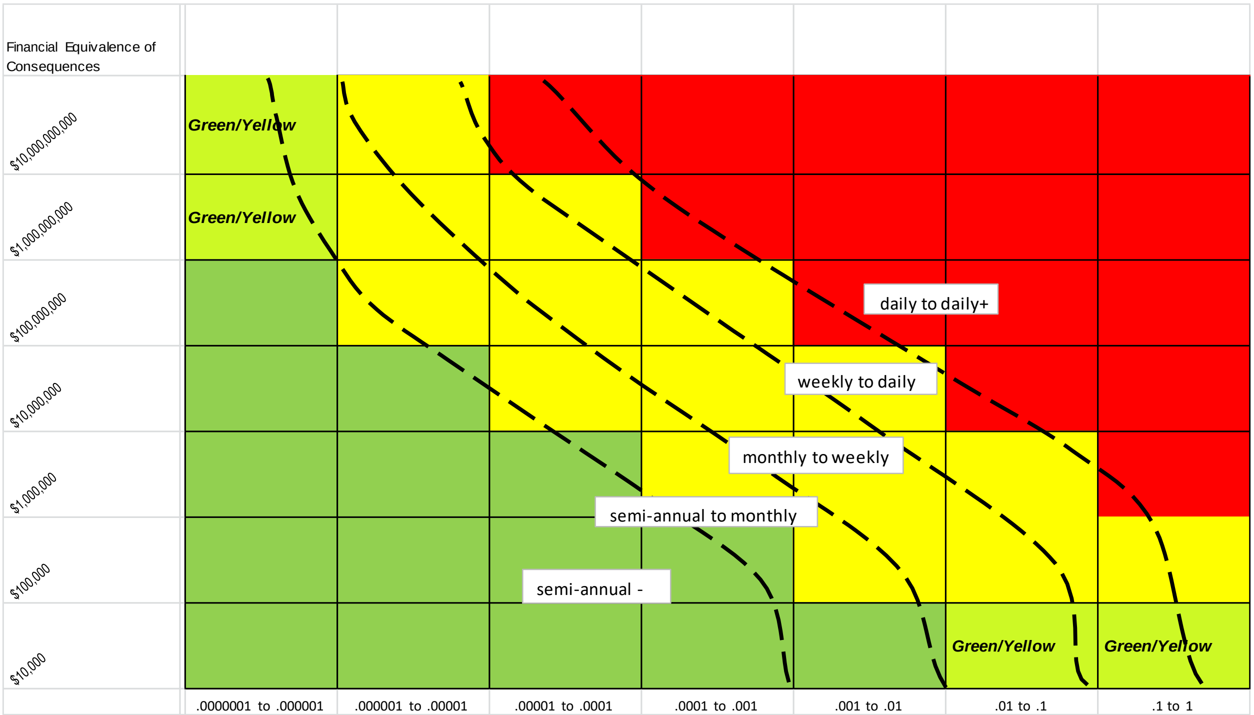
The risk treatments on each primary barrier element (casing, wellheads, valves, cement) should be addressed in the risk treatment options library. API 1171 Section 8, Table 2 can be used to construct a risk treatment option library. An example options library is given in the Appendix 12.

Another way of viewing a risk treatment options library is in the form of a hazard-barrier matrix, similar to one that can be constructed from API 1171, Section 8, Tables 1 and 2, as shown in Appendix 3.

Appendix 13 provides a guide to risk treatments and their effects on LOFI and COFI factors. Operators can re-assess LOFI and/or COFI after choosing risk treatments and estimate the level of risk reduction.

Inspection-monitoring-testing and maintenance frequency are related to risk. Operators can set rules and be internally consistent when setting risk-based approaches to inspection methods and frequencies. An example of super-position of inspection frequency iso-lines on the 7x7 risk matrix is given in Figure 9, below; in this example, the pressure, temperature, flow monitoring frequencies are depicted.

Figure 9



Specifically, for inspection activities, inspection intervals can be established on a site-specific basis using risk-based analysis as an alternative to rule-based frequency. A risk-based inspection plan includes:

- Identifying drivers for loss of primary containment
- Define success criteria for performance of preventive and mitigating barriers for loss of primary containment
- Using past/existing information and new inspection information to identify rates of deterioration of primary containment
- Identifying applicable inspection methods, extent/thoroughness of inspection
- Creating a process to identify the next inspection timing
- Identifying decision points to mitigate (repair, replace, remove from service…) and relating these to the operating limits/operating windows for the primary containment components
- Identifying the process safety management system components that support the inspection plan (this includes audit, training, roles and responsibilities, reassessment triggers, risk targets…)

In identifying decision points, the risk-based inspection analysis requires:

- Understanding/documenting the design basis of containment components
- Identifying damage mechanisms and failure modes
- Assessing probability of failure and probability of consequence
- Ranking the relative risk of one unit (well) to another
- Assessing the strength of the process safety management system

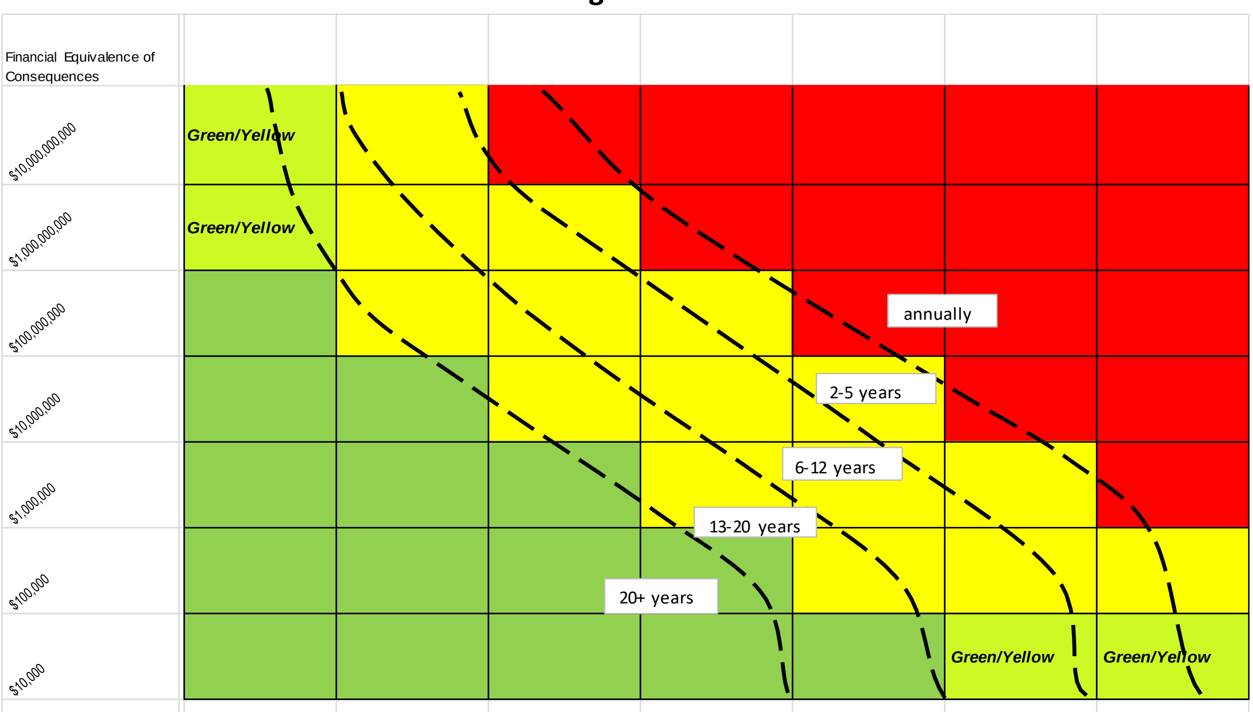
An example of applying a risk-based reliability model to inspection testing frequency is presented in the 2015 SPE paper 175460-MS (Farwana and Taylor, “Determining the Optimal Frequency of Carrying Out Well Integrity Tests”).

Operators are advised to include in their plans an analysis of end of life issues, failure mechanisms that cannot be inspected and might depend on design, operating windows for their assets, time-independent issues, and consequence dominated risk. Non-inspection mitigations can be employed (repair, replace, upgrade, tighten operating windows, install other controls…).

NOTE: Risk-based inspection is an extension of a basic risk management process, but with specific focus on working within a process safety management system and aligning with hazard analyses, operating limits determinations, and other risk management activities. API 580-581 provide focus on maintaining mechanical integrity of pressurized equipment in order to minimize the risk of loss of primary containment due to deterioration/damage mechanisms. The purpose of risk-based inspection is to direct decision-making through prioritization. Inspection can influence the uncertainty of risk by increasing knowledge of the deterioration state and predictability of LOFI. Inspection is a risk management activity that can lead to risk reduction. Inspection results can lead to other mitigation activities to avoid failures.

Another example could be for inspections such as casing inspection surveys – depending on corrosion rates and other probability of failure assessments, an operator might construct a rationale that looks something like Figure 10:

Figure 10



NOTE: ISO 16530-1 is a good reference on well integrity philosophies and practices. Operators might find it beneficial to review ISO 16530 especially with respect to well barrier verification tests, operating *limits, well monitoring, annulus pressure monitoring, and maintenance practices. The development of operating limits is especially important. Operators are advised to adopt philosophies of ISO 16530 with respect to identifying well barrier performance standards; the identification of performance standards for each barrier element is an essential companion to the testing, inspection, and monitoring methods and frequencies, since it helps address the question "what do operators do if information reveals a performance weakness against a set standard?"*

NOTE: Applied well failure modeling concepts from ISO 16530-2 are discussed in Girling,et al, "Advanced Well Failure Modelling Improves Well Integrity, Safety, and Reliability", SPE paper 175473-MS. Earlier references include Molnes and Strand, "Application of an Equipment Reliability Database in Decision Making", SPE paper 63112, 2000, and Molnes and Sundet, "Reliability of Well Completion Equipment", SPE paper 26721, 1993.

Step 4: Risk Management Plan

Gas storage operators can record their risk management process and decision outcomes in a risk management plan. The risk management plan becomes a living document that is reviewed at some minimum regular frequency or as prudent based on new information and lessons learned. Due to the expected long life of a storage asset, operators can expect that the risks to storage wells will change over time; the operator monitors changing conditions and adjusts their risk management plan accordingly. Similarly, a new storage well could have different risk management plan aspects, or requirements, that a mature well might not have, or the aspect may no longer be a key risk element.

The Plan follows directly from the risk evaluation and risk treatment decision process. The Risk Management Plan should cover real-time monitoring and operations as well as "offline" risk management decision making.

A Risk Management Plan is a document that contains executable actions within the context of the risk management process steps, the operator's risk drivers, risk targets and performance metrics ranking of well facilities and statements of prioritization based on the relative risk estimated by this LOFI/COFI framework (a view that can lead to estimates of residual risk and targeted residual risk), and risk reduction evaluation criteria.

A good Plan describes ~~the~~ how the operator will measure success, the decision options, decision executables, and accountabilities. The Plan also includes risk documentation/reporting, risk re-assessment intervals, and other risk management recommendations.

An operator's Risk Management Plan includes, ideally, a top or introductory section that covers description of the operator's storage assets and systematic risk management process approach used for the assets. Distinctions that might be needed for specific assets or components can be described in the top section. The top introductory section of the Risk Management Plan includes:

- Risk management process steps
- Risk management goals and objectives
- Risk drivers and risk appetite (or specific risk tolerances or thresholds if known)

- A summary and ranking of the storage facilities and wells, prioritized on relative risk
- Risk reduction targets
- Risk reduction evaluation criteria
- Risk treatment effectiveness evaluation criteria

The Risk Management Plan includes a section for each field, ideally containing:

- Summary of major risk drivers (hazards, threats, and risk management goals)
- Summary of most critical and highest risk components
- Ranked summary of individual wells

The Risk Management Plan includes within each field section and listing of each well, ideally containing:

- LOFI and COFI and basis
- Acceptability of risk level and decision to accept or reduce risk
- Decision options, including
    - address of safety valves
    - inspection/monitoring/testing types and frequencies
    - rework/rehabilitation (if necessary)
    - Decision executables and accountabilities
    - Re-assessment interval

The target audience includes both the technical staff and management. This Guidance recommends that the person accountable for the risk management review also have decision making authority with the organization's resource allocation processes, in order to direct that adequate resources are allocated to managing and reducing risk with the organization's storage wells. The value of such a single accountability (leadership position) includes:

- Authority to prioritize work to make sure the risk analysis gets done
- Obtain the necessary funding to reduce risk
- Achieve what was intended by the risk management and risk reduction process

Operators adopting this Guidance will be able to develop a robust view of the risk management process, a holistic and interactive view of threats and hazards and the preventive and mitigation barriers that protect life, environment, and service quality, a quantitative approach to risk analysis, evaluation, and risk reduction by various treatments, and a systematic reporting and continual improvement process that manages risk with respect to storage facilities.

Step 5: Continual Improvement- Review and Reassessment

The final step involves a periodic review of the risks presented to storage wells and the effectiveness of the preventive and mitigative measures being utilized. API 1171 in Section 8.7 requires that the operator periodically review and update their risk assessment. This Guidance embraces that requirement as demonstrated in Figure 1.

