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Final Report

Risk Assessment and Treatment of Wells

Prepared for
Pipeline and Hazardous Materials Safety Administration

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LIST OF ACRONYMS

ALARP	As Low As Reasonably Practicable
AOF	Absolute Open Flow
BOP	Blowout Preventer
BOPE	Blowout Preventer Equipment
CCS	Carbon Capture and Sequestration
CFD	Computational Fluid Dynamics
C-FER	C-FER Technologies (1999) Inc.
DHSV	Downhole Shut-off Valve
FMEA	Failure Mode and Effects Analysis
FMECA	Failure Mode, Effects, and Criticality Analysis
F-N	Frequency-Number
FORM	First Order Reliability Method
GWP	Global Warming Potential
HRA	Human Reliability Analysis
IC	Intermediate Casing
IPR	Inflow Performance Relationship
IR	Individual Risk
LSIR	Location-specific Individual Risk
NPP	Nuclear Power Plant
PAFM	Problem-associated Failure Mode
PC	Production Casing
PHMSA	Pipeline and Hazardous Materials Safety Association
PIR	Potential Impact Radius
PRA	Probabilistic Risk Assessment
POD	Probability of Death
POF	Probability of Failure
POI	Probability of Ignition
QRA	Quantitative Risk Assessment
SAGD	Steam-assisted Gravity Drainage
SC	Surface Casing
SCC	Social Cost of Carbon

SME	Subject Matter Expert
SORM	Second Order Reliability Method
SSSV	Sub-Surface Shut-off Valves
TAP	Technical Advisory Panel
UGS	Underground Gas Storage

EXECUTIVE SUMMARY

C-FER Technologies (1999) Inc. ("C-FER") carried out the project "Risk Assessment and Treatment of Wells" for the US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) to develop guidelines for the risk assessment of underground gas storage (UGS) wells subject to periodic well entry. The focus of the guidelines is on the development and application of quantitative risk assessment (QRA) methods and models, but the underlying concepts are also applicable to qualitative assessments. The guidelines are intended to provide UGS well operators with information to support the development, selection and application of risk-based models that will facilitate decision making with regard to well entry activities. They are also intended to provide regulators with information to support evaluation of the risk assessment methods and models used by industry.

The risk assessment guidelines address the following:

- Methods and models that can be used for failure frequency and failure consequence estimation, including discussion of the advantages and limitations inherent in the use of different methods and models;
- Risk measures required to provide a suitable basis for quantifying and evaluating the public safety and the environmental risks posed by UGS well operation and periodic well entry;
- The process required to integrate the failure frequency and failure consequence estimates, obtained separately for normal well operation and periodic well entry, into meaningful measures of combined well entry plus operating risk for the purpose of estimating the public safety and environmental risk levels; and
- Suggested approaches for evaluating the safety and environmental risk estimates produced, including a discussion of acceptance criteria for public safety risk and a risk-based framework for evaluating the environmental risk associated with different well entry scenarios for the purpose of determining the preferred course of action.

A secondary project objective was to illustrate the application of the QRA process to selected UGS well configurations subject to periodic well entry. In addition to demonstrating the application of a defensible QRA process, the directional findings of the example assessments are intended to support the development of best practices for the selection of preferred well completion configurations and the optimization of well entry practices.

The UGS well configurations considered in the demonstration analysis were selected to include a range of representative UGS well completion configurations that are applicable to typical wells serving depleted hydrocarbon reservoirs and salt caverns. The results obtained from the analysis of these well configurations support the following directional findings:

- General
    - Risk estimates developed using a QRA process are highly dependent on the assumed failure frequencies and failure mode splits for key well components and activities. The key items include wellhead failure during well entry or normal well operation, and production casing failure during operation in cases where the production casing is the only downhole barrier.
    - Cavern wells are shown to be associated with higher safety and environmental risk levels than reservoir wells. This is because salt caverns are typically designed for higher operating flow rates than reservoir wells, and cavern wells, unlike reservoir wells, are not subject to the flow throttling effects of reservoir deliverability constraints.
- Well Safety Risk
    - Typical reservoir and cavern wells do not pose a significant safety risk to the public unless routinely occupied locations are in close proximity to the wellhead.
    - Modest setback distances can achieve broadly acceptable levels of individual safety risk for typical reservoir and cavern wells. However, explicit guidance is required to define appropriate setback distances that adequately account for the impact of key well attributes on hazard zone size (including production string diameter, well depth, and gas storage pressure).
    - Well entry is typically the largest contributor to the annual safety risk posed by a UGS well, particularly for entry activities involving coiled tubing work or a well workover. On this basis, additional precautions during complex and invasive well entries on wells in proximity to occupied areas may be warranted.
- Well Entry Risk
    - Well configurations that support the use of less complex and less invasive well entry methods for inspection and remediation are generally associated with lower life-cycle operating risks.
    - Well entry for integrity management purposes is most beneficial if efforts target components that serve as a single barrier to a gas release.
    - Periodic well entry for inspection and remediation of production casing, when it is the sole downhole barrier, is difficult to justify on a frequent basis unless casing condition is known to be poor. If remediation work is to be performed, it should be planned to maximize the time to the next required well entry.
    - Periodic well entry for inspection and remediation of production casing, when it is not the sole downhole barrier, is difficult to justify in typical situations due to the reduced risk

reduction benefit afforded by casing integrity enhancement. Casing inspection in these situations may, however, become more justifiable if and when reliable casing integrity evaluations can be performed without removal of the tubing string.

The literature review and research carried out during this project identified areas where further work is required to support the preparation of defensible QRAs for UGS wells subject to well entry. The suggestions for further work are as follows:

- Given the importance of historical data on well and well component failures, and the relative lack of such data that is specific to UGS wells, efforts should be made to expand the reporting and analysis of UGS well and well component failure incident data. The reporting of failures of UGS wells has been a PHMSA requirement since 2017; however, it is recommended that both the reporting requirements for, and the granularity of the information provided on, UGS well failures should be revisited.

- Central to well failure consequence modeling is release rate estimation. Accurate release rate estimation requires models that can explicitly account for the various flow conditions that develop along the length of each credible release pathway. Gas flow upwards through the casing cement and/or the surrounding formation in the event of a casing breach is not well understood and further work is required to enable better estimation of gas flow rates to the surface though these pathways.

- Current setback requirements for developments adjacent to UGS wells, where they exist, are inconsistent. To enhance public safety and promote greater consistency in defining setbacks, explicit guidance is required to define well-specific setback distances that adequately reflect the possible extent of the hazard zone that would develop in the event of a credible worst-case release followed by gas ignition, which depends on key well attributes, including the diameter of the production string, the depth of the well and the gas storage pressure.

- To facilitate the broader use of QRA for safety-based decision making, a widely accepted, consensus-based set of safety risk acceptance criteria is required. To this end, an effort should be made to assemble a group of informed stakeholders to review options and decide on what set of criteria should be adopted for use in assessing UGS well safety.

- True optimization of the well entry frequency requires methods and models that can convert downhole component condition and inspection data into defensible estimates of component reliability over time. An important application of this would be a methodology for using data obtained from high-resolution casing corrosion inspection logs to estimate casing failure probability, as a function of time, with and without selected defect remediation. Such methods, involving the use of structural reliability models, have been developed for use in the pipeline industry and are adaptable to UGS wells. Work in this area is ongoing, but efforts to accelerate the development and application of such methods are warranted.

ACKNOWLEDGEMENTS

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1. INTRODUCTION

1.1 Terms of Reference

This document is the primary deliverable for the project "Risk Assessment and Treatment of Wells" that was carried out by C-FER Technologies (1999) Inc. ("C-FER") for the US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) This project was carried out to develop guidelines for the risk assessment of underground gas storage (UGS) wells subject to periodic well entry. The work was carried out under the guidance of a Technical Advisory Committee, consisting of experts from the gas storage industry, who provided input throughout the project and review comments on the final project report.

1.2 Background and Objectives

The use of risk-based methods to guide operational and integrity management decisions is an established practice in many industries. In the pipeline industry, for example, risk assessment is used to inform various activities, including inspection program planning, pressure test interval evaluation, and fitness-for-service assessment. Although the use of risk assessment in the US to evaluate and manage the integrity of oil and gas wells has been less common in the past, it is now established as a recommended practice for UGS wells serving depleted hydrocarbon reservoirs, aquifers and salt caverns through the industry-led development and publication of API RP 1170 and 1171 in 2015 (1,2). PHMSA's mission to improve safety and reduce the environmental impact of gas storage and related assets has led to API RP 1170 and 1171 being incorporated by reference into 49 CFR 192 (3), and the recommended practices for risk assessment contained in Section 8 of API 1171 are, as of March 2020, applicable to all UGS wells in the US (4).

API RP 1171 includes a list of potential integrity threats to the well, reservoir and surface components of a UGS well that must be assessed and managed by operators. One of the threats to wells identified in API 1171 is "well intervention", which is also referred to as "well entry". Well entry may be required for various reasons, including monitoring or enhancing well production, performing well integrity diagnostics, repairing or replacing downhole or wellhead components, changing production or injection zones, well suspension, or well abandonment. One common objective of well entry is to reduce the likelihood and magnitude of a gas release due to time-dependent damage mechanisms (e.g. corrosion) by ensuring that the well is leak-free through pressure testing, and by periodic component inspection and the repair of failure critical damage. However, temporary changes to the well barrier configuration may be required to facilitate entry and the nature of these invasive actions, combined with the potential for human error during these labor-intensive activities, results in an increase in the probability of well failure during well entry. In some cases, the risks associated with the act of well entry could outweigh the subsequent risk reduction benefits afforded by well entry.

Using quantitative risk assessment (QRA) methodologies to assess well risk before, during and after entry provides the information necessary for determining what combination of entry actions and entry frequencies will achieve a net reduction in operating risk, and may also inform the determination of an optimal well entry plan that will minimize the operating risk over the remainder of the well life.

The primary objective of this project was the development of guidelines for the risk assessment of UGS wells subject to periodic well entry. The focus of the guidelines is the development and application of QRA methods and models, but the underlying concepts are also applicable to qualitative assessments. The guidelines are intended to provide UGS well operators with information to support the development, selection and application of models that will facilitate decision making with regard to well entry activities. The guidelines are also intended to provide regulators with information to support evaluation of the risk assessment methods and models used by industry.

A secondary project objective was to demonstrate the application of specific QRA methods to the estimation and evaluation of the risks associated with representative UGS well configurations subject to periodic well entry. These demonstration assessments are intended to illustrate the application of the QRA process, as described in the guidelines, and to support the development of best practices for different well completion types and well entry practices.

The development of the guidelines was informed by a comprehensive review of risk assessment methods and models currently employed on oil and gas wells (with an emphasis on UGS wells), as well as a review of risk-based assessment methods and models used in other industries.

The development of both the guidelines and the demonstration analyses were informed by the results obtained from a survey of UGS well operators and subject matter experts that focused on identifying typical well configurations and well entry procedures, hazards posed by well entry, reasons for well entry, and typical frequencies of well entry.

1.3 Scope of Work

The QRA process consists of two key elements: risk estimation and risk evaluation.

Risk estimation involves quantifying system risk, a process that requires risk analysis, which involves a number of steps, including defining the system to be considered, identifying the threats that can lead to failure, estimating the frequency of failure, estimating the consequences of failure, and estimating the risk through integration of the estimated failure frequencies and failure consequences. The guidelines developed herein focus on the following components of the risk analysis process:

- Failure frequency estimation – including identification and discussion of the strengths and limitations of the various methods and models available for estimating the frequency of well failure during operation and during periodic well entry.
- Failure consequences estimation – including identification and discussion of well safety and environmental consequence measures, and discussion of methods and models that can be used to quantify the respective loss measures.
- Risk estimation – including discussion of the methods and models required to combine the failure frequency and consequence estimates into meaningful measures of safety and environmental risk during well operation and well entry, and how best to combine the operational and entry risk measures for the purpose of risk evaluation.

Risk evaluation involves applying values and judgments to assess the estimated risk level in order to determine whether or not it is acceptable or tolerable in the context of the situation under consideration and make risk reduction decisions, where necessary. The guidelines developed herein focus on the following with respect to risk evaluation:

- Risk evaluation based on acceptance criteria – including identification of risk measures for which acceptance criteria currently exist and commenting on their applicability to UGS well risk assessment.
- Risk evaluation in the absence of acceptance criteria – describing how combined measures of operating and entry risk can be evaluated in the absence of acceptance criteria to inform decisions regarding well entry.

1.4 Document Organization

The document is organized into the following sections:

- Industry Survey – describes the industry survey that was developed and sent to selected operators and subject matter experts. The intent of the survey was to develop a better understanding of prevalent UGS well configurations, well entry activities and the associated well entry methods, and to identify specific operator concerns regarding the development and application of QRA methods for assessing the risk associated with well entry activities.
- Literature Review – describes the review conducted to identify failure frequency and failure consequence estimation models, and risk estimation and assessment methods currently being used within the UGS industry and in other industries, including: the pipeline industry, the nuclear industry, the offshore oil and gas industry, the aviation industry and the power transmission industry.
- Guidelines for Quantitative Risk Assessment – serves as a stand-alone document providing guidance to assist UGS well operators in developing, selecting and applying QRA methods

and models for the purpose of well entry decision making and to assist regulators in evaluating the suitability of operator-specific risk models.

- Example Applications of Quantitative Risk Assessment – describes the application of specific QRA methods and models to a representative set of UGS well configurations to evaluate the risk implications of periodic well entry and to illustrate how the QRA process can be used to support decision making with regard to well entry as it affects the overall safety and environmental risk posed by ongoing UGS well operation.

- Summary and Recommendations – summarizes the key project findings and provides recommendations for future work required to address information and/or modeling gaps that act as impediments to the broader use of QRA methods and models for the management of the safety and environmental risks posed by UGS wells subject to periodic well entry.

2. INDUSTRY SURVEY

2.1 Introduction

An industry survey was conducted to collect information on UGS well configurations and well entry activities. The survey was sent by e-mail to a group of operators and subject matter experts (SMEs) in the North American UGS industry. The survey form delivered to potential respondents is presented in full in Appendix A, Attachment 1. A total of seven responses were received, representing operators responsible for a total of 5404 wells distributed across 86 storage fields. The consolidated and anonymized survey responses are provided in Appendix A, Attachment 2.

2.2 Objectives and Methodology

The purpose of the industry survey was to develop an understanding of: 1) prevalent well configurations; 2) prevalent well entry activities and the associated well entry methods; 3) anticipated new well configurations, well entry activities and entry methods; and 4) operator concerns regarding the development and application of risk models for assessing the risk associated with well entry activities and optimizing the type and frequency of such activities.

The final version of the survey was developed in consultation with the Technical Advisory Panel (TAP) and is comprised of eight sections. In the first section, background information, such as the number of storage wells, the number of storage fields and the types of storage fields owned/operated, was requested. The second, third and fourth sections sought information on well configuration types currently in use and any new well configurations being considered for future use (for wells associated with depleted hydrocarbon reservoirs, aquifer reservoirs and salt caverns, respectively). The fifth, sixth and seventh sections requested information on well entry activities that support the inspection, maintenance and efficient operation of wells (for wells associated with depleted hydrocarbon reservoirs, aquifer reservoirs and salt caverns, respectively). Finally, the eighth section sought feedback on important considerations or key concerns that should be taken into account when developing and applying a risk-based approach to well entry optimization.

The survey questionnaire was delivered to a selected group of operators and SMEs.[1] The survey responses received represent approximately 20% of the 448 UGS fields in North America, as identified by the North American Cooperation on Energy Information (5). Table 2.1 summarizes

[1] Prior to finalizing the list of candidate survey respondents and distributing the survey, C-FER was made aware by PHMSA of the Paperwork Reduction Act that constrains the level of industry involvement that is deemed appropriate to support government sponsored research. This act was interpreted to limit survey participation to a maximum of nine respondents.

the number of storage wells and storage fields operated by the companies that responded to the survey. The numbers are broken down by field type, and the proportion of North American fields represented by the survey is also provided. It is noted that none of the survey respondents operate aquifer reservoir storage facilities; however, it is understood that well configurations and operating practices are very similar for wells serving depleted hydrocarbon reservoirs and aquifer reservoirs.

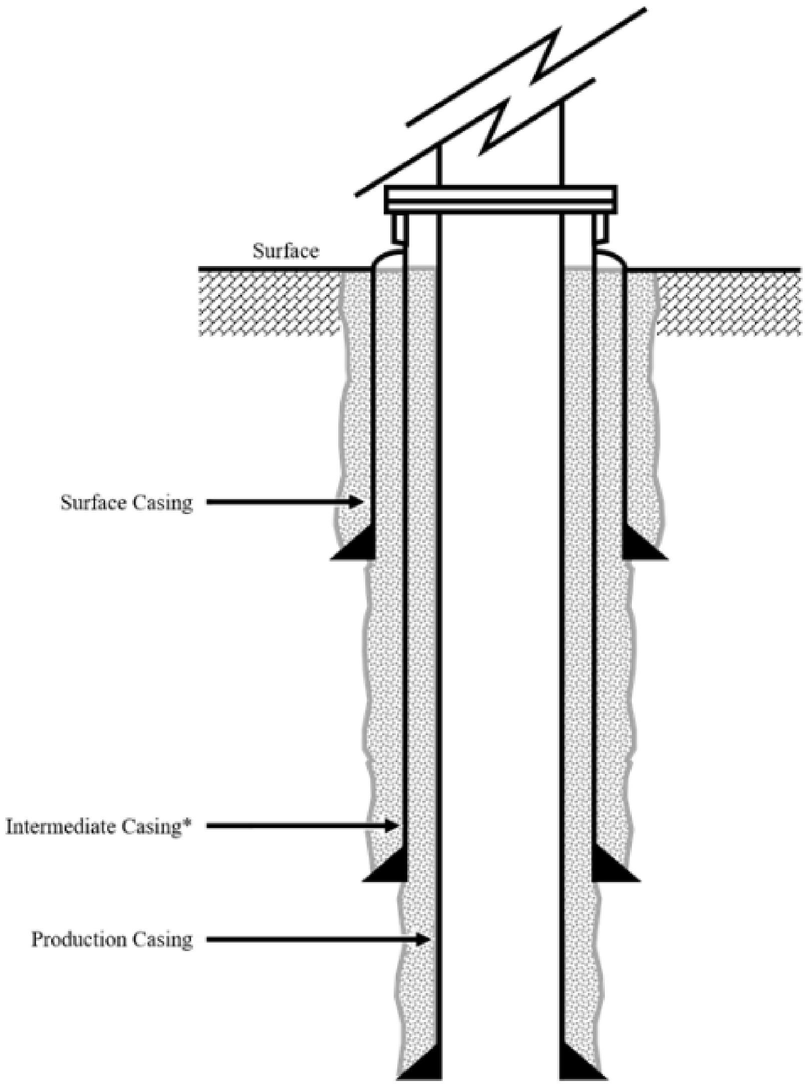
Field Type	**Number of Storage Fields (% of North American Total)**	**Number of Storage Wells**
Depleted Hydrocarbon Reservoir	75 of 358 (21%)	5360
Aquifer Reservoir	0 of 45 (0%)	0
Salt Cavern	11 of 45 (24%)	44
All	*86 of 448 (19%)*	*5404*

Table 2.1 Summary of Survey Respondents' Assets

2.3 Summary of Results

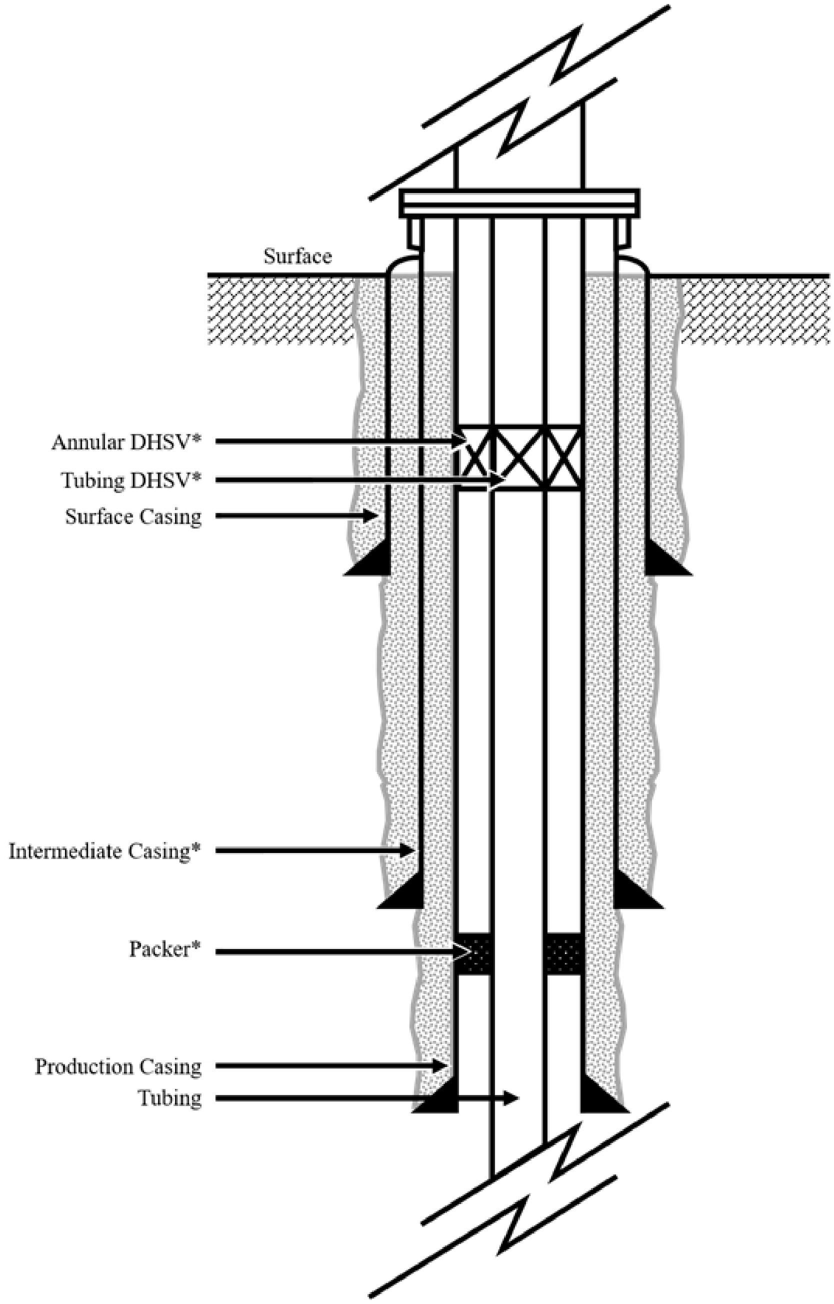
2.3.1 Well Configuration

Major components of UGS wells include the wellhead, upper completion, and lower completion. The focus of the industry survey was the configuration of the upper completion, or wellbore, from the surface down to the bottom of the production casing or tubing, if present. Wells were characterized in terms of selected well attributes, such as the well direction, the flow string and the well casing cement height(s). Configurations were also characterized by the presence or absence of several key components, including tubing, downhole shut-off valves (DHSVs), packers, integrity liners, and well casings. Figure 2.1 and Figure 2.2 were provided alongside the survey as visual aids and to ensure consistent use of terminology.



*Component may or may not be present.

Figure 2.1 UGS Well Configuration Without Production Tubing



*Component may or may not be present

Figure 2.2 UGS Well Configuration With Production Tubing

2.3.1.1 Well Direction

Surveyed wells were classified as either vertical or horizontal. The majority of UGS wells in North America are vertically drilled and completed. However, the use of horizontal wells for depleted reservoirs is increasing due to the potential to deliver higher flow rates relative to vertical wells. In this regard, it was noted that new or retrofitted horizontal wells can replace the flow capacity of several vertical wells. Therefore, some operators are opting to plug and abandon vertical wells in favor of new horizontal wells, effectively reducing their facility well counts and, hence, their facility risk, without significantly reducing facility flow capacity. Salt caverns, in contrast to depleted reservoirs, are effectively open vessels that offer very high deliverability and there are, therefore, no advantages to the use of horizontal wells. Of the depleted reservoir wells captured by the survey, 96% were vertical. All salt cavern wells surveyed were vertical.

2.3.1.2 Well Casing

Wells are completed with a series of concentric casing strings that act as a barrier to establish hydraulic isolation of the storage gas from the external rock formation and from groundwater. Typically, at least two casing strings are used; every well surveyed had at least a surface casing and a production casing. The annular space between casing strings can be cemented either partially or fully to the surface.

Surface Casing: Most depleted reservoir wells (84%) and all salt cavern wells surveyed had surface casing that was cemented to the surface. However, it was noted that, on some wells, the surface casing is open-ended at the surface with the master valve attached to the production casing only.

Intermediate Casing: Intermediate casing was identified as present in 47% of wells in depleted reservoir storage fields. None of the depleted reservoir wells surveyed had more than one intermediate casing string. Approximately half of the intermediate casing strings present in depleted reservoir wells were cemented to the surface.

Intermediate casings were more prevalent in salt cavern storage fields. Intermediate casing was present in 61% of salt cavern wells, and most of these had multiple intermediate casing strings. All intermediate casings on salt cavern wells surveyed were cemented to the surface.

Production Casing: Only 32% of depleted reservoir wells had the production casing cemented to the surface, 20% were cemented to a height above the adjacent shoe of the outer casing string, and 48% were cemented to a height below the adjacent shoe of the outer casing string. It was noted that the quality of the cement surrounding the production casing can be poor close to the surface on many wells.

Most of the salt cavern wells surveyed (70%) had production casing cemented to the surface; those that didn't have cement to the surface had cement at least to a height above the adjacent shoe of the outer casing string.

2.3.1.3 Tubing and Packer

Some wells are equipped with tubing: an additional smaller diameter pipe set within the production casing to produce or inject fluids. The tubing is often set on a packer, which provides an additional physical barrier to gas releases through the casing into the surrounding formation. Tubing can present challenges during well entry as many activities, including inspection of the production casing, require that the tubing first be pulled from the well.

Of the depleted reservoir wells surveyed, there were significantly more wells without, rather than with, tubing (89% versus 11%). All the depleted reservoir wells reflected in the survey used the tubing to isolate the inner casing string from the storage gas. Nearly all of these wells achieved isolation with a packer; however, some had the tubing cemented to the surface instead of being set on a packer. All the depleted reservoir wells with tubing used the tubing as the flow string.

For surveyed wells in salt cavern storage fields, 27% had tubing and 73% did not. It was noted that, for most salt cavern wells, tubing is typically a hanging brining/debrining string that is not regularly used for gas flow. None of the salt cavern wells surveyed used the tubing as a flow string under normal operating conditions, nor did any of the salt cavern wells surveyed employ the use of a packer to isolate the tubing from the production casing annulus.

2.3.1.4 Downhole Shut-off Valves

DHSVs, also known as sub-surface shut-off valves (SSSVs), are installed in the wellbore of a minority of natural gas storage wells. DHSVs are intended to arrest the release of natural gas from a well in the event that a large leak occurs above the valve. It is understood that there are both benefits and significant concerns regarding the use of DHSVs in the North American UGS industry. The presence of DHSVs necessitates both increased frequency and complexity of well entries. Only 5% of the depleted reservoir wells analyzed in the survey had a DHSV present; of these, 31 were in-line with the production tubing in wells with a full-length tubing string and 219 were installed in wells with a partial tubing string wherein the majority of the wellbore is tubingless. No DHSVs were present on the salt cavern wells surveyed. It was noted that many operators are actively removing their DHSVs unless they are installed on wells in high consequence areas, in areas where a wellhead strike is a credible threat, or in jurisdictions that require a DHSV.

2.3.1.5 Liners

Two of the wells surveyed had liners for wellbore integrity purposes, both of which were salt cavern wells. It is understood that expandable liners and scab liners are an effective casing repair technique, but they can make the well more difficult to inspect and can reduce the well flow capacity as their installation results in a reduction of the inside diameter of the casing.

2.3.2 Well Entry

In the survey, well entry was characterized in terms of the reasons for, and the associated methods and the key attributes of, the entry procedures. Key attributes included the typical entry frequency for a given entry type and reason for entry, the applicable well direction(s), and the type of barrier(s) in place during the entry. An opportunity was also provided for additional operator comments with respect to specific well entry activities. For consistency in the tabulation and interpretation of survey information on well entry activities, a prescribed list of reasons for well entry was adapted from the Ground Water Protection Council and Interstate Oil and Gas Compact Commission (6) and provided to respondents for selection via a drop-down menu.

The prescribed list of reasons for well entry included the following:

- Casing integrity logs,
- Casing repair (e.g. patches, liners, remedial cementing),
- DHSV work,
- Downhole sensor (e.g. temperature, noise, bottom hole pressure),
- Drilling,
- Fishing jobs,
- Hydraulic fracturing,
- Milling,
- Perforating,
- Re-completion,
- Tubing removal,
- Well cleanout,
- Wellbore stimulation, and
- Wellhead valve replacement.

Additional reasons for well entry provided by survey respondents included:

- Setting tubing plugs and shifting downhole sleeves,
- Sidetracking,
- Well plugging and abandonment, and
- Wellhead replacement.

2.3.2.1 Well Entry Frequency

Storage wells have long service lives and may require a broad range of well entry activities over the course of their service life. Operators submitted a typical frequency (e.g. once per year, several times in the lifetime of the well, or once or twice in the lifetime of the well) for each well entry activity and Appendix A summarizes these results. Four well entry activities were highlighted as being either particularly frequent or particularly important for present-day UGS facility operation, and warrant further discussion:

- *Well plugging and abandonment* was highlighted as a priority for operators and, in many cases, is the foremost risk mitigation strategy, particularly for older wells that cannot be worked over.
- *Wellhead replacement* was also noted as a particularly common present-day practice as operators modernize their wells to incorporate API-6A wellhead equipment and to accommodate annular pressure monitoring at the wellhead.
- *Casing integrity logs* were identified as a well entry activity that is performed with a frequency ranging from once or twice to several times in the life of each well, depending on well configuration, well condition and state regulatory requirements. It was noted that casing integrity logs on wells with tubing require that the tubing be pulled to obtain reliable log results; thus, well entry in such wells is typically more complex and resource intensive than entry in wells without tubing.
- *DHSV work* (e.g. testing, maintenance, replacement, temporary abandonment and removal) was identified to be very frequent in wells with DHSVs, in part due to the recognized reliability issues associated with these components.

2.3.2.2 Well Entry Methods

For consistency in the tabulation and interpretation of survey information, four well entry methods were provided as selection options in the survey: 1) wireline or slickline, 2) coiled tubing, 3) snubbing unit and 4) drilling rig and/or service-type pulling unit. One additional entry method was submitted by an operator: pumping operations. Pumping operations involve the injection of a fluid (other than storage gas) into a well and it may be used when performing wellbore stimulation, corrosion treatment, scale treatment, well cleanout or well killing.

2.3.2.3 Barriers

Barriers are defined by ISO 16530-1 (7) as "a combination of components or practices that contribute to the well system reliability to prevent or stop uncontrolled fluid flow". The ISO standard goes on to classify barriers as either hardware barriers, operational barriers, human barriers or administrative controls. The configuration of these well barriers changes before, during and after well entry. Survey respondents were asked to identify barriers particularly relevant during well entry, with a focus on hardware barriers that are present during well entry, but are not present during normal operating conditions. Well entry hardware barriers included the following (classified by well entry method):

- For wireline or slickline operations:
    - Blowout preventer (BOP) and related equipment (BOPE),
    - Bridge plug,
    - Grease injection control head,
    - Liquid for hydrostatic overbalance, and
    - Pack-off on lubricator.
- For operations employing coiled tubing:
    - BOP and BOPE, and
    - Pack-off on lubricator.
- For operations employing a snubbing unit:
    - BOP and BOPE,
    - Bridge plug, and
    - Pack-off on lubricator.
- For operations employing a drilling rig and/or service-type pulling unit:
    - BOP and BOPE,
    - Bridge plug,
    - Liquid (mud system) for hydrostatic overbalance, and
    - Fluid-filled cavern.