Underground storage wells are long life assets and, for an operator with a number of wells, it is very likely that the threats and hazards affecting a given well will change over time, both new ones developing and existing ones that change imperceptibly over a short timeframe but cumulatively becoming critical over a longer time period. A periodic update to the risk analysis presented in this Guidance requires the operator to do a thorough reassessment.

The operator's review will strive to:

- Identify time dependent threats, such as corrosion, surface encroachments, third party damage, etc.
- Determine the effectiveness with existing preventive and mitigative measures
- Determine the effectiveness with the risk reduction measures, if any, implemented from prior reviews
- Update the factors utilized in the generic failure frequency (Gff- presented in detail in Appendix 5) calculations and the resultant risk ranking
- Update the organization's risk tolerance level utilized in the previous analysis for the current tolerance level

The time interval for the periodic review and reassessment will be short enough to identify operational and monitoring trends and measure the effectiveness of the preventive and mitigative measures but long enough that the data and information that can be brought into the analysis are meaningful.

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Appendix 1

Leading and Lagging Indicators for Storage Wells

The following are some examples of leading (forward-looking) and lagging (retrospective) indicators that could be used for natural gas storage wells as discussed in this Guidance:

A. Leading indicators
   - Repairs and reconditioning completed vs. plan
   - Storage well integrity management implementation vs. plan (ex. number of wells with casing inspection logs run vs. planned)
   - Percentage of wells in compliance with integrity management plan's preventative and mitigative measures
   - Mean time to kill/repair/abandon a well after detection of a critical anomaly
   - Staffing level for technical positions
   - Training of staff and contractors

B. Lagging indicators
   - Number of reportable storage gas releases
   - Percentage of reportable storage gas releases vs. total number of wells for operator/in a field
   - Number of well barrier elements failing inspection/testing
   - Percentage of wells with anomalies vs. time
   - Number of wells out of service pending repairs/abandonment
   - Number of wells operating under an enhanced frequency of inspection due to its condition
   - Number of wells with annulus pressure that is storage gas
   - The cause of each failure as a percentage of all failure modes
   - Number of safety related incidents (e.g. number of injuries, near misses, etc.) by company personnel and contractors

Appendix 2

Decision-Making Methodology

Decision making methodology was depicted in the steps below.

Frame the Decision

↓

Evaluate Current Conditions

↓

Develop Goals and Objectives

Identify alternative success paths

↓

Evaluate Alternatives and Decide

↓

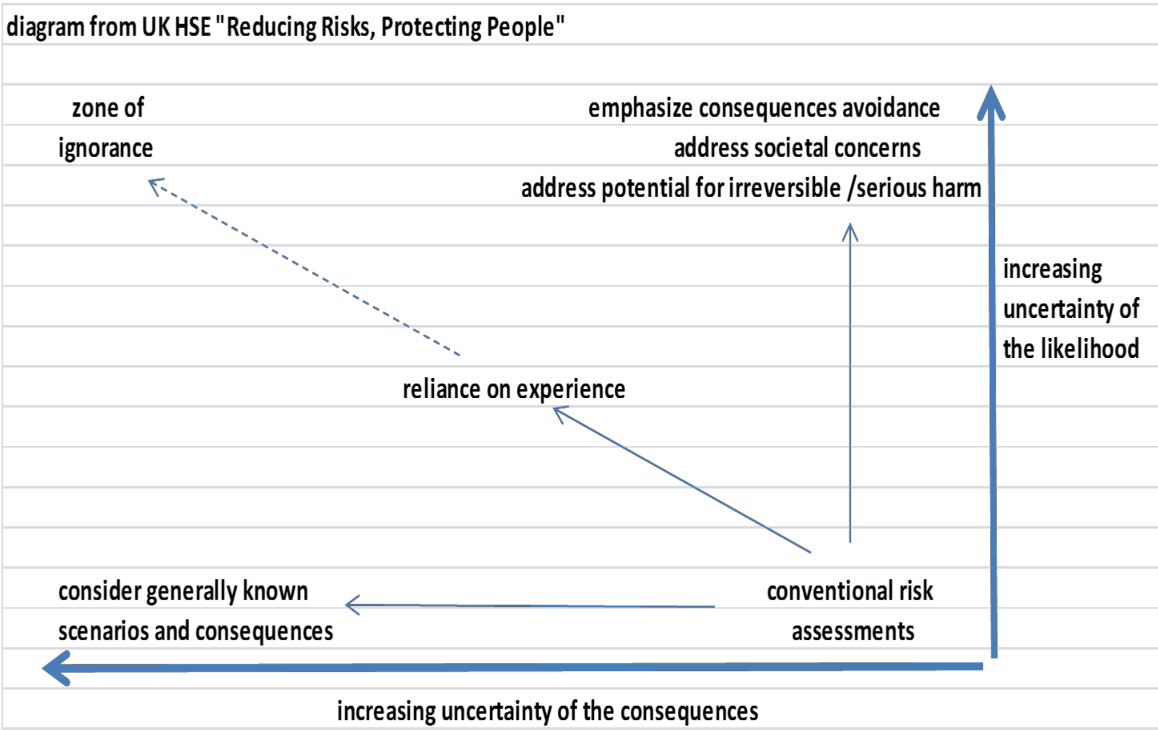
Implement, Check and Review

The first step in the decision-making process is to frame the decision: "what is the context in which the decision is to be made?" The product of the framing exercise is a question of goals and desired outcomes - 'what do I want to achieve by this risk management process?' Framing bounds the decision - what tolerances are allowed or preferred? Framing accounts for the decision objectives, the perspectives of the decision-makers and stakeholders, and internal and external rules and guidelines.

Values drive objectives, and each value may have one or more objectives. Each objective has attributes, or aspects, that make up the whole of the objective. Each attribute can be weighted with respect to the part it plays in making up the objective. The sum of all fractional attribute weightings equals unity (1).

The decision process evaluates the current condition. Decision makers need to understand the problem and have insight into the consequences of a decision; the decision-maker does not need to be an expert but must seek out the expertise and perspective needed for insight and understanding. Skepticism and open-mindedness are valuable traits when evaluating decisions with increasing uncertainty or increasing potential consequences, as might frequently be the case in integrity management decisions. When uncertainty increases and potential consequences are great, a precautionary approach can be employed. Therefore, operators must watch for their experiential bias and protect against unwarranted optimism by assessing the breadth and extent of their own, and the industry's, zone of ignorance. The figure shown as Appendix 2 - 1 diagrams the reason for the application of the precautionary principle. Creating decision process rules compelling review and/or application of lessons learned from previous problems or decisions will be helpful in continual improvement of decision quality and the decision process.

Appendix 2 - 1



The decision must have alternatives based on achieving the pre-defined success criteria for system performance and risk. Alternative success paths should be identified in advance. Operators must innovate and try alternative approaches if past approaches have been of limited success. Alternatives should have a reasonable chance to address the problem and maintain or reduce risk inside the tolerable risk zone. Risk might be tolerable if:

- It is below a threshold of likelihood of occurrence and below a threshold of consequences related to an occurrence
- It is in a region that is justifiably already tolerated
- The cost of reducing risk exceeds the cost/consequences saved or reduced, or the cost is higher than the additional factor of safety provided
- Regulations allow for the risk level

The following guidelines are helpful in managing uncertainty:

- Look back at previous, similar problems and their actual outcomes. By reviewing lessons learned operators can gain some insight into the associated uncertainties.
- Modelling is helpful for quantifying uncertainty and bringing clarity. Modelling does not reduce uncertainty; it represents it in an explicit manner.
- Modelling should be decision-focused in order to reduce unneeded analysis. The modelling should be at the simplest level needed for the decision. Modeling should combine physical process models and logic-based analysis and decision-making models.

Implementing and Monitoring the Effectiveness of a Decision

Implementation includes communicating the decision to the appropriate parties and documenting the decision-making process that led to the decision. The decision results can be monitored to identify and document the actual outcome attained by the decision. A lessons learned review can incorporate the decision-making process and actual outcome for use in future decision-making. This continual improvement step is important for improving the quality of future decision-making. Documentation of the decision process provides for sustainability within organizations, since the human resources involved in integrity management risk-based decisions will continually change.

Table shown as Appendix 2 - 2 provide guidance for operators who desire to incorporate and document structured decision-making processes in Step 1 of their risk management process.

Appendix 2 - 2

FRAMING/ STRUCTURING	MODELING/ EVALUATING	ASSESSING/ DECIDING	IMPLEMENT
People	Understanding	Test Model/Results	Communicate decision
Perspective*	Insight	Discuss, Think critically	Record decision and decision process
Problem	Communicate quantitative results	Assimilate	
		Revise	
Tools:	**Tools:**	**Tools:**	**Tools:**
Decision Hierarchies	Influence Diagrams	Sensitivity Analyses (tornado/spider plots)	Decision Summary
Brainstorming	Decision Trees	Trade off (efficiency/frontier plots)	Notification, Review, Approval
Influence Diagrams	Monte Carlo simulations	Confidence limits	Procedures, standards, policies (revised if necessary)
Strategy Tables	Optimization	Decision criteria	Monitoring and Evaluation plans
Decision Trees	Alternative Success Path	Success Path Availability and Selection Criteria	Procedures for Success Path Implementation
Lesson Learned Listings			

* = when considering “Perspective”, include lessons learned from past decisions

The methodology is scalable to the time and resources required/available.

Decision criteria include equity based criterion (equal rights of protection), utility-based criterion (typically a monetary-based criterion), technology-based (risk reduction achieved through application of best available technology and residual risk accepted); these criteria are not mutually exclusive.

Values Hierarchy

In framing/structuring the decision question, the context must be determined and this is dependent on values and objectives, as presented in Appendix 1 - 3:

Appendix 2 - 3

VALUES (Material Contexts)	OBJECTIVES	ATTRIBUTES/ SCALES	WEIGHTS
Each value must have associated objectives (there can be more than one objective per value); *values drive objectives*	Each objective is associated with an attribute, which can show how an alternative achieves the objective	The attribute is a quantity and must be scalable to enable comparison of the effect of alternatives	Each attribute is weighted; sum of all weights must equal 1 or 100%
Values are things that matter in the context of the decision	All values have safety objectives, if applicable		More weight assigned where consequences could have societal impact

<u>Decision Elements</u>

In the table in Appendix 2 - 4 below, the decision elements are listed in the top row and are required as part of the decision process. The items listed in each column are those that have a bearing on how each element is worked.

Appendix 2 - 4

ALTERNATIVES	OBJECTIVES AND PREFERENCES	INFORMATION/ DATA	PAYOFFS, OUTCOMES, AND CONSEQUENCES OF EACH ALTERNATIVE FOR EACH OBJECTIVE	DECISION (CHOICE AMONG ALTERNATIVES)
If there are no alternatives, then there is no decision to be made	Policies/Rules/ Laws/Regulations	Includes address of uncertainties and unknowns for the data inputs	Includes address of uncertainties and unknowns for payoff potential	Reason for decision given in terms of evaluation of alternatives against objectives
Includes the no-action alternative	Strategy: what should operators be doing; must be consistent with values	Citation of data sources	Citation of sources for payoff evaluation	Basis stated
		Resolution of conflicting information		Cost/Benefit and cost effectiveness
				Compliance requirement
	Tactics: how to do it			Decision recorded (document)
	Maximize objectives and/or preferences consistent with Asset Mgmt Plan and/or short- and long-term business objectives			
	Risk acceptance criteria and tolerability thresholds			

The aspects listed below increase decision process strength:

- Transparency of the factors considered in making the decision; clarity of the decision criterion used
- Consistency of decision-making process
- Input to the decision-making process from internal stakeholders and potentially impacted parties
- Assurance that risks to people, to the environment, and to property are addressed
- Constraint by / within tolerability limits
- Evaluation with respect to reducing risk even if inside tolerability limits
- Address of individual risk and societal risk, as applicable
- Increasingly precautionary approach aligned with increasing uncertainty; prioritization of risks with greater uncertainty
- Alignment with trends, preferences, and expectations in societal, scientific / engineering, economic, and regulatory domains
- Alignment to internal and external standards, rules, and regulations to assure application of accepted good practice
- Evaluation of current state: hazards that exist and the controls currently in place, and effectiveness of the controls
- Use of quantitative methods to the extent possible
- Description of the uncertainty of the inputs based on knowledge uncertainty, model uncertainty, and predictability limits
- Risk assessments framed and described as to limitations and uncertainties
- Multi-person peer review
- Clarity with respect to targeted control, monitoring, or treatment action and targeted action proportional to the level of risk
- Assignment of accountability and responsibility for targeted actions
- Communication and consensus across disciplines and stakeholders.
- A description of inter-dependencies and any secondary effects expected as a result of actions targeted in the decision
- A description of the risk remaining after treatment or control
- A record (document) that characterizes the issue / question to be decided, the alternatives evaluated, the basis for the decision, an implementation plan for the decision, a review timing to evaluate the effectiveness of the decision, and appendices or links to inputs and processes used in making the decision

Operators interested in a thorough treatment of decision quality also can refer to SPE Technical Report "Guidance for Decision Quality for Multi-Company Upstream Projects", Draft Revision H.8, 21 September 2015.