Survey respondents noted that, when it comes to well entry, human factors and process safety management are of particular importance. Several operational barriers, human barriers or administrative controls were identified by survey respondents as essential for safe well entry. These non-hardware barriers, by barrier type, include:

- Operational barriers:
  - Detection and monitoring equipment (e.g. pressure, temperature, weight indicator, tension indicator and drilling indicators),
  - Records review processes (e.g. well barrier schematics and wellbore profiles; characterization of stored hydrocarbons; anticipated temperatures and pressures; anticipated presence of water, fluids, deposits, or scale; and restrictions in the wellbore),
  - Equipment fitness-for-purpose assessment processes (with safety factors for pressure containment),
  - Well entry procedures and work instructions, and
  - Threat and hazard identification and associated review processes.
- Human barriers:
  - Company and contractor training,
  - Company and contractor supervision, and
  - Company and contractor safety management programs.
- Administrative controls:
  - Management of change, and
  - Record keeping.

2.3.2.4 Hazards

Respondents were also asked to identify relevant hazards associated with each well entry activity. The following list presents a summary of typical hazards encountered during well entry:

- For wireline or slickline operations:
  - Balling of the slickline cable within the lubricator;
  - Damage to the well or wellhead;
  - Failure of seal elements in the lubricator;
  - Failure of the BOPE;
  - Failure of the grease injection control head/pack-off to contain the well pressure;

  - Failure of the hoist equipment;
  - Getting a tool stuck in the well;
  - Operator error; and
  - Stranding of the wireline cable within the lubricator.
- For operations employing coiled tubing:
  - Damage to the well or wellhead;
  - Failure of seal elements in the lubricator;
  - Failure of the BOPE;
  - Failure of the hoist equipment;
  - Failure of the injector head, which can cause tubing to be blown from well;
  - Failure of the pack-off to contain the well pressure;
  - Getting a tool stuck in the well;
  - Operator error; and
  - Parting or leaking of the coiled tubing above the injector head.
- For operations employing a snubbing unit:
  - Dropping of the tubing;
  - Failure of the BOPE; and
  - Light-pipe blowout.
- For operations employing a drilling rig and/or service-type pulling unit:
  - Dropping of the work string;
  - Failure of the BOPE if primary barrier is lost;
  - Failure of the downhole assembly;
  - Failure of the rig structure;
  - Failure to recognize a gas influx in the well;
  - Failure to run a sufficient kill string;
  - Getting a tool stuck in the well;
  - High wind;
  - Increase of pressure in the formation;
  - Loss of hydrostatic pressure above the storage zone;

- o Operator error (e.g. crown-out);
- o Poor cement job above the storage zone; and
- o Subsidence of the ground.

2.3.3 Key Concerns

In the survey, key stakeholder concerns were divided into two categories:

1. **Risk modeling**: concerns associated with risk model development and application in general (e.g. lack of data to support failure probability characterization for selected components, lack of well-defined failure consequence measures), and
2. **Well entry analysis**: concerns specific to the risk analysis of well entry activities (e.g. lack of data to support characterization of failure probability increase during entry, sensitivity of entry-related well failure to factors not identified in this survey).

A total of 17 comments were provided, 12 of which pertained to general risk modeling and the remainder to well entry analysis. (The specific comments provided by each survey respondent are included in Appendix A).

The general risk modeling concerns identified are summarized as follows:

- Lack of data to support failure probability characterization;
- Lack of a well-defined framework for translating component failure probabilities into loss of well control probability;
- Lack of understanding of interaction effects between barrier system failures;
- Well data acquisition and integration challenges;
- Difficulty in reassessing risk over time; and
- Difficulty relating well characteristics, such as absolute open flow (AOF), pressure and component size, to a measure of consequence.

Concerns specific to well entry analysis are summarized as follows:

- Lack of data to support characterization of the failure probability increase during well entry;
- Prescriptive regulations mandate frequencies for well entry, so risk modeling needs to account for differences between jurisdictions;
- Risk modeling needs to reflect the increased need for well entry due to increased well complexity and number of downhole components; and

- Human and organizational factors involved in well entry accidents are poorly understood and difficult to account for in a risk model.

3. LITERATURE REVIEW

3.1 Underground Gas Storage Industry

3.1.1 Search Methodology and Data Collection

A literature review was conducted to identify models available for risk assessments of UGS facilities. A search of engineering and technology databases identified 59 relevant publications for detailed review. Seven publications examined historical incidents of well failures, and twelve publications used historical data to produce failure rates for wells or well components. Six publications focused on determining possible failure pathways in wells or UGS facilities and identified barriers to these pathways. Four publications described models for well failure consequences. The 30 remaining publications presented risk assessment methodologies for wells or UGS facilities. Quantification of risk, the focus of this review, was a component of 22 of the methodologies described in these publications, while 8 used SME opinion or historical data to qualitatively express risk as a score or index. A critical review of all identified risk assessment methodologies, including the advantages and disadvantages of each, is presented in this section.

In addition to assessments of UGS facilities, the review identified models used to assess the risk of wells used for any purpose. Whether used for UGS or not, most wells have similar components and are likely to share many failure modes. Of the 30 reviewed risk assessment methodologies, 4 were developed specifically for UGS facilities, 3 addressed Carbon Capture and Sequestration (CCS) facilities, and the remaining assessed other types of wells or well components. Most of the assessments focused on the drilling or operational stages of a well, but seven also included an assessment of risk due to workover activities.

3.1.2 Risk Analysis Process

3.1.2.1 Overview

A generic risk management framework is illustrated in Figure 3.1. The focus of this review (risk analysis) is shown to be a sub-process within this overall framework. The system definition, threat identification and risk estimation tasks are discussed in the following subsections, while failure frequency estimation and consequence estimation are discussed separately in Sections 3.1.3 and 3.1.4, respectively.

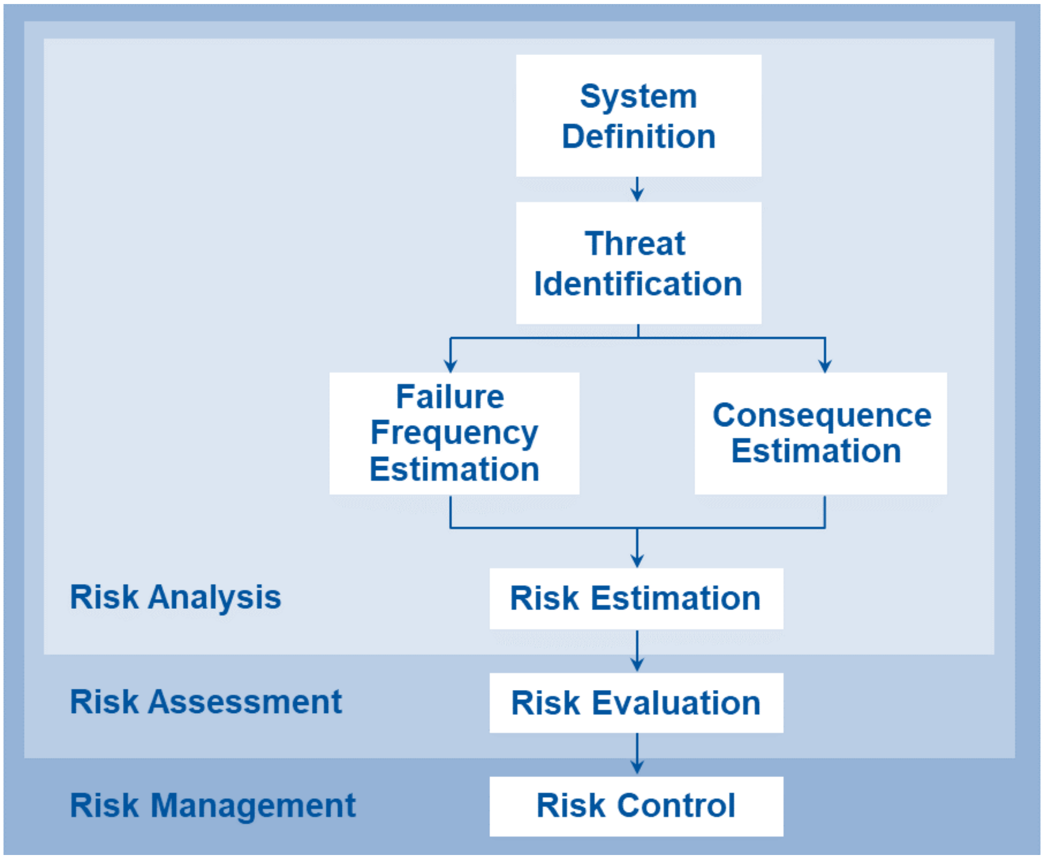


Figure 3.1 Risk Management Framework

3.1.2.2 System Definition

Most of the reviewed risk assessment methodologies analyzed the wellhead and downhole equipment present on a representative well configuration or in the form of a case study. The components present in the well varied based on the type of well being assessed and the well's phase of operation. SME opinion was commonly relied on to identify the boundaries of the assessment and create a representative well configuration. In some cases, such as Patroni (8), Harrison and Ellis (9) and DeWolf et al. (10), the assessment focused on wells within UGS facilities. Studies that evaluated the risk associated with workover or well entry procedures include Woodyard (11), Durham and Paveley (12), Worth et al. (13), DNV et al. (14), Edmondson and Hide (15) and Macary and el-Haddad (16).

In some cases, the assessment was expanded to include the risk associated with an entire storage facility. Due to the long-term containment requirements, the analysis of CCS facilities by Pawar et al. (17), Larkin (18) and Gerstenberger et al. (19) considered the geological integrity of the storage facilities in their assessment. Wickenhauser et al. (20) included formation stability and porosity in their comprehensive risk assessment of salt caverns used for gas storage.

3.1.2.3 Threat Identification

API RP 1171 (2) defines 12 possible threats to storage facilities within 3 categories: wells, reservoirs, and surface threats. As not every facility is susceptible to all threats, threat identification must be incorporated into every risk assessment. Relevant threats can be determined using a screening process based on historical data or SME opinion. Detailed reviews of incidents at UGS facilities, such as in Evans and West (21), or hydrocarbon wells, such as in Davies et al. (22), can assist in identifying threats that have caused previous failures. However, using historical data as the primary basis of threat identification could result in neglecting risk due to new or uncommon threats that have not yet produced observable failures. This is especially true for UGS facilities, where only a few significant incidents have been studied in detail.

The threats considered in the reviewed literature varied considerably depending on the subject and scope of the assessment. Wickenhauser et al. (20) consolidated threats to salt cavern gas storage into corrosion, equipment failure, erosion, operations, hydrate formation, mechanical damage and natural forces threats. DeWolf et al. (10) considered equipment component failures, external events involving human intervention (including both normal operations and unauthorized or accidental intrusions), and natural events in their study of UGS wells. In their qualitative assessment of salt cavern conversion for gas storage, Harrison and Ellis (9) identified 22 root causes that could lead to significant gas releases. The study performed in Patroni (8) identified five problems threatening the mechanical integrity of gas storage wells: internal corrosion, external corrosion, casing burst, casing collapse and threaded connection leaks.

3.1.2.4 Risk Estimation

3.1.2.4.1 Failure Modes and Pathways

Most papers analyzed the potential for a significant release of hydrocarbons from the wellbore or surface equipment to the atmosphere. A significant release or well blowout was considered as the sole failure mode in studies such as those by Worth et al. (13), Harrison and Ellis (9) and Abimbola et al. (23). Wickenhauser et al. (20) classified releases by small leaks, large leaks and ruptures, while Edmondson and Hide (15) distinguished between small and large hydrocarbon releases. The risk assessment of CCS facilities in Larkin (18) considered minor, major and catastrophic leakage as possible failure scenarios. For use in QRAs, models distinguishing between different failure modes are preferable as the consequences of failure can vary considerably depending on the type or mode of failure.

To identify potential failure modes, representative well schematics or well barrier diagrams are often produced to graphically delineate leak paths. An example well schematic with potential leak paths from DeWolf et al. (10) is provided in Figure 3.2. Durham and Paveley (12) and Dethlefs and Chastain (24) provide other examples of these schematics. The creation of the well schematics and identification of leak pathways often rely on SME opinion. Because the configuration varies between wells, the schematic used in the assessment is often illustrative of a typical configuration, and not reflective of any particular well.

Multiple structured expert elicitation methodologies were used to identify possible failure modes once the system was defined. DeWolf et al. (10), Molnes and Iverson (25) and DNV et al. (14) performed failure mode and effects analysis (FMEA) to identify system failure modes. This process involves a systematic review of sub-systems by industry experts who identify the causes and effects of individual component failures. Performing an FMEA allows for the identification of single points of failures and determination of the event chains, which involve multiple component failures, that will lead to an undesired system failure. An extension to this approach, the failure mode, effects, and criticality analysis (FMECA), was performed by Durham and Paveley (12) and IDM Engineering (26,27) to rank and screen multiple possible failure modes. An FMECA expands on FMEA by assigning criticality measures, often in the form of qualitative probability and consequence scores, to each component failure. This allows for a comparison between the criticality of each failure mode, enabling later risk assessments to focus on the critical failure modes. Patroni (8) used problem-associated failure mode (PAFM) couples to track failures that can arise from several causes. This process creates a new PAFM couple for each unique combination of a problem and associated failure. A comparison between the PAFM couples for multiple wells will therefore ensure that a well with multiple problems leading to the same failure is associated with higher risk.

In some cases, failure modes outside of the wellbore were considered. Wickenhauser et al. (20) considered leakage through the formation above gas storage caverns. Pawar et al. (17), Larkin (18) and Gerstenberger et al. (19) considered migration of gas from CCS facilities as additional failure modes.

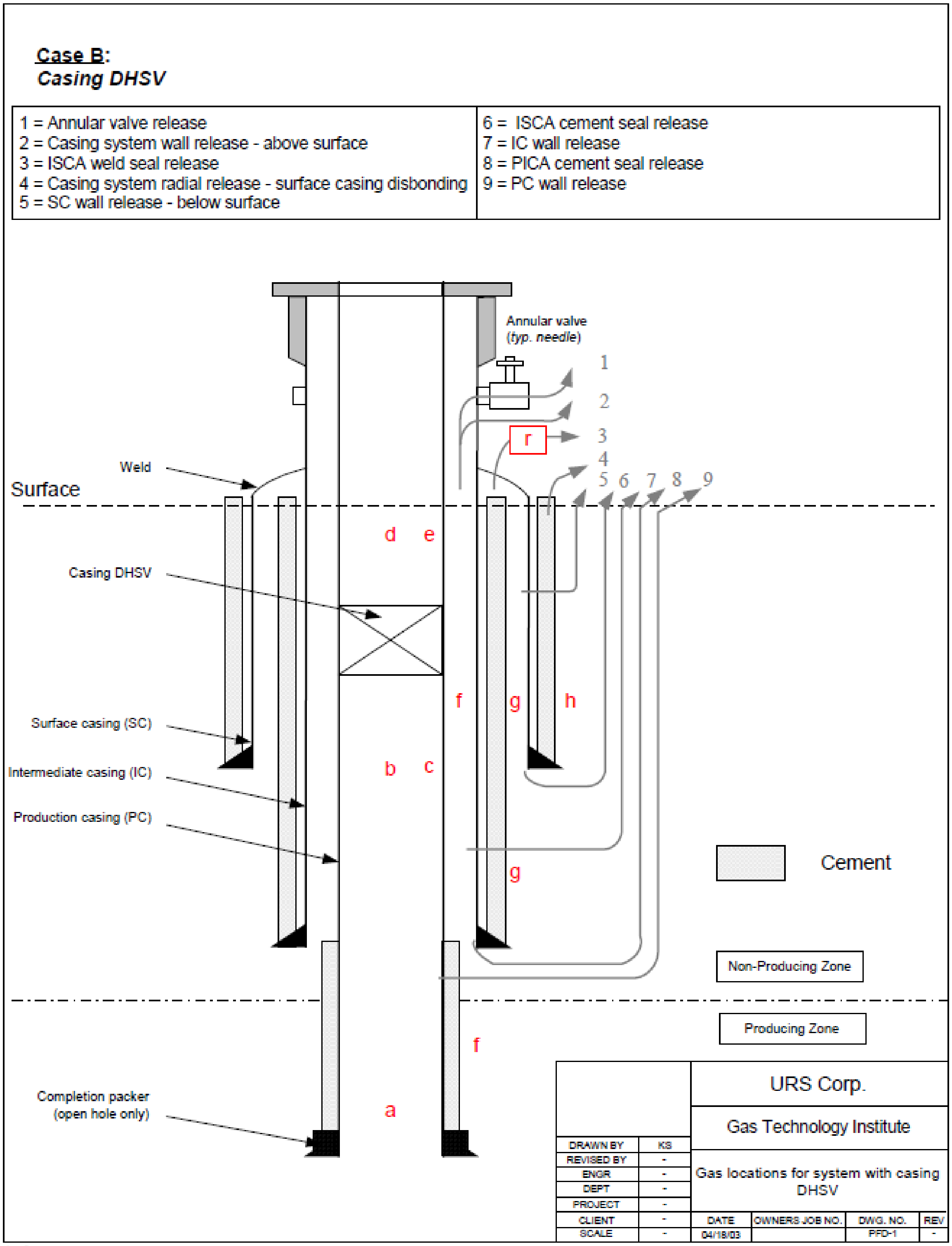


Figure 3.2 Well Configuration Schematic with Leak Paths from DeWolf et al. (10)

3.1.2.4.2 Risk Measures

Much of the reviewed literature focused on the reliability of wells or well components. Some studies evaluated the probability of failure over a fixed length of time or per single operation. Woodyard (11) and Gerstenberger et al. (19) evaluated the probability of a leak occurring over the lifetime of a well or CSS facility. Macary and el-Haddad (16) evaluated the probability of individual workover operation success, while Khakzad et al. (28) and Vandenbussche et al. (29) determined the probability of kicks and blowouts during a drilling operation. Instead of failure probabilities, failure rates were produced in da Fonseca et al. (30) and DeWolf et al. (10). Failure rates are a preferred measure as they provide consistent comparisons between assets and can allow for changes in risk over time.

Individual risk was the most commonly used measure of life safety risk. This measure is the probability that an individual working or living near a well is exposed to a fatal or injurious hazard level. Wickenhauser et al. (20), Edmondson and Hide (15), and Book and Bates (31) presented individual risk measures. Societal risk, which is a measure of the total expected number of fatalities or injuries due to proximity to a well, was less commonly evaluated. Wickenhauser et al. (20) and Edmondson and Hide (15) initially considered societal risk, but determined that there was no credible risk to the public. Worth et al. (13) evaluated the expected number of people effected by well incidents by considering the possibility of multiple workers present at the worksite.

Environmental risk was evaluated primarily for liquid producing or fracturing wells. King and King (32) used qualitative categorizations of environmental consequences, while Liu et al. (33), Worth et al. (13) and Durham and Paveley (12) quantified environmental consequence in terms of spill volumes or rates. The environmental consequences of a natural gas release were quantified using a global warming potential (GWP) measure in NGSS (34).

The costs associated with multiple risk measures were often combined to form a measure of economic risk in terms of dollars per year, operation or well. This approach was used in Wickenhauser et al. (20), Abimbola et al. (23), Worth et al. (13) and DNV et al. (14). Using a combined risk measure to express all consequences allows for consistent comparisons between assets and potential maintenance actions.

Qualitative risk measures were also commonly used in the reviewed literature, especially when comparing multiple facilities or screening for potential high-risk locations. Alvarenga (35) and Dethlefs and Chastain (24) presented separate frequency and consequence scores on a risk matrix. Qualitative probability and consequence measures were also used in Durham and Paveley (12) and IDM Engineering (27) as part of the FMECA process. An initial estimate of qualitative risk prioritizes potential failure modes and allows the subsequent quantitative assessments to focus on the threats and failure modes that are deemed most critical. Vandenbussche et al. (29) combined probability and consequence scores to produce an overall well risk rating.

To make comparisons between risk levels at a high level, qualitative risk measures can be created by placing bounds on quantitative risk measures. For example, the well risk screening tool developed in Powell and Scyoc (36) categorizes wells into one of three safety tiers based on a quantitative assessment of individual and environmental risk.

3.1.3 Failure Frequency Models

3.1.3.1 Introduction

Failure frequencies were estimated in the reviewed literature using one or more of the following approaches:

- SME opinion,
- Historical data, and
- Analytical models.

The following sections describe each of these approaches to frequency estimation.

3.1.3.2 Subject Matter Expert Opinion

All risk assessment methodologies reviewed employed input from experts at some point in the process. SME opinion was used as the primary source of frequency estimation in the reviewed literature presenting qualitative risk measures. For use in QRAs, SME opinion was employed to identify potential risks and address gaps in existing models through structured questionnaires. Using SME opinion is advantageous when assessing risk due to threats that are not well represented in historical data, or for processes that are not easily represented by analytical models.

SME opinion served the following purposes in the reviewed literature:

- Identifying relevant threats and possible failure modes. This information was often used to determine the structure of the fault trees or Bayesian networks employed in analytical frequency estimation (10,12,13,14,19,25,26,27,29).
- Directly assigning a probability index or score for assessment using a risk matrix (24). The probability, or likelihood, categories used in these assessments are often associated with a range of quantitative failure rates and a description of each category to assist SMEs with their selections.
- Determining uncertainties associated with CCS facility risk. Larkin (18) elicited SME opinion using three structured processes. The first, a pairwise comparison, provided qualitative rankings of risk factors by asking experts to compare such factors and determine which has

more risk. The second process then compared SME opinion to known variables to quantify the uncertainty associated with the opinion of each SME. Weightings from this process were applied to SME opinion during the third process, which evaluated the likelihood and severity of 29 hazards based on a 5-level scale. The rankings, uncertainties and risk scores were then converted to quantitative risk measures and associated uncertainties.

- By using a modified-Delphi method. Harrison and Ellis (9) ranked potential risks associated with converting salt caverns for use in compressed natural gas storage. This methodology involves multiple rounds of structured expert elicitation. After each round, the responses from the experts were summarized and anonymized, allowing the experts to revise their answers in the following round. This led the group towards a consensus-based ranking of potential risks.
- Estimating frequencies of individual component failures or basic events present in graphical models (e.g. fault trees), producing quantitative failure frequencies (10,11,13,15). These frequencies can be estimated directly through SME opinion, or can be created by ranking the likely frequencies and comparing them to an existing point of reference with a known frequency.

The utility of SME opinion is contingent on the availability of the appropriate expertise. Therefore, SME opinion is not suitable where new threats or new applications are being studied. Subjectivity inherit in SME opinion can also introduce bias into failure frequency estimation. Therefore, methods relying on SME opinion should only be used when it is not possible to apply more rigorous and objective methodologies.

3.1.3.3 Historical Data

Many methodologies used historical data as the basis of, or as a contributor to, frequency estimation. Historical-based frequency estimations are advantageous because:

- They use empirical evidence as a basis, therefore offering higher confidence in the estimated values than would be obtained based on SME opinion.
- Using historical data within a rational structured calculation process allows the assessment to be repeated between systems and updated when new data is available. A clear process also allows the approach to be more defendable when subject to review.
- Historical data can be used to quantitatively estimate generic well or facility failure frequencies, or it can produce well-specific failure rates when combined with appropriate adjustment factors.

The specific functions served by historical data in the reviewed literature are:

- To directly estimate the probability of failure based on failure frequencies of existing wells and facilities (22,31,37,38,39). Due to a limited number of failures, these estimates are often associated with broad groups of assets spanning multiple jurisdictions. Further granularity in frequency estimates increases the data requirements drastically.
- To directly determine the blowout frequency during workovers when assessing risk over the lifetime of steam-assisted gravity drainage (SAGD) wells (12,13).
- To estimate frequencies of individual component failures or events for use in graphical QRAs (10,11,12,13,15,30).

The disadvantages of basing frequency estimation on historical data are:

- Failure frequencies are often developed from databases encompassing a wide variety of well types, operational parameters and environmental conditions. This calls into question their applicability to any specific well or facility.
- Historical data reflects practices of the past and may not reflect conditions of newly constructed wells or UGS facilities, as discussed in Edmondson and Hide (15) and Keeley (39).
- The lack of sufficient failure incident data will prevent the use of a historical-based approach to frequency estimation for newly identified threats or applications.
- Accurate historical failure frequency estimates are contingent on consistent failure reporting practices and data collection over a time period sufficient to provide a meaningful incident count. The interpretation and appropriate use of historical incident data often requires significant engineering judgment, which contributes to the uncertainty associated with the resulting failure frequency estimates.

3.1.3.4 Analytical Models

Analytical models were used in the reviewed literature to perform detailed assessments of failure frequencies due to a specific threat, or to combine basic event failures into a comprehensive assessment of well or facility failure frequency. The advantages of analytical models over SME opinion or historical data are:

- The failure frequency estimates are specific to the well or facility.
- The influence of system modifications can be quantified. This allows for a comparison of mitigation options, facilitating decision making.
- There is an ability to provide a more detailed description of the failure modes, providing more information for consequence and risk analysis.

- Uncertainty associated with the model inputs can be quantified and incorporated into the expected risk measures.
- The development of analytical models identifies gaps in existing data, guiding future collection efforts.

Disadvantages associated with analytical frequency models include:

- There is a need for accurate deterministic models that define the various conditions under which component failure will occur and the need for detailed information describing the condition of the components.
- The complexity of some analytical models requires greater expertise to characterize the required inputs and understand the process.

The analytical models used in literature can be classified as either structural reliability models or graphical models, with the latter consisting primarily of fault trees and Bayesian networks.

Structural reliability models were used to directly estimate failure frequencies based on uncertainty in the properties and loading conditions of well components. Most of the structural reliability models reviewed analyzed one well component or threat in isolation, but the models could be incorporated into a larger risk assessment. Monte Carlo simulation was commonly used to determine failure frequencies by developing probabilistic descriptions of the parameters used by deterministic failure models. Models of this nature included:

- An analysis in Kinik (40), which evaluated the potential for hydrocarbon release from wells due to sustained casing pressure. The study developed mathematical models to describe the casing shoe strength. The input parameters were then described probabilistically, and Monte Carlo simulation was used to compare the distribution of casing shoe strength to the applied loads.
- A similar study by Liao et al. (41) used Monte Carlo simulation on models of casing collapse and pressure resistance to evaluate the probability of casing failure due to internal pressure and external loading.
- Wickenhauser et al. (20) assessed well failure rates due to corrosion by considering uncertainties in the accuracy and detection capabilities of the tools used to measure corrosion features in the well, as well as the uncertainties in the property of the well material.
- An economic analysis by Semeco et al. (42) probabilistically defined the flow characteristics of production wells over their expected lifetime. This assessment was used to determine the possible economic value of new wells.

Graphical models express the structure connecting basic random events that contribute to well failure. Often constructed based on well schematics or leak paths developed in FMEA or similar analyses, these models are typically formed as fault trees or Bayesian networks. Fault trees are the more common graphical model. The basic events in fault trees are connected with 'AND' and 'OR' gates, using basic probability theory to derive the probability of the top event, which is most often a leakage of hydrocarbons to the atmosphere (15,43). Models developed in Woodyard (11), DNV et al. (14) and Worth et al. (13) combined fault trees for production and workover operations to estimate total well leak or release probability. DeWolf et al. (10) and Wickenhauser et al. (20) developed fault trees for application to UGS facilities. Figure 3.3 shows the top level events of the fault tree developed in Wickenhauser et al. (20) for salt cavern storage. Basic event probabilities were derived from a combination of historical data and SME opinion. A significant challenge associated with the use of fault trees is the lack of applicable and accurate accepted basic event probabilities.

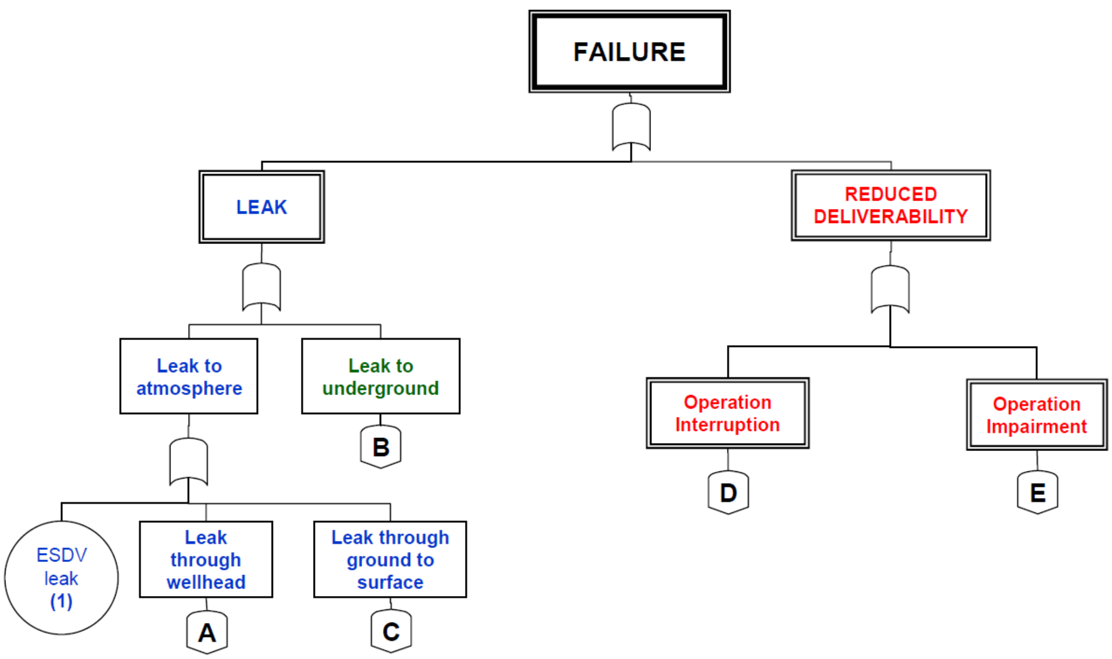


Figure 3.3 Top Level Events from Fault Tree in Wickenhauser et al. (20)

Bayesian network models express relationships between events as conditional probabilities, as opposed to gates. In some cases, fault tree models can be converted to Bayesian networks. Khakzad et al. (28) and Abimbola et al. (23) converted fault trees into Bayesian networks to determine the probability of a kick or blowout occurring during well drilling. Gerstenberger et al. (19) used SME elicitation to develop the structure of a Bayesian network evaluating risk associated with CCS facilities. Bayesian networks are advantageous because they are able to incorporate uncertainties in the relationships between basic events, as opposed to fault trees, which have a fixed relationship between events. Greater flexibility allows Bayesian networks to be updated with new data or improved expert knowledge. The disadvantage of a Bayesian network approach stems from the need to develop the required conditional probabilities tables, which often must be developed based on judgment because the required data does not exist.

3.1.4 Consequence Estimation Models

3.1.4.1 Introduction

As with frequency estimation, the consequences of failure can be predicted using SME opinion, historical data or analytical models. The advantages and disadvantages of using each source for consequence estimation are largely similar to those of frequency estimation. Amongst the QRAs reviewed, consequences were most commonly addressed with analytical models. The consequences of failure addressed in the reviewed literature can be categorized into three groups:

- Life safety,
- Environmental impact, and
- Financial impact.

Life safety consequences were most commonly addressed, followed by financial impacts. Environmental consequences were less frequently considered in the reviewed literature, especially in those assessing gas wells and facilities. Sections 3.1.4.3 to 3.1.4.5 address each category individually.

3.1.4.2 Hazard Scenarios

It is possible for multiple hazards to contribute to the consequences within each category. While Wickenhauser et al. (20) considered a jet fire as the primary hazard scenario for UGS facilities, Worth et al. (13) also included oil pool fires, hazardous gas plumes and steam jets in their life safety assessment of SAGD wells. Event trees are commonly used to identify the possible hazard scenarios and determine the relative probability of each. Event trees can be combined with a fault tree estimating failure frequency, creating a bow-tie analysis. Event trees and bow-ties were used in the reviewed literature as follows:

- Book and Bates (31) identified eight scenarios for blowouts during well drilling operations and expressed their relationship using an event tree. The dispersion of H_2S resulting from each event was used to quantify life safety consequences.
- Abimbola et al. (23) categorized offshore well blowout consequences using an event tree based on the presence of various safety barriers. The scenarios considered both gases and liquids escaping from the well, leading to either a vapor cloud and an oil spill, a vapor cloud

explosion and a pool fire, multiple explosions and fires, or a catastrophe involving continuous fires with multiple fatalities and significant damage to property and the environment. Each scenario was assigned a loss value to determine overall financial risk.

- Vandenbussche et al. (29) used an event tree analysis to evaluate the range of potential flow rates from a well during a blowout.

3.1.4.3 Life Safety Consequences

A variety of models were identified for quantifying the life safety consequences associated with gas releases and it was found that models developed specifically for hazard assessments of natural gas pipelines have been adapted for use on wells and UGS facilities. Most of these models focus on the impact of thermal radiation from a sustained jet fire and/or the toxicity implications of H_2S where sour gas is involved. It is noted that flash fires, which can pose a significant life safety threat in the event of heavier-than-air gas releases (e.g. propane or butane), are not a credible threat for natural gas due to the buoyant nature of natural gas.

Selected consequence models encountered in the review of literature on natural gas well life safety hazards include the following:

- Developed by Stephens (44), this simple model estimates the potential impact radius (PIR), which defines the distance from a natural gas pipeline rupture, within which the sustained radiant heat intensity from an ignited release is sufficient to present a significant potential for fatality and to cause significant damage to property. Wickenhauser et al. (20) used this model to predict whether a life safety risk existed for the public outside of cavern facilities. Worth et al. (13) borrowed key assumptions from the PIR model to determine consequences of well failure during operation and workovers. Oak Ridge National Laboratory (45) also developed a modified version of the PIR model intended for use on UGS wells.[2]

- Book and Bates (31) used a combination of Shell software packages to model the hazards associated with blowouts containing H_2S and to calculate contours of individual risk around the wellhead. The FRED dispersion modeling software was used to determine the plume size and shape. The SHEPHERD software was then used to integrate the plume concentrations into the risk calculations.

[2] It is noted that the Oak Ridge model, which is based on theoretical considerations and is calibrated to known accidents, is considered problematic, particularly with regard to some of the outflow modeling assumptions and the interpretation of hazard zone size information obtained from reported incidents.

3.1.4.4 Environmental Impact

Environmental consequences were typically quantified when performing risk assessments on liquid production or storage wells. Based on the failure mode and formation conditions, various release rate and dispersion models were used to calculate spill volume in Liu et al. (33), Worth et al. (13) and Durham and Paveley (12). As done in Worth et al. (13), environmental hazards can be monetized using the estimated cost to remediate the effects and pay any related penalties.

Although not modeled in the reviewed studies, the environmental risks of UGS facilities were acknowledged by Michanowicz et al. (37) and Evans and West (21). The gas storage risk assessment in Wickenhauser et al. (20) assumed negligible environmental consequences due to the dissipation of released gas into the atmosphere or non-potable water aquifers. However, historical incidents have indicated that failures of gas storage facilities can release large amounts of product into the atmosphere, adjacent formations or aquifers. Once released, gas presents environmental hazards as a contaminator to water sources and as a greenhouse gas contributing to climate change. The environmental impacts associated with the Aliso Canyon incident were studied extensively by NGSS (34). The greenhouse gas consequences in this study were quantified using a GWP measure.

3.1.4.5 Financial Consequences

The components of financial consequences varied significantly in the reviewed literature. Most of the components were associated with direct costs related to well failures, while some studies also converted life safety or environmental consequences into financial measures.

- The financial consequences of UGS failure in Wickenhauser et al. (20) were composed of costs associated with service interruption, repairs and lost product.
- Worth et al. (13) also considered environmental cleanup costs and costs associated with life safety in their financial risk assessment. The latter was calculated using the US Department of Transportation's recommendations for the equivalent cost benefit of averting a fatality.
- Abimbola et al. (23) assigned loss values to each branch of their event tree and calculated the financial risk as a function of time during drilling operations.
- DNV et al. (14) estimated financial risk using detailed modeling of lost production and repair costs on offshore wells.
- Financial impacts were the primary factor considered in the qualitative model presented by Dethlefs and Chastain (24). Bounds on each of environmental remediation costs, asset damage costs and business interruption costs provided guidance to select a consequence severity category.

3.1.5 Summary and Conclusions

This literature review evaluated risk assessment methodologies available for wells and UGS facilities. The risk assessments produced both qualitative and quantitative measures of risk. Qualitative methodologies, producing risk indexes or scores, were often proposed for use as a screening tool or to rank multiple facilities based on risk. Detailed risk assessments used in decision-making processes more commonly relied on risk quantification. Measures used in these studies included failure rates for reliability studies, individual risk for life safety risk assessments and release volume for environmental impact assessments. These measures can be monetized and combined with direct failure costs to produce quantitative combined risk measures.

Most methodologies assessed the risk of a significant hydrocarbon release from the wellbore or related equipment. The focus of these assessments was on failure of well equipment. Risk assessments of UGS and CCS facilities also considered geological integrity and the risk of leakage to adjacent formations and aquifers. While most studies considered wells during normal operation, a few considered the risk associated with workover activities and their impact on overall well risk. Once the system and relevant threats were identified, possible failure modes were identified by evaluating system diagrams created with input from SMEs.

For reviewed risk assessments that produced quantitative risk measures, overall well failure frequencies were most commonly estimated using fault trees. The structures of the fault trees were created using SME opinion based on the scope of the risk assessment and failure modes of concern. Where available, historical data was used for basic event probabilities within the fault tree. The basic events were combined to derive the rate for the top event, usually a significant hydrocarbon release. Some studies used multiple fault trees to assess different phases of well operation. Instead of fault trees, a few studies proposed Bayesian networks to capture the uncertainty in the frequency estimation inputs and structure. Instead of graphical models, a limited number of studies developed structural reliability models to predict failures due to an individual threat.

Quantitative consequence estimation typically considered life safety hazards. Where multiple hazard scenarios existed, event trees were used to determine the relative probability of each scenario. The primary contributor to life safety risk was found to be thermal radiation resulting from ignition of uncontrolled gas releases from wellheads, especially during workover activities when many people are near the well. Existing analytical models and software packages intended for use on natural gas pipelines were commonly adapted for use on well releases. The consequence models can be combined with frequency estimates to produce measures of individual and societal life safety risk.

Reservoir and dispersion modeling were used by a few studies to assess the environmental risk of well failure. While more commonly assessed for liquid producing wells, the environmental risks from UGS wells and facilities have been highlighted by recent failures. Beyond the potential contamination to nearby aquifers and ecosystems, natural gas escaping from storage facilities can reach the atmosphere, where its behavior as a greenhouse gas can have adverse long-term consequences.

Financial consequences, expressed as annual expected costs, consisted of multiple components, including lost product, repair and interruption costs. The models used to predict these costs varied significantly depending on the context and purpose of the risk assessments. Life safety and environmental consequences were also expressed as financial equivalents to present a total risk measure. While none of the studies reviewed attempted to monetize the long-term economic cost of greenhouse gas emissions, it is noted that all proposed US regulatory measures affecting the oil and gas industry are currently subject to a form of cost-benefit analysis wherein the social cost of carbon emissions is explicitly considered.

3.2 Other Industries

Risk assessment methodologies currently in use in other industries were surveyed to complement the information gained from a similar review of methods and models currently employed for wells and associated with UGS facilities (summarized in Section 3.1). The other industries considered include:

- Pipeline,
- Nuclear,
- Offshore oil and gas,
- Aviation, and
- Power transmission.

Much of the information in this review of risk methods and models used in other industries was adapted from a review carried out as part of a previous project for PHMSA by C-FER that produced guidelines for the development and application of risk assessment models for pipelines (46). In addition, C-FER's background expertise in performing quantitative pipeline risk assessments was used to augment the information in the reviewed literature.

Given that well entry risk is the focus of the current project and that risks due to well entry are potentially highly influenced by human factors, extra attention was paid to the human factor component of risk assessments as developed and applied in other industries.

A detailed breakdown of the review findings is provided in Appendix B. A summary of those findings is provided below.

- **Pipeline industry:**
  - The published literature pertaining to the pipeline industry indicates that QRA methods are used extensively for risk screening and ranking, for location-specific risk analysis and assessment, and as a basis for decision making as it pertains to integrity maintenance planning and execution. Failure frequency estimation is most commonly performed on a threat-by-threat basis using historical data or historical data with adjustment factors to account for the effects of key line-specific parameters that influence the threat-specific failure frequencies. Probabilistic models are also well established for select integrity threats, including corrosion and mechanical damage. Consequence estimation models address safety, environmental impact (for hydrocarbon liquid spills) and financial losses. Analytical models are commonly used for safety consequence estimation, but the lack of consensus on how environmental impact should be measured has led to a range of analysis approaches based on methods that involve SME opinion together with analytical models for select parameters, such as spill volume.
  - Human factors are largely addressed indirectly in pipeline risk assessments. Incorrect operation and maintenance is a recognized integrity threat; however, it is typically addressed in frequency estimation using historical data, meaning that it does not reflect line-specific factors. It is also reflected indirectly in the probabilistic modeling approaches used for estimating the frequency of failure due to mechanical damage.
- **Nuclear industry:**
  - The nuclear industry has long used probabilistic risk assessment (PRA) as part of a program to ensure the safe operation of nuclear power plants (NPPs). PRAs are defined at three different levels that address different domains: the NPP reactor core, the NPP containment system, and the public and surrounding environment. The uncertainties involved in each PRA level heavily influence acceptance criteria. Modern PRAs draw from a wide range of quantitative analysis techniques, including event trees, fault trees, and Monte Carlo methods, to quantify failure frequency and risk.
  - The use of human reliability analysis (HRA) in the nuclear industry has a long and well-established history. Models such as THERP, SPAR-H, and ATHEANA describe systematic methods for identifying activities that are vulnerable to human error during NPP operation, as well as for quantifying the specific effects of human cognition and working conditions on the frequencies of those errors.
  - Many of the original HRA models developed for use in the nuclear industry have been successfully adapted to other industries. One likely barrier to the application of HRA models to UGS wells is the highly controlled and procedural nature of work in an NPP control room versus on-site at a UGS well. Recent development of HRA models for use in maintenance operations at NPPs may be more relevant to UGS well entry.

- **Offshore oil and gas industry:**
  - Hazard identification plays a key role in the risk assessment process in the offshore industry, and several formalized methods of hazard identification are used in the development and application of qualitative and quantitative risk assessments.
  - Several common and effective modeling techniques are used to quantify failure frequency and risk, including event trees, fault trees and bow-tie analyses.
  - The literature reviewed identifies HRA as a key component to a comprehensive risk assessment, though guidelines emphasize key components of HRA as opposed to specific methods and models for accounting for human error in the risk assessment process. The Human Factors summit report published by SPE (47) identified several human factors associated with process safety, along with guidelines on how to move the industry forward in these areas.
- **Aviation industry:**
  - The aviation industry relies extensively on incident data to inform the risk assessment process. As demonstrated in the aviation industry's FAA and EASA guidelines, the aggregation of industry-wide data using well-defined formats facilitates data sharing and improves the process of hazard identification. Data collection in the aviation industry is further facilitated by incorporating it into operational processes.
  - The aviation industry has many well-established tools for the documentation and analysis of incidents involving human error. These tools allow operators and risk analysts key insights into the role of cognitive and environmental factors, leading to operational incidents.
- **Power transmission industry:**
  - The literature from the power industry describes various structured approaches to carrying out generic risk assessments. For example, the North American Electric Reliability Corporation (48) recommends different risk assessment models based on the severity of the event involved. A full QRA is recommended for high frequency and low consequence events to facilitate cost-benefit analysis of different risk management strategies. Scenario-specific analyses and extreme value theory models are recommended for low frequency, high consequence events.
  - The sources reviewed mention HRA as one possible component of an overall risk assessment, but there is little elaboration on HRA methods or models.

4. GUIDELINES FOR QUANTITATIVE RISK ASSESSMENT

4.1 General

The guidelines provided in this section describe a framework for conducting QRAs on UGS wells subject to well entry. The development of these guidelines was informed by the information obtained from the UGS industry survey described in Section 2 and the findings from the literature survey as summarized in Section 3 and Appendix B.

The purpose of the guidelines is to assist operators in developing, selecting and applying QRA methods and models for use in decision making as it pertains to well entry activities. The guidelines are also intended to help regulators evaluate the suitability of the QRA models developed and used by storage well operators. The intended audience is assumed to be familiar with the concepts implicit in the QRA process and its general application within the industry.

4.2 Scope of the Guidelines

These guidelines address the estimation and evaluation of the risks associated with ongoing well operation and periodic well entry. The risk estimation process involves determination of both the frequency and consequences of well failure, and the integration of those quantities into meaningful measures of well risk. The risk evaluation process, for the purpose of decision making, involves comparing the risk estimates developed for well operating and entry scenarios to risk acceptance criteria, where available and applicable, and/or to the risk levels associated with other well operating and entry scenarios. The focus of the guidelines is on quantitative risk analysis and assessment methods; however, both the framework and the general underlying concepts are also applicable to qualitative analyses and assessments. The quantitative methods discussed define failure likelihoods in terms of the frequency of failure *per well-year* for ongoing well operation and as the frequency of failure *per well entry* for periodic entry events. These methods define failure consequences in terms of quantifiable physical parameters, such as the chance of fatality or number of fatalities for public safety, or in terms of the total quantity of gas released for environmental impact. The guidelines acknowledge and address the fact that operational well risk can be favorably impacted by periodic well entry, and that the act of well entry is a potential cause of well failure in and of itself.

The guidelines are intended to provide a general framework and guidance for building, applying and evaluating operator-specific QRA models, and not to recommend or endorse any particular methods or models for estimating failure frequencies or consequences.

4.3 Framework

Figure 4.1 illustrates the steps involved in conducting a QRA and indicates how these steps relate to and incorporate standard risk assessment process elements. The high-level QRA process diagram on the left-side of Figure 4.1 identifies the steps involved in defining the purpose of the assessment, selecting appropriate models, collecting the required information, performing the risk assessment and documenting the findings. The risk assessment sub-process diagram on the right-side of Figure 4.1 focuses on the specific steps involved in the computation of risk (i.e. risk estimation) and the follow-on risk evaluation step that will inform decision making.

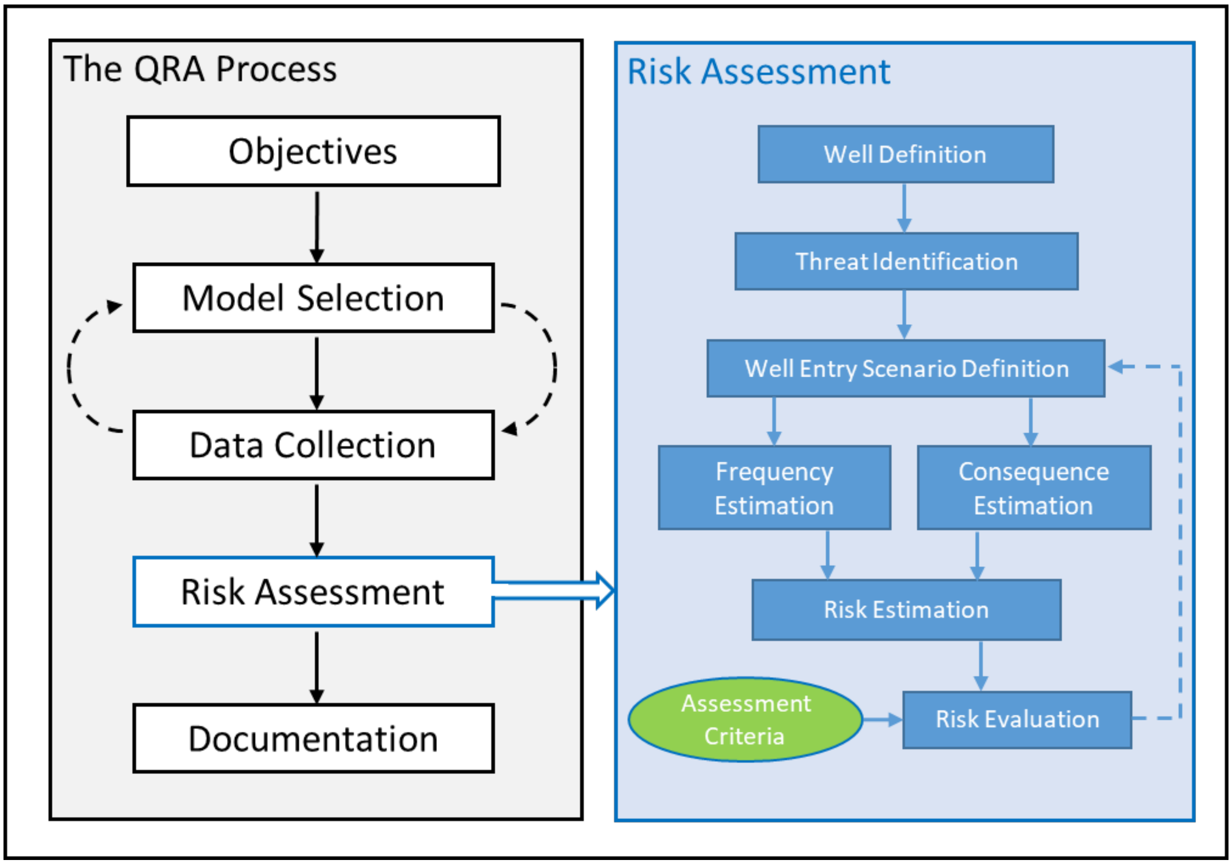


Figure 4.1 Framework for the QRA Process

The high-level steps involved in carrying out a QRA are:

1. Identify the assessment objectives.
2. Select appropriate models for failure frequency and failure consequence estimation.
3. Collect the relevant data related to the well configuration, well components and operating parameters, and to the candidate well entry activities.

4. Assess well risk in response to periodic well entry activities.

5. Document the process covering the data used, the details of the methods and models used for the estimation of failure frequencies and consequences, the selection of risk measures, and the results of the risk assessment.

The risk assessment sub-process (item 4 above) involves the following steps:

1. **Well definition:** Define the well configuration, including the individual components that constitute barriers to gas releases for all credible gas release pathways.

2. **Threat identification:** Identify all applicable and knowable threats to well barrier component integrity during normal well operation.

3. **Well entry scenario definition:** Define the well entry activities to be evaluated and their intended impact on the operational integrity of well components.

4. **Frequency and consequence estimation:** Estimate the failure frequencies and failure consequences during normal well operation, both before and after well entry, and during well entry.

5. **Risk estimation:** Estimate the required risk measures using the calculated failure frequencies and failure consequences.

6. **Risk evaluation:** Compare the results obtained from risk estimation to appropriate acceptance criteria, where available, and/or to the results obtained from alternative well entry scenarios that may differ in terms of the type or frequency of well entry, or the anticipated impact on the well operating risk following well entry (see dashed line in Figure 4.1).

Conducting a QRA can be an iterative process due to the interdependencies between the steps involved. For example, at the model selection stage, the type of data and the specific parameters required are driven by the chosen modeling approach, while model selection may be dependent on the available data. At the risk assessment stage, since the risk evaluation step can involve comparing risk estimates obtained from various well entry activities with different well entry frequencies, the assessment process can be iterative due to the different well entry scenarios that may have to be considered to determine the preferred course of action.

The individual steps in the QRA process, as outlined above, are described in detail in Section 4.4.

4.4 The QRA Process

4.4.1 Objectives

The purpose of a QRA may include one or more of the following:

- Identify high-risk wells, well configurations or well entry methods;
- Evaluate the changes in risk over time, including the impact of periodic well entry;
- Guide integrity management decisions, including those involving well entry;
- Evaluate well risk against prescribed acceptance criteria; and
- Demonstrate regulatory compliance.

The objectives define the scope and critical aspects of the QRA process, including the:

- Physical assets to be included and the boundaries of the system to be evaluated;
- Operational conditions to be considered;
- Level of detail required in the risk estimation and the resources needed to complete the analysis;
- Threat categories to consider and the failure frequency estimation models required;
- Risk measures to be quantified, which will drive the selection of consequence estimation models; and
- Duration of the assessment period to account for time-dependent effects and/or periodic events, such as well entry.

4.4.2 Model Selection

4.4.2.1 Failure Frequency Estimation

4.4.2.1.1 Introduction

Failure frequency models can be categorized into one of three analysis levels, depending on the degree to which they make use of objective data and engineering models. The levels of analysis, in order of increasing objectivity, are:

- Level 1: SME Opinion
- Level 2: Historical Data
- Level 3: Probabilistic Models

In carrying out a QRA, different levels of analysis may be employed to address different threat categories or different aspects of the model being used to evaluate an individual threat (e.g. defining the distributions of the random inputs to a probabilistic model). The following sections describe different frequency estimation approaches and strategies to increase confidence in the results obtained from each level of analysis, and to ensure that comparing or combining the results leads to reasonable conclusions.

4.4.2.1.2 Level 1 – SME Opinion

Failure frequencies can be estimated by polling SMEs, where the estimates provided are effectively judgment calls based on the SME's knowledge and experience. Failure frequency estimation through the elicitation of SME opinion is perceived to be easier than other methods and is often employed for risk ranking and screening.

The benefits of an approach based on SME opinion are:

- It requires limited resources and is simple to implement.
- It provides failure frequency estimates in the absence of relevant historical data or recognized engineering models.
- It compensates for data gaps by leveraging well-specific information through the experience of the SMEs.

Since the approach depends heavily on the judgment of the SMEs involved, the degree of subjectivity reflected in the assessment results is higher than that associated with other levels of analysis. The limitations of this approach are:

- Verification and validation of results is difficult without the results of other levels of analysis.
- Uncertainty is high since the model components are defined subjectively, including:
  - The parameters considered to be influential in determining the results;
  - The relationships between these parameters and the risk estimates; and
  - The estimated value of each parameter.
- The influence of different sources of uncertainty cannot be quantified.
- The influence of different mitigation measures is difficult to estimate.
- It does not provide guidance on the collection of new data to improve the model and reduce the associated uncertainty.

Quantifying failure frequencies based on SME opinion is appropriate when the available data and models do not support the use of other levels of analysis. When SME opinion is employed, the following guidelines can be followed to improve the failure frequency estimates:

- Separate failure frequency estimates by threat category and well component to make the situations for which SME judgment is required as specific as possible.
- Express failure frequencies as a function of three elements representing exposure, mitigation, and resistance (49) to ensure consideration of all relevant issues and recognize the influence of mitigation.
- Use structured approaches to elicit SME opinion on failure rates. Examples of structured approaches are:
    - The Delphi method, as detailed by Ayyub (50), which is an iterative process used to reach a consensus amongst a panel of experts, resulting in a reduction of bias in the opinion of any single expert opinion; and
    - The guidelines for SME elicitation used by the US Nuclear Regulatory Commission (51), which are a simplified version of the Delphi method and other standardized expert elicitation techniques with guidance on developing customized questionnaires.

The above approaches are intended to ensure that the risk estimates obtained are consistent with the knowledge and opinions of the SMEs, but their use does not change the subjective nature of the results. Therefore, this option should only be employed when the application of other approaches is deemed impractical.

4.4.2.1.3 Level 2 – Historical Data

Historical data is used to estimate generic failure frequencies based on industry-wide data. These generic failure frequencies can be made more well-specific by applying modification factors to the generic frequencies that reflect the impact of key well attributes on failure likelihood.

<u>Generic Failure Frequencies</u>

Historical data from industry-wide failure databases can be used to either 1) estimate the generic failure frequency of individual wells or well entry activities, or 2) estimate the generic failure frequencies for individual well components. The former well- or entry-specific approach is typically used for high-level well risk screening or risk ranking activities as a means to benchmark the results of more component-specific well failure frequency estimates, or where well component failure frequency data is not available. The latter well component or well entry component approach is preferred when a more detailed well-configuration-specific QRA is to be performed.

The primary benefits of the historical data approach to frequency estimation are:

- It allows for rapid QRA while reducing subjectivity through the use of recorded incident data.
- It uses industry-wide data, which reduces the need for the well-specific data collection that would be required for the application of more detailed models.
- It allows for repeatability of the analysis based on appropriate documentation of the data used.

The main limitations of this approach are:

- It does not reflect well-specific parameters (e.g. well operating pressure or component condition).
- It does not necessarily identify or quantify the contribution from specific integrity threats to the overall well or well component failure frequency.
- It cannot be used to estimate failure frequencies for rare and newly identified threats.
- It does not provide a basis for characterizing the effect of risk mitigation actions.
- It makes it difficult to identify important parameters influencing the failure frequencies as historical records do not typically include all of the relevant parameters for the wells or components that failed.
- It does not provide guidance for the collection of new types of data.
- It reflects past well characteristics and operational factors, which may not be representative of the future condition of aging wells and changing operational factors.

With this approach, an estimate of failure frequency would ideally be obtained by selecting historical data from well configurations and/or well entry procedures that are similar to those of the well or entry procedure being analyzed. This, however, is generally not possible since much of the available incident data does not include the required information on the specific attributes of the wells that failed. While efforts have been made in recent years to include more detailed well information in failure incident databases, the large number of parameters that influence failure frequency generally make data subsets that match any given well configuration too small to provide reliable failure frequency estimates.

Failure Frequencies with Modification Factors

To overcome some of the limitations inherent in generic failure frequency estimates, modification factors can be developed and applied to the historical-based frequency estimates to obtain more well-specific and component-specific failure frequencies (29,52). Modification factors can be developed using engineering models, statistical analysis or SME opinion. The benefits of this refinement are:

- It improves the applicability and accuracy of the frequency estimation process, while being easier to implement than a full probabilistic approach.
- It allows for consideration of well-specific factors.

As the basis for the development of modification factors is not standardized, the definition of these factors will typically include significant subjective input. The disadvantages of this approach are:

- It involves greater subjectivity compared to an approach based on probabilistic models.
- Significant effort is required to develop defensible modification factors.

When this approach is used, the accuracy of failure frequency estimates can be enhanced in the following ways:

- By developing modification factors based on engineering models and probabilistic methods, where possible;
- By considering the guidelines set out in Section 4.4.2.1.2 for the elicitation of SME opinion, if expert opinion is used in the development of modification factors; and
- By considering other levels of analysis for rarely occurring threats as the use of small sample sizes from recorded incident data can underestimate the true likelihood of such failures.

4.4.2.1.4 Level 3 – Probabilistic Models

Probabilistic models include models that employ structural reliability methods or graphical logic models, such as fault trees, directed acyclic graphs and Bayesian networks. With the probabilistic approach, engineering principles, established analytical methods and formal probability logic are used to evaluate well-specific failure frequencies.

The use of logic models is generally a necessary step if the overall well or well entry failure frequency is to be estimated from the failure frequencies for individual well components (see Section 4.4.4.5.3). In this regard, it is noted that the individual well component failure frequencies required to implement the logic models can be obtained from SME opinion, historical data, well-component-specific probabilistic models or a combination of the three methods. The use of probabilistic models for well component failure frequency estimation generally involves the use of structural reliability methods; however, Bayesian networks can also be employed.

The benefits of a probabilistic modeling approach are:

- It can reflect relevant well-specific factors through consideration of the relevant input parameters.
- It has the potential to provide the most objective estimates of failure frequencies compared with other levels of analysis.
- It can be based on recognized and validated engineering models.
- It facilitates consideration of rare and newly identified threats based on fundamental engineering and probabilistic principles.
- It can account for specific integrity maintenance actions and mitigation measures by considering changes to the model input parameters (e.g. update the production casing failure frequency estimate based on high-resolution casing log data or reflect the impact on casing failure frequency resulting from the repair of selected corrosion features).
- It identifies the most influential parameters affecting the failure frequency.
- It identifies data gaps, which helps in prioritizing future data collection efforts.
- It allows for analysis upgrades to include state-of-the-art engineering models as they become available.
- It provides direction for reducing the overall analysis uncertainty, either through data collection or engineering model improvements.

As is the case with all engineering models, the results obtained from probabilistic models must be evaluated in the context of the approximations made in defining the inputs, the mathematical relationships used to model failures, and the numerical methods used to estimate the failure frequencies.

The limitations of this approach are:

- Substantial effort may be required to characterize the required model inputs.
- Considerable computational effort may be required, depending on the model implementation.
- The complexity of the models result in them being perceived as a ‘black box’ by unfamiliar users, leading to skepticism regarding the results.

The results obtained from probabilistic models, particularly those employing structural reliability methods to evaluate individual well components, can be improved by considering the following actions:

- Including and accounting for all possible sources of uncertainty, including model errors and measurement errors;
- Ensuring the goodness-of-fit in the probability distributions used to represent random or uncertain input parameters, particularly the fit in the distribution tail region since the distribution tails have a significant influence on estimates of low failure frequencies;
- Considering the guidelines set out for the elicitation of SME opinion in Section 4.4.2.1.2, if judgment is used to characterize required model inputs; and
- Applying appropriate techniques in the implementation of probabilistic calculations (e.g. use an appropriate sample size in Monte Carlo simulations to obtain accurate failure probabilities and ensure that first- and second-order reliability methods (FORM/SORM) converge to the correct solutions).

As noted above, probabilistic models may require the use of judgment in characterizing some inputs and in selecting appropriate engineering models and reliability methods. However, the degree of subjectivity inherent in using these models, in combination with subjectively defined inputs, is limited in comparison to that associated with the use of other methods. In addition, the subjectivity inherent in this approach can be progressively reduced through additional data collection, improved engineering models and standardized probabilistic calculation methods.

4.4.2.2 Failure Consequence Estimation

4.4.2.2.1 Overview

The consequences resulting from the uncontrolled release of natural gas from an underground storage well can be categorized as health- and safety-related, environmental and financial. The primary safety-related consequences of gas release are injuries or fatalities as a result of exposure to thermal radiation from sustained jet fires that result in the event of gas ignition. The health concern is the impact on quality of life from long-term exposure to low concentrations of various compounds that make-up the natural gas mixture released. The primary environmental concern is the long-term impact of methane released into the atmosphere. Methane, the principal component of natural gas, is a heat-trapping greenhouse gas, which contributes to global warming and, thereby, climate change. Well failure can also result in substantial financial losses, most of which are borne directly by the well operator.

Financial losses, though potentially significant, are less of a concern to the public. Chronic health issues stemming from gas storage well failure require very long duration release events (which are extremely rare) to produce adverse health impacts, and the health impacts have yet to be studied to the point where they can be assessed reliably. On that basis, the focus in these guidelines is on the near-term public safety-related consequences and the longer-term environmental consequences of storage gas releases.

4.4.2.2.2 Safety Consequences

The most meaningful measures of the public safety impact resulting from a gas release are, from the perspective of an individual, the chance of a serious injury or fatality and, from the broader perspective of society as a whole, the expected number of injuries or fatalities. These outcomes will depend on the likelihood of gas ignition given a release and the size of the thermal radiation hazard zone that develops in the event of gas ignition. It can be shown that the hazard zone size is primarily dependent on the rate of a gas release (53). Given a natural gas release rate, analytical models exist to estimate the thermal radiation intensity as a function of distance from the point of release and other models exist that relate the heat intensity (and assumptions regarding exposure time) to the chance of injury or fatality.

The likelihood of gas ignition, during normal well operation and well entry, is best estimated using historical data (e.g. from the Energy Institute (54)). However, judgment is generally required in interpreting the available incident data since much of it pertains to offshore and/or onshore wells used for purposes other than UGS.

The gas release rate will depend on the well configuration (including, but not limited to, the well size and depth), the well operating parameters at the time of failure (e.g. gas storage pressure and temperature) and the particular flow pathway that is established (by barrier failure) from the gas storage location through to the atmosphere. The release rate for each credible pathway and barrier failure mode combination is best estimated using a model-based approach. The modeling can range from simplified approximate analytical models that focus on the flow rate through the most restrictive element of the pathway to more complex numerical models that explicitly account for the various flow regimes that develop along the length of the release pathway (which effectively behaves as a series of ducts and orifices). Numerical modeling could include the case-specific development and application of computational fluid dynamic (CFD) models or the use of proprietary ‘nodal analysis’ software (e.g. see Brown and Lea (55) and Petroleum Experts (56)).

It is noted that, for reservoir wells that are distinct from cavern wells, reservoir delivery limitations may throttle the gas release rates to some extent, particularly for high-release rate failure pathways. It is noted further that this throttling effect may not be a significant factor in estimating the safety consequences of near-immediate gas ignition, before reservoir throttling takes effect, but it will be a consequence mitigating factor in the longer-term, making it more of a consideration when estimating the safety consequences in the event of significantly delayed ignition or in assessing the total amount of gas released, which is more relevant for environmental consequence estimation.