Appendix 3

Managing Storage Well Integrity

Specific Threats and Hazards

									3rd Party Damage- Intentional & Unintentional		
Preventive and Mitigative Measures	Casing Corrosion	Material Defects	Erosion	Equipment Failure	Annular Pressure/ Flow	Design	O&M Activities	Well Intervention	Surface Encroachment	Well Impact/Damage	Outside Forces- Natural Causes
Casing condition inspection program	X	X	X		X	X		X			
Monitor field's pressure, rate & inventory	X	X								X	X
Cement analysis and evaluation					X	X					
Internal corrosion monitoring	X	X	X		X	X		X			
Plugged & abandoned well review & surveillance				X				X		X	
Monitor annular rates, pressures or temperatures	X	X	X	X	X					X	
Surface and subsurface shut-off valves	X	X	X	X	X	X				X	X
Monitor cathodic protection systems	X	X	X		X						
Operate, maintain and inspect valves and other components		X	X	X		X					
Collect & evaluate plugged and abandoned well records and rework or replug				X		X					
Develop design standards for new wells	X	X	X	X	X	X	X	X	X	X	X
Evaluate current completion of existing wells for functional integrity & determine if remediation monitoring is required	X	X	X	X	X	X			X	X	X
Procedures	X	X	X	X	X	X	X	X	X	X	X
Training of personnel & contractors & establishment of procedures	X			X	X	X	X	X	X	X	
Third party damage- encroachments (TPDE)- ensure surface operating rights agreements	X	X	X	X	X			X		X	
TPDE- work with landowners, local planning/zoning staff on surface operating rights								X	X	X	
TPDE- use of pipeline public awareness activities									X	X	
TPDE- monitor use of surface & subsurface around wells & enforce setback rights	X			X	X			X	X	X	
Third party damage- intentional/unintentional (TPDIU)- install protection equipment									X	X	
TPDIU- include storage facilities in corp. security plans										X	
TPDIU- liaison with local, state & federal law enforcement agencies										X	
TPDIU- develop storage well release contingency plan	X	X	X	X				X		X	
TPDIU- 811 Call Before You Dig programs										X	
Routine patrols and surveillance & event specific surveillance	X	X	X	X	X				X	X	X
Outside force- natural (OF)- develop design specifications for areas prone to flooding, earth & river movements, etc.				X		X				X	X
OF- monitor areas prone to flooding, earth & river movements, etc.				X						X	X
OF- Plug & abandon well and drill a replacement in a more stable location				X		X		X	X	X	X
Remote control capabilities											X
Implement training & safety programs for company & contractor personnel	X	X	X	X	X	X	X	X		X	X
Develop detailed drilling & well servicing procedures	X	X	X	X	X	X	X	X		X	X

Note - the above is a generalized representation of P&M Measures that could potentially be applicable to specific Threats & Hazards. Actual applicability is site specific

Source: API Recommended Practice 1171, Section 8 Tables 1 and 2

Note: the above is a generic example of storage well threats/hazards correlated with the relevant preventive and mitigative measure(s). The actual correlation for a specific storage well might differ from the above representation.

Appendix 4

Management Systems Factor

Further guidance on maturity building in process safety management and focusing on the importance of human and organizational factors:

This Guidance advises that it is premature for integrity management programs that are recently modified to conform with API 1170/1171 to employ "credits" for management system maturity when evaluating LOFI. Nevertheless, this appendix presents additional considerations and guidance on this subject to eventually help advance and evaluate an operator's program maturity.

API 580-581 employ a factor for process safety management effectiveness, with an extensive questionnaire to elicit a rating from an operator through a multi-input process. The management systems adjustment factor could be applied to reduce the probability of failure; the questions address many human and organizational factors that help to discover and respond to signs of barrier degradation or decay or incipient loss of containment. Thus, the questionnaire is indicative of the quality of the integrity management system.

However, operators must take stock of the quality of the process safety/integrity management system and account for human error. Smith, in Reliability and Maintainability and Risk (Appendix 6 from the 7th Edition, Elsevier, 2005 [and an Eight Edition is available), cites approximate error rates for a range of task complexity – from simplest possible tasks, to simple routine tasks, to routine tasks needing careful attention, to complicated, non-routine, and high-stress tasks. At each step of increasing complexity, the error rate grows roughly by a factor of 10: simple tasks having error rates of 1 in 10,000 to 1 in 1000, to simple tasks needing careful attention having error rates of 1 in 1000 to 1 in 100, to complex tasks having error rates up to 1 in 10, with even higher rates when under stress or increasing complexity. A poorly designed, implemented, or governed management system could induce higher error rates. The existence of a management system is not, in itself, a good barrier unless tested and subjected to performance criteria, as identified in the Society of Petroleum Engineers references given previously. Further, Awolusi, in the 2011 SPE paper 149517, "Barriers that Delimit Risk Perception and Impact Effective Transfer of Safety Training in the Petroleum Industry", discusses the impact that inconsistent risk perception is a human trait embedded in organizations and threatens the effectiveness of safety training. Alowusi describes four major human behavior impediments: individual motivation, groupthink, absence of organizational and supervisory leadership initiative, and encumbrance of regulatory models.

When the storage industry has a greater state of maturity in building integrity management systems, the probability of failure could be modified to give credits for operators with strong management systems and demerits to those operators with weak or non-existent management systems. The rating questionnaire provides a positive effect to continual improvement for those who employ it, by identifying the process safety management system facets in which the operating company is weak.

The gas storage industry implementation of API 1171/1170, reference to API 1173, and trends in the industry post-Aliso Canyon incident now cause the industry to start building process safety management. This Guidance develops a gas storage adaptation of API 581 management systems factor philosophy. This Guidance provides an initial questionnaire fitted to the requirements of API 1171, API 1173, and other standards. Gas storage operators are encouraged to use the questionnaire appearing in this Appendix to estimate their systems maturity level, identify gaps, and develop continual improvement actions.

The following tables are an abridged version of the evaluation process found in API 581 for determining an operator's integrity management system's maturity level (Management System Factor). The evaluation questions are grouped in to 13 categories for a total of 52 questions. Note that under several of the questions, a reference to the applicable API 1171 section has been provided.

Management System Self-Assessment Maturity Guide	
Title	Storage Adaptation Questions
Leadership and Administration	3
Process Safety Information	10
Process Hazard Analysis	5
Management of Change	4
Operating Procedures	3
Safe Work Practices	2
Training	3
Mechanical Integrity	11
Pre-Startup Safety Review	2
Emergency Response	2
Incident Investigation	2
Contractors	4
Audits	1
Total	52

Leadership and Administration	
1	**Organization (company) has a leader-endorsed commitment statement to gas storage process safety management - the prevention of loss of control, the preservation of safety for employees and the public, and the preservation of service reliability to customers**
2	**Responsibilities for gas storage process safety are defined in applicable manager's job description and key performance areas, and annual objectives are established for managers and other leaders**
3	**Managers and other leaders are required to have training in process safety awareness and leadership, including aspects of risk management, mechanical integrity, operating procedures and supervisory control, emergency management, incident investigation, audit, process safety information, and records and documentation**

Process Safety Information	
1	**Each storage facility has a system map of pipeline and valve infrastructure, well access infrastructure, well locations, and storage station process flow diagrams**
2	**Storage facility maximum operating pressure, flow rates, and other integrity-related parameters as applicable are known to operators and supporting technical staff**
3	**Each well has a wellbore profile diagram and wellhead and valve diagram, with sizes, design/current pressure ratings, and safety factors of design/current pressure rating vs. maximum operating pressure.**
	API 1171 – Section 11.5.2: *The operator's established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, management of change processes, elements of process safety management, and other requirements as specified by regulations and the operator.*
4	**Well diagrams identify the primary barrier envelope and the physical barrier elements to loss of containment. Secondary barrier elements are identified on the diagrams.**
5	**Maximum allowable pressures are identified, along with any thresholds for alarms and interventions for pressure containing equipment at wells, lines, and station equipment. If there are other limit conditions with respect to flow rates, fluid quality, or other parameters, these limits are listed on the well diagrams and/or station process flow diagrams.**
6	**Equipment design/manufacture/construction records are available for employee use and stored in secure locations**
7	**Work history of pressure containing equipment, including repairs and replacements, are available for employee use and stored in secure locations**
8	**Employees working with pressure containing equipment are trained to know where storage facility and equipment information is located and how to apply safe operating limits.**
9	**Employees working with pressure containing equipment are trained on how to recognize and respond to exceedances of safe operating limits or to other abnormal conditions.**
10	**Material safety data sheets are available and conveyed to workers engaged in the use of any covered substances in the course of storage well or facility work**
Process Hazard Analysis	
1	**Critical storage facilities have been identified and the range of hazards and threats have been evaluated. A long-term plan is in place to perform "critical storage facility" process hazard analyses (PHA), including refresh periods.**
2	**Storage facility criticality and priority is estimated on the basis of storage volume, pressure, fluid composition, population and workers in proximity to the facility, the size and complexity of the well, gathering system, and storage station layout, and the service criticality and reliability criticality of the storage facility**
3	**Storage facility PHA include physical hazards, human factors, engineering and administrative controls, a review of equipment integrity/reliability issues, a review of incidents and failures, changes in the physical and cultural geography of the facility siting and layout, and other factors that could affect the critical functioning of the facility and/or the consequential impact of a failure**

4	**Findings resulting from a PHA are put into an action plan with assignments of response timing, responsibility, sharing of information, and implementation of remedies. The action plan is monitored for completion of tasks.**
5	**Means to systematically address likelihood and consequence are established and used consistently throughout the company; means may be qualitative, semi-qualitative, or quantitative but the same means are used from one facility to another**
Management of Change	
1	**Management of Change (MOC) procedures are in place as required by API 1171, Section 11.**
	API 1171 – Section 11.2.1: *Specific operations related to natural gas storage wells and reservoirs requiring procedures include but are not limited to drilling, well workover and reservoir integrity monitoring and management programs.*
	API 1171 – Section 11.5.3: *The operator should define a management of change process to promote safety when unanticipated conditions are encountered in well drilling, completion, servicing and workover operations. The process should include requirements for approval or authority for deviating from the procedures, making decisions, waiving existing procedures, and documentation of the change.*
	API 1171 – Section 11.11.1: *Revision of procedures and processes is an acceptable practice but the operator shall require changes to be accomplished in a controlled manner. The program documentation, framework, and procedures shall be revised before the change can be implemented. Not all changes need be approved through a formal management of change (MOC) process. Some changes are expected and may not be subject to a formal change control process. The operator should define the types of changes determined to be significant and requiring a management of change.*
	API 1171 – Section 11.11.2: *The operator should develop and maintain a MOC process that addresses changes in equipment, processes, materials, or procedures. The MOC process should include procedures to identify impacts associated with changes and determine the effect of the change on the storage facility. The MOC process should address approval authority and responsibility for the change and document implementation of the change.*
	API 1171 – Section 11.11.2: *A MOC procedure should include a process for approval of deviations from the procedures when necessitated by abnormal/emergency conditions*
	API 1171 – Section 11.11.2: *The operator should update procedures, communicate and document changes to procedures in accordance with the operator's MOC process and verify that personnel engaged in operating and maintaining the storage reservoir and wells are aware of and trained in those changes.*
2	**The MOC procedure is used when new facilities or equipment are installed and when changes in storage facility safe operating pressures, flows, or other parameters are changed. The MOC procedure includes steps of informing impacted workers and other stakeholders of the change, making changes to procedures and documents, and, when necessary, training in application of the change**

3	**The MOC procedure includes review by impacted stakeholders and approval by defined levels of management**
4	**Occasions for use of temporary or emergency changes where a full stakeholder review is not practical are identified along with limitations on use or duration of such changes and with specification of approval authority**
Operating Procedures	
1	**Procedures are in place for storage well operation, monitoring, and maintenance, as required by API 1171.**
	API 1171 – Section 6.10.2: *construction procedures (per 11.2)*
	API 1171 – Section 6.10.3: *well work procedures and supervision*
	API 1171 – Section 8.7.4: *The operator should develop procedures that define the data or information to be reviewed, and methods of data trending or normalization in the context of the risk assessment, by analyzing such factors as integrity performance, the number and types of issues that are occurring, as well as other conditions that might trigger an evaluation at a shorter frequency*
	API 1171 – Section 9.2.2: *Following the risk assessment, the operator should develop and maintain a program and procedures to address storage reservoir and well integrity monitoring practices for each storage facility, multiple facilities, and/or system-wide.*
	API 1171 – Section 9.3.2: *Surface and subsurface safety valve systems, where installed, shall be function-tested at least annually. The tests shall be conducted in accordance with manufacturer's recommendations and the operator's procedures.*
	API 1171 – Section 9: *measurement and gauge calibrations*
	API 1171 – Section 10.2.2: *The operator may develop site-specific security and safety procedures for employees, contractors, and authorized visitors and establish and maintain training on the site-specific procedures.*
	API 1171 – Section 10.5.1-2: *Site inspections. The operator should develop and implement procedures to enable an effective inspection (see list of items to include in inspections).*
	API 1171 – Section 10.6.3: *A Blowout Contingency plan is company specific and should identify the procedures, equipment, and personnel needed to avoid or respond to a loss of well control situation.*
	API 1171 – Section 11.2.1: *The operator shall develop and follow procedures for the construction, operation and maintenance of natural gas storage wells and reservoirs to establish and maintain functional integrity. When practicable, the operator's procedures should incorporate applicable industry-recommended practices that promote personal and process safety, resource conservation, environmental stewardship, mechanical integrity, and reliable performance.*