A range of models for estimating thermal radiation as a function of distance from the release point, and the likelihood of injury or fatality given a heat intensity and an exposure time, are available employing varying levels of refinement.

A relatively simple model that is well suited to such an analysis would be a variation on the gas jet fire model developed by Stephens et al. (44) for the determination of the PIR for natural gas pipeline ruptures. The key modification required to apply this model to gas storage wells would be the replacement of the release rate component with a release rate determined using a more applicable model, as described above.

More detailed fire hazard models, which consider additional factors such as meteorological conditions, transient effects and location specific consideration of sheltering times, are available as proprietary software packages, e.g. DNV PHAST (57).

4.4.2.2.3 Environmental Consequences

The most basic measure of the potential long-term environmental impact is the total quantity of gas released, which requires estimation of the effective sustained release rate and the release duration. The approach to release rate estimation is described in Section 4.4.2.2.2. The release duration will depend on the cause of failure (i.e. well operation versus well entry, as it affects the time required to detect a release and the nature of the equipment on-hand to stop the release), the mode of failure (e.g. release through small versus large openings) and the failure location (as it affects the time required for detection and remediation).

The release duration required for environmental impact assessment is best estimated based on historical data (e.g. see Molnes and Sundet (58)). However, SME opinion and or engineering judgment is generally required when interpreting the available incident data, since the data is limited and much of it pertains to offshore wells.

4.4.2.2.4 Monetizing Safety and Environmental Consequences

The safety impact of injuries or fatalities can be monetized using methods that have been developed to establish the value of a statistical life saved or the value of a prescribed level of injury averted (e.g. see HSE (59) and Moran and Monje (60)) and, in this format, it facilitates assessing safety risk through cost-benefit analysis (see Section 4.4.4.6).

Similarly, there may be a desire to express the long-term environmental impact in monetary terms. In this regard, the most common monetization approach involves multiplying the total quantity of gas released by social cost of carbon (SCC), which is the marginal cost of the future impact caused by the release of an additional tonne of greenhouse gas, expressed as a carbon dioxide equivalent. The calculation of the SCC involves estimating the residence time of equivalent carbon dioxide in the atmosphere and then estimating the associated impact on climate and human health, as measured by the amount of damage done and the cost required to compensate for the damage. There are well-established methods and models available for the determination of the SCC (e.g. see Nordhaus (61)). As is the case for safety, expressing the environmental impact in financial terms facilitates environmental risk assessment through cost-benefit analyses (see Section 4.4.4.6).

4.4.3 Data Collection

4.4.3.1 Data Requirements

The parameters required for QRA will depend on the models used to assess the failure frequencies and failure consequences. In general terms, information will be required that defines the configuration of the well and associated components, the well operating parameters, any relevant well component condition data obtained through previous monitoring or inspection, anticipated well entry activities, and information on the surrounding land use. This information will typically include, but not be limited to, the following (as adapted from the California Code of Regulations (62)):

- Hole diameter and depth of drilled hole;
- Sizes, weights, grades and connection types for casing and tubing;
- Type and location of other downhole components, including DHSVs, packers, sliding sleeves and other components that form part of primary, secondary or tertiary barriers to gas releases;
- Depths of casing shoes, stubs and liner tops;
- Extent of cement fill behind or between casing, including top and bottom of cemented intervals;
- Identification and configuration of wellhead components and wellhead valve assemblies, including pressure ratings;
- Age and condition of well components, including information obtained from visual inspections, pressure tests and downhole inspections (e.g. cement bond logs and casing metal loss inspection logs);
- Well component malfunction or failure history;
- Gas storage pressure and temperature ranges and total gas inventory;

- Land use in the immediate vicinity of the wellhead, including proximity to roadways and permanently or periodically occupied areas, and the effective traffic or population densities associated with these areas;
- Protective barriers or other measures in place to prevent accidental interference with above-ground well components; and
- Anticipated future well type activity, including types of entry (e.g. wireline, coiled tubing, snubbing or workover), associated well entry plans and intended outcomes.

4.4.3.2 Data Gaps

Historical data gaps are largely associated with the fact that much of the high-quality failure frequency data pertains to offshore wells. Until such time as onshore operating well incident data and, in particular, UGS well incident data becomes more broadly available, reliance on data from other well types will be required. To address some of the issues associated with using the data currently available, the following options can be considered:

- Elicit SME opinion to adjust for perceived differences in well-, well-component- or well-entry-type failure frequencies between UGS wells and the well types reflected in the available data. A similar exercise may be warranted to either estimate or adjust the proportion of well or well component failures that are likely to be associated with different failure modes (i.e. small versus large effective opening sizes) that will impact gas release rates (i.e. relevant for consequence estimation).
- Perform sensitivity analyses by varying the failure frequencies for key components over a range of values. The range of values should represent optimistic, pessimistic and best estimates. Based on the sensitivity of the risk measure to different assumptions, a cautious best estimate can then be determined for the final risk measure.

Probabilistic model gaps will most likely be associated with the use of structural reliability models for well component failure frequency estimation. In this regard, the missing data may pertain to the specific loads or pressures that the component is required to sustain, material properties of the component, the characteristics of the damage (e.g. metal loss feature size and depth) that contributes to the potential for component failure, or the uncertainty inherent in the model that is being used to define the combination of parameters that could result in failure (i.e. model error). These data gaps can be addressed to some extent by:

- Using input data from similar wells or leveraging data from other industries (e.g. the pipeline industry) where reliability-based models are more commonly used (20,41); and
- Performing sensitivity analyses by varying the unknown QRA inputs over a range of values. The range of values should represent optimistic, pessimistic and best estimates. Based on the

sensitivity of the risk measure to different assumptions, a cautious best estimate can then be determined for the final risk measure.

An alternative approach to address data gaps would involve revisiting the model selection process and choosing a different frequency estimation method that does not require the missing data.

4.4.4 Risk Assessment

4.4.4.1 Overview

The risk assessment process elements are shown on the right-side of Figure 4.1. The figure identifies the specific steps required for quantitative risk analysis, which ends with risk estimation, and the additional step of risk evaluation. The individual elements that make up the risk assessment process are addressed in the following sections.

4.4.4.2 System Definition

This step involves defining the physical boundaries of the system to be evaluated and the time period over which it is to be evaluated. Since well entry has the potential to influence wellhead and downhole component integrity, and also to cause failure at the wellhead or downhole, the system analyzed typically includes the wellhead, associated valve assemblies and all downhole components that form part of the primary, secondary or tertiary barriers to gas releases. Ideally, the risk assessment should cover the remaining operating life of the well. However, to manage the assessment effort, it is generally more practical to consider an evaluation period that is long enough to include one or more well entries, which makes the evaluation period dependent on the anticipated well entry frequency. Regardless, the evaluation period should be consistent with the nature of the decision being made.

4.4.4.3 Threat Identification

API RP 1171 (2) provides a list of integrity threats for natural gas storage wells serving depleted hydrocarbon reservoirs and aquifers, which are also applicable to storage wells serving salt caverns. A credible list of threats, including those mentioned in API RP 1171, but excluding those associated with well entry (see Section 4.4.4.4), is as follows:

- Failure of mechanical equipment due to material defects, deterioration or overloading (including, but not limited to, valves, flanges, casing or tubing hangers associated with the wellhead, and downhole components, including packers, sliding sleeves and DHSVs);
- Corrosion- or erosion-induced failure of the casing or tubing string and the associated mechanical connectors between casing and tubing joints and, in the event of casing failure,

the subsequent failure of the casing cement to prevent gas flow horizontally into the surrounding formation or vertically along the casing-to-cement interface towards the ground surface;

- Unintentional damage to the wellhead (accidental impact);
- Intentional damage to the wellhead (vandalism or sabotage);
- Weather-related damage to the wellhead (e.g. lightning);
- Outside force damage to downhole components, particularly the well casing, resulting from near-surface or sub-surface ground movement attributable to heavy rain, flooding, subsidence, landslides or seismic events; and
- Incorrect well operation and maintenance activities.

Other relevant threats may be identified based on failure causes identified in PHMSA's gas transmission and gathering systems incident database (see 2010 to 2019 data (63)), which, since 2017, has included gas release incidents from UGS wells.

4.4.4.4 Well Entry Scenario Definition

For the purpose of risk assessment, a well entry scenario can be defined by the type of well entry, the anticipated frequency of entry and the intended outcome of entry (i.e. component condition inspection versus component repair or replacement).

The act of well entry constitutes a threat to well integrity because it involves the temporary reconfiguration of various well components and the temporary installation of additional well components, producing one or more temporary well configurations that could lead to well failure during the well entry process.

Well entry events can be broadly categorized by the complexity of the entry process involved and the invasiveness of the procedure in terms of the extent to which operational barriers to gas release must be temporarily removed, reconfigured or replaced. Well entry type categories, in increasing order of complexity and invasiveness, are:

- Wireline or slickline operations;
- Operations employing coiled tubing;
- Operations employing a snubbing unit; and
- Operations employing a drilling rig and/or service-type pulling unit.

The hazards associated with these entry activities, many of which can lead to well containment failure, include:

- For wireline or slickline operations:

  - Balling of the slickline cable within the lubricator;
  - Stranding of the wireline cable within the lubricator;
  - Damage to the well or wellhead;
  - Failure of seal elements in the lubricator;
  - Failure of the BOPE;
  - Failure of the grease injection control head/pack-off to contain the well pressure;
  - Failure of the hoist equipment;
  - Getting a tool stuck in the well; and
  - Operator error.
- For operations employing coiled tubing:
  - Failure of seal elements in the lubricator;
  - Parting or leaking of the coiled tubing above the injector head;
  - Failure of the injector head, which can cause tubing to be blown from well;
  - Damage to the well or wellhead;
  - Failure of the BOPE;
  - Failure of the hoist equipment;
  - Failure of the pack-off to contain the well pressure;
  - Getting a tool stuck in the well; and
  - Operator error.
- For operations employing a snubbing unit:
  - Dropping of the tubing;
  - Failure of the BOPE; and
  - Light-pipe blowout.
- For operations employing a drilling rig and/or service-type pulling unit:
  - Dropping of the work string;
  - Failure of the BOPE if primary barrier is lost;
  - Failure of the downhole assembly;
  - Failure of the rig structure;

- o Failure to recognize a gas influx into the well;
- o Failure to run a sufficient kill string;
- o Getting a tool stuck in the well;
- o High wind;
- o Increase of pressure in the formation;
- o Loss of hydrostatic pressure above the storage zone;
- o Poor cement job above the storage zone;
- o Subsidence of the ground; and
- o Operator error.

Historical incident data (62) suggests that the probability of failure during well entry is proportional to the complexity and invasiveness of the well entry procedure, with coiled tubing work having a higher probability of failure during entry than wireline operations, snubbing operations having a higher probability of failure than coiled tubing work, and operations requiring a drilling or service rig having a comparable or higher probability of failure than snubbing operations. This stems in part from the fact that well entry is a labor-intensive activity, making operator error (i.e. human factors) a significant contributor to the probability of well failure during entry, and increasingly complex entry operations provide more opportunities for human error to occur.

For the purpose of these guidelines, wireline and slickline activities are collectively referred to as “wireline operations”, and well entries that involve the use of a snubbing unit, a drilling rig or a service-type pulling unit are collectively referred to as “workovers”. At a minimum, well entry scenarios should be differentiated by assigning each to one of three categories:

- Wireline operations,
- Operations involving coiled tubing, or
- Workovers.

The overall risk of well failure is also dependent on the frequency of entry, with more frequent entry events presenting more opportunities for well failure. On that basis, an entry scenario should also be characterized by its anticipated frequency (i.e. number of years between entry events). In this regard, it is noted that some downhole work will require more than one well entry. For example, casing inspection and remediation will typically involve two entry operations: one to inspect the casing and a second to carry out repairs identified following analysis and interpretation of the results obtained from the initial entry. In addition, the types of entry required will depend on the well configuration. For example, detailed metal loss logging of the production casing can be performed by wireline in tubingless well completions, but detailed logging will require tubing removal via a workover in wells with tubing in place.

4.4.4.5 Risk Estimation

4.4.4.5.1 General

In a QRA, the risks are estimated as the expectation of losses resulting from failure, which generally means that the magnitude of the failure consequence measures are multiplied by their frequencies of occurrence. The selection and application of failure frequency and failure consequence estimation models is addressed in Section 4.4.2.1 and Section 4.4.2.2. Specific consequence measures for safety and environmental risk evaluation of gas storage wells are also discussed in Section 4.4.2.2. The following sections describe how these measures can be used to estimate and convey combined well operation and entry risks.

4.4.4.5.2 Risk Measures

Overview

As discussed in Section 4.4.2.2, well failure consequences can be classified as safety-related, environmental and financial, with safety and environmental consequences being of particular interest to the public. The corresponding safety and environmental risks are the probability-weighted measures, or the expected values, of the respective safety and environmental consequences.

The safety and environmental risk measures applicable to UGS wells, consistent with the consequence measures discussed in Section 4.4.2.2, are discussed below.

Public Safety Risk

Quantitative safety risk estimation and evaluation has evolved to the point where there is consensus that public safety risk should be evaluated from two complementary perspectives: that of the individual and that of society as a whole.

Specific safety risk measures that address the concerns of the individual include:

- **Individual Risk (IR):** a risk measure that is usually defined as the annual probability of fatality for a person living or working in proximity to a hazardous facility (e.g. UGS well). It is typically calculated for a given location, such as a residence or business, where individuals can be present for extended periods of time. It is estimated on an annual basis with due consideration of the likelihood of well failure leading to gas release, the likelihood of gas ignition given well failure, and the likelihood of fatality or injury for an individual occupying the location of interest at the time of ignition, taking into account that the person may be indoors or outdoors or away from the area at that time. The IR of fatality is a widely used safety risk measure, with many published standards and guidelines providing explicit guidance on IR acceptance criteria (see Section 4.4.4.6). The IR of serious injury is sometimes evaluated in addition to individual fatality risk; however, acceptance criteria specific to individual injury risk are less common.

- **Location-specific Individual Risk (LSIR):** a risk measure similar to IR, except that, in estimating the LSIR, it is assumed that the receptor at the location of interest is subject to continuous outdoor exposure. In this regard, the LSIR is a notional, rather than actual, measure of risk. The advantage of the LSIR as a measure of IR is that it can be applied universally, regardless of specific land use and site occupancy conditions. By assuming continuous outdoor exposure, the IR level given by the LSIR provides a conservative estimate of the actual IR. The LSIR of fatality or serious injury is also an established safety risk measure and some published standards and guidelines provide guidance on LSIR acceptance criteria (see Section 4.4.4.6).

Specific safety risk measures that address the concerns of society as a whole include:

- Societal risk can be defined as the annual expected number of fatalities or serious injuries associated with the population living or working in proximity to a hazardous facility (e.g. UGS well). The estimation of the expected number of fatalities follows a process similar to that employed for estimating individual fatality risk, except that the results are aggregated over the entire population living or working in proximity to the well. The same approach can be employed to estimate the annual expected number of serious injuries. While these measures of societal risk are rational and objective, they are what is known as risk-neutral measures of societal risk and an alternative measure or representation of societal risk is more commonly employed as a basis for conveying and evaluating societal risk because it can account for risk aversion (see below).

- Societal risk can also be represented by an F-N curve, which is a plot of the annual frequency, F, of incidents resulting in N or more fatalities or serious injuries (see, for example, Figure 4.3). An F-N curve is associated with a specific facility (e.g. UGS well). The F-N curve representation of societal risk is generally preferred over a calculation of the total expected number of fatalities or serious injuries because it provides a means to compare the societal risk level to acceptance criteria that incorporates risk aversion. Risk aversion means that the acceptable level of the expected fatality or injury risk associated with any single failure scenario is progressively reduced as the number of fatalities or injuries associated with a single event increases (see also Section 4.4.4.6). Similar to IR, societal risk as represented by an F-N curve, particularly where N is estimated in terms of the number of fatalities, is a widely used safety risk measure, with many published standards and guidelines providing explicit guidance on acceptance criteria (see Section 4.4.4.6).

The safety risk measures described above are defined on an annual exposure basis, largely because the associated evaluation criteria (see Section 4.4.4.6) are defined on an annual basis. The chosen safety risk measures should therefore be estimated in each year of well operation over the evaluation period of interest, with the highest annual values being of the most interest. Given that well entry can be shown to contribute significantly to well risk in the year during which it is carried out, the highest levels of well safety risk will typically occur in years when one or more well entries are performed.

To the extent that gas storage wells are typically located in relatively sparsely populated areas, where the number of casualties resulting from well failure and gas ignition would be limited, the most relevant measure of safety risk is usually the IR, and the simplest measure of IR is the LSIR. On that basis, it is suggested that, at a minimum, the annual safety risk associated with well operation and periodic entry should be estimated in terms of the LSIR at a prescribed offset distance from the wellhead. A more detailed public safety risk evaluation and/or safety evaluations of wells in proximity to populated developments would warrant estimation of IR contours (see Figure 4.2) and/or IR transects (see Figure 4.3) and F-N curves (see Figure 4.4), which should involve explicit consideration of effective population densities and/or area occupancy patterns (i.e. time spent indoors versus outdoors versus away).

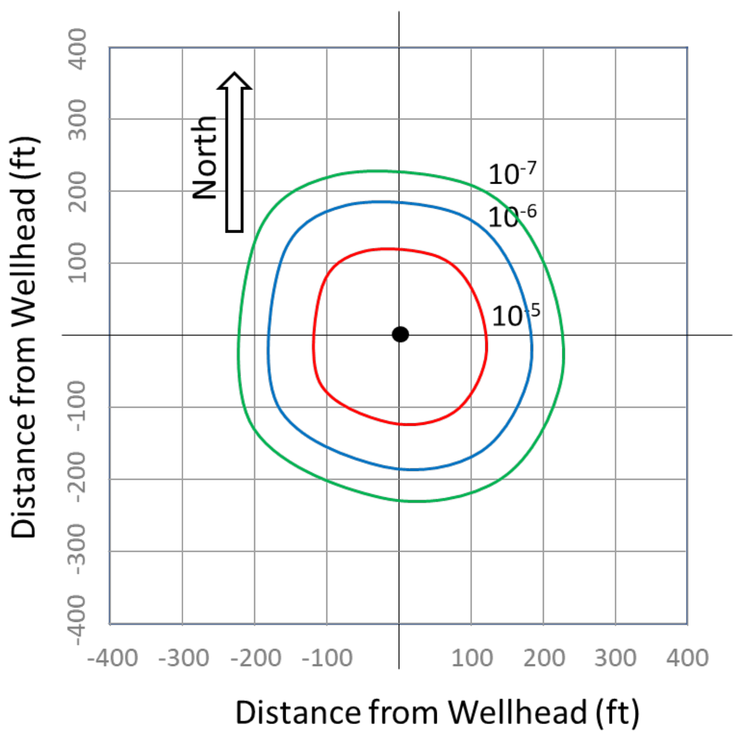


Figure 4.2 Individual Risk Contours

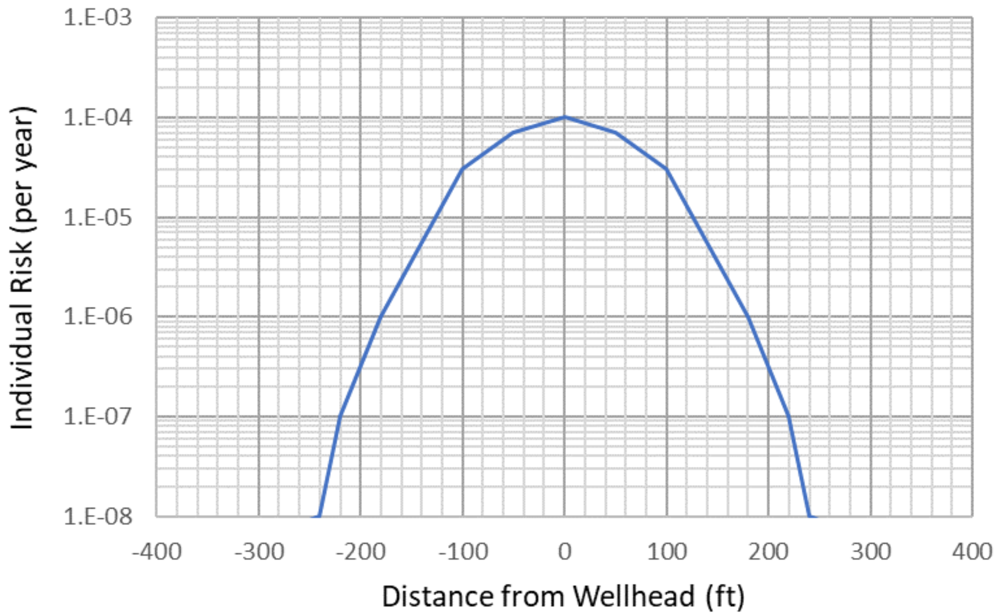


Figure 4.3 Individual Risk Transect

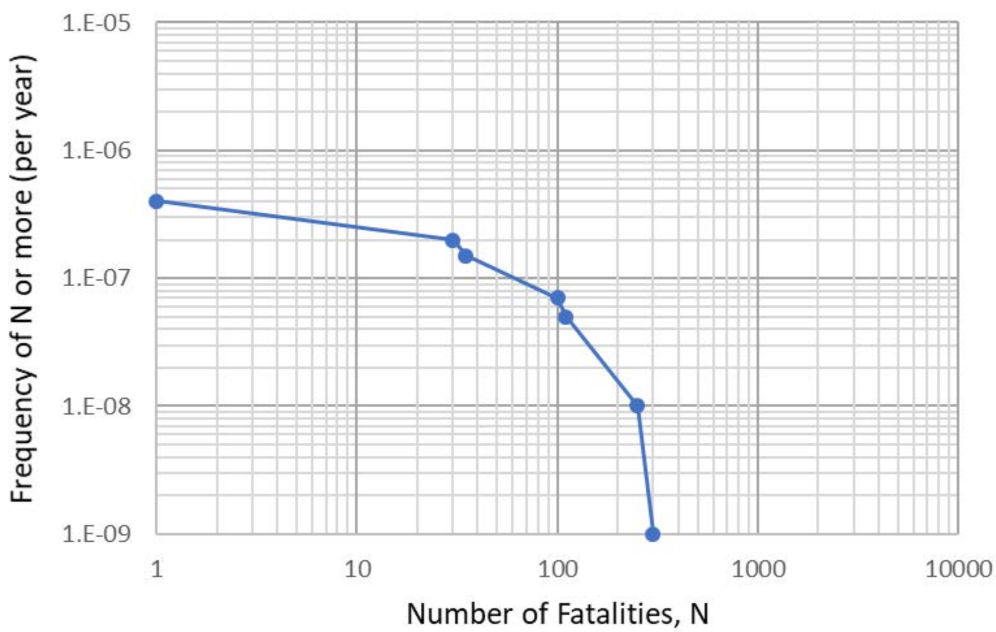


Figure 4.4 Societal Risk Expressed as an F-N Curve

Environmental Risk

As discussed in Section 4.4.2.2, the most basic measure of the long-term environmental impact of UGS well failure is the total quantity of gas released. Given that models exist that show that the magnitude of adverse impact on climate, human health and quality of life is, for a given hydrocarbon product, directly propositional to the quantity of gas released. The total release quantity serves as an objective relative measure of the future environmental impact. The corresponding risk measure is the probability-weighted or expected quantity of gas released, which can be calculated on an annual basis and aggregated over the duration of the evaluation period.

It is noted that, while the expected quantity of gas released is widely accepted as an objective, albeit indirect, measure of future environment impact, there is no established precedent for, or guidance on, acceptable levels of environmental risk when expressed in these terms.

4.4.4.5.3 Risk Estimation Methods

Well Operating Risk

When the well operating risk is to be based on the failure probabilities or failure frequencies of individual well components, the risk estimation process generally requires a failure pathway characterization framework that provides a structured and repeatable process for identifying and characterizing all possible gas flow pathways from the storage gas location through the well to atmosphere.[3] Once the failure frequency and release consequences for each distinct pathway failure scenario have been estimated (using the methods and models described in Section 4.4.2.1 and 4.4.2.2), the total well risk is obtained by simply summing the risk (i.e. the expected loss) attributable to each distinct pathway failure scenario.

The failure pathway characterization process is, however, complicated by the fact that individual barrier components can fail in different ways (i.e. different failure modes) and for pathways associated with multiple barriers, with each barrier having multiple failure modes, there are potentially a large number of distinct pathway failure scenarios that must each be identified and

[3] This pathway characterization process is not necessary if the overall well failure frequency and the mode of well failure is to be estimated in aggregate from historical data or based on SME opinion. It is noted, however, that such a simplified analysis will not reflect well-specific factors that would be expected to influence the failure frequency and, thereby, the risk of well operation.

analyzed in terms of their frequency of occurrence and the consequences that result from their occurrence.

For complex systems, where system failure requires the concurrent failure of multiple system components, there are various methods available to estimate the probability or frequency of system failure. Three methods have been identified as being particularly well suited to well failure risk estimation. They are described below, along with comments on their respective strengths and limitations.

1. **Fault trees:** Fault tree analysis is widely used to model well reliability. Fault trees are graphical representations of the causal relationships between individual component failures that lead to system failure (see Figure 4.5). When applied to releases from UGS wells, fault tree events represent failures of the various components and barriers within the well that are designed to prevent a gas release. The probabilities of individual component failures are combined based on the Boolean logic of the fault tree to provide a total well failure rate.

   Fault trees provide a visual representation of the failure logic of the system, making them relatively easy to understand, and they can serve to identify the component failure combinations that contribute most to the probability or frequency of well failure. However, the structure of a fault tree does not accommodate multiple modes of individual component failure. This limitation can be overcome to some extent by building multiple fault trees that focus on failures that are associated with different failure modes. However, this can become an unwieldy process for systems with multiple barriers to failure and multiple modes of failure for individual barriers.

2. **Directed acyclic graphs:** Directed graphs can model various types of information, including component dependencies that lead to an undesirable event. Using this approach for UGS well analysis, a collection of vertices (i.e. nodes) representing well components are connected by arcs (i.e. branches) representing possible flow paths between components (see Figure 4.5). A failure-mode-specific probability of occurrence can be assigned to each branch, and each well failure pathway scenario is represented by a unique combination of non-cyclic, failure-mode-specific branches connecting a series of nodes that represent a particular series of barriers that could fail and, thereby, enable uncontrolled gas movement from the gas storage location to atmosphere.

   While offering a clear visual representation of the possible flow pathways from the gas storage location to the atmosphere, given the potential for multiple failure modes for individual well barrier components, the visual representation is not well suited to identifying the components and pathways that contribute most to the well failure. However, generic software tools exist that can be used to develop and solve directed acyclic graphs, and each pathway failure scenario can be tagged with its frequency of occurrence and the attributes of the pathway necessary for consequence analysis. (i.e. the failure modes associated with each component in each failure pathway scenario).

3. **Bayesian networks:** Bayesian networks are a form of directed acyclic graphs; however, they offer the advantage of accommodating more general probabilistic relationships between components. They can also accommodate the modeling of dependencies between component failures based on multiple information sources, including SME opinion, in a structured format.

   While Bayesian networks can offer advantages over other methods, they are analytically complex and can be computationally intensive for realistic representations of gas storage wells. Such models are, therefore, not generally amenable to development or routine use by individual operators. Proprietary models are under development (e.g. DNV GL (64)) and operators will likely be able to access such models through software licensing arrangements or consulting services.

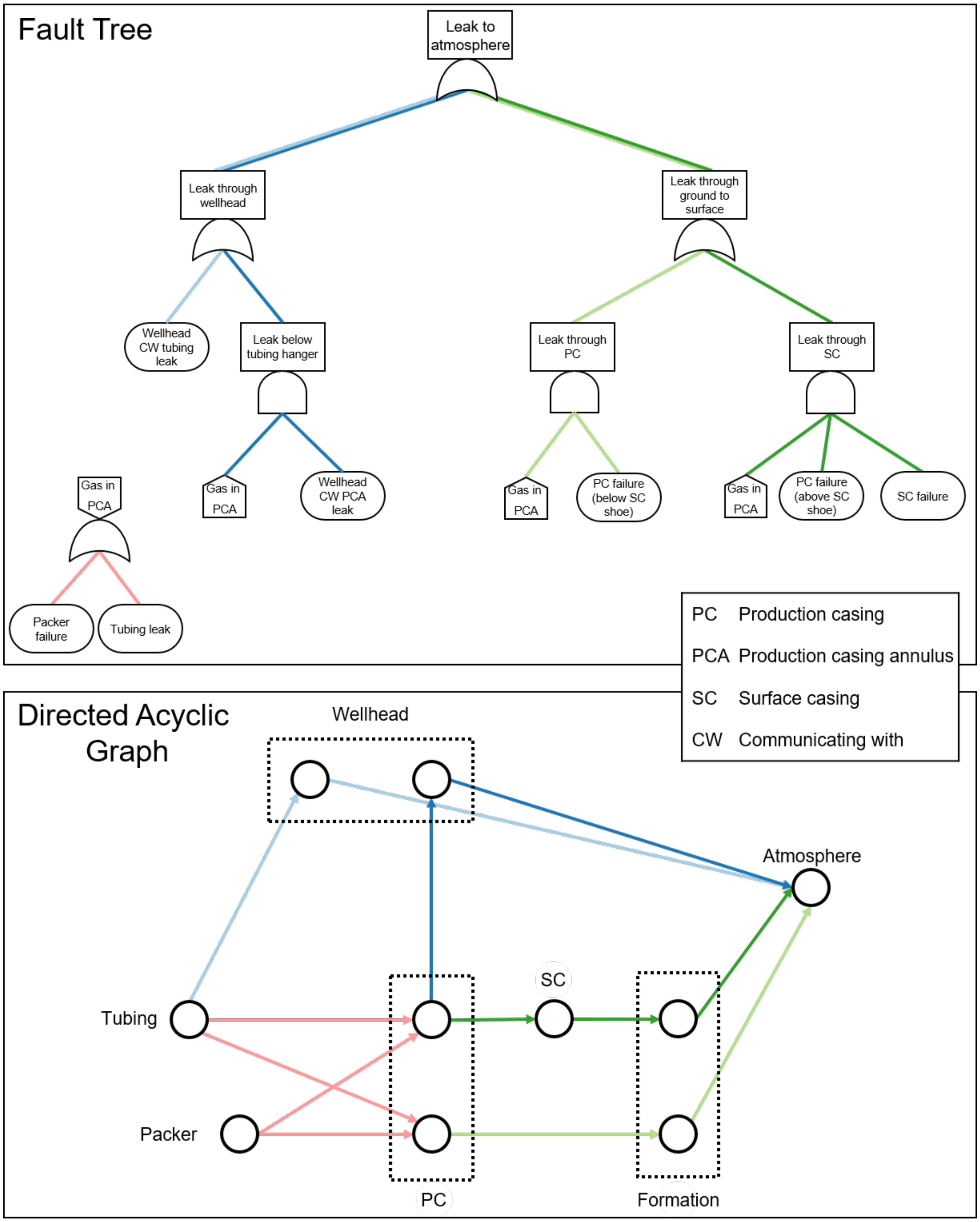


Figure 4.5 Fault Tree and Directed Acyclic Graph Representations of UGS Well Release Pathways

Well Entry Risk

The calculation of well entry risk can be carried out using the well-component-specific modeling approach described above for calculating the well operating risk. This would entail adopting one of the above-described failure pathway characterization methods and applying it to each of the temporary well barrier configurations that are established in the process of carrying out the well entry activity of interest. However, beyond the fact that this will be a more analytically intensive exercise due to the multiple well barrier configurations that will have to be analyzed, the greatest challenge to the application of this approach to well entry is the lack of availability of the information required to estimate the frequency of failure of the temporary and permanent barrier components that are in play during the various stages of the well entry process. Very little information to support the estimation of the probability of temporary and/or permanent barrier failure during well entry is currently in the public domain and the limited information that is available is specific to offshore wells.

The alternative to a barrier-component-specific approach is to estimate the risk of well entry in aggregate terms. This implies that the frequency of failure and the likelihoods of different failure modes are estimated collectively for the entire well entry process. The most defensible basis for estimating the frequency of well failure during entry in aggregated terms is to use historical data. Such data exists and various sources (e.g. IOGP (65)) provide failure frequency data that differentiates between different types of well entry, including wireline operations, operations that involve coiled tubing and workovers. Other data sources can be used to estimate the relative frequency of the mode of failure (e.g. SINTEF (58,68), CAPP (66), HSE (67)). The biggest limitation of this data is that much of it pertains to offshore wells and associated offshore well entry practices.

The alternative to the direct use of historical data is SME opinion; however, a more effective approach would involve the use of historical-based well entry failure frequencies, together with modification factors based on SME opinion, to address the impact on failure frequency of key attributes of the well or the well entry process being evaluated, including consideration of how differences in well design, operating parameters, and the complexity and invasiveness of well entry activities influence the failure frequency. This type of integrated approach has been developed for estimating entry risk for offshore wells (14) and a similar approach could be developed and tailored to well entry for UGS wells.

It is noted that, due to the labor-intensive nature of well entry activities, human error is a significant factor in entry-related well failure. The human error contribution to well entry failure is implicitly reflected in historical incident data, which means that it is accounted for in general terms in the risk estimation process when historical data forms the basis for well entry failure frequency estimation. However, specific methods and models for quantifying the potential for human errors have been developed to varying degrees in other industries (see Section 3.2 and Appendix B), and the potential exists to leverage these methods and incorporate a human factor influence component into the failure frequency modification factors that could be used to make generic well entry failure frequency estimates more reflective of the degree to which human error potential is being addressed by the well entry practices, procedures and training.

4.4.4.6 Risk Evaluation

General

The preceding section of these guidelines provides information on risk measures and risk estimation methods intended to facilitate quantifying meaningful measures of the life safety and environmental risk posed by UGS well operation and periodic well entry. The evaluation of these safety and environmental risk estimates can involve either a separate evaluation of the calculated safety and environmental risk levels, or the safety and environmental risk estimates can be combined into a single measure of well risk that can then be evaluated.

While the option to combine and evaluate a single overall measure of risk is conceptually attractive, it can be problematic in application. To develop a single combined measure for the combined risk, the safety and environmental risk measures must first be converted into a common unit of measure prior to their combination. This can be achieved by monetizing the respective losses, and methods and models do exist for monetizing safety losses based on the value of a statistical life and for monetizing future environmental impact of natural gas releases in terms of the SCC. However, while doable, decision making based on such a combined risk measure usually entails some form of cost-benefit analysis. While it can be argued that this is a rational and objective approach, the monetization of safety and environmental impacts remains somewhat controversial, as is decision making when based narrowly on cost-benefit analysis.

The obvious alternative is to evaluate safety risk separately from environmental risk. The advantage of this approach is that it avoids the analysis complexity and potential controversy inherent in risk monetization and cost-benefit analysis. This approach involves the following two steps:

1. Evaluate safety risk on an annual basis and compare the estimated values for the adopted safety risk measures to prescribed safety risk acceptance criteria. An acceptable well operation and periodic well entry strategy is shown to achieve a public safety risk level in each year of the evaluation period that does not exceed prescribed threshold levels.

2. Evaluate environmental risk on an annual basis and aggregate the risk over the evaluation period. The preferred well operation and periodic well entry strategy is shown to achieve the lowest aggregated level of environmental risk over the evaluation period. This implies that various well operation and well entry strategies would have to be evaluated and compared, including the no entry option.

It must be acknowledged, however, that the disadvantage to considering life and safety risk separately is that it does not provide a means to estimate or assess total risk and, in this regard, the alternative risk monetization approach facilitates inclusion of financial risks in the combined overall risk estimate.

Safety Risk Criteria

Central to the safety risk evaluation step are safety risk criteria (i.e. safety risk thresholds), against which the estimated safety risk levels can be compared. As discussed in Section 4.4.4.5.2:

- For gas storage wells located in relatively sparsely populated areas where the total number of casualties resulting from well failure and gas ignition would be limited, the most relevant measure of safety risk is usually the IR, and the simplest measure of IR is the LSIR.
- For gas storage wells located in proximity to populated developments, more detailed safety risk evaluations are warranted based on consideration of both IR and societal risk as represented by an F-N curve, both of which should involve explicit consideration of effective population densities and/or area occupancy patterns.

It is noted and emphasized that, while the LSIR, IR and F-N curves are widely accepted measures or representations of safety risk, with many published standards and recommended practices providing explicit guidance on acceptance criteria, consensus-based criteria for these risk measures, intended for direct application to facilities transporting or storing natural gas, do not yet exist in North America.[4]

To provide guidance for the selection of safety risk criteria for use in evaluating the safety risk posed by UGS wells subject to periodic well entry, the following information is provided.

Individual Risk:

A selection of representative IR criteria, defined in terms of the annual chance of fatality, is as follows:

[4] It is noted that NFPA 59A 2019 – Standard for the Production, Storage and Handling of Liquified Natural Gas (LNG) (67), does provide explicit guidance on safety risk evaluation, including acceptance criteria. However, natural gas stored in a liquid state (i.e. LNG) presents hazards that differ somewhat from those associated with natural gas stored in a gaseous state (i.e. natural gas transported in pipelines and stored in UGS wells).

- UK HSE (70) and the Irish CER (71)– The broadly acceptable IR threshold is set at 1×10^{-6} per year and the maximum tolerable individual risk level is set at 1×10^{-4} per year, with the requirement that, where the risk falls between the broadly acceptable and maximum tolerable risk levels, an effort should be made to demonstrate that it is as low as reasonably practicable.

- Netherlands RIVM (72)– The acceptable value of IR for new developments is set at 1×10^{-6} per year and for existing developments at 1×10^{-5} per year, with the requirement that, where the risk exceeds 1×10^{-6} per year, effort is required to try to achieve a risk level not exceeding 1×10^{-6} per year.

- NFPA 59A (69)– The acceptable limit for LSIR is given as 3×10^{-7} per year for sensitive establishments[5] and 5×10^{-5} per year for all other public areas, with the requirement that, where the risk level exceeds the applicable acceptability limit, it shall be reduced to a tolerable level by implementing risk mitigation measures.

The above suggests that an individual fatality risk level in the range of 10^{-6} to 10^{-5} per year, subject to land use considerations and perhaps with consideration of whether the UGS well is new or existing, constitutes a defensible threshold for IR acceptability. In addition, assessing the LSIR against an IR threshold in this range would also be reasonable, albeit conservative, since the LSIR calculation presumes continuous outdoor exposure, whereas the more generalized measure of IR usually takes site occupancy time and indoor versus outdoor exposure into account.

Societal Risk:

A selection of representative societal risk criteria, defined in terms of F-N curves, where N represents the number of fatalities, are shown in Figure 4.6.

With reference to the specific curves shown in Figure 4.6, it is noted that a societal risk criterion associated with a line having a slope of minus 1 on a log-log plot of frequency versus number of fatalities (i.e. the NFPA and CER curves) implies an effectively risk-neutral approach to risk acceptance. A criterion associated with a slope steeper than minus 1 (i.e. the Netherlands curve) implies that it incorporates a progressive degree of aversion to single incidents that can result in progressively larger numbers of fatalities, with a steeper slope implying a criterion incorporating a greater degree of aversion to risks associated with large scale incidents. It is often stated that adopting a societal risk criterion that incorporates aversion serves to enhance public safety. However, it can be argued that, in a resource-constrained world, affording a higher level of protection to people living in more densely populated areas comes at the expense of reduced protection for people living in smaller groups (i.e. in less populated areas where the number of

[5] Sensitive establishments are defined as institutional facilities that might be difficult to evacuate, including, but not limited to, schools, daycare facilities, hospitals, nursing homes, jails and prisons.

fatalities resulting from a single event would be lower). On that basis, it can be argued that the most equitable societal risk criteria would be risk-neutral.

Consistent with the above perspective, the fatality-based F-N criterion recommended by the US National Fire Protection Agency for liquefied natural gas facility risk assessment (69), which is also recommended for more general application by the Irish CER (71), is suggested as a defensible threshold for evaluating societal risk as it pertains to UGS wells.

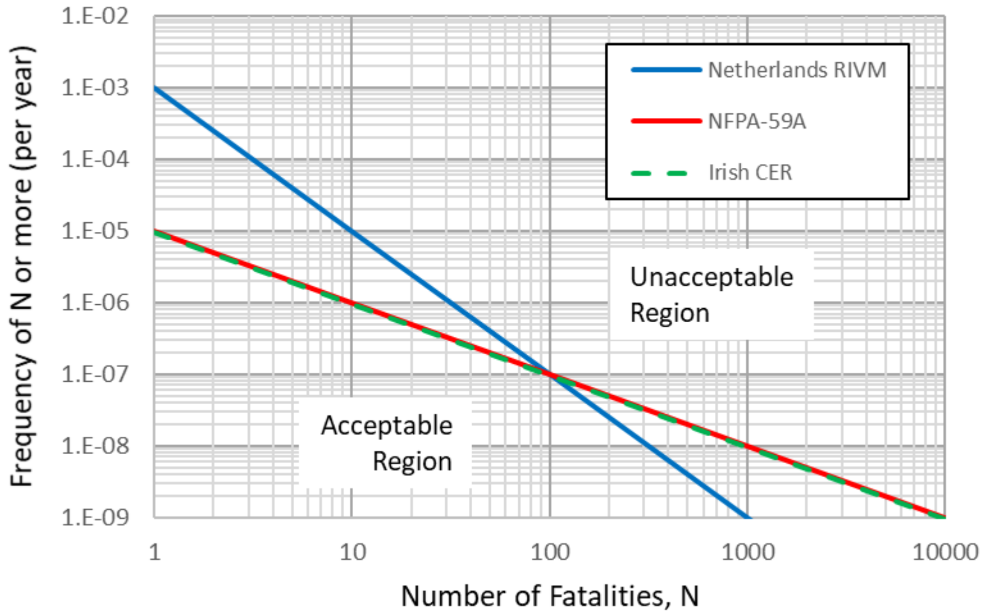


Figure 4.6 Representative Societal Risk Criteria

It is noted that the F-N curve for an individual well must plot below the chosen criterion line to be deemed acceptable. An F-N curve that extends above the chosen criteria line is unacceptable unless the risk can be shown to be As Low As Reasonably Practicable (ALARP). The ALARP concept, as originally developed and embodied in regulations in the UK and the Netherlands, which has subsequently been embraced in other countries, is intended to provide a structured and consistent process to support decision making with regard to the acceptability or tolerability of societal risk for facilities that are assessed to have risk levels that exceed prescribed limits. The demonstration of ALARP requires, depending on the situation, either an informal or formal analysis to support a position that the effort required for further risk reduction would be disproportionate to the benefit gained. An informal approach to demonstrating this could involve showing that the system under consideration has been designed and is being operated and maintained according to recognized best practices. A more formal approach to demonstrating ALARP usually involves a cost-benefit analysis wherein the cost of risk reduction must be shown to significantly exceed the expected value (in dollar terms) of the adverse outcomes avoided by risk reduction. Additional guidance on demonstrating ALARP is available from various sources (e.g. UK HSE (69), CER (71)).

4.4.5 Documentation

Appropriate documentation of the QRA process provides justification for the decisions made; a record of changes made to process, data, or models; and continuity in the case of changes in ownership or personnel. Documentation should contain sufficient information to allow an informed third-party to verify the process and models used. Elements to consider in documenting the risk assessment are as follows:

- Objectives of the assessment, including the scope of analysis, system definition, operational conditions and entry actions considered, and assessment period covered;
- Basis for the identification of relevant threat categories, including any formal hazard identification methods employed;
- List of threats considered and rationale for threat screening used to exclude threats;
- Identification of data used in the analysis, including:
    - Sources of the data;
    - Approach for addressing data gaps; and
    - Comments on data quality from each source;
- Identification of models selected for the assessment and the rationale for the selection;
- Summary of assumptions and limitations associated with each model employed;
- Where the model employs SME opinion:
    - Data submitted for the SME’s review;
    - Description of the approach used to obtain the opinion from the SMEs;
    - Questions submitted to the SMEs and the format in which they were asked;
    - Background and qualifications of each SME; and
    - Minutes of the meeting, if a group workshop was conducted;
- Where the models employ historical data:
    - Basis for the selection of data relevant to the system under evaluation;
    - Identification of modification factors, if applied; and
    - Process of developing the modification factors;

- Where probabilistic models are used:
    - Description of each model component;
    - Basis for the probability distributions used for random or uncertain input parameters;
    - Approach used to address time-dependent factors (e.g. corrosion growth);
    - Approach taken to differentiate between different failure modes; and
    - Characterization of uncertainty inherent in models used (i.e. model error);
- Loss measures considered in consequence estimation;
- Methods and models used for consequence estimation;
- Intermediate results obtained in the QRA process:
    - Failure frequencies for individual well components and/or failure pathways; and
    - Consequence estimates for individual failure pathways (e.g. release rates and release durations);
- Results of any sensitivity analyses performed to establish values for key parameters; and
- Format used to present the risk results to the decision-makers.

5. EXAMPLE APPLICATION OF QUANTITIATIVE RISK ASSESSMENT

5.1 Overview

The example analyses and assessments described herein are intended to illustrate the application of a defensible QRA process to selected UGS well configurations subject to periodic well entry. In addition to illustrating the application of the QRA process, the directional findings of the example assessments are intended to support the development of best practices for the selection of preferred well completion configurations and the optimization of well entry practices.

The UGS well configurations considered in the analysis were selected to include a range of representative UGS well completion configurations that are applicable to typical wells serving depleted hydrocarbon reservoirs and salt caverns. The well configurations were made as simple as possible and the set of well components included in the assessments was limited, to the extent possible, in the interest of clarity of presentation.

Risk levels were calculated for each well configuration under both normal operating conditions and during well entry events. Risk levels under operating conditions (“operational risk”) were estimated as a function of well type and configuration on an annual basis. Risk levels associated with well entry (“entry risk”) were estimated as a function of well entry type on a per entry basis. A combination of historical incident data, analytical models and judgment was used to estimate both the frequencies and consequences of well failure required for risk estimation. The QRA framework described in the guidelines was then followed to develop estimates of combined well operating plus well entry risk for the purpose of risk evaluation.

For each well type and completion configuration, the public safety risk and the environmental risk were estimated and evaluated separately.

The safety risk for each well configuration was estimated and evaluated on an annual basis, as a function of well entry type, by comparing the calculated combined operating plus entry risk in a year during which entry was assumed to occur (i.e. “operational risk” plus “isolated entry risk”) to a set of prescribed safety risk acceptance criteria.

The environmental risk was estimated for each well type and completion configuration based on normal well operation, together with a prescribed set of routine periodic well entries that reflect well entry activities and entry frequencies that are considered typical for each well configuration (i.e. “operational risk” plus “baseline entry risk”). Because acceptance criteria are not currently available for the environmental risk posed by natural gas releases, the annual average environmental risks for each well type and completion configuration were compared and contrasted to illustrate how well type and well configuration affect the overall environmental risk level.

The effect on environmental risk of a set of additional well entry scenarios, for selected well completion configurations, was then analyzed and assessed over a range of evaluation periods (2, 5, 10 and 20 years), which, depending on the well entry scenario being considered, can also be interpreted to represent well entry intervals. For each well configuration and entry scenario combination analyzed, the total environmental risk over the prescribed set of evaluation periods (or entry intervals) was then compared to determine which combination of entry activities demonstrated a net reduction in overall environmental risk and which combination was associated with the lowest environmental risk. This comparative analysis of well entry scenarios also included a sensitivity analysis that explored the impact of the assumed entry-related well failure rates on the analysis outcomes. The results of these well entry scenario analyses and assessments are intended to illustrate how well entry options can be evaluated for the purpose of decision making as it pertains to the selection of entry actions and/or entry frequencies.

Collectively, the results of these example assessments served to provide the basis for a number of high-level directional findings that are intended to support the development of best practices for the selection well completion configurations and the optimization of well entry practices that will ensure acceptable levels of public safety and minimize the life-cycle environmental risks posed by UGS wells.

A limitation of this demonstration analysis is that the time-dependent nature of well component reliability is not accounted for. Component deterioration and the resulting progressive increase in failure probability over time is, therefore, not reflected in this analysis. While methods and models for addressing this time-dependency have been developed and applied in other industries (e.g. pipeline reliability deterioration due to corrosion growth; see Stephens and Nessim (73) and Stephens and van Roodselaar (74)), they are not yet established for risk and reliability assessment of well components, such as casing subject to corrosion growth. This is an area of active research (75) as accounting for progressive deterioration is essential to the true optimization of well entry frequency.

5.2 Well Configurations

In consultation with the project TAP members, several high-level well configurations were identified as being representative of typical UGS well configurations and/or well configurations that would serve as a basis to illustrate the implications on well risk of the presence of selected well components. Three hypothetical well configurations were chosen for wells that serve depleted hydrocarbon reservoirs or aquifers and three for wells that serve salt caverns. The different ‘reservoir well’ configurations are denoted as R1, R2, and R3 (see Figure 5.1) and the ‘cavern well’ configurations are denoted as C1, C2, and C3 (see Figure 5.2). Each set of wells is ordered by increasing complexity of the downhole components, with each configuration being an augmented version of the previous configuration that includes additional components. The key differentiating characteristics of each group of three well configurations are summarized as follows:

- **Reservoir wells (R):**
  - o **R1** – the simplest possible well configuration with only production and surface casing.
  - o **R2** – the same configuration as R1 with the addition of a tubing and packer assembly creating an isolated production casing annulus.
  - o **R3** – the same configuration as R2 with a tubing-retrievable DHSV.
- **Cavern wells (C):**
  - o **C1** – the simplest well configuration (identical to R1).
  - o **C2** – the same configuration as C1 with the addition of intermediate casing extending down to the fracture depth.
  - o **C3** – the same configuration as C2 with a tubing string in place (without a packer) to facilitate well operation and cavern maintenance.

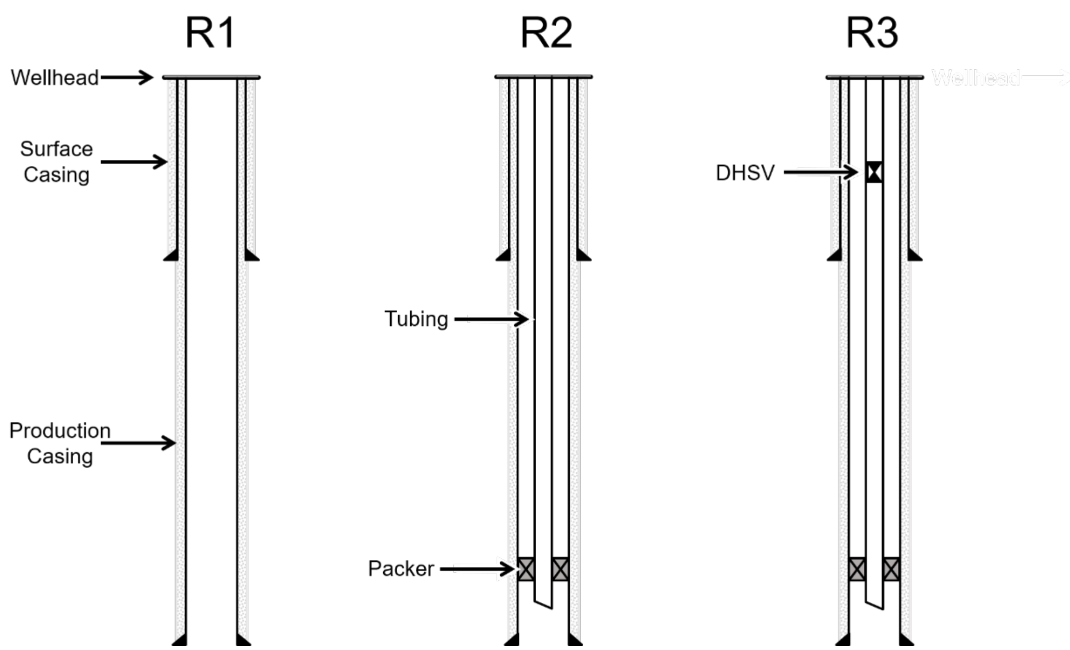


Figure 5.1 Reservoir Well Configurations R1, R2, and R3

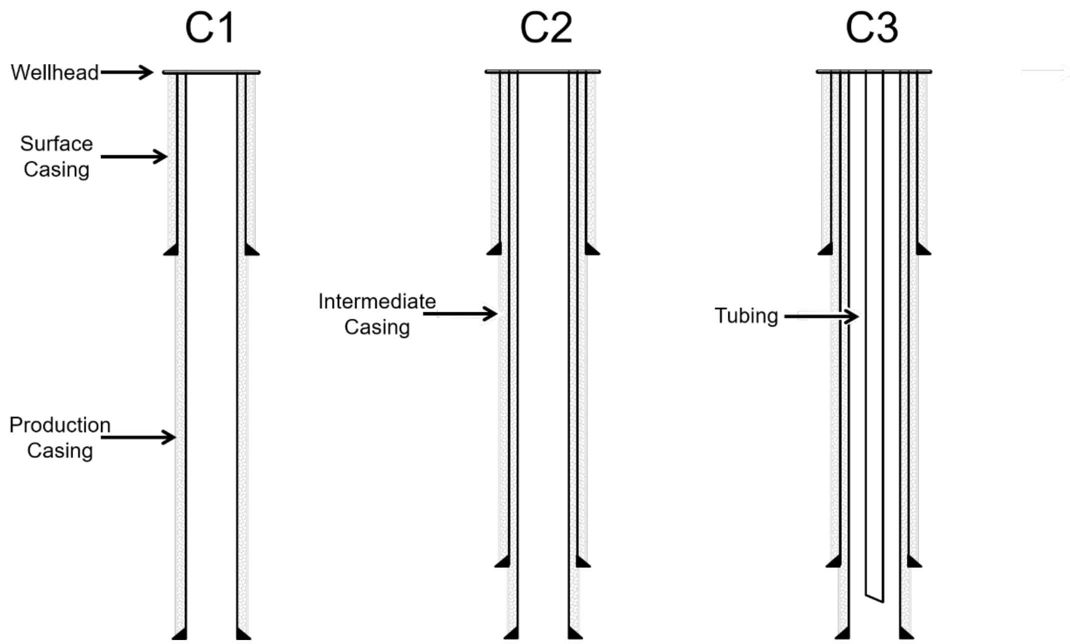


Figure 5.2 Cavern Well Configurations C1, C2, and C3

The attributes of the example wells, such as casing diameter and well depth, were chosen based on the attributes of typical wells as determined from the available literature and engineering judgment supported by input obtained through SME consultation. Basic well attributes, such as well depth, and gas storage pressure and temperature, were assigned to all well configurations to focus the comparative evaluation of risk on the effect of the well type (i.e. reservoir versus cavern) and downhole component configuration.

The downhole well component attributes for each well type and configuration are summarized as follows, along with the basis for their selection (see also Table 5.1):

- **Common Well Attributes**
  - *Pressure and temperature*. A gas storage pressure and temperature of 2000 psig and 100 °F, respectively, were assigned based on typical UGS well characteristics summarized in GRI-05/0172 (10).
  - *Well Depth*. A well depth of 5000 feet was selected based on typical UGS well characteristics summarized in GRI-05/0172 (10).
  - *Fracture depth*. The fracture depth was set at 80% of the well depth to be in general alignment with industry guidance (76), i.e. 4000 feet for wells with a depth of 5000 feet.

    - *Production casing*. A production casing diameter of 7 inches was chosen as typical based on SME opinion.

- **Configuration-specific Well Attributes**

    - *Surface casing*. The depth of all surface casing was taken to be 10% of the total well depth, i.e. 500 feet. Diameters were selected from API specifications for casing and tubing (76) with a diameter of 10 ¾ inches for wells without intermediate casing and 16 inches where intermediate casing was present (i.e. C2 and C3) being chosen as representative for a well with a 7-inch diameter production casing.

    - *Intermediate casing*. For cavern configurations C2 and C3 where intermediate casing is present, its depth was assumed to extend to 4500 feet, being the midpoint between the length of the production casing and the fracture depth. The diameter was assumed to be that of the surface casing in wells without intermediate casing or 10 ¾ inches.

    - *Tubing*. A diameter of 4 ½ inches was selected based on SME opinion. The depth was assumed to match that of the production casing (i.e. 5000 feet). Tubing strings are present in configurations R2, R3, and C3. For the reservoir cases, the tubing strings are set on a packer placed near the bottom of the production casing to provide production casing isolation. Cavern configuration C3 contains a suspended debrining string, which is used to facilitate well operation and cavern maintenance.

    - *Downhole Shut-off Valve*. The depth of the DHSV was set at 50% of the surface casing depth (i.e. 250 feet) based AOF value of 350 MMSCFD was selected for reservoir wells as a basis for estimating throttled flow rates due to sustained reservoir deliverability constraints where applicable. The chosen value represents the midpoint of the range provided in GRI-05/0172 (10) (i.e. 200 to 500 MMSCFD).

Well	Production Casing		Surface Casing		Intermediate Casing		Tubing		DHSV
	Diam. (inches)	Depth (feet)	Diam. (inches)	Depth (feet)	Diam. (inches)	Depth (feet)	Diam. (inches)	Depth (feet)	Depth (inches)
R1	7	5000	10 ¾	500	—	—	—	—	—
R2	7	5000	10 ¾	500	—	—	4 ½	5000	—
R3	7	5000	10 ¾	500	—	—	4 ½	5000	250
C1	7	5000	10 ¾	500	—	—	—	—	—
C2	7	5000	16	500	10 ¾	4500	—	—	—
C3	7	5000	16	500	10 ¾	4500	4 ½	5000	—

Table 5.1 Key Downhole Well Component Attributes for Example Wells

5.3 Probability Estimation

As described in the guidelines, frequency estimation for each well configuration requires consideration of the pathways that have potential to allow a gas release to atmosphere, which depends on the components (i.e. barriers) in each configuration. In addition to considering the set of barriers that must concurrently fail to cause a release though each pathway, the modes of failure are an additional factor in the consequence analysis. Three modes of failure were considered in this analysis for each barrier, namely small openings (small leaks), large openings (large leaks), and maximum openings (ruptures).

The release pathways for each reservoir configuration are shown in Figure 5.3. In configuration R1, three components act as barriers: the wellhead, production casing, and surface casing. Configuration R2 has two additional barrier components in the form of a production tubing string and packer. The tubing and packer assembly serves to isolate the production casing annulus from the reservoir gas, thereby changing the failure pathway through the production casing from a single-barrier pathway to a double-barrier pathway. It also restricts the flow rate resulting from wellhead failure due to the reduced effective cross-section area of the flow path (i.e. reducing the effective area from that of the production casing to that of the production casing anulus or production tubing). The introduction of the DHSV in configuration R3 adds a second barrier to what would otherwise be a single-barrier pathway for gas flow from the part of the wellhead communicating directly with the production tubing.

In the set of cavern well configurations shown in Figure 5.4, the release pathways for configuration C1 are the same as those found in reservoir configuration R1. In contrast to configuration C1, the intermediate casing added to the C2 configuration adds one additional barrier to what would otherwise be a single-barrier pathway through the production casing. The gas release pathways for configuration C3 are assumed to be effectively the same as for C2, because the tubing string is present solely to facilitate well operation and cavern maintenance. Gas production in configuration C3 is up through the annular space between the production casing and tubing, and the tubing, therefore, does not modify the release pathway through the production and intermediate casing.

A fault tree analysis approach was selected for modeling combinations of barrier failures and failure modes to account for each potential scenario leading to a release to atmosphere. Fault tree analysis is a widely used approach to model well reliability. However, as noted in the guidelines, fault trees are not well suited to differentiating between system failures based on the mode of component failure. (Differentiating well failure frequencies based on component failure modes is important for subsequent consequence analysis.) For the example analyses, this limitation was overcome by building multiple separate fault trees, with each fault tree focused on estimating the frequency of failure for pathways that would be associated with similar gas flow release rate.

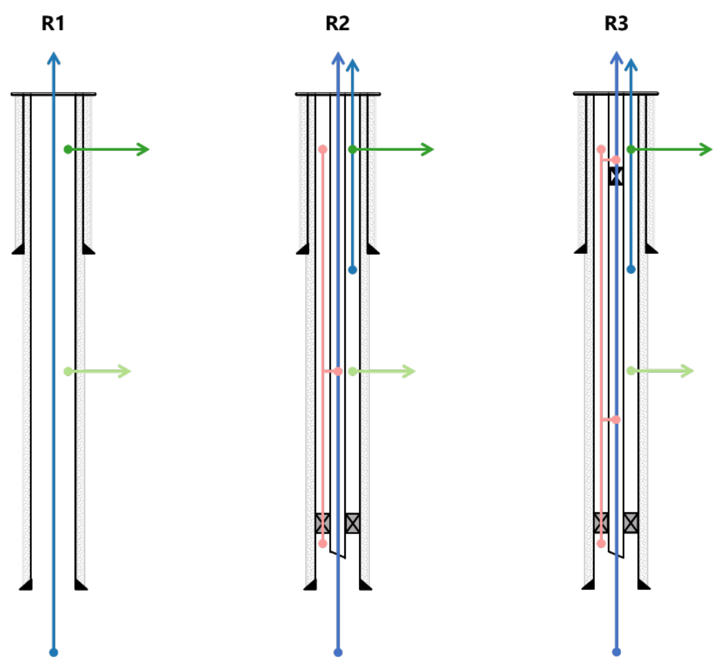


Figure 5.3 Release Pathways for Reservoir Well Configurations R1, R2, and R3

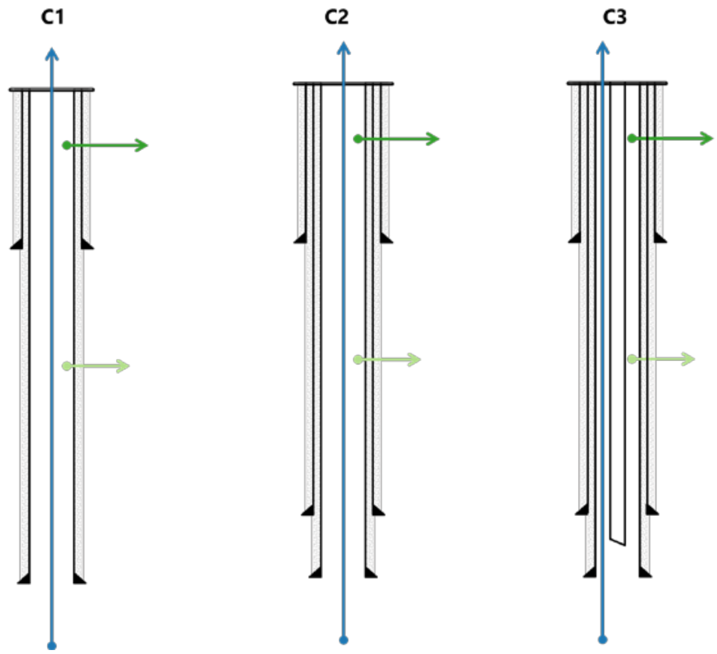


Figure 5.4 Release Pathways for Cavern Well Configurations C1, C2, and C3

5.3.1 Operational Failure

Each of the well configurations described in the previous section were analyzed to determine all potential failures pathways and expected release rates due to different failure modes of the components along each failure pathway. All failure modes that result in similar release rates were identified and a representative fault tree was developed. For example, Figure 5.5 shows the potential failure pathways for reservoir well configuration R1, and the associated fault tree for small leak failures. The basic event frequencies required for this fault tree are the failure frequencies for each of the wellhead, production casing (PC)—above and below the surface casing—and surface casing (SC). The failure of casing and casing cement are modeled as a combined failure event and, thus, cement failure is not represented as a separate basic event.

Starting from the top event, a leak to the atmosphere is possible either by a leak through the wellhead or a leak through the ground. This is denoted by an "OR" gate in the fault tree. A leak through the ground can occur due to failure of the PC or the SC and these events are also connected by an "OR" gate. For a leak to occur through SC, both PC and SC must fail; this is denoted by an "AND" gate in the fault tree. Given the framework provided by the fault tree, once basic event frequencies are determined, the total frequency of a leak to the atmosphere can be evaluated.