	API 1171 – Section 11.2.1: *Procedures shall be in place prior to the development of a new storage facility.*
	API 1171 – Section 11.2.1: *The procedures should address the minimum requirements for construction including drilling and other well entry work, reservoir integrity monitoring and management, operations and maintenance, emergency response, control room communications and responses, personnel safety, safety management systems and site-specific procedures determined to be necessary by the operator.*
	API 1171 – Section 11.2.1: *Specific operations related to natural gas storage wells and reservoirs requiring procedures include but are not limited to drilling, well workover and reservoir integrity monitoring and management programs*
	API 1171 – Section 11.2.1: *Current procedures shall be available and readily accessible to operations, maintenance and storage personnel. Procedures may be kept in paper or electronic format*
	API 1171 – Section 11.2.2: *Procedures should be reviewed at a minimum frequency mandated by regulatory requirements, or if no requirements exist, as determined by the operator*
	API 1171 – Section 11.2.2: *Procedures should be modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions or as experience dictates*
	API 1171 – Section 11.2.2: *Procedure reviews should be documented and deficiencies or other changes noted in the review records. Implementation of changes should be documented as per 11.11.*
	API 1171 – Section 11.2.3: *The operator should identify and document deficiencies, non-conformance or deviations from established procedures and correct deficiencies or modify procedures as appropriate.*
	API 1171 – Section 11.3.2: *Procedures should outline and define routine inspection, testing and monitoring activities (see Section 9), preventive and mitigative (P&M) measures for risk reduction (see 8.6), recognition of abnormal operating conditions and the associated schedules and record keeping requirements.*
	API 1171 – Section 11.3.2: *The operator should establish general procedures for well isolation necessary to perform maintenance functions, including options of venting, flaring, blow down or other isolation procedures, as well as an assessment of the characteristics and volume of fluids in the context of safety, and environmental protection.*
	API 1171 – Section 11.3.2: *The operator should develop procedures to identify abnormal operating conditions, respond to those conditions, and document those events. The procedures should require a periodic review of documented abnormal operating conditions for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence*
	API 1171 – Section 11.5.1-2:

	The operator's established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, management of change processes, elements of process safety management, and other requirements as specified by regulations and the operator.
	API 1171 – Section 11.6.1-2: *The operator should establish a work plan when performing wireline, slickline and logging operations, well testing and other well operations requiring well entry. The plan should incorporate operator-established practices and procedures that are founded on industry recommended practices and applicable to the specific work to be performed.*
	API 1171 – Section 11.7.1-2: *interaction with control room*
	API 1171 – Section 11.8.1-2: *integrity/risk management*
	API 1171 – Section 11.9.1-2: *incorporation of safety and environmental protection into operating and well work procedures*
	API 1171 – Section 11.10.1-2: *public awareness - damage prevention notification procedures*
	API 1171 – Section 11.11.1-2: *MOC procedures*
	API 1171 – Section 11.12: *training to procedures for workers, contractors, supervisors*
	API 1171 – Section 11.13: *procedures for handling of records and documents*
2	**Employees interacting with or responsible for monitoring, testing, operating, or maintaining pressurized equipment are trained in awareness and application of the procedures.**
3	**Company has well handover or turnover procedure (see ISO 16530 examples)**
Safe Work Practices	
1	**Company has "safety-critical operating procedures" covering hot work, energy isolation/lock-out/tag-out, confined space, opening/entering/closing barrier elements, critical lift, security/access and vehicular travel, and/or other procedures deemed critical for specific sites or facilities**
2	**Affected employees are trained on safety critical procedures. Managers/leaders are trained in authorization and audit requirements**
Training	
1	**Company has a training plan specific to roles interacting with pressurized storage equipment; the plan includes courses, knowledge/competency evaluations, completion timing and refresh periods, and retention of training records**
	API 1171 – Section 11.12.2: *The operator should confirm by training and testing that persons assigned to operate and maintain storage wells and reservoirs possess the knowledge, skills and abilities necessary to carry out their duties and responsibilities including those required for startup, operation*

	and shut down of storage facilities. The operator should provide refresher training on a periodic basis to enable personnel to understand and adhere to current operating procedures.
	API 1171 – Section 11.13.1: *The operator shall maintain training records - identify individual trained, training course name/description and method delivered and method tested, date completed*
2	**The training includes 1) site specific orientation, basic hazards, emergencies; 2) application of safety management plans when engaged in work on or potentially impacting energized (pressurized) equipment; and 3) training specifically targeted to roles on company procedures as identified in previous sections**
	API 1171 – Section 11.12.1: *The operator should provide training for personnel responsible for operating, maintaining, and monitoring storage wells and reservoirs in accordance with their duties and responsibilities. Training should address procedures specified in Section 11, safety procedures, recognition of abnormal operating conditions and emergency conditions. Training programs may consist of various methodologies including but not limited to classroom, computer based and on-the-job training.*
	API 1171 – Section 10.2.2: *The operator may develop site-specific security and safety procedures for employees, contractors, and authorized visitors and establish and maintain training on the site-specific procedures.*
3	**Training program effectiveness is reviewed and modifications and updates are made**
	API 1171 – Section 11.12.1: *Training programs should be reviewed periodically to determine effectiveness. The operator should modify training programs when changes occur in technology, processes, procedures or facilities.*
Mechanical Integrity	
1	**Company has an integrity plan for storage wells identifying inspection, monitoring, and preventive maintenance tasks and frequencies for barrier elements**
	API 1171 – Section 5.4.7: *The operator should develop a facility integrity plan that covers the storage facility. The facility integrity plan documents work performed during a containment assurance analysis detailed in this subsection, identifies required integrity work and implementation schedule during and after construction, identifies integrity monitoring required during commissioning as detailed in Section 7, and identifies operations monitoring requirements detailed in Section 9 and Section 11.*
2	**The integrity plan includes wellhead component and valve visual inspection, valve open/close/seal function testing, valve actuator testing, and valve maintenance**
3	**The integrity plan includes well flow tubular condition assessment, thinning occurrence and thinning rate evaluation, and means to determine causes of thinning**
4	**The integrity plan includes acquisition of data/information to cover gaps in barrier element records and documents, specifically with respect to cement conditions, tubular material, and wellhead component and valve component material**

5	**The integrity plan includes assessment of time-dependent mechanical damage from vibration, fatigue, or other factors, and from time-independent damage from impact, earth forces, or other causes**
6	**Safe operating limits are adjusted in response to integrity plan task findings**
7	**The integrity plan contains tasks covering requirements of API 1171 Section 9 for wells.**
8	**Additional tasks for gas storage reservoir integrity monitoring, as required in API 1171 Section 9, are included in an integrity plan**
9	**The integrity plan defines how integrity issues are cataloged and prioritized. Issues are tracked, prioritized, resolved, and issue types and occurrences are trended. Issue information is part of regular risk assessment review.**
10	**Corrective maintenance tasks are identified from issues lists and the completion of corrective maintenance is tracked**
11	**Integrity plan tasks are reviewed for quality of execution and revised and updated at regular intervals to incorporate lessons learned**
Pre-Startup Safety Review	
1	**Prior to startup of a new facility or of a significantly modified facility, operating procedures are developed and employees trained in their use; the procedures include operations, maintenance, safety, and emergency procedures**
2	**Pressure containing equipment is physically checked and pressure containment capability is verified prior to operation. Safety devices detection, (isolation, and mitigation) are checked for proper response and operation**
	API 1171 – Section 7.2.1: *Facility integrity and baseline performance conditions should be established and documented in order to allow identification of anomalous conditions during commissioning and operation.*
	API 1171 – Section 7.2.2: *Mechanical integrity tests and/or mechanical condition evaluation shall be performed prior to project commissioning in order to verify that each well is capable of meeting the designed operating conditions*
	API 1171 – Section 7.2.3: *Baseline pressure and volume conditions of the reservoir should be established and documented prior to commissioning, as discussed in 5.3. Observation well baseline conditions such as wellbore pressure, pressure of monitored annuli, gas composition and liquid level should be documented prior to commissioning*
	API 1171 – Section 7.3.1: *The material balance behavior of a storage reservoir shall be monitored relative to the original design and expected reservoir behavior established prior to commissioning and startup. Unexpected conditions detected during monitoring shall be evaluated and corrected in order to avoid an incident or loss*
	API 1171 – Section 6.9.1: *A new well, or a well that has had its existing production casing modified from its previous condition during workover activities, shall be tested to demonstrate mechanical integrity and suitability for the designed operating conditions prior to commissioning*

Emergency Response	
1	**Company has an emergency response plan for storage facilities; the plan is reviewed annually with training and drills for affected employees and the plan is conformant with API 1171 Section 10**
	API 1171 – Section 10.6.1: *For site security and safety, the operator shall develop and implement a structured Emergency Preparedness / Response plan in order to address accidental releases, equipment failures, natural disasters, and third-party emergencies.*
	API 1171 – Section 10.6.2: *Storage operations and applicable staff shall receive training in the use of the Emergency Preparedness / Response plan. The training can include mock drills and participation in table top exercises at regular intervals. The table-top exercises or mock drills can include civil emergency responders to enhance understanding and successful incident response.*
	API 1171 – Section 11.4.2: *The operator shall establish a program to determine operator familiarity with emergency plans and procedures and periodic testing of the effectiveness of the plan in accordance with 10.6.*
2	**Company has a specific plan for storage well loss of control (storage well emergency or blowout contingency plan) conformant at a minimum to API 117 Section 10**
	API 1171 – Section 10.6.3: *The operator shall have a Blowout Contingency plan in place. A Blowout Contingency plan is company specific and should identify the procedures, equipment, and personnel needed to avoid or respond to a loss of well control situation.*
Incident Investigation	
1	**Company has an incident investigation procedure and standard formats for incidents involving significant loss of containment at reportable levels, fires, explosions, property loss at reportable levels, injuries, and defined levels of near misses.**
2	**Incident investigation report significant findings/lessons learned are shared with affected employees as well as those personnel at similar facilities who could benefit from the lessons learned**
Contractors	
1	**Company has processes to select contractors based on equipment and personnel capabilities (knowledge, skills, experience) as well as environmental, health, and safety performance**
	API 1171 – Section 11.12.4: *The operator should develop a method to verify contractor training which may include a review of the contractor's safety training programs, worksite checks of individual contractor employee training, or operator observation of contractor work performance.*
	API 1171 – Section 6.10.3: *The operator should document that contractor equipment is suitable and personnel are capable for the work being performed and aware of the operator's procedures related to such work.*

	API 1171 – Section 11.12.3: *A supervisor should confirm that operating and contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work. A supervisor should verify that operating and contractor personnel understand and adhere to reporting requirements in the operator's procedures.*
2	**Contractors selected for work are made aware of company procedures, work plans and expectations, and emergency response actions**
	API 1171 – Section 11.12.4: *The operator should provide and specify the scope of work to be performed by contractors. The operator should define minimum qualification or experience requirements for contractors performing work on their storage wells and reservoirs. The operator should provide training to contracted personnel that includes applicable site-specific safety procedures, awareness of rules pertaining to the facility, reporting requirements and the applicable provisions of emergency action plans.*
	API 1171 – Section 11.5.2: *Drilling, completion, servicing and workover plans should be reviewed with rig crews and other contractors as applicable prior to performing the work.*
	API 1171 – Section 11.6.2: *The operator should review the wellbore entry plan with the contractor prior to beginning the work.*
	API 1171 – Section 11.12.3: *A supervisor should confirm that operating and contractor personnel conducting gas storage well and reservoir operations are qualified to perform the work.*
3	**Pre-job meetings and daily tailgate meetings are conducted with contractor personnel included**
4	**Company has a process to evaluate contractor safety performance and contractor personnel safety training**
Audits	
1	**Managers and other leaders are expected to perform self-assessments of the process safety management elements in this section. Formal and informal audits and self-assessments are documented, items are noted for improvement, and action plans are implemented.**

Appendix 5

Likelihood of Failure Index Damage/Deterioration Factors

Gff - Generic Failure Frequency:

The storage industry and others have reviewed the potential for failure at several times, specifically in 2005 by a Gas Research Institute sponsored study undertaken by URS Corporation, and then again during development of API 1171. The studies, which relied on a mix of operator data and publicly known data, a range of generic failure frequency was found to be in the E-05 per well-year range. This Guidance recommends a ranged starting point for estimation of probability of failure:

Generic failure frequency, well failure, per well-year: ~N x E-05 per well-year.

The recommended ranges of N come from operator data supplied to the referenced studies.