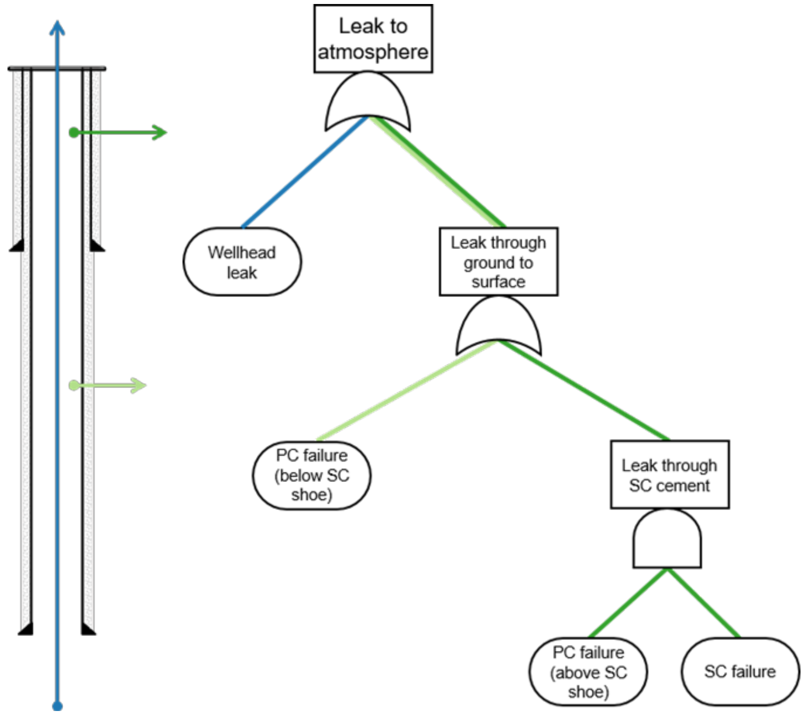


Figure 5.5 Schematic and Fault Tree for Reservoir Well Configuration R1 – Failure by Leak

The basic event failure rates (i.e. failure frequencies of individual components) were estimated using a historical data approach, supplemented by engineering judgment. To this end, failure rate data was gathered from multiple sources and evaluated for applicability. Where possible, values were selected from data specific to UGS wells. The selected component failure rates are summarized in Table 5.2, along with the data sources. The overall failure rates used for the production and intermediate casings were apportioned based on the relative length of production casing (or production plus intermediate casing) with and without surface casing behind it.

The proportion of these total component failure rates attributable to each failure mode (small, large or maximum openings) were determined based on historical data in conjunction with engineering judgment. The failure-mode-specific allocations (i.e. failure mode splits) developed using this approach are summarized in Table 5.3, along with the data sources used in their development.

The operational well failure frequencies were calculated for each failure mode and well configuration on a per well-year basis and are shown in Table 5.4. These frequencies were calculated using fault trees for each well configuration (such as is shown in Figure 5.5) in combination with the component failure rates from Table 5.2 and the failure mode splits shown in Table 5.3.

The operational well failure frequencies are dominated by failures of single-barrier pathways, namely failures of the wellhead or production casing below the surface casing shoe. The probability of a leak through multiple-barrier pathways, such as the surface casing, is multiple orders of magnitude lower. A comparison of failure frequencies for the different well configurations shows that the operational well failure frequencies decrease as the number of components that are required to establish a leak pathway increase.

The proportion of failures attributable to pathways involving either through-casing or through-wellhead releases is also shown in Table 5.4. The results show that, for well configurations with single-barrier pathways involving both the wellhead and the production casing (i.e. R1 and C1), the proportion of failures attributable to the wellhead is slightly less than half the total (with the remainder being attributable to the production casing failure pathway). For the remaining well configurations, which all involve additional downhole components that add a second barrier to pathways involving the production casing, the proportion of failures attributable to pathways involving the wellhead overwhelm the contribution from any other pathways.

Barrier	Data Source	Failure Frequency (per well-year)
Surface casing (SC)	GRI* (10)	8.0×10^{-6}
Production and intermediate casing (above SC shoe)	GRI* (10)	8.0×10^{-6}
Production and intermediate casing (below SC shoe)	GRI* (10)	7.2×10^{-5}
Wellhead Assembly	GRI (10)	5.4×10^{-5}
Tubing	AGA (10)	2.3×10^{-5}
Packer	SINTEF (58)	2.9×10^{-3}
DHSV	AGA (10)	2.0×10^{-5}

*inferred from GRI production casing failure rate

Table 5.2 Component Failure Rates for Operational Well Failure Estimation

Barrier	Failure Mode Split			Source
	Small Leak	Large Leak	Rupture	
Surface casing (SC)	83%	12%	5%	CAPP (66)
Production and intermediate casing (above SC shoe)	83%	12%	5%	CAPP (66)
Production casing and intermediate (below SC shoe)	83%	12%	5%	CAPP (66)
Wellhead Assembly	79%	17%	4%	HSE (67)
Tubing	91%	7%	2%	SINTEF (68)
Packer	85%	10%	5%	Engineering judgment
DHSV	0%	56%	44%	SINTEF (58)

Table 5.3 Well Component Failure Modes and Relative Contributions to Operational Well Failure Frequency

Well Configuration	Failure Rate (per well-year)				Proportion Due to Wellhead Failures
	Small Leak	Large Leak	Rupture	Total	
R1	1.0×10^{-4}	1.8×10^{-5}	5.7×10^{-6}	1.3×10^{-4}	43%
R2	4.3×10^{-5}	9.1×10^{-6}	2.1×10^{-6}	5.4×10^{-5}	100%
R3	3.6×10^{-7}	9.8×10^{-9}	8.7×10^{-10}	3.7×10^{-7}	43%
C1	1.0×10^{-4}	1.8×10^{-5}	5.7×10^{-6}	1.3×10^{-4}	43%
C2	4.2×10^{-5}	9.1×10^{-6}	2.1×10^{-6}	5.4×10^{-5}	100%
C3	4.2×10^{-5}	9.1×10^{-6}	2.1×10^{-6}	5.4×10^{-5}	100%

Table 5.4 Operational Well Failure Frequency by Failure Mode for Each Well Configuration

5.3.2 Isolated Well Entry Failure

For the example analyses, well entry failure frequencies were estimated for the act of well entry as a whole based on historical data that differentiates well entry failures by entry type (i.e. wireline operations, operations involving coiled tubing and workovers). A comprehensive assessment of various offshore well entry activities and their respective failure rates was carried out by the IOGP (65) and this study was used as the primary source of well entry failure frequencies in this analysis (see Table 5.5). Recognizing that offshore well operations and outcomes may differ somewhat from those of onshore wells, particularly onshore UGS wells, workover failure rates reported in an industry-supported study by GRI (10) that was specific to onshore UGS wells was also considered. The workover failure rate reported in the GRI study was 2.4×10^{-4} per entry, approximately half of the rate provided in the IOGP study. While the data set used in the GRI study was more limited than that reflected in the IOGP study, and given that the IOGP rates are cautiously pessimistic values intended for generic use in risk assessment, the lower failure rate obtained from the GRI study for workovers supported a decision to adopt a reference set of well entry failure frequencies equal to one-half the nominal IOGP values (see Table 5.5).

Entry Type	IOGP Failure Rate (per entry)	Reference Failure Rate (½ IOGP) (per entry)
Wireline	9.0×10^{-6}	4.5×10^{-6}
Coiled Tubing	1.1×10^{-4}	5.5×10^{-5}
Workover	4.0 × 10-4	2.0×10^{-4}

Table 5.5 Reference Failure Frequencies for Well Entry Activities

As for operational well failure frequency estimation, the mode of failure was also accounted for in estimating well entry failure frequencies. The mode splits used for well entry failures were derived from offshore hydrocarbon releases statistics compiled by HSE (67). The proportions of well entry failure attributable to each mode was taken to be independent of well entry type. The values used are shown in Table 5.6.

Failure Mode	Mode Splits
Small Leaks	9%
Large Leaks	73%
Ruptures	18%

Table 5.6 Well Component Failure Modes and Relative Contributions to Well Entry Failure Frequency

Based on the above, the reference well entry failure frequencies per well entry, by failure mode, for each type of well entry, were established (see Table 5.7).

Entry Type	Failure Rate (per well entry)			
	Small Leak	Large Leak	Rupture	Total
Wireline	4.1×10^{-7}	3.3×10^{-6}	8.1×10^{-7}	4.50×10^{-6}
Coiled Tubing	5.0×10^{-6}	4.0×10^{-5}	9.9×10^{-6}	5.50×10^{-5}
Workover	1.8×10^{-5}	1.5×10^{-4}	3.6×10^{-5}	2.00×10^{-4}

Table 5.7 Refence Failure Frequencies by Failure Mode for Well Entry by Type of Well Entry

5.3.3 Baseline Well Entry Failure

Estimation of the average annual well entry failure frequency (i.e. the baseline entry failure frequency) involved assessing the frequency of occurrence of typical well entry activities. The model used for the estimation of the baseline entry failure frequency is

$$FoF_{well-entry} = \sum_{i=1}^{3}\sum_{j=1}^{3} F(failure \mid entry\ type)_{ij} \times P(entry\ type \mid well\ entry)_i \times F(well\ entry) \qquad [5.1]$$

where $FoF_{well\text{-}entry}$ is the average baseline entry failure frequency per well-year, $F(failure \mid entry\ type)_{ij}$ is the frequency of failure for well entry type i and failure mode j, $P(entry\ type \mid well\ entry)_i$ is the probability that well entry type i will be selected given a well entry, and $F(well\ entry)$ is the average well entry frequency per year.

Baseline well entry frequencies were estimated based on two key assumptions:

1. Well entry type is a function of well configuration, with wells having a tubing string in place requiring more complex and/or invasive entry types than wells without tubing.
2. Baseline well entry frequency is a function of the well configuration, with wells having more downhole components requiring more frequent entry.

The baseline well entry frequencies for a given well configuration were determined from a combination of data sources, including information from offshore well and UGS well operator experience (77) and information obtained from the project survey. The selected well entry frequencies shown in Table 5.8 are intended to reflect entries routinely carried out on typical wells to restore or enhance well deliverability and to perform component testing and maintenance work. The consideration of the frequency associated with periodic casing integrity inspection and any associated casing remediation is excluded from this baseline entry evaluation because it will be addressed separately.

Reason for Well Entry	Well Entry Frequency (entries per year)	
	Wells with Tubing	Wells without Tubing
DHSV work – in configurations with DHSVs	3.00×10^{-2}	0
Casing work	8.02×10^{-5}	8.02×10^{-5}
Tubing work – in configurations with tubing	3.20×10^{-2}	0
Packer work – in configurations with tubing & packer	0	0
Cleanout and stimulation	2.00×10^{-2}	2.00×10^{-2}
Wellhead assembly work	1.00×10^{-3}	1.00×10^{-3}
Casing integrity testing	Considered separately	Considered separately
Downhole sensor work	0	0

Table 5.8 Baseline Entry Frequency for Each Entry Cause

When one of the tabulated reasons for well entry necessitates a well entry, an appropriate entry method must be selected, which can involve a workover, coiled tubing work, or a wireline entry. The probability that one of these three entry types will be required to address each reason for well entry was estimated based on industry survey data and consultation with SMEs. The available data indicated that work done on the casing or tubing, as well as casing integrity inspection, will require a workover. Available data also suggests that most, but not all, work done on DHSVs will require a workover. Conversely, downhole sensor work is assumed to only be addressed via wireline entry. Cleanout and stimulation are assumed to require either a workover or coiled tubing entry, whereas wellhead assembly work is assumed to involve either a workover or wireline entry. The estimated probabilities of each entry type being employed for each well entry reason are shown in Table 5.9.

Reason for Well Entry	Wells with Tubing			Wells without Tubing		
	Workover	Coiled Tubing	Wireline	Workover	Coiled Tubing	Wireline
DHSV work	80%	10%	10%			
Casing work	100%			100%		
Tubing work	100%					
Packer work						
Cleanout and stimulation	40%	60%		40%	60%	
Wellhead assembly work	40%		60%	40%		60%
Casing integrity testing	100%			10%		90%
Downhole sensor work			100%			100%

Table 5.9 Probability of Entry Type Given Well Entry for Each Reason for Well Entry

The selected annual baseline entry frequencies for each entry reason were combined with the probabilities of entry by entry type for each well configuration to obtain total baseline entry frequencies per year by entry type for each well configuration. The baseline entry frequencies by entry type for reservoir and cavern wells are shown in Figure 5.6 and Figure 5.7, respectively. The well entry activities for configurations R1, C1 and C2 consist primary of wireline entries due to the absence of tubing in those configurations. Conversely, workovers are the dominant contributor to the well entry frequencies in configurations R2, R3, and C3, as tubing work requires a workover or the equivalent (i.e. snubbing).

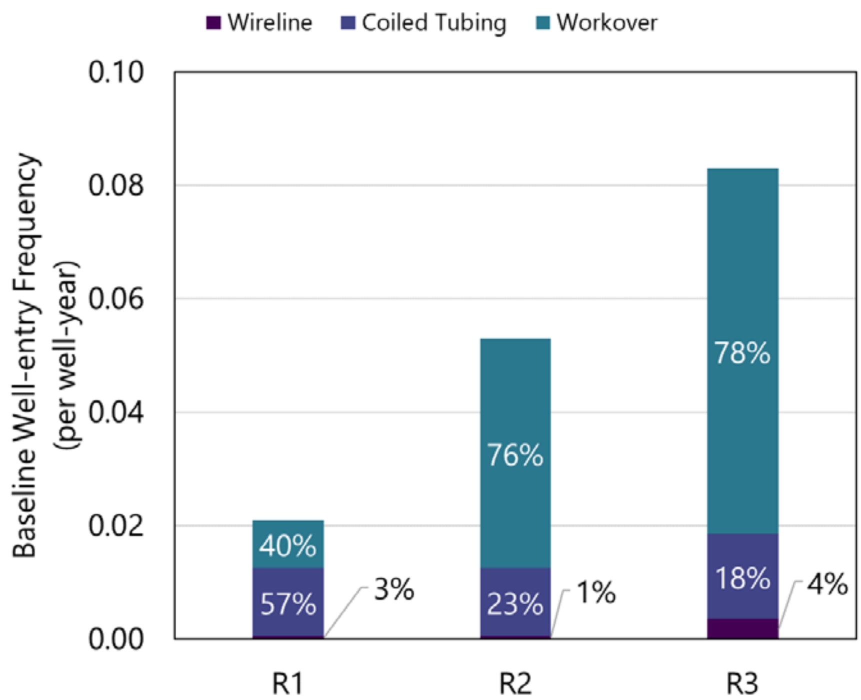


Figure 5.6 Baseline Well Entry Frequencies for Reservoir Wells by Entry Type

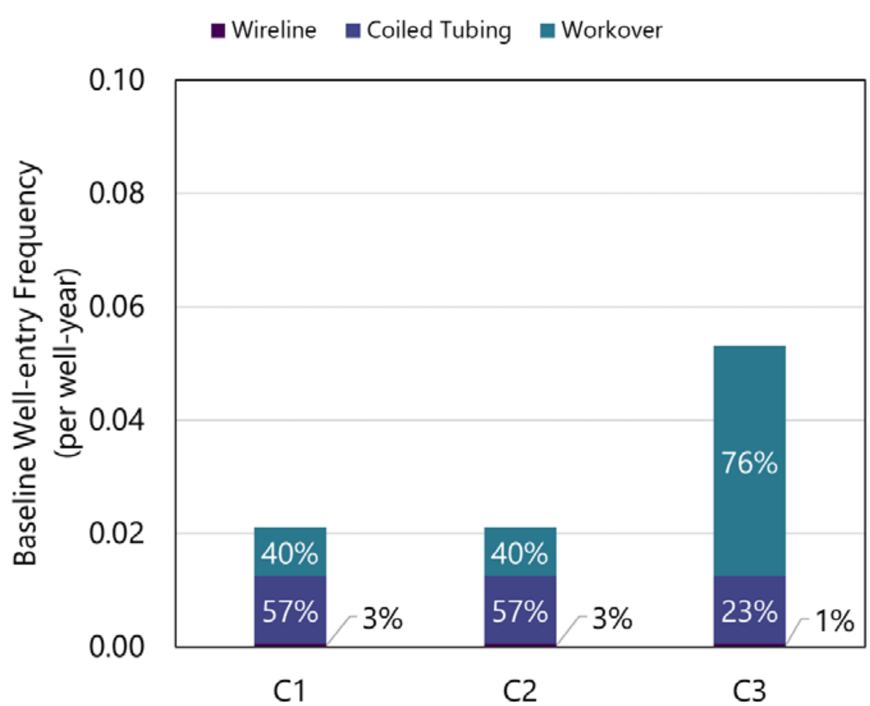


Figure 5.7 Baseline Well Entry Frequencies for Cavern Wells by Entry Type

Based on the above selected values for well entry frequency, entry type probability given well entry, and failure rate given entry type, the total baseline entry failure frequency per well-year was calculated for each well configuration using Equation 5.1. The resulting values are shown in Table 5.10.

Well Configuration	Failure Rate (per well-year)			
	Small Leak	Large Leak	Rupture	Total
R1	2.1×10^{-7}	1.7×10^{-6}	4.2×10^{-7}	2.4×10^{-6}
R2	7.9×10^{-7}	6.4×10^{-6}	1.6×10^{-6}	8.8×10^{-6}
R3	1.2×10^{-6}	1.0×10^{-5}	2.5×10^{-6}	1.4×10^{-5}
C1	2.1×10^{-7}	1.7×10^{-6}	4.2×10^{-7}	2.4×10^{-6}
C2	2.1×10^{-7}	1.7×10^{-6}	4.2×10^{-7}	2.4×10^{-6}
C3	7.9×10^{-7}	6.4×10^{-6}	1.6×10^{-6}	8.8×10^{-6}

Table 5.10 Baseline Entry Failure Frequencies by Failure Mode for Each Well Configuration

5.3.4 Combined Operational and Baseline Well Entry Failure Frequencies

Given the calculated operational and baseline entry failure frequencies, the total baseline failure frequencies per well-year were calculated as the sum of the two for each well configuration. The total combined annual failure frequencies are shown in Table 5.11 for reservoir well configurations and Table 5.12 for cavern well configurations.

Additionally, the proportion of the total failure frequency that can be attributed to baseline well entry activities, rather than well operation, are also shown for each configuration. The proportion of the total failure frequency ascribed to well entry is highest for well configurations having multiple downhole component barriers to product release (i.e. R2, R3 and C2 and C3). This stems from the fact that multiple downhole barriers lowers the overall operational failure frequencies, but it increases well entry failure frequencies because more entries are required to manage the additional downhole components and the required entries can be more invasive and, thereby, failure prone (i.e. workovers), particularly for wells where the additional downhole barrier involves tubing that must be removed to facilitate well entry.

Well Configuration	Failure Mode Subset Included	Operation + Baseline Entry Failure Rate (per well-year)	Proportion Ascribed to Well Entry	Proportion Included in the Subset of Modes
R1	SL + LL + RU	1.3×10^{-4}	2%	100%
	LL + RU	2.6×10^{-5}	8%	20%
	RU	6.2×10^{-6}	7%	5%
R2	SL + LL + RU	6.3×10^{-5}	14%	100%
	LL + RU	1.9×10^{-5}	41%	31%
	RU	3.7×10^{-6}	42%	6%
R3	SL + LL + RU	1.4×10^{-5}	97%	100%
	LL + RU	1.3×10^{-5}	100%	89%
	RU	2.5×10^{-6}	100%	18%

Table 5.11 Combined Operational and Baseline Entry Failure Frequencies for Reservoir Wells

Well Configuration	Failure Mode Subset Included	Operation + Baseline Entry Failure Rate (per well-year)	Proportion Ascribed to Operation	Proportion Included in the Subset of Modes
C1	SL + LL + RU	1.3×10^{-4}	2%	100%
	LL + RU	2.6×10^{-5}	8%	20%
	RU	6.2×10^{-6}	7%	5%
C2	SL + LL + RU	5.6×10^{-5}	4%	100%
	LL + RU	1.3×10^{-5}	16%	24%
	RU	2.6×10^{-6}	17%	5%
C3	SL + LL + RU	6.2×10^{-5}	14%	100%
	LL + RU	1.9×10^{-5}	42%	31%
	RU	3.7×10^{-6}	42%	6%

Table 5.12 Combined Operational and Baseline Entry Failure Frequencies for Cavern Wells

For discussion purposes, the tabulated failure rates for each well configuration are displayed for various combinations of failure modes: either all modes combined, large leak and rupture, or rupture only. These failure mode subsets serve to highlight that ruptures are expected to account for a relatively low proportion of the total expected number of failures per year (5 to 18% for reservoirs and 5 to 6% for caverns).

Focusing on the high-consequence rupture failures only, first for the reservoir well configurations analyzed, the introduction of a tubing and packer assembly in configuration R2 is shown to reduce the rupture failure frequency by 40% (compared to configuration R1 without a tubing and packer), but the further introduction of a DHSV, while significantly lowering the operational rupture frequency, yields a further reduction in the total rupture failure frequency of only 32% (which amounts to only a 60% reduction in the rupture frequency compared to configuration R1 without tubing, packer and a DHSV). This is because the DHSV requires more frequent and invasive workovers to maintain, so the entry-related rupture failure frequency increases to a degree that it significantly undermines the operational reliability improvement afforded to the well by the presence of a DHSV.

For the cavern well configurations analyzed, the introduction of an intermediate casing in configuration C2 is shown to reduce the rupture failure frequency by 58% (compared to configuration C1 without intermediate casing), but the presence of a suspended tubing string in configuration C3 is shown to increase the rupture failure frequency by 42% compared to the same configuration without the tubing string. This is because the presence of the tubing string, while facilitating well operation and cavern maintenance, increases the likelihood that well entry will require a more invasive entry method to first remove the tubing, thereby increasing the entry-related contribution to the total rupture failure frequency.

5.4 Consequence Estimation

5.4.1 Flow Modeling

The consequences of well failure are largely a function of the flow rate of the gas being released, which depends on the characteristics of the failure pathway between the gas storage location and the atmosphere. For safety consequences, the gas release rate was used in combination with a modified version of the C-FER jet fire model (44) to estimate the extent of the thermal radiation hazard zone that would develop in the event of an ignited gas release, and the chance of fatality as a function of distance from the wellhead. For environmental consequences, the release volume was chosen as the risk measure, and it was estimated as the product of release rate and release duration.

Analytical models provide a means to calculate flow rates within the multiple flow paths that could develop within the well. The models required should address flow through holes or openings where failure occurs, and flow through either the production casing or tubing and, ideally, flow to the ground surface outside the casing. The simplified model described herein provides results that are deemed adequate for most QRAs of UGS wells. For flow-through holes, the release rate was estimated using one of two simple equations that are chosen depending on whether the flow is choked (i.e. sonic across the orifice) or not. These equations assume steady-state compressible flow through a circular orifice. For flow along the casing or tubing, a compressible, steady-state, adiabatic flow model assuming a constant cross-sectional area was used. The use of this model, customarily referred to as a Fanno flow model, is appropriate because it accounts for temperature changes in the gas, as well as friction effects, as the gas travels through the casing and/or tubing.[6]

Predictions of gas outflow were obtained by using the above models to calculate flow rates for each orifice and duct along each flow path. The flow through each component was calculated separately, assuming a driving pressure equivalent to that of the full cavern/reservoir pressure, regardless of its location in the path. The flow rate for a given flow path was then estimated by selecting the lowest of the individual duct and orifice flow rates. This approach does not account for interactions between the various ducts and orifices comprising a given flow path and, therefore, tends to overestimate the flow rate. While conservative, this approach was determined to be sufficiently accurate for flows through the release pathways that have a dominant impact on overall well risk for the well configurations evaluated herein.

Application of this approach required assumptions about certain key input parameters—specifically, the orifice discharge coefficient and the duct surface roughness. The discharge coefficient and the surface roughness were assumed to be 0.6 and 0.00181 inch, respectively, for all cases.

Other input parameters, such as duct length, duct inner diameter, orifice diameter, inlet pressure and outlet pressure, are prescribed by the reservoir and well attributes, and are unique to each individual flow path.

Finally, the required thermodynamic gas properties (specific heat ratio, density, viscosity, compressibility factor, etc.) were based on the assumption that the storage gas is 100% methane.

5.4.2 Release Rates and Well Deliverability

The hole sizes specified for each failure mode and their corresponding flow rates are given in Table 5.13. For small leaks, large leaks and ruptures, the hole diameters were taken to be 1%, 10%, and 100% of the duct diameter (i.e. casing or tubing), except in the case of casing ruptures where

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[6] An isothermal model could also be used to approximate flow through a constant area duct; however, isothermal flow models tend to overestimate the flow rate, and are more appropriate for uninsulated ducts in which the flowing fluid is subsonic and has a low specific heat ratio (~1.0). Most of the calculated outflows applicable to gas well failure are choked (i.e. they reach sonic conditions at some point along the flow path). Furthermore, it is not reasonable to assume that the ducts (i.e. tubing and casing strings) that are surrounded by consolidated soil are uninsulated. On that basis, it was determined that isothermal flow models are not appropriate for this application.

a smaller value equal to 25% of the duct diameter was assumed. This assumption was based on the observation that flow through a production casing opening does not lead to a direct release to the atmosphere, but rather movement through the ground to the surface. Depending on the soil consolidation and the location of the casing opening, flow through the soil can further throttle the release rates. In some cases, casing hole releases have also been observed to tunnel through the soil to ground surface. It was assumed that a casing rupture event would not likely create an effective opening equivalent in size to the casing area. The assumption of an effective casing opening of 25% of the casing cross-section area, to acknowledge flow throttling by the formation, is obviously a crude approximation. However, it is noted that this is a known area of uncertainty for well failure modeling (78) and further research is required to develop more accurate models.

An additional consideration required to properly assess flow rates in the assessment of reservoir wells is reservoir deliverability. The estimated release rates from the previously described models do not consider formation deliverability constraints and, as such, are directly applicable to cavern well configurations only. Consideration of deliverability constraints in depleted reservoir storage wells is required to determine the extent of the flow rate throttling. In this study, deliverability-limited flow rates were calculated from a representative depleted reservoir inflow performance relationship (IPR) curve with an assumed 350 MMSCFD open flow (~75 kg/s), which represents the midpoint of the open flow range reported in the GRI study (10) for typical UGS well open flow values. An approximation to the IPR curve for a given reservoir is given by (79):

$$Q = Q_{max}\left(1 - \left(\frac{P}{P_{max}}\right)^2\right)^n \qquad [5.2]$$

where Q is flow rate, P is pressure, P_{max} is downhole pressure, Q_{max} is the maximum open flow rate, and the exponent n is a parameter that ranges between 0.5 and 1.0. A representative value of 0.65 was selected for the n parameter in this illustrative analysis. (Note that n is a secondary parameter that does not strongly influence the results obtained from the use of the approximate IPR curve.)

Figure 5.8 shows pressure versus flow rate relationships for a complete wellhead failure, where flow is assumed to travel the entire length of the well (5000 feet) to the wellhead through either the production casing or tubing. As cavern flow is not subject to deliverability constraints, the flow rate of each failure path in a cavern well was calculated using maximum downhole pressure. A constant reference line at maximum downhole pressure is shown on Figure 5.8; its intersection with the curve associated with each failure path indicates the value of the flow rate used for cavern well releases.

Figure 5.8 also shows the IPR curve that describes the deliverability limitations that apply to the reservoir well configurations. The points of intersection of the wellhead failure pathway curves with the IPR curve indicate the throttled flow rates that will develop in the event of wellhead failure of a reservoir well. The limiting effect of deliverability is more pronounced for the production casing release scenario due to its larger duct size compared to that of the tubing.

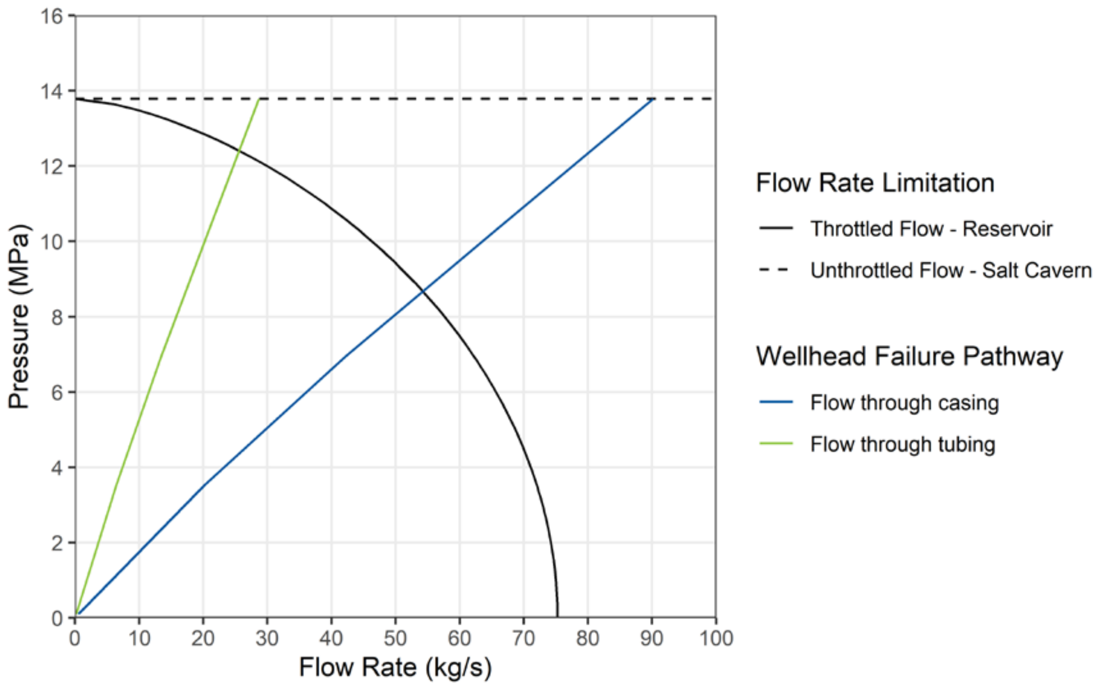

Figure 5.8 Pressure vs. Flow Rate for Wellhead Failures Considering Deliverability Throttling

The reservoir inflow performance literature can be interpreted to suggest that initial flow rates from reservoir wells will not be limited by deliverability constraints to the same degree as longer-term releases. Given this, the use of deliverability-throttled flow rates would be non-conservative in the estimation of life safety risk, since gas ignition, if it occurs, is likely to be near-intermediate, implying the establishment of a burning gas jet and harm to exposed individuals before the flow throttling effects of the reservoir fully develop. In contrast, environmental risk is a function of the total released volume over the duration of the release event, wherein deliverability constraints are expected to dictate the applicable average flow rate for reservoir wells. Therefore, for the purposes of this analysis, safety risk for reservoir well configurations was calculated using flow rates that were assumed to be uninhibited by deliverability constraints, whereas environmental risk calculations were based on reservoir-throttled flow rates. For cavern well configurations, both safety and environmental risk were based on unrestricted flow rates, as flow throttling does not occur. In Table 5.13, calculated release rates are shown for single-barrier (i.e. dominant) failure paths for small leaks, large leaks, and ruptures. The unrestricted flow rates are shown together with reservoir-throttled flow rates in parentheses for release scenarios where the reservoir throttling effect has a significant impact on the effective sustained release rate.

Flow Path	Failure Mode	Orifice Diameter (mm)	Release rate (kg/s)
Wellhead release (flow through tubing)	Small Leak	1	0.012
	Large Leak	11	1.46
	Rupture	114	28.7 (25.4)†
Casing hole release	Small Leak	2	0.048
	Large Leak	18	3.91
	Rupture	44.4*	23.8
Wellhead release (flow through casing)	Small Leak	2	0.048
	Large Leak	18	3.91
	Rupture	178	90.16 (54.7)†

*Effective hole sizes for casing ruptures assumed to be 25% of the casing diameter
†Deliverability-limited values calculated from a representative reservoir IPR curve with a 350 MMSCFD open flow.

Table 5.13 Release Rates for Dominant Single Barrier Failure Scenarios

5.4.3 Release Duration

As environmental consequences are characterized in this study in terms of the released volume, the volume estimate requires computation of both flow rate and duration. The expected release duration was determined by 'distribution fitting' to historical release duration data from a reliability study of well completions for offshore wells (58). Offshore releases are expected to have longer durations than comparable onshore wells, suggesting that the data provides a conservative basis for this example analysis. The historical release durations were found to be log-normally distributed, as shown in Figure 5.9. (The figure also shows the release durations for selected historical well failures, including the 2015 Aliso Canyon UGS well release.) It is noted that release events associated with large release rates will typically have a relatively short duration, but the historical data suggests that very long duration events are also possible. The potential for infrequent but long duration releases has a significant effect on the expected value assumed with the release duration distribution. The best-fit lognormal distribution has an expected value of 20 days. This release duration was applied to all well failure modes.[7]

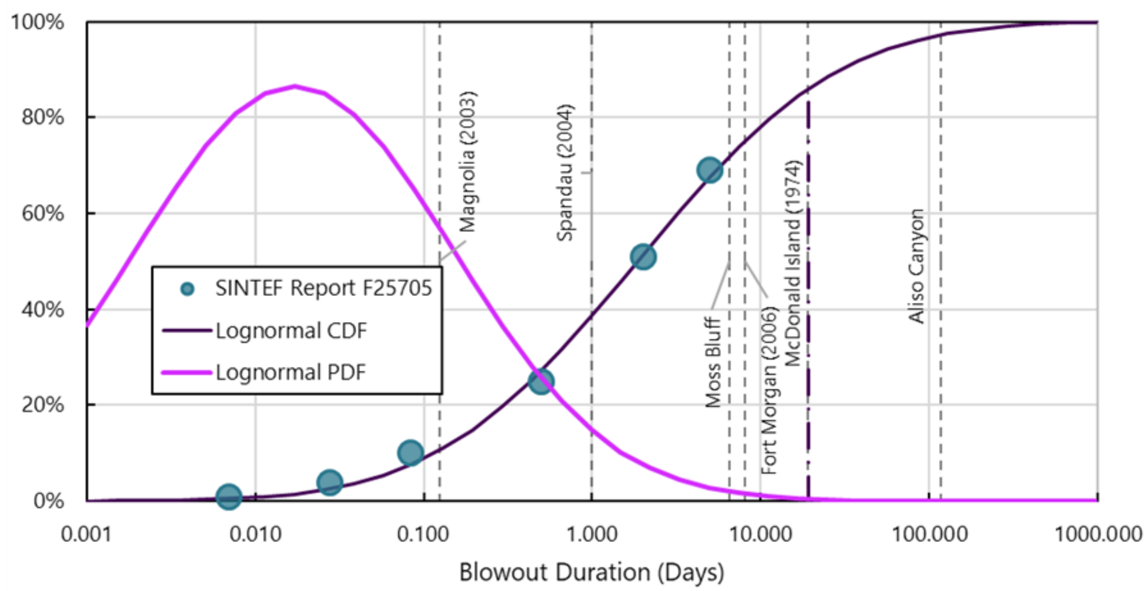

Figure 5.9 Distribution Fit for Release Durations Based on Data from SINTEF (58,68)

5.5 Risk Estimation and Evaluation

5.5.1 Safety Risk

5.5.1.1 Overview

As described in the guidelines, life safety risk is generally best estimated and evaluated in terms of both IR and societal risk. Estimation of societal risk requires information regarding land use in the vicinity of the well (as it affects occupancy times), population density and population proximity to the well. IR requires similar land use information and the selection of offset distances at which to calculate risk. To avoid making analysis assumptions that restrict the interpretation of results, it

[7] It is acknowledged that the offshore incident data that formed the basis for this release duration characterization is not directly applicable to small leaks, because they are not fully reflected in the SINTEF data (57,66). However, the contribution to the total expected release volume from small leaks was found to be small (see Section 5.5.2.2), meaning that the environmental risk estimates developed in this analysis are not significantly influenced by the assumed small leak duration.

was assumed that the well configurations evaluated are all located in relatively sparely populated areas where IR is usually the governing measure of public safety risk and LSIR was chosen as the IR measure because LSIR assumes continuous outdoor expires, making it effectively land-use-independent.

The LSIR is given by

$$LSIR = \sum_{i=1}^{n} \sum_{j=1}^{3} POF_{ij} \text{ x } POI_j \text{ x } POD_{ij} \qquad [5.3]$$

where $POFij$ is the probability of failure (POF) for pathway i, failing in mode j (for the year in question); $POIj$ is the probability of ignition (POI) for failure mode j (per event); $PODij$ is the probability of death (POD) at the location of interest for ignited release through pathway i, failing in mode j (per event); and n is number of distinct well failure pathways to surface.

The POF is available from the failure frequency analysis previously described in Sections 5.3.1 and 5.3.2. The POI is estimated from relevant historical data, as described in Section 5.5.1.2. The POD is determined from the release rates calculated as previously described in Section 5.4.2, using an adaptation of C-FER's gas jet fire hazard model (44) as described in Section 5.5.1.4.

The extent of the hazard zones potentially associated with injury and fatality, resulting from exposure to the thermal radiation produced by the jet fire resulting from gas ignition, are developed in Section 5.5.1.3. These hazard zone distances were used to inform the selection of the offset distance chosen to evaluate the LSIR.

5.5.1.2 Probability of Ignition

The primary contributor to life safety risk is ignition of the escaping gas stream. In this analysis, all ignited releases were assumed to pose a safety risk. The POI was estimated separately for well failures during normal operation and well entry based on relevant historical data.

For well failure during operation, the POI was estimated as a function of release rate as suggested in UKOOA (80), which provides POI values that are recommended for use in oil and gas scoping QRAs. The POI values provided for gas releases by UKOOA are 1%, 3% and 10% for release rates that correspond to the small leak, large leak, and rupture, failure mode categories employed in this assessment.

For well failure during well entry, a UGS-specific study by GRI (10) reports that significant UGS well releases have a POI of approximately 50%. This higher POI is attributed to the greater likelihood of ignition sources in proximity to the wellhead during well entry and/or the greater likelihood of actions in the vicinity of the wellhead during well entry that have the potential to cause ignition due to static electrical discharge. Based on this information, the UKOOA POI values used for operational failures were scaled up by a factor of five, yielding POI values for well entry of 5%, 15% and 50% for the small leak, large leak, and rupture release categories, respectively. These ignition probabilities are summarized in Table 5.14.

Failure Mode (Release Rate, kg/s)	Probability of Ignition	
	Operational	Well Entry
Small leak (<1)	1%	5%
Large Leak (1 to 50)	3%	15%
Rupture (>50)	10%	50%

Table 5.14 Probability of Ignition Values for Operational and Well Entry Failures

5.5.1.3 Hazard Zones

While not directly used in estimating IR or societal risk, the determination of the extent of the thermal radiation hazard zones that develop in the event of gas ignition is relevant for land use planning, specifically the establishment of appropriate development setback distances. In this regard, it informed the selection of the offset distances from the wellhead at which the LSIR was calculated for the well configurations evaluated in this study.

Using the jet fire heat intensity versus distance model developed by Stephens et al. (44), as adapted to incorporate the gas release rates developed for the various well configurations and failure pathways considered herein, the distance from the wellhead to locations at which the heat intensity would correspond to prescribed heat intensity levels were determined for failures of the wellhead. These distances define the radii of circular hazard zones centered on the wellhead.

The inner hazard zone, defined by the radial extent beyond which the heat intensity would not be expected to exceed 5000 Btu/hr/ft^2 (15.8 kW/m^2), encompasses the zone within which the chance of fatal burn injury in the event of an ignited wellhead release is significant for exposed individuals that are able to reach shelter in a reasonable time period (i.e. 30 seconds).[8] The outer hazard zone, defined by a heat intensity threshold of 1,600 Btu/hr/ft^2 (5 kW/m^2), delineates the zone beyond which the chance of sustaining a serious burn injury would be very low for exposed individuals that are able to reach shelter in a reasonable time period.

[8] The extent of the inner zone associated with a heat intensity threshold of 15.8 kW/m^2 corresponds to the heat intensity threshold used to delineate the PIR that is referenced in US Federal regulations 49 CFR 192 (81) for the integrity management of natural gas pipelines in high consequence areas.

The calculated hazard zone distances to the perimeter of the inner (fatal) hazard zones and outer (injury) hazard zones are summarized for all well configurations, by failure mode, in Tables 5.15 and 5.16 for operational and entry-related failures, respectively. Also included in the tables for reservoir wells are the reduced hazard zones distances that apply if ignition is delayed and the release rates are assumed to be throttled by reservoir deliverability constraints (see values in parenthesis).

Well Configuration	Failure Mode	Reservoir Wells Hazard Zone Distance(m)		Cavern Wells Hazard Zone Distance (m)	
		Inner	Outer	Inner	Outer
1	Small leak	1	1	1	1
	Large leak	8	15	8	15
	Rupture	40 (31)	71 (55)	40	71
2	Small leak	1	1	1	1
	Large leak	5	9	8	15
	Rupture	22 (21)	40 (38)	40	71
3	Small leak	1	1	1	1
	Large leak	8	15	8	15
	Rupture	23 (23)	41 (41)	40	71

Table 5.15 Hazard Zone Distances for Operational Failures

Well Configuration	Failure Mode	Reservoir Wells Hazard Zone Distance (m)		Cavern Wells Hazard Zone Distance (m)	
		Inner	Outer	Inner	Outer
1	Small leak	1	2	1	2
	Large leak	8	15	8	15
	Rupture	40 (31)	71 (55)	40	71
2	Small leak	1	2	1	2
	Large leak	8	15	8	15
	Rupture	40 (31)	71 (55)	40	71
3	Small leak	1	2	1	2
	Large leak	8	15	8	15
	Rupture	40 (31)	71 (55)	40	71

Table 5.16 Hazard Zone Distances for Well Entry Failures

5.5.1.4 Probability of Death

Various empirical models are available for estimating the POD as a function of the dosage of thermal radiation received. For a given well failure scenario and gas release rate, this calculation depends on the location of interest and the time for an exposed individual to reach shelter. The POD is usually expressed using a probit function, a special form of a quantile function that can be used to relate POD to the severity of hazard exposure (i.e. the hazard dosage). For thermal radiation exposure, the hazard dosage is usually expressed as a function of heat intensity, I, and exposure time, t. The most commonly cited probit function for fatality due to thermal radiation exposure was derived by Eisenberg et al. (82), which takes the form:

$$Y = -14.9 + 2.56 \ln\left(t \cdot I^{4/3}\right) \qquad [5.4]$$

where Y is the probit value, t is the exposure time in seconds, and I is the heat flux in kW/m^2.[9]

[9] A similar relationship was used by Stephens et al. (43) to delineate the hard zone extent represented by the PIR formula for natural gas pipeline integrity management in high consequence areas.

The POD is determined by calculating the cumulative value of the distribution function at Y for a normal distribution with a mean and standard deviation of five and one, respectively. The resulting POD versus heat intensity relationship, for an assumed exposure period of 30 seconds, is shown in Figure 5.10. Also shown in Figure 5.10 are the heat intensity levels that define the perimeter of the fatality and injury hazard zones develop in Section 5.5.1.3.

Given a location, the heat intensity versus distance relationship adapted from the fire model by Stephens et al. (44) is used to obtain the heat intensity for a given ignited release scenario and the Eisenburg probit function is then used to estimate the POD for the assumed exposure period.

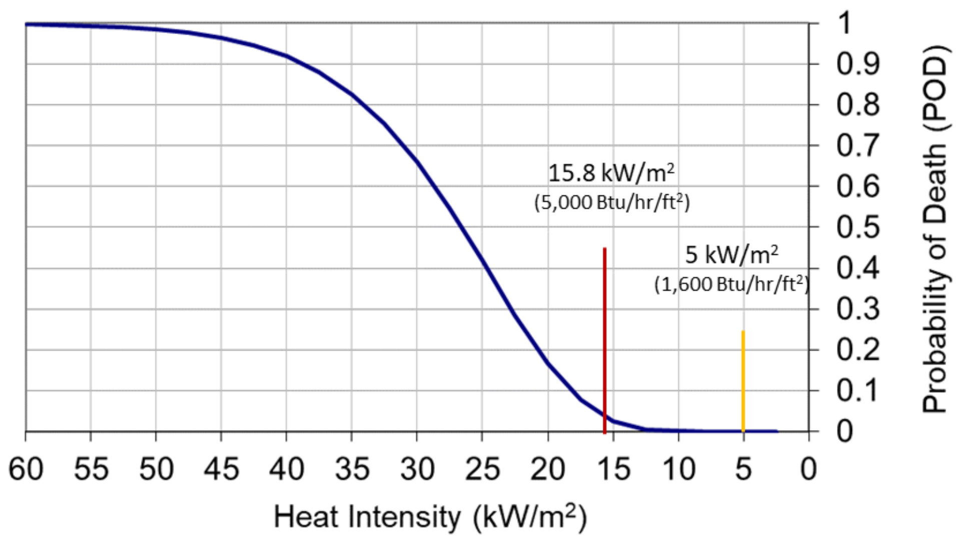

Figure 5.10 Probability of Death Due to Thermal Radiation

5.5.1.5 Location-specific Individual Risk

The LSIR for each well configuration was estimated using Equation [5.3], together with the information summarized in Sections 5.5.1.2 through 5.5.1.4. The LSIR values were calculated as the sum of the annual LSIR attributable to normal well operation and the additional LSIR attributable to well entry for the year within which entry was assumed to occur. The combined annual LSIR was determined assuming that well entry in the year under consideration involved either a wireline operation, an operation involving the use of coiled tubing or a workover. For wells with configurations that include tubing, consideration was also given to the LSIR in the year when two workovers are performed (e.g. once to inspect the casing and again to make casing repairs).

The combined well operation plus well entry LSIR values were first estimated at a setback distance of 30 m (100 feet), that being the minimum setback distance identified in a review of regulations for various states.[10] The LSIR was also estimated at a larger setback distance of 40 m (130 feet), which corresponds the maximum radial extent of the inner hazard zone as determined in Section 5.5.1.3.

The LSIR values, calculated as a function of well entry type, for each well configuration, are summarized in Figure 5.11 for a 30 m setback and in Figure 5.12 for a 40 m setback. The percentages shown at the bottom of each bar represent the proportion of the LSIR that is attributable to well entry. The lighter colored bars shown nested inside the solid colored bars for reservoir wells represent the reduced LSIR values that result if gas ignition in the event of rupture is assumed to be delayed such that gas flow rates are throttled by reservoir deliverability constraints prior to ignition. Also shown in the figures are two risk thresholds (i.e. 10^{-6} and 10^{-5}) that, depending on land use, may be interpreted to define acceptability thresholds for individual fatality risk (see Section 4.4.4.6).[11]

At a setback distance of 30 m (see Figure 5.11), the LSIR values are shown to be dominated by well entry risk and, on that basis, it is not surprising that the LSIR values are similar for all well configurations, but with higher LSIR values being associated with more complex and failure prone entry types (i.e. coiled tubing work and, more particularly, workovers). Based on the assumption of immediate ignition (in which case reservoir deliverability does not constrain outflow), the results show that, in a year when wireline work is performed, the LSIR level for all well configurations is below the lowest 10^{-6} IR threshold value. When coiled tubing work is performed, the LSIR values in that year exceed the 10^{-6} threshold. When a single workover is performed, the LSIR approaches or reaches the 10^{-5} threshold, depending on well configuration, and when a double workover is performed in a single year, the 10^{-5} threshold is exceeded. The results also show that if gas ignition is delayed, flow rate throttling due to reservoir deliverability constraints lowers the LSIR values for reservoir wells by approximately one order of magnitude for all entry types.

[10] This setback distance is the minimum value prescribed by various states, including New York, Ohio, Pennsylvania, Michigan, and West Virginia, which were found to range from 100 to 300 feet.
[11] Note that assessing LSIR against IR thresholds that are typically defined under the assumption that location occupancy is not continuous is conservative.

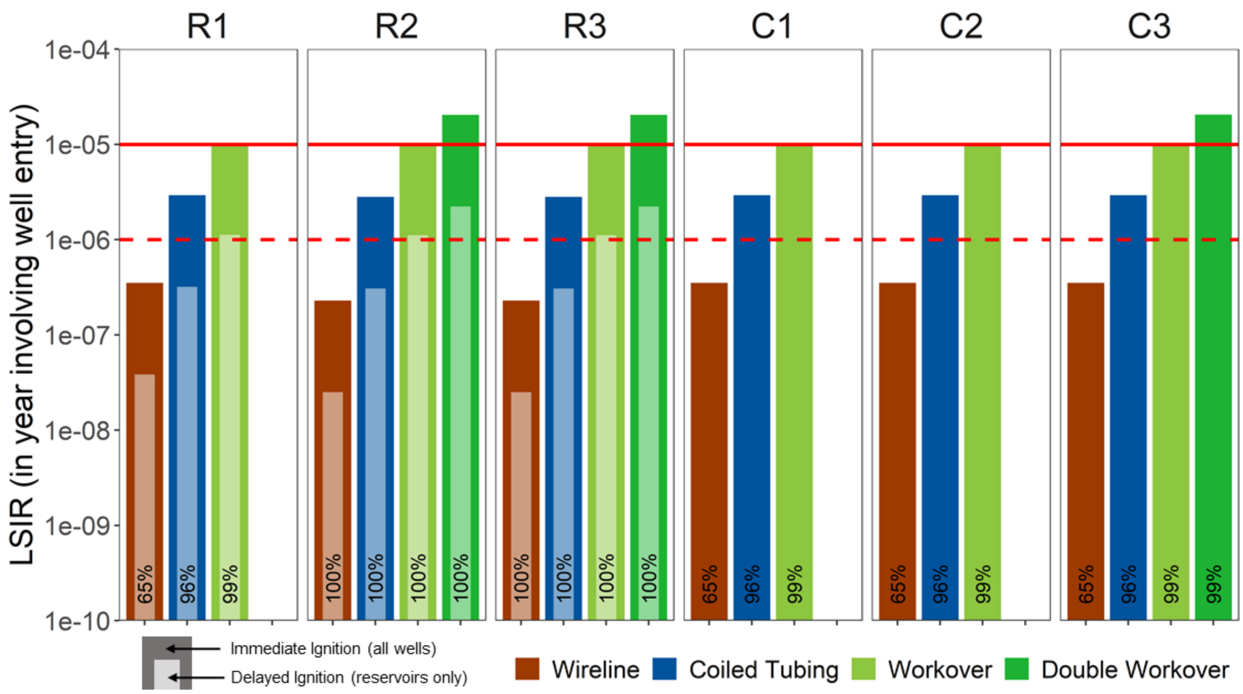

Figure 5.11 LSIR for Each Well Configuration and Entry Type at 30 m Setback Distance

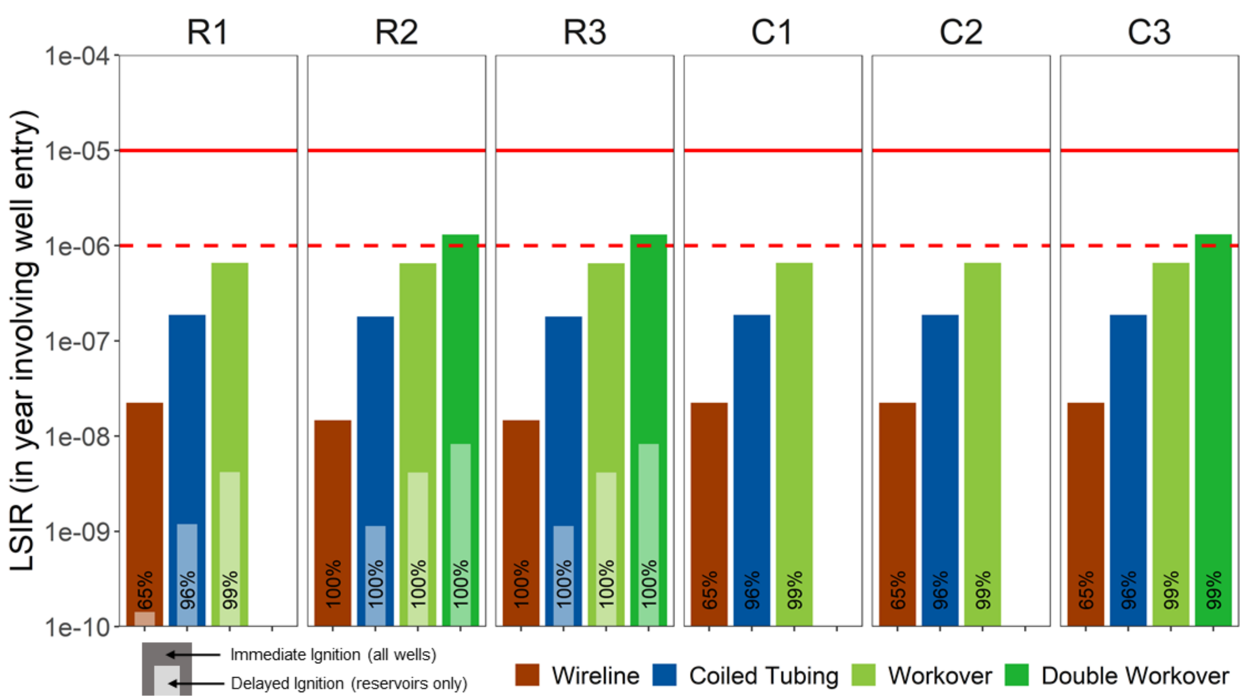

Figure 5.12 LSIR for Each Well Configuration and Entry Type at 40 m Setback Distance

At an increased setback distance of 40 m (see Figure 5.12), the LSIR values are shown to be approximately one order of magnitude lower for all well configurations and well entry types. This highlights the sensitivity of IR to the offset distance and shows that a modest 33% increase in offset, to a distance equal to the perimeter of the inner hazard zone (see Section 5.5.1.3), lowers the LSIR for all well configurations and entry actions (except for a double workover) to a level below the lower 10^{-6} IR threshold. At this distance, delayed ignition in combination with reservoir deliverability throttling is also shown to lower the LSIR values for reservoir wells by two orders of magnitude for all entry types.

Collectively, these results indicate that, for typical UGS well sizes and configurations, entry involving wireline operations does not pose a significant safety risk to the public, but coiled tubing work and, more particularly, workovers do present a more significant threat to public safety and the findings suggest that increased setback distances, on either a permanent or temporary basis (i.e. during invasive well entry operations), may be warranted. The results also suggest that the setback distance for a given well should reflect the anticipated size of the hazard area associated with the worst-case well failure, which depends on the maximum achievable gas outflow rate, which in turn can be shown to depend on key well parameters, including well diameter, well depth and gas storage pressure.

5.5.2 Environmental Risk

5.5.2.1 Overview

As described in the guidelines, a simple objective measure of the potential long-term environmental impact of a UGS well release is the total quantity of gas released. The environmental risk measure considered in this demonstration analysis is, therefore, the probability-weighted or expected gas release volume.

This expected release volume, $V_{release}$, is given by:

$$V_{release} = \sum_{i=1}^{n} \sum_{j=1}^{3} POF_{ij} \times Rate_{ij} \times Duration_{ij} \quad [5.5]$$

where POF_{ij} is the POF for pathway i, failing in mode j (for the year in question); $Rate_{ij}$ is the release rate for failure for pathway i, failing in mode j (per event); $Duration_{ij}$ is release duration for failure for pathway i, failing in mode j (per event); and n is the total number of distinct well failure pathways to surface.

The *POF* is available from the failure frequency analysis previously described in Sections 5.3.1 and 5.3.2. The *Rate* and *Duration* are available from the consequence analysis previously described in Sections 5.4.2 and 5.4.3, respectively. For estimating the reservoir well risk, deliverability-throttled flow rates were used. For cavern wells, the unlimited flow rates, assuming full storage pressure as the driving pressure, were used.

The guidelines also indicate that there is as yet no established precedent for an acceptable level of environmental risk when expressed in terms of the expected release volume. Risk evaluation is therefore approached on a comparative basis, wherein well configurations and maintenance strategies involving well entry are evaluated in terms of the differences in the calculated expected release volumes between the various well configurations or between various hypothetical well entry activities and frequencies.

A comparative evaluation of the estimated average annual environmental risk for the well types and well configurations developed for consideration in this demonstration analysis is described in Section 5.5.2.2.

A comparative evaluation of the estimated environmental risk for a set of hypothetical well entry scenarios, involving a subset of well configurations, is described in Section 5.5.2.3. Given that well entry is a periodic activity, the comparative analysis of hypothetical well entry scenarios involved aggregation of the calculated annual environmental risk over prescribed evaluation periods. To facilitate comparisons between entry scenarios having different evaluation periods, the cumulative risks for each well entry scenario and associated evaluation period were annualized prior to comparison.

It is noted that the expected release volume estimates obtained using Equation [5.5] conservatively ignore the fact that for long duration, high flow rate releases, the flow rates will trend downwards over time as the gas supply is depleted and the storage pressure falls. It is also noted that the expected release volume given by Equation [5.5] presumes that gas ignition does not occur. In fact, gas ignition, should it occur, will convert the natural gas, predominantly consisting of methane, into carbon dioxide and water vapor. Carbon dioxide is also a greenhouse gas, but it is less potent in that regard than methane. In the interest of analysis simplicity and to achieve consistently conservative estimates of long-term environmental impact, the effect of gas ignition on long-term environmental impact was therefore ignored. Also, given that the environmental risk evaluation presented herein is based on relative differences in expected release volume, rather than the absolute value of the expected release volume, a consistently conservative approach to estimating the expected release volume will not significantly impact the risk evaluation results.

5.5.2.2 Environmental Risk Comparison – Impact of Well Type and Configuration

A comparative evaluation of the environmental risk for the well types and well configurations developed for consideration in this demonstration analysis involved calculating and combining the annual operating risk and the baseline well entry risk, the latter of which is effectively the annual average of the risk resulting from routine, periodic well entry activities required to maintain the different well configurations considered herein (see Section 5.3.4).

The calculated annual environmental risk attributable to well operation is shown for each well type and configuration, by mode of failure, in Table 5.17. The average annual environmental risks attributable to routine periodic well entry (i.e. baseline well entry) are shown in Table 5.18. The combined annual environmental risk estimates are shown in Figure 5.13.

Well Configuration	Operational Environmental Risk (SCF per well-year)				Proportion Due to Wellhead Failures
	Small Leak	Large Leak	Rupture	Total	
R1	3.5×10^2	6.2×10^3	2.1×10^4	2.7×10^4	52%
R2	5.8×10^1	1.3×10^3	5.0×10^3	6.4×10^3	100%
R3	7.7×10^{-1}	2.7	2.3	5.7	36%
C1	3.5×10^2	6.2×10^3	2.8×10^4	3.4×10^4	62%
C2	1.4×10^2	3.2×10^3	1.8×10^4	2.1×10^4	100%
C3	1.4×10^2	3.2×10^3	1.8×10^4	2.1×10^4	100%

Table 5.17 Operational Environmental Risk for Each Well Configuration

Well Configuration	Well Entry Environmental Risk (SCF per well-year)				Proportion Due to Wellhead Failures*
	Small Leak	Large Leak	Rupture	Total	
R1	9.5×10^{-1}	6.2×10^2	2.1×10^3	2.8×10^3	100%
R2	3.5	2.3×10^3	8.0×10^3	1.0×10^4	100%
R3	5.5	3.6×10^3	1.3×10^4	1.6×10^4	100%
C1	9.5×10^{-1}	6.2×10^2	3.5×10^3	4.2×10^3	100%
C2	9.5×10^{-1}	6.2×10^2	3.5×10^3	4.2×10^3	100%
C3	3.6	2.5×10^3	1.5×10^4	1.7×10^4	100%

*All well entry releases were assumed to be at the wellhead.

Table 5.18 Baseline Well Entry Environmental Risk for Each Well Configuration

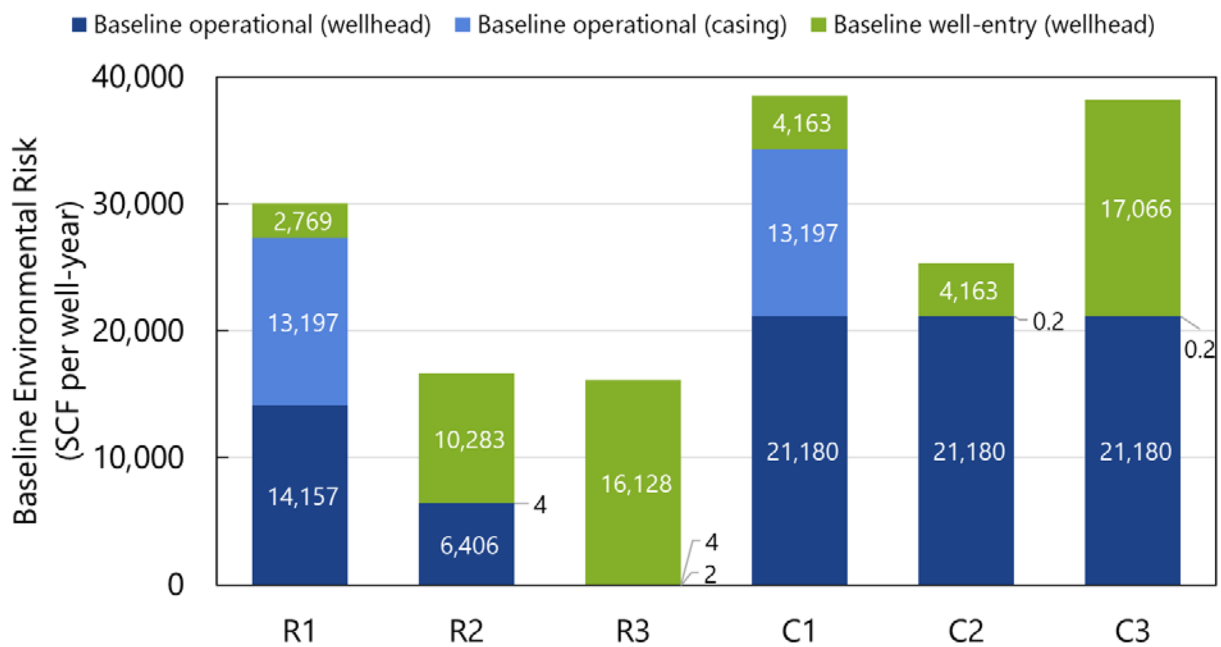

Figure 5.13 Combined Operation and Baseline Entry-related Environmental Risk for Each Well Configuration

The tabulated intermediate environmental risk results provided in Tables 5.17 and 5.18 show that the environmental risk is dominated by the contribution from rupture failure of the wells. They also show that the contribution from small leak failure is relatively insignificant in comparison to the contribution from the other two modes of well failure modes.

With regard to the combined results shown in Figure 5.14, and considering reservoir wells, the environmental risk associated with well configuration R1 is shown to be dominated by the contribution from well operation, with about half of that being associated with failure of the single-barrier pathway involving the wellhead and half from the single-barrier pathway involving the production casing. The contribution from well entry is shown to be small because this simple well configuration is associated with a relatively low frequency of well entry due to the reduced number of downhole components (compare to other configurations) and the fact that less invasive entry types are typically required due to the lack of tubing.

The environmental risk associated with well configuration R2 is shown to be approximately half that of configuration R1. The elimination of operational risk due to casing failure is attributable to the fact that this configuration includes a tubing and packer assembly that creates a second barrier to casing-related failure. The risk attributable to wellhead failure is lower than that of configuration R1 because the dominant flow path in the event of wellhead failure is through the production tubing rather than through the casing. The contribution to environmental risk from well entry is significantly increased relative to that for configuration R1 because the presence of a tubing and packer assembly dictates more frequent and invasive well entry operations.

The environmental risk associated with configuration R3 is shown to be marginally lower than that of configuration R2. While the additional presence of the DHSV substantially lowers the operational risk, this reduction in risk is almost entirely offset by the significant increase in well entry risk, as dictated by the additional well entry operations required to maintain the DHSV.