Production wells converted to storage, N= ~9.3E-05;

New or reconditioned wells with current design standards, N is as low as ~2E-05

URS: 2.3 E-05 to 6.4 E-05 casing or cement failure (single barrier)

API 581, pipe: 3.06 E-05 (single barrier)

GUIDANCE: For wells with single barrier casing and minimal cement, this Guidance suggests using Gff of 9.3E-05 per well-year; for "new style" wells with robust casing and cement designs, use 2.3E-05 per well-year. However, if an operator has their own failure frequency, then they may use that or the API 581 default rate for pipe (~3E-05 per well-year).

NOTE: The URS study referenced in this Guidance determined rates for individual components of the well barrier envelope – casing, cement, wellhead, valves. The rate presented as a generic failure frequency in this Guidance is a fair representation of the overall failure frequency, with failures during well drilling and servicing removed. In some cases, such as wellheads and valves, failure frequencies are less than for casing and cement. Accordingly, as this Guidance develops a Probability of Failure, the sum of the failure factors for casing, cement, wellhead and valves, is multiplied by the assumed generic failure frequency. Operators using the methodology in this Guidance may select a generic failure frequency of their own but are advised to review the available information on failure rates.

<u>Dfthin:</u>

Dfthin = [(WTorig/WTcurrent) * ((1000^(MOP/Burstadj) /(1000^.8))* Icond + FLOCOMP]

WTcurrent = WTlast – (CR * YRS); if no last inspection or no inspection, then

WTcurrent = WTorig – CRdefault*AGE

Where:

WTorig = wall thickness- original

WTcurrent = wall thickness- current state

Burstadj = burst strength, adjusted for current condition of casing

YRS = years since last casing inspection

AGE = casing age

Icond = factor describing totality of casing inspection findings – expressed by an index relating to the number of joint with Class 3 + Class 4 defects, and ranged for characterization of the defects as generalized corrosion or isolated pitting; (note that the WT and Burst terms use the worst-case defect only)

NOTE: For base conditions and no notable defects or condition-driving issues, then write "1", but all decreases in overall casing condition from an ideal state get scalable values greater than 1 in order to drive the Dfthin factor higher.

NOTE: This guidance focuses on failure related to primary barrier elements. Therefore, this guidance views secondary barriers as consequence mitigation; such barriers are not intended to be a container in normal operation – the loss of containment on a primary barrier element is an exceedance of a normal operating condition, thus by definition an abnormal operation. While a secondary barrier might prevent further migration of gas, the situation is not intended to be anything but temporary, allowing some time for the operator to control the well and relieve the pressure on the secondary containment. Therefore, CREDIT for multiple barriers (full competent cement sheath, additional casing string, etc.) – will be given in the consequence determination logic.

NOTE: Rationale for Burst adjustment: Upon inspection, an operator might obtain, from the inspection contractor or on the operator's own correlation, an estimate of adjusted internal yield or burst pressure. The calculation in this Guidance uprates the scale of the analysis by using 1000, and uses an exponent of 0.8 to indicate the safety factor recommended for pressure containing equipment, operating pressure to 80% of pressure-containing capability, or a pressure rating of equipment 1.25x the operating pressure.

NOTE: Rationale for Icond. The overall casing condition is important to take into account. There is little information on which to base scaling of the index values. However, a focus on worst-case defect, which most of the Dfthin will do, could lead to ignoring important aspects of thinning, such as multiple joints with significant defects and the character of those defects. Therefore, this Guidance creates the Icond factor, to focus attention on those wells that have numerous joints with significant defects, and upscales those conditions that have more generalized defects. This philosophically aligns with failure mode potential for larger leaks occurring when pipe is more generally thinned than when it is corroded at small points. This Guidance also recommends that operators provide feedback on failure potential and mode so that the use of the Icond factor can become more informed and based on greater experiential data.

FLOCOMP = subfactor for fluid composition, including sand/particulates, acid gases, water.

FLOCOMP = (V*sand) + acid gas + water

NOTE: While this Guidance uses numerical values of 0, 5, & 10 and 1, 5, & 10, etc. for the following variables, operators have the latitude of using different numerical values for the low/mid/high points in addition to the latitude of additional or fewer mid-points than what this Guidance shows. Operators can modify the numerical ranging values to best fit their particular assets while maintaining consistency across the assets. Values may be ranged between marker values for categories below.

Sand/particulates:

- 0 – never produced to surface
- 5 – occasionally (~<10% of flow time) produced to surface
- 10 – frequently (~>50% of flow time) produced to surface

Velocity Factor, V:

- 1 – velocity below 3500 ft/MINUTE
- 5 – velocity occasionally (~<10% of flow time) greater than 3500 ft/MINUTE
- 10 – velocity frequently (~>50%) above 3500 ft/Min

Acid Gases (H2S, CO2, O2):

- 0 – acid gas components not present or in trace amounts
- 2 – acid gas components present in minor concentrations (check gas Ppartial)
- 10 – acid gas components present in greater concentrations w/water

Free Water of Composition potentially damaging:

- 0 – no significant water production
- 2 – water occasionally (~<10% of operating days) produced to surface or influx to well
- 10 – frequent (~>50% of operating days) water production to surface

NOTE: Rationale for FLOCOMP: sand or particulate production at sustained high velocity is an aggressive erosion mechanism. Acid gas may be an aggressive attack mechanism but often depends on the presence of water. Water may be an aggressive attack mechanism depending on chemical composition.

Unlike API 581, this Guidance is not assigning credits to inspection frequency and/or effectiveness. Methods for assigning credits can be developed in the future once there is more widespread maturity in the industry.

<u>Dfmechanical:</u>

Dfmech depends on vibration and/or cyclic pressure-temperature fatigue, earth-induced and human-induced tensile, compression, shear, or other stress:

Dfmech = Dfprev + Dfvib*Fb + Dfearth*Fbearth + Dfwork

Vibration/shaking/cyclic stress loading:

Per API 581, if there have been past fatigue failures, shaking and vibration in proximity to the well, then a factor should be applied for such incident rates of known failure.

Previous Failures related to vibration:

Dfprev
0=None
50=One
500=More than One

The factor for mechanical fatigue due to vibration, shaking, or other non-static, repeating stress (such as from pressure, temperature loading) relates to both the force (visible/audible shaking or audible noise in pipe) and Frequency Dfvib*Fb:

Dfvib
0 – None,
1 – Minor,
50 – Moderate,
500 – Severe

Fb
1 – occurs more than >25x/year
0.2 – occurs between 4x and 25x/yr
0.02 – occurs between 1x and 4x/yr

Earth Forces – Land/Water Movements and Tension, Shear, Compressive Stress – - is the well in a known seismic/tsunami zone, floodplain, mass slide area, subsidence area (Dfearth)? Are there any current mitigations (Fbearth)?

Dfearth:
0 – no significant earth movement (seismic shear or compression, subsidence w/o mitigation)
50 – moderate potential for earth movement (seismic shear or compression, subsidence w/o mitigation)
500 – high potential for earth movement (seismic shear or compression, subsidence w/o mitigation)

Fbearth:
1 – no physical controls
0.1 – one physical barrier/control
0.01 – multiple physical barriers/control

Human/Procedurally – Induced Stress on the Well:

Well Workovers that create extreme tension, compression, shear, or wear on casing –

Dfwork:
0 –5 based on operator evaluation of stresses that might have occurred during well work

Dfwork is somewhat subjective and left to an operator's discretion and assessment, thus the uncertainty keeps this factor at a low number

NOTE: The effects of vibration, tensile and compressive or shear stresses might relate to casing thread type, connections (flanged vs. welded), and possibly other induced stress due to well inclination. Operators could elect to add a "tension/geometry complexity factor".

The effects of cyclic loading and tension/compression/shear, pressure and temperature, vibration could be different for casing constrained by cement and unconstrained, as well as the way in which the casing is hung in the wellhead.

It should also be noted that this risk to the well is different from, and not meant to be a substitute for, the risk posed while doing the actual well work. Dfwork only represents the resultant stress, if any, on the well after the well work is completed.

Dfimpact:

Impact risk depends on susceptibility to vehicular impact or to strike by other objects. Impact risk is separated into "vehicles", which could have much higher mass*acceleration, and "objects", which might be less frequent and mostly would have lower mass*acceleration. This category also can include impacts due to vandalism, although the potential for vandalism/terrorism is not evaluated specifically in this Guidance. "Objects" impact risk can take into account the lower mass*acceleration events and/or the very low frequency events, such as lightning strikes.

Dfimpact can take into account 3rd party subsurface risk from mining, drilling, near-surface, surface and subsurface construction that could impact the well at the surface and near subsurface or have cascading effects downhole, such as could occur from pipeline construction and operation, cathodic protection interference, and other general construction risk.

Dfimpact = (Dfveh-const + Dffallobj) * Fbimpact

Dfimpact depends on vehicle and other 3rd party strike potential and the weight/speed of the causative agent (RV, cars/trucks, trains, boats, planes, farm eqpt):

<u>Dfveh-const</u>
0 – Insignificant potential for vehicular strike
5 – Low potential
50 – Moderate potential
500 – High potential

Subsurface impact risk due to mining, drilling or cascading impacts from cathodic protection systems can be rated as low to high depending on the amount of operator collaboration with the 3rd party operator(s) and intensity of activity and mitigations. Similarly, near-subsurface activities related to pipeline construction and general construction can be evaluated as low to high depending on an operator's ability to control setback from wells.

Objects include heavy trees, large rocks, very large animals – mass * acceleration:

<u>Dffallobj</u>

0 – insignificant potential for being struck by heavy object
1 – low potential
5 – moderate potential
10 – high potential

This Guidance permits a credit for preventive controls. The controls must be rated usually or highly effective. The credit incentivizes application of effective controls.

<u>Fbimpact</u>
1 – no physical controls
0.1 – one physical barrier/control
0.01 – multiple physical barriers/controls

Fwhv – Wellhead/Valve LOFI:

Wellhead and/or valve failure relate to wellhead component condition and functionality with respect to containing pressure and isolating flow. External condition of wellhead components can be evaluated with various visual and non-destructive testing techniques. Internal conditions might relate to the aggressiveness of flow conditions and therefore some of the damage subfactors already addressed in Dfthin, such as FLOCOMP, already address degradation and damage of wellhead and valve internal components. Mechanical damage and impact damage also interact and thus the damage to wellhead components from such degradation/damage types has been addressed.

Similar to casing or tubing, the wellhead design factor is important in the evaluation of condition and functionality.

The wellhead failure is assessed by:

Fwhv = Fapi*Dwhc + Fapi*Dvseal:

<u>Dwhc - Wellhead Condition:</u>
0 – new/like new studs and nuts, little atmospheric corrosion
1 – minor wear and surface/atmospheric corrosion on parts, nuts, studs
2 - moderate wear and surface/atmospheric corrosion on parts, nuts, studs
5 – severe wear and surface/atmospheric corrosion on parts, nuts, studs; exposed flow string, restricted entry, or no annular access ports
10 – severe and aggressive wear and harsh environmental conditions difficult to control, exposed flow string, restricted entry size, no annular access

Functionality testing of valves and seals is assessed by Dvseal.

<u>Dvseal</u> - Valve and WH Seal Condition and Function:
0 – no issues with valve sealing or wellhead seals, FLOCOMP =0
1 – very minor valve or seal leakage, FLOCOMP >0<2
2 – minor valve leakage, minor wellhead seal issues, FLOCOMP 2-9

5 – valve seal issues, other wellhead seal issues, FLOCOMP scores 10 - 100
10 – valves fail to seal, other wellhead seal issues, FLOCOMP scores >100

Design and pressure rating is assessed by Fapi.

<u>Fapi:</u>
1 = API materials, verified, pressure rating 1.20 to 1.25 x MOP
2 to 5 = API materials, verified, pressure rating 1.15 (2), 1.1 (3), 1.05 (4), 1.0 (5) x MOP
6 to 9 = non-API materials, verified pressure rating >1.2(6), 1.15 (7), 1.1 (8), 1.05 (9) x MOP
10 = for materials which cannot be pressure-rating verified, multiply condition factor by 10.

The operator might be able to obtain material specifications or test materials that are non-API standard. However, establishment of pressure ratings for pieces of equipment not fabricated to a standardized process cannot be done by sampling selected pieces currently in stock or in service. Each such non-standard component would need to be tested to verify and document its capabilities.

NOTE: External conditions related to atmospheric corrosion on the wellhead/tree are easily detected through visual inspection, and can possibly be rated via existing NACE standards for pipe evaluation. The wear that is of concern for the tree is not external, but internal. Excessive wear/abrasion/erosion on the valve sealing mechanism is detected through regular valve testing for sealing functionality.

NOTE: For additional reading, refer to DNVGL-RP-0142 Wellhead fatigue analysis.

Fcmt - Casing cement sheath LOFI:

The cement factor assessment addresses the cement sheath sealing and zonal isolation verification and certainty.

Cement sheath inadequacies or failure could relate to some of the damage subfactors addressed in Dfthin. Mechanical factors that affect the casing also can affect cement but have been accounted for in the Dfmech analysis.

Fcmt depends on condition and functionality. Condition assessment includes length of cement seal and quality of seal, both of which can be taken from cement bond / integrity logs; however, those logs do not demonstrate whether the apparent cement seal prevents flow.

Further functional performance assessment can be demonstrated by noise, temperature, or other logs that might show flow/no flow across cemented intervals.

Lastly, an open annulus in which fluids can flow, whether from storage or from other zones, could contribute to attack of casing and/or cement quality.

Therefore, this Guidance has three parts to evaluation of Fcmt: a cement condition factor, a cement functionality factor, and an annular flow factor.

Fcmt = Dcondition *Fann * Ffunction

The annular flow factor ranges from 1 to 10, as determined by the operator. Annular flow assessment should include nature of the liquids and gases flowing – are they potentially corrosive or destructive, and are the fluids more indicative of storage sourcing, or is the lack of isolation of flow otherwise hazardous to the public.

NOTE: evaluation of the criticality of annular pressure and flow can be highly site specific and subjective. ISO 16530-1 (Section 8.5 "Annular Pressure Management") and API 90-2 "Annular Casing Pressure Management for Onshore Wells" provide guidance on evaluating and managing annular pressure and flow.

<u>Fann:</u>
1 = no or insignificant flow
5 = annular flow of significance but not clear as to storage origin and more likely native
10 = annular flow of significance and probable storage source; annular flow assessment should include nature of the liquids and gases flowing – are they potentially corrosive or destructive

Annular flow can be assessed by measurements of flow or of shut in pressure tests. The composition of the annular fluid flow can be determined by sampling and various chemical and physical analyses. These tests would be integrated with the well's completion data to ascertain the origin of any annular pressure and volume and identify whether a breach of containment of the storage gas exists. While the identification of storage gas in the annular region likely requires some kind of immediate attention, native annular pressure/flow should not be automatically dismissed until it is ascertained whether it poses a significant threat to safety and/or the environment.

The condition assessment is based on height of cement – does the cement sheath have isolation continuous into the next casing string – and on the quality of the cement bond, which could be inferred from a bond index, variable density display, or other means of determining effective casing attenuation and acoustic coupling to the borehole wall. Operators can use bond index or other self-developed assessment indices to scale cement bond quality from 1 to 100; the percentage of the casing length isolated with cement also can be used to scale Dcondition from 1 to 100. Cement condition assessment can determine isolation of porous zones that could act as collector zones should storage gas leak; the condition assessment also can determine isolation of fresh water zones and hydrocarbon bearing zones that could be contaminated or could contaminate other zones by cross-flow.

Operators might not have a cement bond/integrity log. In some cases, well records might indicate the volume of cement slurry pumped, and sometimes the cement slurry composition might be documented, or sometimes an after-pumping temperature survey is recorded. Operators can estimate a top of cement from such records and use the information to evaluate Dcondition, but without a cement bond/integrity log there is no verification of any kind of the as-built integrity or functional performance of the cement, and therefore the Dcondition cannot be less than 51.

Dcondition: - Condition Assessment of cement integrity (log-based)
1 – 50 cement integrity log shows isolation probable (quality of bond index and length of cement used to scale lo-hi)
51 - 100 – no cement integrity log or no isolation evident from log (other cement information might provide reasons for lower scores; less information and less certainty of isolation/sealing should drive higher scores)

NOTE: from API 581, there is the concept of "effectiveness of inspection". Even among vintages of "bond" logs, there are different qualities an operator might assign (and now there are bond logs in a gas-filled borehole). At some very, very low-grade level, a good record of cement placement might serve as a basal level of effectiveness (better than knowing nothing); a report of circulation of cement to surface would be helpful, but such reports are not an inherent verification of cement quality and isolation potential. Other cement pumping-related records, pressures, times, etc. might be part of a verification of placement and probable effectiveness, but not verification. A temperature log run after cementing can be helpful in noting cement top, but again is not verification of integrity. In the range from knowing nothing and being completely blind to knowing something but having no verification log, operators can note the lack of cement verification as a gap in the essential records for integrity assessment, and then develop an action item in the well's risk management plan to close the gap.

Cement functionality demonstration is assessed by some sort of flow or isolation log – a noise, temperature, tracer survey, or hydraulic isolation testing. This function essentially provides a credit to operators who obtain additional cement functionality demonstrations beyond a cement bond/integrity log.

Ffunction:
0.1 = adjustment factor for a test showing no flow across the cement sheath
1 = no test;
2-9 = ambiguous or unclear tests, based on the degree of uncertainty, magnitude of anomaly
10= tests showing flow across the cement sheath

Appendix 6 –

Likelihood of Failure Index Credit Adjustment

The equation with the approximate measures of management system implementation and maturity include:

CREDIT = (Yrs IMP Program factor) * (Test Completion factor) * (Maturity-Robustness factor)

Where:

> Yrs IMP Program factor = number of years employing an integrity management program aligning to API 1170-1171
>
> Test Completion factor = completion of asset information on primary well barrier elements – percentage of wells with casing inspection surveys, wellhead and valve assessments, and cement integrity and functionality assessments (includes verification/documentation of materials and design and estimated current mechanical strength)
>
> Maturity-Robustness factor = maturity and robustness of inspection program, including repeat casing inspections, frequency of pressure and fluid flow monitoring, and other testing

Appendix 5 contains additional details and potential ranges for the three factors.

Credit will be between maximum of 1.0 and minimum of 0.125

<u>IMP program years:</u>
0-2 Cyrs=1.0;
3-4 Cyrs=0.9;
5-7 Cyrs=0.7;
8 or more Cyrs=0.5

<u>Test completion:</u>
<=75% Ctest=1.0;
75-85% Ctest=0.9;
85-95% Ctest=0.7;
>95% Ctest=0.5

<u>Maturity + Robustness:</u>
Cmr=1: few repeat tests, little well-based information
Cmr=0.9: many wells with 1 repeat test, manual observations more than monthly
Cmr=0.7: many wells with 2 repeat tests, mix of manual and remote/real time observation
Cmr=0.5: many wells with 2 or more repeat tests, remote/real time observations on most wells, supplemented with manual observations

A more robust management systems factor can be developed over the next few years as the storage industry matures in applying API 1170-1171 concepts as well as the concepts of this Guidance.

Appendix 7

Notes on Value of Statistical Life (VSL)

From: Guidance on Treatment of the Economic Value of a Statistical Life in U.S. Department of Transportation Analyses, 2012

"For future years, the formula for calculating future values of VSL is therefore:

VSL2012+N = VSL2012 x 1.0107N
where VSL2012+N is the VSL value N years after 2012
and VSL2012 is the VSL value in 2012 (i.e., $9.1 million)."

"Most regulatory actions involve the reduction of risks of low probability. For these low-probability risks, we shall assume that the willingness to pay to avoid the risk of a fatal injury increases proportionately with growing risk. That is, when an individual is willing to pay $1,000 to reduce the annual risk of death by one in 10,000, she is said to have a VSL of $10 million. This guidance for the conduct of Department of Transportation analyses is a synthesis of empirical estimates, practical adaptations, and social policies.

"Prevention of an expected fatality is assigned a single, nationwide value in each year, regardless of the age, income, or other distinct characteristics of the affected population, the mode of travel, or the nature of the risk. When Departmental actions have distinct impacts on infants, disabled passengers, or the elderly, no adjustment to VSL should be made, but analysts should call the attention of decision-makers to the special character of the beneficiaries.

"Analysts should project VSL from the base year to each future year based on expected growth in real income, according to the formula prescribed. Analysts should not project future changes in VSL based on expected changes in price levels.

"Alternative high and low benefit estimates should be prepared, using a range of VSLs prescribed from $5.2 million and $12.9 million (for 2012 as a base year). Because detailed WTP estimates covering the entire range of potential disabilities are unobtainable, we use an alternative standardized method to interpolate values of expected outcomes, scaled in proportion to VSL. Each type of accidental injury is rated (in terms of severity and duration) on a scale of quality-adjusted life years (QALYs), in comparison with the alternative of perfect health. These scores are grouped, according to the Abbreviated Injury Scale (AIS), yielding coefficients that can be applied to VSL to assign each injury class a value corresponding to a fraction of a fatality.

<u>VSL-based financial equivalence in 2017 $</u>

Fatal	*=$9.597 million*
Critical	*0.593*fatal = $5.691 million*
Severe	*0.266*fatal = $2.553 million*
Serious	*0.105*fatal = $1.008 million*
Moderate	*0.047*fatal = $0.451 million*

*Minor 0.003*fatal = $0.029 million*
*Insignificant 0.0001*fatal = $0.001 million (added to table below as AIS=0)"*

Federal Aviation Administration*: "For analyses conducted in 2015, OST guidance suggests that $9.4 million be used as the current estimate for the VSL, measured 2014 dollars. To address the issue of uncertainty, OST notes that the following ranges values ($5.2 million to $13 million) should be used when conducting sensitivity analysis."*

Appendix 8

Discussion on GRI-00/0189

The following text, taken from the October, 2000 GRI C-FER Study, is provided to demonstrate the close similarities between the C-FER methodology and the Guidance's methodology. Per the C-FER Study:

*L=t*I^n   Where t=exposure time, I=heat flux, and n= an index*

"If it is assumed that within a 30 second time period an exposed person would remain in their original position for between 1 and 5 seconds (to evaluate the situation) and then run at 5 mph (2.5 m/s) in the direction of shelter, it is estimated that within this period of time they would travel a distance of about 200 ft (60 m). On the further assumption that, under typical conditions, a person can reasonably be expected to find a sheltered location within 200 ft of their initial position, a 30 second exposure time is considered credible and is, therefore, adopted as the reference exposure time for people outdoors at the time of failure."

From the GRI/CFER study: "Note that the onset of burn injury within the reference exposure time is associated with a heat flux in the range of 1,600 to 2,000 Btu/hr ft2 (5 to 6.3 kW/m2), depending on the burn injury criterion. The chance of fatal injury within the reference exposure time becomes significant at a heat flux of about 5,000 Btu/hr ft2 (15.8 kW/m2), if the significance threshold is taken to be a 1% chance of mortality (i.e., 1 in 100 people directly exposed to this thermal load would not be expected to survive).

"For property, as represented by a wooden structure, the time to both piloted ignition (i.e., with a flame source present) and spontaneous ignition (i.e., without a flame source present) can also be estimated as a function of the thermal load received. For buildings, the thermal load Lb is given by an equation of the form (Lees 1996):

*L = (I − Ix)*t^n*

where Ix is the heat flux threshold below which ignition will not occur.

"…calculated estimates of the exposure times required for both piloted and spontaneous ignition at selected heat intensity levels of 5,000 Btu/hr ft2 (15.8 kW/m2), corresponds to piloted ignition after about 20 minutes (1,200 seconds) of sustained exposure. …Spontaneous ignition is not possible at this heat intensity level. It is therefore assumed that this heat intensity represents a reasonable estimate of the heat flux below which wooden structures would not be destroyed, and below which wooden structures should afford indefinite protection to occupants. Some earlier wood ignition models, which appear to be the basis for the often cited 4,000 Btu/hr ft2 (12.6 kW/m2) threshold for piloted wood ignition, are in fact associated with an almost indefinite time to ignition and are, therefore, considered to be overly conservative given the transient (decaying) nature of real pipeline rupture fires. A heat flux of 5,000 Btu/hr ft2 has, therefore, been adopted as the threshold heat intensity for the purpose of sizing a high consequence area."

Appendix 9

Discussion on Valued Environmental Components

The valued environmental components (VEC) and value ranges used as a starting point recommendation in this Guidance are given in Appendix 9 - 1, below:

Appendix 9 - 1

			Min-Max Estimates		
Valued Environmental Component, or VEC	Calculation Basis	Factors	min	max (at 10 Bcf emitted)	
Soil Stability	30-day flow volume, subsurface impact range probability, potential for gas and water to form slurries and create slumps, mud pots, heaves, or other instability. Cost is for remediation, earthwork, etc. Use topsoil and substrate types and hydrology to determine liquefaction potential in the event of a gas release: hard rock or clay substrate, probability of consequence =.1; mixed layer silt/clay, probability of consequence = .3; sandy soils, probability .5-.8, loamy soils, probability .5-.1	tens of $/cubic yd up to ~($100/cubic yd) * 30 day vol factor * 11,060 [note, 11060 yds is perimeter of a circle of 1 mile radius]; note multiplier for soil/rock type in substrate	$111	$11,060,000	
Vegetation Health and Soil Productivity	30-day flow volume and subsurface impact range probability; based on natural vegetation (lower unless unique species) vs. agriculture (higher depending on crop values). Cost is for damages.	thousands to tens of thousands of $ per acre impacted (probable range $2000-$13000/acre/yr); requires review of land use in the area	$40,200	$26,130,000	per Bcf emitted and total affectation on 2010 acres (circle with r=1 mile); minimum is for less than 10 mmcf
Water Supply Security	30-day flow volume, subsurface impact range probability, number of water wells (order of magnitude) in impact area. Cost per impacted acre assumes water well adapters or replacement, ongoing testing, drilling of vent and monitor wells, and other measures. Multipliers: 1 or fewer water wells in the area, multiply by .01; 2-10 water wells in area of impact, multiply by .1; 10-100 water wells in area of impact, multiply by 1; more than 100 water wells in area of impact, multiply by 10, then multiply by a factor of 10 for each additional factor of ten for number of water wells in the area of impact	thousands to tens of thousands of dollars per acre impacted per year, multiplied by usage density (water well count as a proxy) - rough average of ~$2100/acre/yr	$42,228	$4,222,848	per 1-mile radius of impact

Greenhouse Gas emissions social costs	30-day flow volume, calculate tons and multiply by $1128/ton of methane	$1128/metric ton (PHMSA IFR RIA)	$21,770	$21,770,400	per Bcf emitted (max); per mmcf emitted (min)

Fluid Flow/Transport of Toxins/Pollutants	potential and magnitude multiplier (.01 if not expected to have anything but gas and some non-resident water; .1 if some higher TDS water; 10 for potential for BTX and chloride or other known contaminants in the area). Cost is for investigation, remediation/cleanup, reclamation, monitoring	potential for $1 million per event site, multiplied by contaminant type and release volume index	$10,000	$10,000,000	per event site

Operators can use the weighted ranged widespread area of impact distribution from the safety-subsurface leak framework, as in table in Appendix 9 - 2 below.

Appendix 9 - 2

30-day volume radius of impact tiers (miles)	1	2	3	6	9	total
probability of impact	0.8	0.18	0.0189	0.001	0.0001	1

Operators can multiply the Table 9 - 1 value ranges by the impact probability distributions above, then by the Release Volume Index below in Appendix 9 - 3, if wanting to range and test sensitivities.

Appendix 9 - 3

30-day volume mmcf	volume index
<1	0.001
1-10	0.01
10-100	0.1
100-1000	1
1000-10,000	10
>10,000	100

A methane volume to tons converter is provided in Appendix 9 - 4:

Appendix 9 - 4

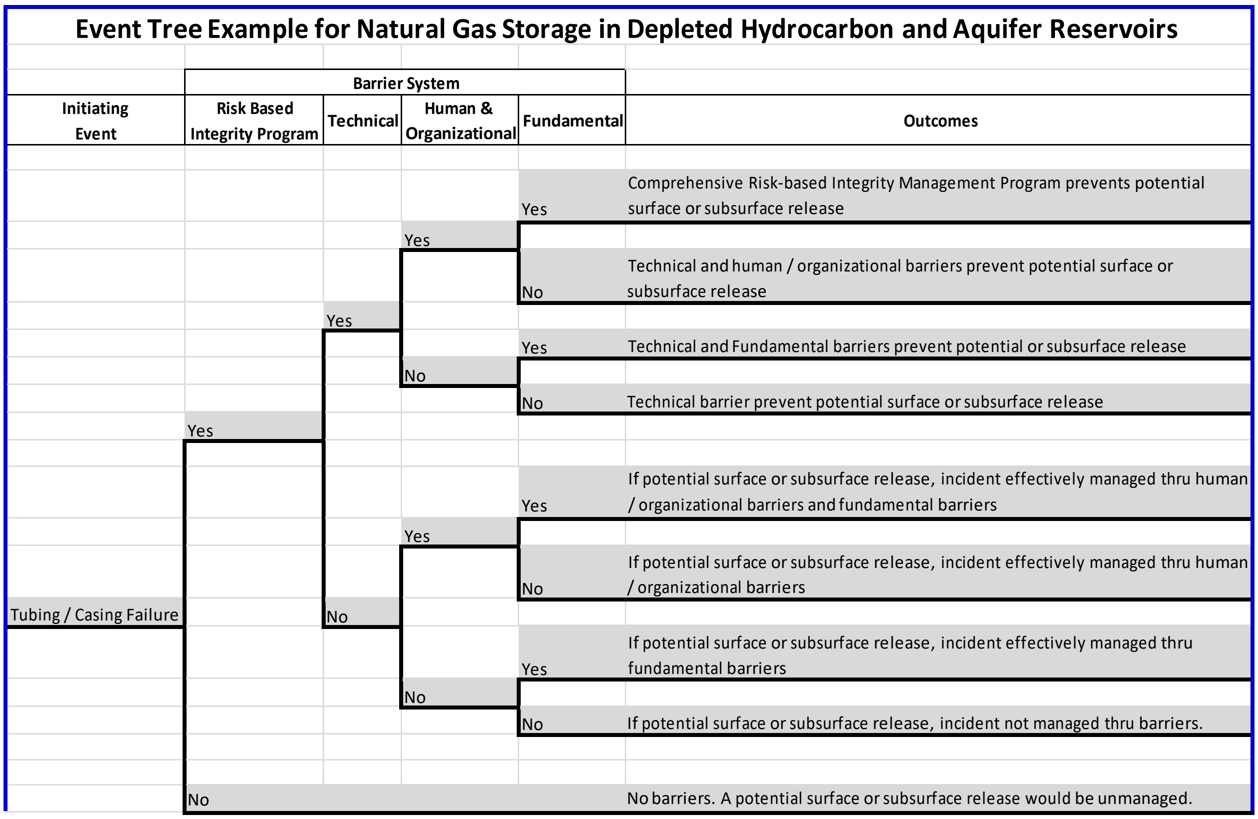
methane mcf	tons methane
1000	19.3
10,000	193.0
100,000	1,930.0
1,000,000	19,300.0
10,000,000	193,000.0
100,000,000	1,930,000.0

Appendix 10

Event Tree Examples

An event tree example is presented in the figure as Appendix 10 - 1, shown below, for general failure of tubing or casing and the barrier categories that could be in place. For each barrier category (technical, human-organizational, fundamental), there could be multiple barriers, each of which would have a success/failure path. The event tree can be used qualitatively or quantitatively to assess robustness of barrier systems and the relative effectiveness and significance of each barrier in detecting, isolation, and/or mitigating the event or its impacts.

Appendix 10 - 1



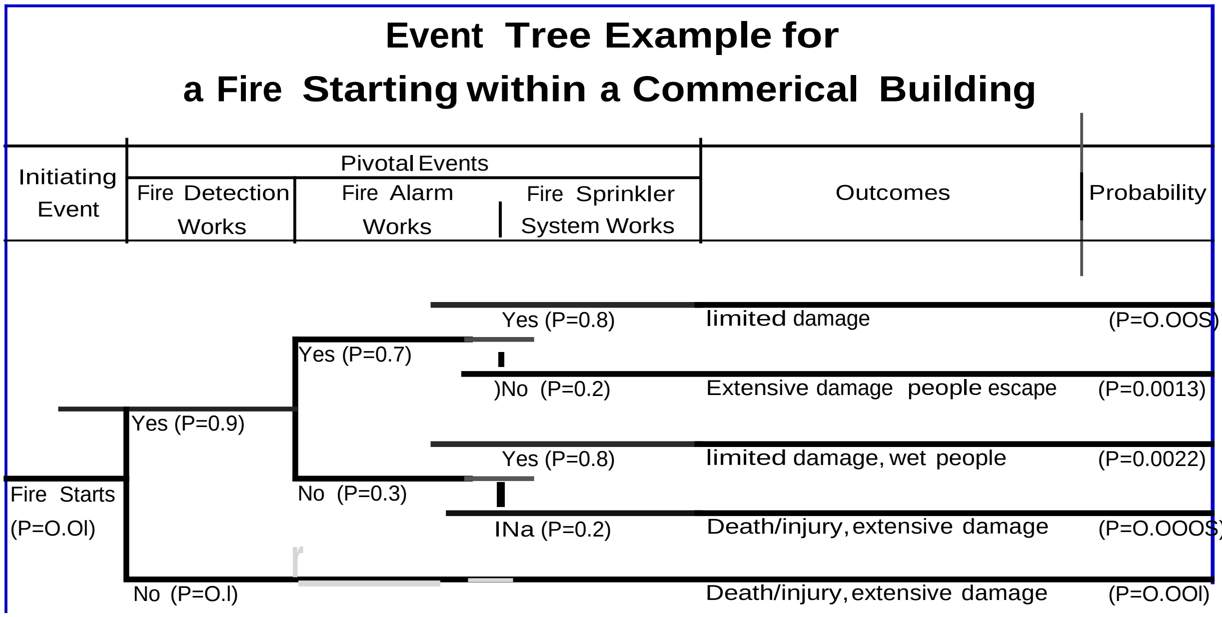
This fault tree is representative of, but not all inclusive of, the potential mitigative barriers in **Table 2 – Preventative and Mitigative Programs of API RP 1171.** Operators should evaluate their specific circumstances and add or subtract barriers as appropriate.

Barrier Descriptions

- **Technical Barriers** include **active** technical barriers that act on demand (e.g. emergency shutdown valve), **passive** barriers that perform continuously (e.g. pipe) and **control** technical barriers that activate other preventive or mitigation barriers, (e.g. gas / fire detection systems).
- **Human and Organizational Barriers** mitigate risk through a system of precedures, emergency response plans, training programs, controls, and audits to ensure that operators have the direction and support framework they need to perform their work properly.
- **Fundamental Barriers** reduce operating risk through workers with experience, training, and skills being able recognize hazards and make prudent operating decisions.

A simple event tree for a building fire is given in Appendix 10- 2 as an example of initial quantification of success/failure outcome probabilities.

Appendix 10- 2



Appendix 11

COFI Credits Classification

This Guidance assigns classifications to detection and isolation systems as noted in the table in Appendix 11 - 1.

For each Detection and Isolation/Containment System, operators can use Appendix 11 - 2 to evaluate the reliability and multiply the reliability credit subfactor by the detection/isolation class subfactor found in Appendix 11 - 3 to get the credit.

If there are multiple systems, the total credit is the product of all the systems: credit1*credit2*credit3*credit(n)

Appendix 11 - 1

Type of Detection System	**Detection Classification**
Instrumentation designed specifically to detect material losses by changes in operating conditions (i.e., loss of pressure or flow) in the system [wells with SCADA]	A
Suitable located detectors to determine when the material is present outside the pressure-containing envelope [daily pressure/temperature/infrared checks]	B
Visual detection, cameras, or detectors with marginal coverage [infrequent visual wellhead inspections, relying on someone to call in a leak]	C
Type of Isolation / Containment System	**Isolation Classification**
Isolation or shutdown systems activated directly from process instrumentation or detectors, with no operator intervention [SSV or SSSV]	A-1
Tubing/Packer or 2nd barrier able to contain the leak	A-2
Isolation or shutdown systems activated by operators in the control room or other suitable locations remote from the leak	B
Isolation dependent on manually-operated valves	C

Appendix 11 - 2

Effectiveness/Reliability	Credit Subfactor, Cdi1
Very Low	set total credit to 1
Low	set total credit to 1
Moderate (>80% reliability)	1
Moderately High (>90% reliability)	0.9
Very High (>98% reliability)	0.7

Appendix 11 - 3

Detection/Isolation Class	Credit Subfactor, class
A	0.75
A-2	0.5
A-1	0.85
B	0.98
C	1

Appendix 12

API 1171 Risk Treatment Options Library

Preventative and Mitigative Actions for Wells

A	B	C	D	E	F	G
Isolation-Removal from Service	**Repair, Replace, Rehabilitate**	**Inspection, Testing, Maint. Program & Frequency Changes**	**Operating Limit Changes & Equip./design Changes**	**Isolation-Relief Safeguards; Detection-alarm systems; Real Time**	**Additional Barriers**	**Other**
set downhole plug; remove from service	replace wellhead components	change pressure, flowrate, monitoring frequency	de-rate, reduce maximum operating pressure	install surface shutdown valve	install tubing/packer, tubing head/hanger and valve	no changes
plug & abandon	replace or repack wellhead seals	change casing inspection frequency	restrict operating sustained or instantaneous flow velocity	install subsurface shutdown valve	install full or partial cemented liner	establish well blowout/loss of control program; increase emergency response plan robustness
maintain setbacks, eliminate encroachme nts	replace flange nuts, studs	change casing inspection method or add inspection methods	change maximum allowable annulus surface pressure	install annular relief valve(s)	install second master valve	increase emergency response training
re-plug older plugged and abandoned wells	replace master valve	run flow or leak monitoring log - noise, temperature, hydraulic isolation	new material safety factors	install/prepare heat shielding for adjacent equipment	install surface barricades or shielding	establish integrity monitoring/analysis training programs
kill well with aqueous fluid	repair valve	change frequency of flow/leak monitoring logging	new metallurgical properties	install water supply/deluge/foam other fire suppression systems	install well casing cathodic protection system	establish third-party well drilling/completion and surveillance program
	repack / replace valve stem	change annulus pressure test/check frequency	new well design standards	install remote / electronic period or real-time pressure, temperature and flowrate monitoring devices	install earth forces mitigations (seismic, subsidence, mass slides, floods, etc.)	review plugged and abandoned wells
	replace casing joints	gas detection surveys (optical, imaging, sniffers)	establish operating limits of wellhead components and tubulars (casing, packers, tubing, etc.)	install alarms for pressure, temperature, flowrate excursions from operating limits	install remote-actuated valve control	implement drilling and completion procedures and safety practices

	repair/replace packer	change safety valve inspection and testing frequency		install gas detection / alarm systems (thermal, optical, compositional)		implement competency assurance programs
	repair/replace tubing	mechanical integrity test (pressure - gaseous or aqueous)		establish response to operating limits alarm threshold exceedances		implement management of change practices
	remedial cementing (squeeze)	run cement bond integrity log		install hydrate, paraffin, inorganic precipitates, or scale inhibition / prevention systems		establish buffer zone for reservoir boundary protection
	back-off/replace casing	establish/change internal corrosion monitoring program/frequency				
	replace well (drill new well in safe location to new standards)	change valve maintenance practices and frequency				
	install casing patch to cover isolated perforations, pits, defects or collar leaks	change wellhead and wellsite inspection and condition documentation practices and frequency				
	install inner string on packer or cement					

Source: API 1171, Section 8 Table 2

Another way of viewing a risk treatment options library is in the form of a hazard-barrier matrix, similar to one that can be constructed from API 1171, Section 8, Tables 1 and 2, as shown in Appendix 1.

Appendix 13

Risk Treatment Impact to LOFI and COFI Factors

The following table provides a guide to risk treatments and their effects on LOFI and COFI factors. Operators can re-assess LOFI and/or COFI after choosing risk treatments and the level of risk reduction.

Risk Treatment Option	Alters LOFI or COFI?	How LOFI or COFI is affected
Continue to operate without restriction per well integrity plans	N/A	means that operator has accepted the estimated level of risk as is, without further mitigation
Immediate action - set-downhole bridge plug, take well out of storage service	COFI, (LOFI?)	AOF=0, (MOP=0)
Immediate action - kill well with aqueous fluid, take well out of storage service	COFI, (LOFI?)	AOF=0, (MOP=0)
Immediate action - restrict operating sustained or instantaneous flow velocity	LOFI/COFI	Might lower LOFI if velocity already is high and is a factor in LOFI, then this also can be a LOFI reducer
Immediate action - change maximum allowable annulus surface pressure	LOFI, COFI	MOP is lower, AOF is lower
Immediate action - de-rate/limit maximum operating pressure	LOFI	MOP
Enhanced data gathering (wellhead pressure, temperature, flow rate, etc and the frequency of collection)	COFI, LOFI	flow duration limitation - apply in COFI credits; LOFI - FLOCOMP, vibration, p/t cycling; capability turned into AOF actual
Enhanced data gathering via remote/electronic period or real-time acquisition devices	COFI, LOFI	flow duration limitation - apply in COFI credits; LOFI - FLOCOMP, vibration, p/t cycling; capability turned into AOF actual
Install alarms for pressure, temperature, flowrate deviations from operating limits	COFI	apply in COFI credits for faster reaction times
Install gas detection/alarm systems (thermal, optical, compositional)	COFI	apply in COFI credits for faster reaction times
Install hydrate, paraffin, inorganic precipitates, or scale inhibition/prevention systems	LOFI	LOFI - treating hydrates or organic or inorganic solids can be preventive for impact / mechanical damage from a moving hydrate; preventing corrosive scales from forming reduces Dfthin.
Establish response to operating limits alarm threshold exceedances	COFI	apply in COFI credits for faster reaction times
Enhanced casing annulus testing and frequency of	LOFI	Dcond, Fann or Ffunc
Enhanced casing inspection logging and frequency of	LOFI	Wtcurrent, Burstadj, number Cl3 Cl4 joints
Enhanced safety valve testing and inspection frequency	COFI	safety valve is a COFI credit factor since it is a consequence mitigation/isolation device
Establish/enhance internal corrosion monitoring program/frequency	LOFI	Wtcurrent, Burstadj, number Cl3 Cl4 joints
Enhance/change valve maintenance practices and frequency	LOFI and COFI	LOFI - increased valve maint and function testing could reduce the Fwhv factor; COFI credit IF the valve in question is an automatic valve or other shut-off valve that is intended to act as a isolation/mitigation device
Enhance/change wellhead and wellsite inspection and condition documentation practices and frequency	LOFI	Dfveh, Dfobj, Fbimpact

Additional logging - run cement bond, GRN, noise, caliper, casing inspection, hydraulic isolation and/or temperature log	LOFI	Wtcurrent, number of Cl3 Cl4 joints, Dcond, Fcmt
Downhole remediation option - plug and abandon well	LOFI and COFI	AOF=0
Downhole remediation option - install/repair tubing and packer, tubing head/hanger	LOFI/COFI	AOF, MOP, number of Cl3 Cl4 joints, Wtcurrent, burstadj, COFI credit for isolation
Downhole remediation option - install full or partial cemented liner	LOFI/COFI	AOF, MOP, number of Cl3 Cl4 joints, Wtcurrent, burstadj
Wellhead remediation option - change-out/repair/paint wellhead valves/flanges/seals/bolts	LOFI	Dwhc, non-API?, Dvseal
Wellhead remediation option - install second master valve	LOFI	Dvseal, non-API?, COFI credit for isolation
Wellhead remediation option - repack/replace valve stems	LOFI	Dwhc, non-API?, Dvseal
Wellhead remediation option - pack-off wellhead seals	LOFI	Dwhc, non-API?, Dvseal
Wellhead remediation option - replace wellhead seals	LOFI	Dwhc, non-API?, Dvseal
Enhanced wellsite security - minimize encroachments (clear brush, remove trees, re-locate equipment, etc)	LOFI	Dfveh, Dfobj, Fbimpact
Enhanced wellsite security - install/repair physical barrier (heat shields, berms, fences, barricades, shielding, etc)	LOFI	Dfveh, Dfobj, Fbimpact
enhanced wellsite security - install water supply, deluge, foam or other fire suppression systems	COFI	apply in COFI credits - mitigation systems
Enhanced wellsite security - install surface/sub-surface safety valve	COFI	apply in COFI credits
Enhanced wellsite security - gas detection surveys (optical, imaging, sniffers)	COFI	apply in COFI credits - detection systems
Downhole remediation option - install de-rate/pressure limiting downhole packer (limiting MOP)	LOFI/COFI	MOP, AOF
Downhole remediation option - pressure test wellbore (MIT test)	LOFI	under MOP safe in Dfthin - an MIT could provide a tested Psafe
Downhole remediation option - remedial cementing (grouting, perforate and squeeze, etc)	LOFI	Dcond, Ffunc
Wellhead remediation option - install/repair annulus pressure vents or add/repair annular valves, rupture disks, to prevent oxygen entry	LOFI	Fwhv
Downhole remediation option - replace/back-off and replace casing joints	LOFI	Dfwork, potential changes to Wtcurrent, Burstadj, and number of Cl3 Cl4 joints
Downhole remediation option - top-off annulus with corrosion inhibitor	LOFI	not directly in the equation, except that an operator might reduce the corrosion rate used in the Dfthin calculation
Regional study - investigate regional geology and adjacent wells, additional logging (bond, GRN, noise, caliper, casing inspection, temp) on adjacent wells, possible remediation of adjacent/plugged wells, addition of vent/observation wells	COFI	COFI environmental
Plugged and abandoned well review and surveillance	reservoir LOFI/COFI	not treated in this guidance effort
Install/monitor cathodic protection as applicable.	LOFI	Wtcurrent if using a generic corrosion rate instead of log data, Burstadj, number Cl3 Cl4 joints, Dwhc
Collect and evaluate plugged and abandoned well records and rework or plug	reservoir LOFI/COFI	not treated in this guidance effort
Develop design standards for new wells	LOFI	new wells will be inherently safer overall
Develop or change material safety factors, metallurgical properties, operating limits of wellhead components and tubulars (casing, packers, liners, tubing, etc.)	LOFI	increases design vs. MOP or flow or other operating conditions, so clearly a LOFI reducer

Evaluate current completion of existing wells for functional integrity and determine if remediation monitoring is required	LOFI/COFI	Rework is a decision outcome of a risk analysis and evaluation; the rework will reduce risk by treating items that drove either LOFI or COFI - so this is possibly a LOFI and COFI reducer, but it depends on the specific well and conditions and specific work that is performed
Procedures	LOFI/COFI	handled in credits for LOFI and credits for COFI
Training of personnel and contractors and establishment of procedures	LOFI/COFI	handled in credits for LOFI and credits for COFI
Implement training/competency assurance and safety programs for company and contractor personnel	LOFI/COFI	handled in credits for LOFI and credits for COFI
Develop detailed drilling and well servicing procedures	LOFI/COFI	handled in credits for LOFI and credits for COFI
Bilateral agreements or statutory requirements for production wells to incorporate additional design features to isolate the storage horizon both during drilling, completion, stimulation and production. Examples include a separate string of cemented casing across the storage horizon and maintaining an adequate vertical and lateral buffer from the storage reservoir	LOFI/COFI	this is a LOFI reducer if viewed from the reservoir risk perspective because designs are modified to reduce risk of failure; but from a storage well perspective looking at that 3rd party well, a better design in that 3rd party well reduces COFI by reducing the possible avenues of leakage
Agreements with 3rd party production operations to have access and observation during the drilling, completion, and production phases	reservoir LOFI/COFI	not treated in this guidance effort
Monitor drilling and mining permits and activity	LOFI	Dfearth, Df impact
Promote development of rules and regulations for the protection of storage from third party oil and gas development	reservoir LOFI/COFI	not treated in this guidance effort
Surface and subsurface set-back requirements from storage wells and well sites for both vertical and lateral buffer zone	LOFI/COFI	LOFI - setbacks reduce the chance of impact or other interference; this is COFI as well for the COFI safety and COFI financial
Gas sampling analysis of storage wells and production wells and collection of production data to review for communication by storage operations	LOFI	V, sand, water, acid gas, FLOCOMP, LOFI reservoir
Acquire 3rd party production wells and mineral rights	reservoir LOFI/COFI	not treated in this guidance effort
Pursue legal options (condemnation, enjoin production, etc.)	reservoir LOFI/COFI	not treated in this guidance effort
Collect and review existing regional geological studies and data	reservoir LOFI/COFI	not treated in this guidance effort
Collect geological, geophysical & reservoir data on existing wells in/adjacent to the storage field	reservoir LOFI/COFI	not treated in this guidance effort
Acquire new data (e.g. electric logs, new wells, core, seismic, well testing, tracer gas studies, etc.)	reservoir LOFI/COFI	not treated in this guidance effort
Establish buffer zone, (vertical & horizontal) with governing agency and update as necessary	reservoir LOFI/COFI	not treated in this guidance effort
Conduct semiannual tests for inventory verification	reservoir LOFI/COFI	not treated in this guidance effort
Acquire property and mineral rights	reservoir LOFI/COFI	not treated in this guidance effort
Establish observation wells based on evaluation of need	reservoir LOFI/COFI	not treated in this guidance effort
Inspect plugged and abandoned wells, review records	reservoir LOFI/COFI	not treated in this guidance effort
Conduct fluid compatibility studies on samples of the reservoir rock and/or review of literature	reservoir LOFI/COFI	not treated in this guidance effort
Conduct internal corrosion studies and evaluate mitigation programs as needed	LOFI	WTcurrent, Burstadj, number Cl3 Cl4 joints

Monitor composition and quality of gas	LOFI	V, sand, water, acid gas, FLOCOMP
Ensure surface operating rights agreements (e.g. leases, easements, etc.) clearly specify storage operator's rights for ingress, egress, and mutual setback distances from wells/structures, etc.	COFI	consequence radius
Work with landowners, local planning/zoning commissions and others on the surface operating requirements around storage wells	COFI/LOFI	consequence radius, could reduce Dfveh, Dfobj
Use of existing Public Awareness activities required for pipelines	COFI/LOFI	consequence radius, could reduce Dfveh, Dfobj
Monitor use of the surface and subsurface around wells and enforce setback rights when encroachments threaten the well	COFI/LOFI	consequence radius, could reduce Dfveh, Dfobj
Install protection equipment (e.g. fences, alarms, etc.) for site security and safety	LOFI	Fbimpact
Include storage facilities into the corporate security plans	COFI	apply in COFI credits
Develop/expand storage well blowout/loss of control contingency plan	COFI	apply in COFI credits
Increase emergency response training	COFI	apply in COFI credits
Liaison with local, state and federal law enforcement agencies	COFI	apply in COFI credits
811 Call-Before-You-Dig programs (Damage Prevention Program)	COFI/LOFI	consequence radius, could reduce Dfveh, Dfobj
Implement management of change practices	COFI	apply in COFI credits
Perform routine patrols and surveillance, and event-specific surveillance activities	COFI/LOFI	consequence radius, could reduce Dfveh, Dfobj
Develop design specifications (e.g. barriers to deflect flood debris) for areas prone to flooding, earth movements, river/stream bed movement and other natural causes	LOFI	Dfearth
Develop/install site-specific plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement and other natural causes	LOFI	Dfearth
Monitor areas prone to flooding, earth movements, river/stream bed movement and other natural causes for impacts on nearby well sites	LOFI	Dfearth
Plug and abandon a well and drill replacement in more stable location	reservoir LOFI/COFI	not treated in this guidance effort
Remote control capabilities	COFI	apply in COFI credits


energy API
INGAA
AGA
American Gas Association

It can be done