Regarding cavern wells, the environmental risk associated with well configuration C1 is shown to be dominated by the contribution from well operation, with both the operational and well entry contributions to environmental risk being higher than for reservoir well configuration R1, even though their configurations are identical. This stems from the fact that the sustained gas flow rates in cavern wells are higher than those of an identical reservoir well due to the flow-throttling effect of reservoir deliverability constraints that apply only to reservoir wells.

The environmental risk associated with well configuration C2 is shown to be about two-thirds of that for configuration C1. This reduction stems from the elimination of operational risk due to casing failure, which is attributable to the fact that this configuration includes full-length intermediate casing that creates a second barrier to casing-related failure.

The environmental risk associated with configuration C3 is shown to be comparable to that of configuration C1, even though configuration C3, like configuration C2, includes a second barrier to casing failure. While the presence of the intermediate casing in configuration C3 virtually eliminates the operational risk attributable to casing failure, this reduction in operational risk is almost entirely offset by the significant increase in well entry risk dictated by the additional well entry operations required due to the presence of the suspended tubing string that serves only to facilitate well operation and cavern maintenance activities.

In general, the component of environment risk attributable to well operation is shown to reduce or remain constant with increasing well complexity, but increasingly complex wells with more downhole components are shown to be subject to higher levels of well-entry-related environmental risk. In some cases (e.g. configurations R2 versus R3), the risk reduction afforded by additional well components (i.e. a DHSV) is effectively offset by the increase in well-entry-related risk (precipitated by more frequent and/or more invasive forms of well entry). The environmental risk posed by cavern wells is shown to be higher than that of comparable reservoir wells due to the higher sustained flow rates that are possible in cavern wells where reservoir deliverability constraints are not a risk mitigating factor. Lastly, the presence of additional downhole components that do not significantly contribute to a reduction in well operating failure rates or failure consequences (e.g. suspended tubing strings in cavern wells) can lead to a significant increase in the overall environmental risk level.

5.5.2.3 Environmental Risk Comparison – Impact of Additional Well Entry

5.5.2.3.1 Evaluation Approach

UGS well operators monitor the integrity of their wells through a variety of inspection and testing activities. The results of these inspections are then evaluated, and a determination is made as to whether maintenance or repair activity is required. Such actions typically involve well entry. This section evaluates the environmental risk implications of a specific set of hypothetical well entry scenarios on a subset of the well configurations previously discussed.

To evaluate whether the impact of an inspection and repair activity requiring well entry is beneficial, the benefit of the repair, which is incurred in the operational phase, must be considered alongside the added risk due to the well entry activities carried out to perform the inspection and subsequent repair. The cumulative effect of this action over the prescribed evaluation period can then be compared to that of other actions, including the 'no action' alternative.

The risk increment due to well entry for inspection and repair is incurred in the year it occurs and is the sum of the inspection well entry risk and the repair well entry risk. It is acknowledged that, occasionally, operators will both inspect and repair the well during a single well entry; however, this scenario was not considered because it was assumed to be less common than inspection entry followed by repair entry.

If, for simplicity in this demonstration analysis (see Section 5.1), it is assumed that the operating risk before and after well component remediation are both time-independent, the total risk, $R_{cumulative}$, over a prescribed evaluation period, E, is given by:

$$R_{cumulative} = E \times \left(R_{baseline} + \Delta R_{operation}\right) + R_{isolated-entry} \quad [5.6]$$

The annual baseline well risk, $R_{baseline}$, in Equation [5.6] is given by:

$$R_{baseline} = R_{operation} + R_{baseline-entry} \quad [5.7]$$

where $R_{operation}$ is the normal operational risk (see Section 5.3.2) and $R_{baseline-entry}$ is the baseline entry risk associated with routine, periodic well entry activities required to maintain the general operability and integrity of a given well (see Section 5.3.4).

The change in operating risk brought about by well entry, $\Delta R_{operation}$, in Equation [5.6], is given by:

$$\Delta R_{operation} = R_{operation,after} - R_{operation} \quad [5.8]$$

where $R_{operation,after}$ is the annual risk of the well operation after the repair and $R_{operation}$is the annual risk of the well operation before the repair.

Finally, the increment in risk due to the isolated well entry sequence under consideration, $R_{isolated\text{-}entry}$, in Equation [5.6] is given by:

$$R_{isolated-entry} = R_{inspection} + R_{repair} \quad [5.9]$$

where $R_{inspection}$ is the risk of the well entry performed for inspection and R_{repair} is the risk of well entry performed for repair.

To enable direct comparison of scenarios that are associated with different evaluation periods, the cumulative risk given by Equation [5.6] can be annualized by dividing it by the evaluation period to give:

$$R_{cumulative,annualized} = \left(R_{baseline} + \Delta R_{operation}\right) + \frac{R_{isolated-entry}}{E} \quad [5.10]$$

The annualized risk following well entry, $R_{cumulative,annualized}$, can then be compared directly to the annual baseline risk, $R_{baseline}$, to determine if a net reduction in risk is achieved by the additional well entry action under consideration.

Implicit in the above expressions for the cumulative environment risk (Equation [5.6]) and the annualized environmental risk (Equation [5.10]) is that the risk reduction afforded by repair lasts for the duration of the evaluation period.

5.5.2.3.2 Well Entry Scenarios

Four well entry scenarios were developed and evaluated in terms of their implications for environmental risk to demonstrate the use of QRA for evaluating the merits of well entry. Entry scenario analysis results are provided for each of three well configurations (R1, C1, and R2) to illustrate how the risk implications vary with well types (i.e. reservoir well R1 versus cavern well C1) and with well configurations (i.e. single downhole barrier in R1 versus double downhole barrier in R2).

Each well entry scenario was evaluated over a range of evaluation periods (i.e. 2, 5, 10 and 20 years). For some of the well entry scenarios considered, these evaluation periods can be interpreted as being analogous to the entry intervals that are associated with follow-on remediation actions required to maintain the assumed level of post-entry well component reliability.

Given that the risk analysis and, thereby, the risk evaluation results are sensitive to the assumed well failure frequencies, in particular the failure frequencies associated with well entry, the well entry scenario analysis also incorporates a sensitivity analysis wherein the reference well entry failure rates were multiplied by factors of 2.0, 1.0, 0.5 and 0.2. The difference in analysis outcomes are presented and discussed.

The four well entry scenarios considered are as follows (see also Table 5.19 for additional details):

- **Scenario 1: well entry for casing inspection.** This scenario involves well entry for inspection resulting in the determination that subsequent entry for casing remediation is not required. For well configurations R1 and C1, this activity is assumed to be achieved by a wireline operation since the wells are tubingless. For well configuration R2, this activity is assumed to require a workover because reliable casing inspection requires tubing removal. Analysis of this scenario is intended to illustrate the implications of casing inspection on a well in average condition that that does not lead to well integrity improvement.

- **Scenario 2a: well entry for casing inspection and repair (typical casing condition).** This scenario involves well entry for inspection, as in Scenario 1, with a follow-on entry involving a workover to remediate the casing. The benefit of the casing repair is modeled as a reduction in the casing failure rate from the baseline value (as determined from historical data) to a value one order of magnitude lower than typical (determined by assuming that high-resolution casing logging, followed by casing remediation, can achieve a long-term improvement in reliability on the order of one order of magnitude[12]). Analysis of this scenario is intended to illustrate the implications of casing inspection and repair on a well with casing in average condition.

- **Scenario 2b**: **well entry for casing inspection and repair (poor casing condition).** This scenario is identical to Scenario 2a, except that the pre-repair casing failure frequency is assumed to be one order of magnitude higher than typical and the benefit of casing repair is modeled as a reduction of the casing failure rate to a value one order of magnitude lower than typical (see Scenario 2a for rationale for failure frequency reduction). Analysis of this scenario is intended to reflect the implications of casing inspection and repair on a well with casing in relatively poor condition.

- **Scenario 3: well entry for wellhead replacement.** This scenario involves well entry by workover to facilitate wellhead replacement (no additional inspection entry is assumed for this

[12] The order of magnitude reduction in average annual failure frequency of casing subject to high-resolution inspection and repair is inferred from the evolution in reliability of natural gas transmission pipelines since the advent of routine high-resolution inline inspection and remediation targeting metal loss corrosion (see data for 2002 to 2009 and 2010 to 2019 (61)).

scenario since inspection of the wellhead can be performed without well entry). The benefit of wellhead replacement is modeled as an order of magnitude reduction in the overall frequency of wellhead failure.

<table>
<tr><th>Scenario</th><th>Intent</th><th>Well</th><th>Inspection</th><th>Condition</th><th>Remediation</th><th>Benefit</th></tr>
<tr><td rowspan="2">1</td><td rowspan="2">Casing inspection</td><td>R1, C1</td><td>Wireline</td><td rowspan="2">Typical</td><td rowspan="2">None</td><td rowspan="2">None</td></tr>
<tr><td>R2</td><td>Workover</td></tr>
<tr><td rowspan="2">2a</td><td rowspan="2">Casing inspection and repair</td><td>R1, C1</td><td>Wireline</td><td rowspan="2">Typical</td><td rowspan="2">Casing repair</td><td rowspan="2">Casing POF reduced by factor of 10 to 0.1 × typical</td></tr>
<tr><td>R2</td><td>Workover</td></tr>
<tr><td rowspan="2">2b</td><td rowspan="2">Casing inspection and repair</td><td>R1, C1</td><td>Wireline</td><td rowspan="2">Casing POF 10 × typical</td><td rowspan="2">Casing repair</td><td rowspan="2">Casing POF reduced by factor of 100 to 0.1 × typical</td></tr>
<tr><td>R2</td><td>Workover</td></tr>
<tr><td>3</td><td>Wellhead replacement</td><td>R1, C1, R2</td><td>None</td><td>Typical</td><td>Wellhead replacement</td><td>Wellhead POF reduced by factor of 10 to 0.1 × typical</td></tr>
</table>

Table 5.19 Well Entry Scenarios Considered in Comparative Evaluation of Environmental Risk

5.5.2.3.3 Results and Discussion

Scenario 1: well entry for casing inspection

In Scenario 1, where well entry is carried out for casing inspection only, the annualized environmental risks for well configurations R1 and C1, for a range of assumptions regarding the frequencies of failure during well entry, are shown in Figure 5.14. These results indicate the degree to which well entry, in the absence of well integrity improvement, increases the annualized environmental risk relative to the baseline 'no entry' case. (It is acknowledged that entry may lead to a reassessment of the condition of the well components, which would provide a basis for reassessing and potentially reducing or increasing the initial failure frequency assumptions; however, this outcome is not reflected in this evaluation.)

The risk increments for well configurations R1 and C1 are shown to be relatively small. For the reference assumptions regarding well failure during entry, the risk increment ranges from 1 to 10%, depending on the assumed inspection interval (herein equated to the evaluation period), with more frequent entry resulting in a higher risk increment. The relatively low increase in risk in all cases is because, for these well configurations, all entries are assumed to be wireline operations, which have relatively low probabilities of failure.

The annualized environmental risks for well configurations R1 and R2, as shown in Figure 5.15, highlights the much higher increment in risk for well configuration R2. For the reference assumption regarding well failure during entry, the risk increment ranges from a 70% increase for a 20-year inspection interval to about a 700% increase for a 2-year inspection interval. The much higher increase in risk for well configuration R2, regardless of the assumed frequency of well failure during entry, is because, for this configuration entry, for the purpose of inspection, it is assumed to require a workover due to the presence of tubing, and workovers are associated with a much higher POF.

Scenario 2a: well entry for casing inspection and repair - typical casing condition

In Scenario 2a, where well-entry is carried out for casing inspection and repair, the annualized environmental risks for well configurations R1 and C1, for a range of assumptions regarding the frequency of failure during well entry, are shown in Figure 5.16. These results indicate the degree to which well entry resulting in a subsequent order of magnitude reduction in the casing failure frequency for the duration of the evaluation period affects the annualized environmental risk relative to the baseline 'no action' option.

For reservoir well configuration R1, and the reference assumptions regarding well failure during entry, the results show that the break-even entry interval is 20 years, with more frequent entry being associated with a higher level of environmental risk than for the baseline 'no entry' case. The results obtained from varying the reference assumptions regarding well failure during entry show that the break-even entry interval falls to 10 years if the well entry failure frequencies are half the reference values and it falls further to about 5 years if the well entry failure frequencies are one-fifth of the reference values. The results of this sensitivity analysis also show that, if the well entry failure frequencies are twice the reference values, the break-even entry interval would be significantly longer than 20 years.

For cavern well configuration C1, the net effects of well entry and subsequent remediation are less favorable than for the corresponding reservoir well configuration R1. For the reference assumption regarding well entry failure, none of the entry intervals achieve a net reduction in environmental risk. If the well entry failure frequencies are lower than the reference assumptions, well entry intervals of 10 and/or 20 years yield a net risk reduction, depending on the entry failure frequencies assumed. The reason that entry and remediation for the cavern configuration is less beneficial is because the release rates resulting from cavern failure during entry are higher than for the corresponding reservoir well and the risk associated with cavern well entry is, therefore, higher than for reservoir well entry.

The annualized environmental risks for well configurations R1 and R2, for the same range of assumptions regarding the frequency of failure during well entry, are shown in Figure 5.17. The results show that, regardless of the assumptions made regarding the frequency of well failure during entry, the break-even entry interval is always greater than 20 years. This outcome stems from the fact that, for well configuration R2, the tubing and packer assembly significantly lowers the impact of casing failure on the overall frequency of well failure, thereby reducing the risk reduction benefit achieved by casing remediation. In addition, well configuration R2 requires entry by workover for both inspection and casing repair, which increases the risk contribution from well entry relative to that for well configuration R1, which, due to its lack of tubing, can be inspected using a lower risk wireline operation.

Scenario 2b: well entry for casing inspection and repair - poor casing condition

In Scenario 2b, where well entry is again carried out for casing inspection and repair, the only difference between Scenario 2b and 2a is that the casing failure rate is assumed to be 10 times higher than in Scenario 2a prior to inspection and remediation. The annualized environmental risks for well configurations R1 and C1, for a range of assumptions regarding the frequencies of failure during well entry, are shown in Figure 5.18. Again, these results indicate the degree to which well entry resulting in a subsequent order of magnitude reduction in the casing failure frequency for the duration of the evaluation period affects the annualized environmental risk relative to the baseline ‘no action’ option.

For reservoir well configuration R1, and the reference assumptions regarding well failure during entry, the results show that all entry intervals considered yield a net reduction in environmental risk, with the longest 20-year entry interval achieving the lowest level of risk. The results are similar for cavern well configuration C1, with all entry intervals considered, except for 2 years, achieving a net reduction in risk, with the longer 20-year interval achieving the lowest level of risk. The results obtained from varying the reference assumptions regarding well failure during entry show that, if the frequency of well entry failure is lower than the reference assumption, all entry intervals considered result in a net risk reduction in environmental risk and that, even with an increase in the assumed frequency of well entry failure, well entry intervals of 5 years or more or 10 years or more are shown to achieve a net risk reduction for well configuration R1 and C1, respectively.

The annualized environmental risks for well configurations R1 and R2, for the same range of assumptions regarding the frequency of failure during well entry, are shown in Figure 5.19. As was the case for well entry Scenario 2a, the results show that, regardless of the assumptions made regarding the frequency of well failure during entry, the break-even entry interval is always greater than 20 years. This outcome again stems from the fact that, for well configuration R2, the tubing and packer assembly significantly lowers the impact of casing failure on the overall frequency of well failure, thereby reducing the risk reduction benefit achieved by casing remediation and the presence of the tubing increases the risk of well entry because both inspection and repair require a workover.

Case 3: well entry for wellhead replacement

In Scenario 3, where well entry is carried out for wellhead replacement, the annualized environmental risks for well configurations R1 and C1, for a range of assumptions regarding the frequencies of failure during well entry, are shown in Figure 5.20. These results can be interpreted to indicate the remaining well life (following wellhead replacement) required to justify wellhead replacement, with replacement being justifiable if there is a net reduction in environmental risk.

For both well configurations R1 and C1, based on the reference assumptions for the frequencies of well entry failure, wellhead replacement is shown to achieve a net reduction in risk (thereby justifying replacement) for a remaining well life of 20 years or longer. If the frequencies of well entry failure are assumed to be one-half the reference values, wellhead replacement is justified for a remaining life as low as 10 years, and if the frequencies of well entry failure are one-fifth of the reference values, wellhead replacement is justified for a remaining life as low as 5 years.

The annualized environmental risks for well configurations R1 and R2, for the same range of assumptions regarding the frequency of failure during well entry, are shown in Figure 5.21. For configuration R2, a net reduction in environmental risk required to justify wellhead replacement is shown to be achieved for a remaining life of 20 years or less only if the frequency of well entry failure is one-fifth of the assumed reference values.

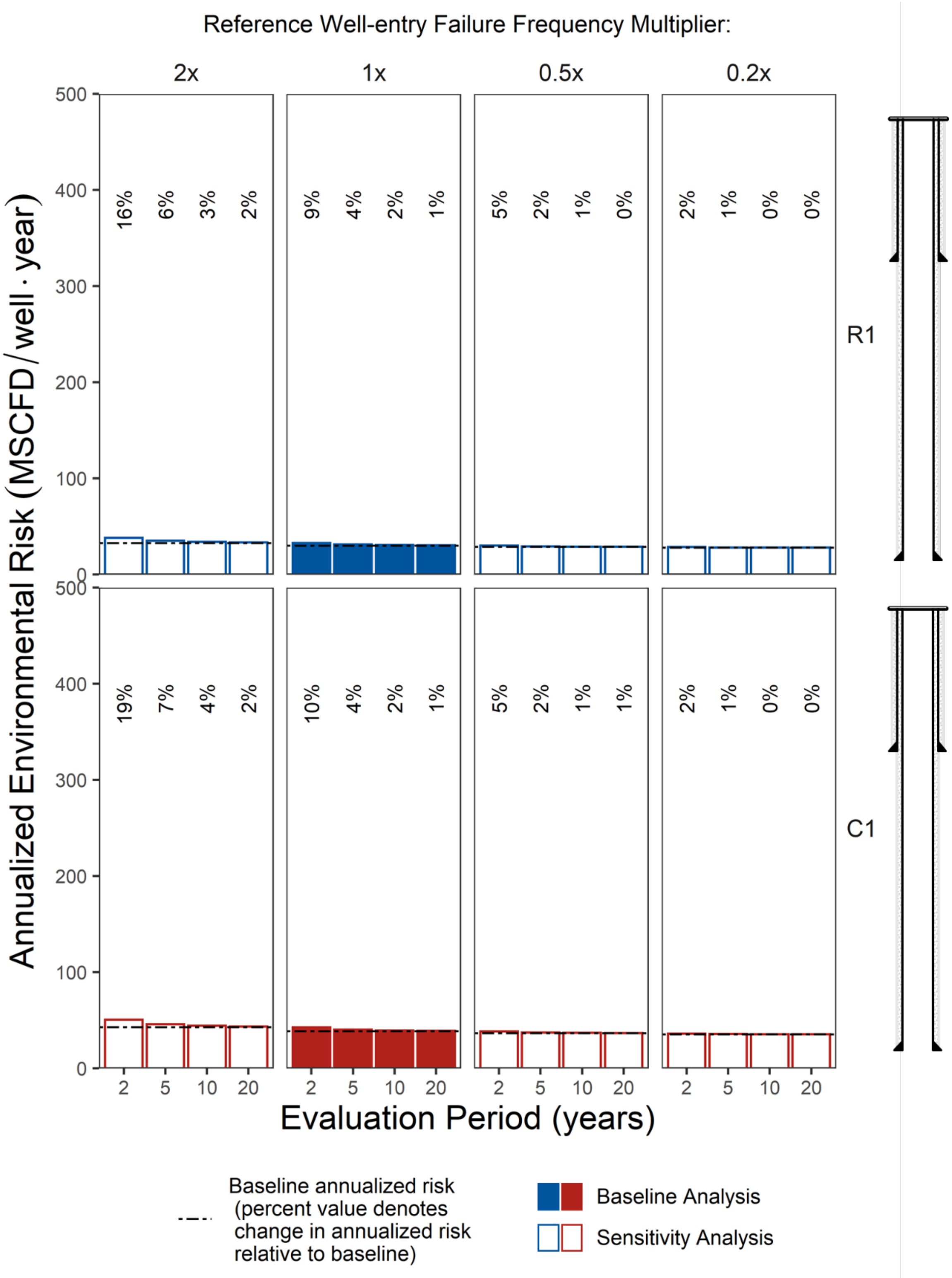

Figure 5.14 Entry Scenario 1: Annualized Environmental Risk vs. Evaluation Period for R1 and C1

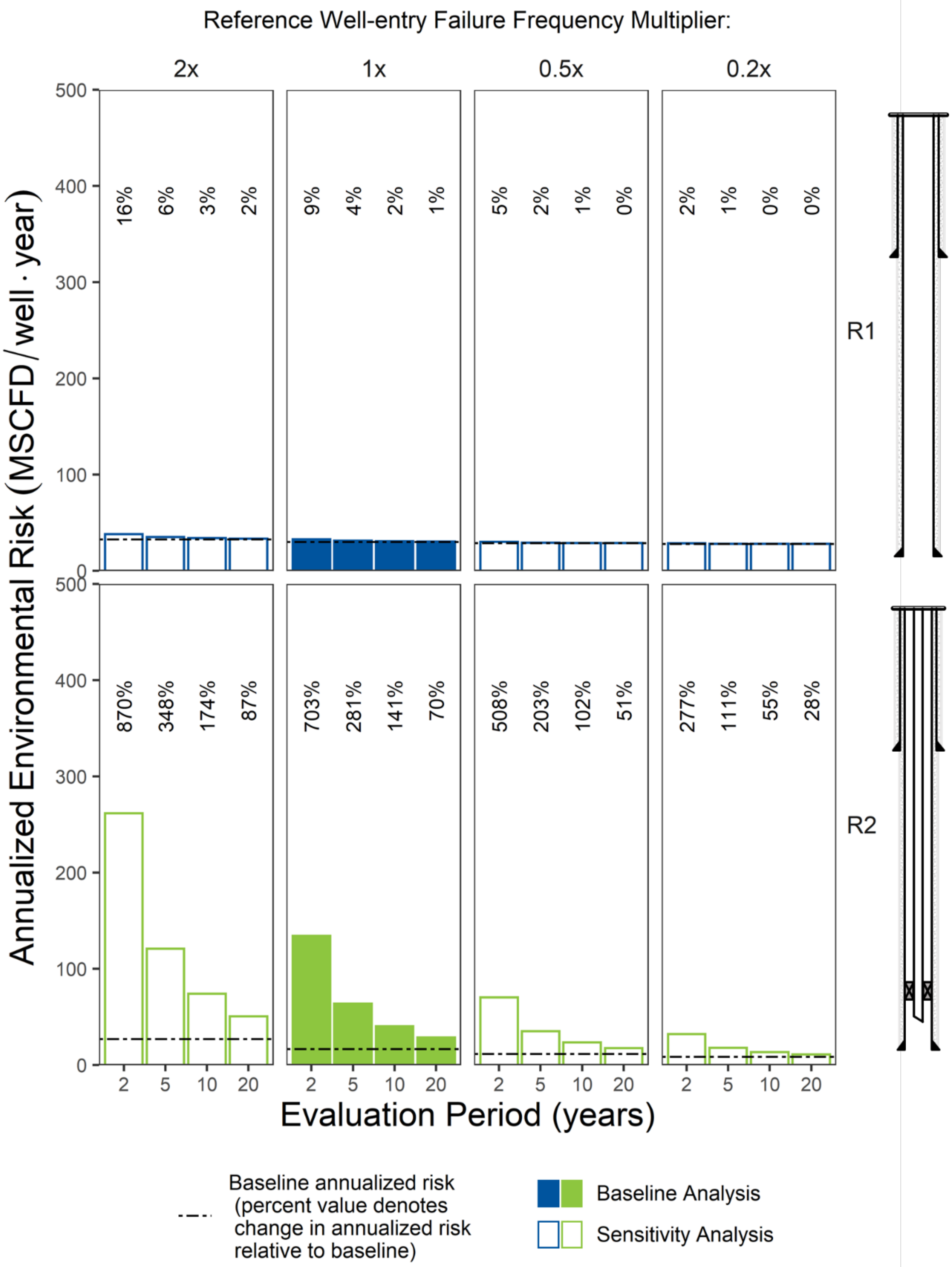

Figure 5.15 Entry Scenario 1: Annualized Environmental Risk vs. Evaluation Period for R1 and R2

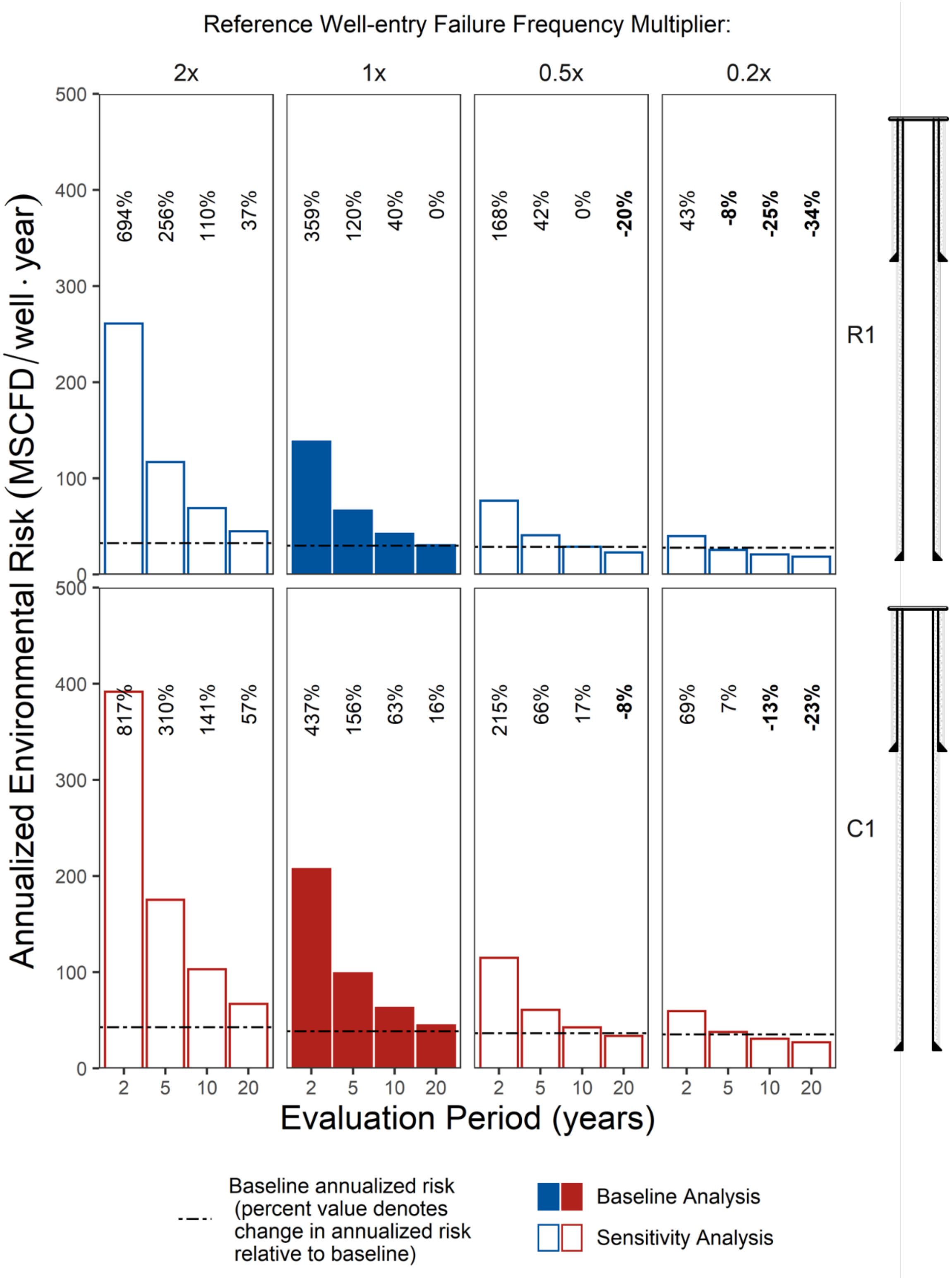

Figure 5.16 Entry Scenario 2a: Annualized Environmental Risk vs. Evaluation Period for R1 and C1

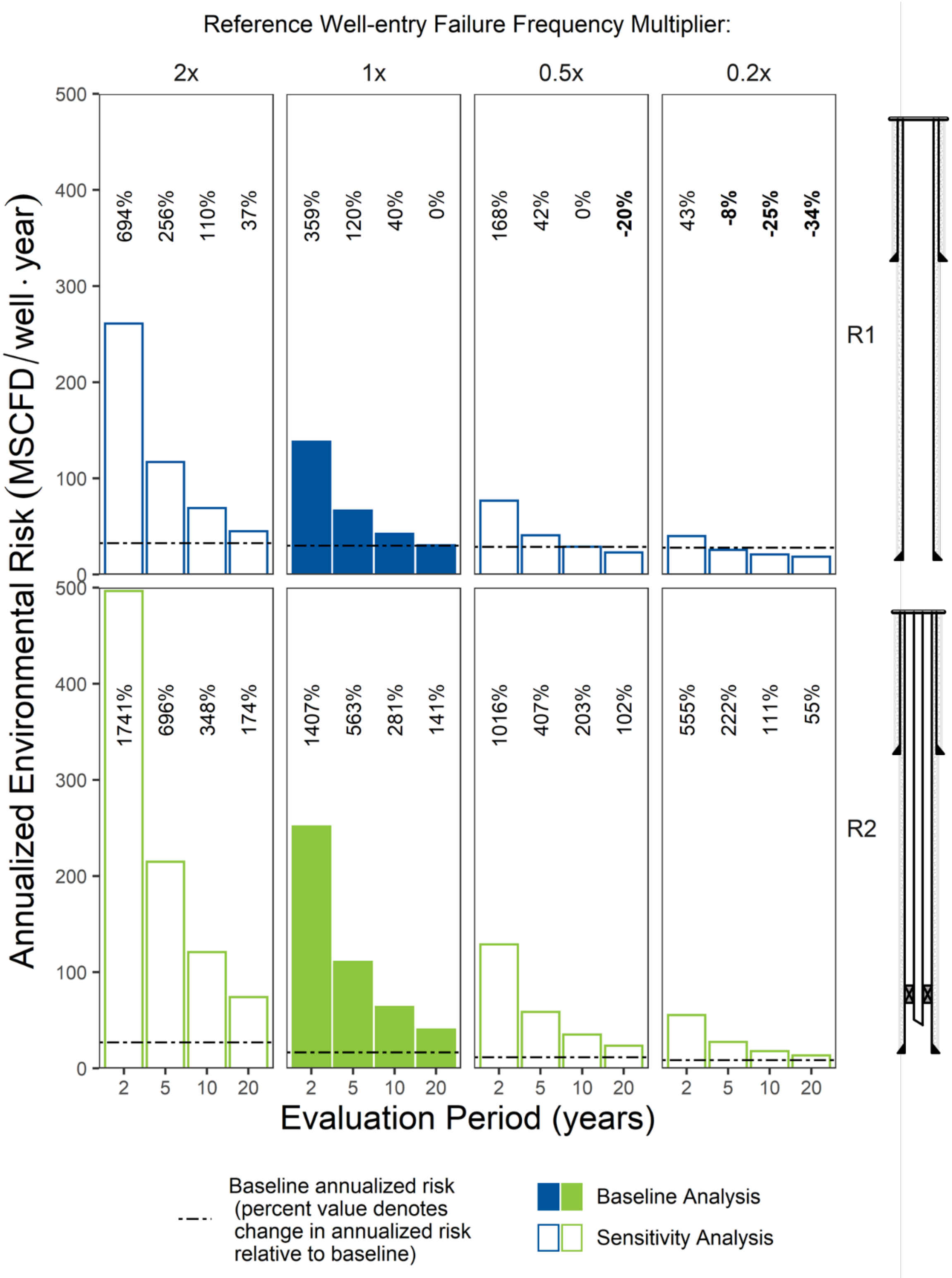

Figure 5.17 Entry Scenario 2a: Annualized Environmental Risk vs. Evaluation Period for R1 and R2

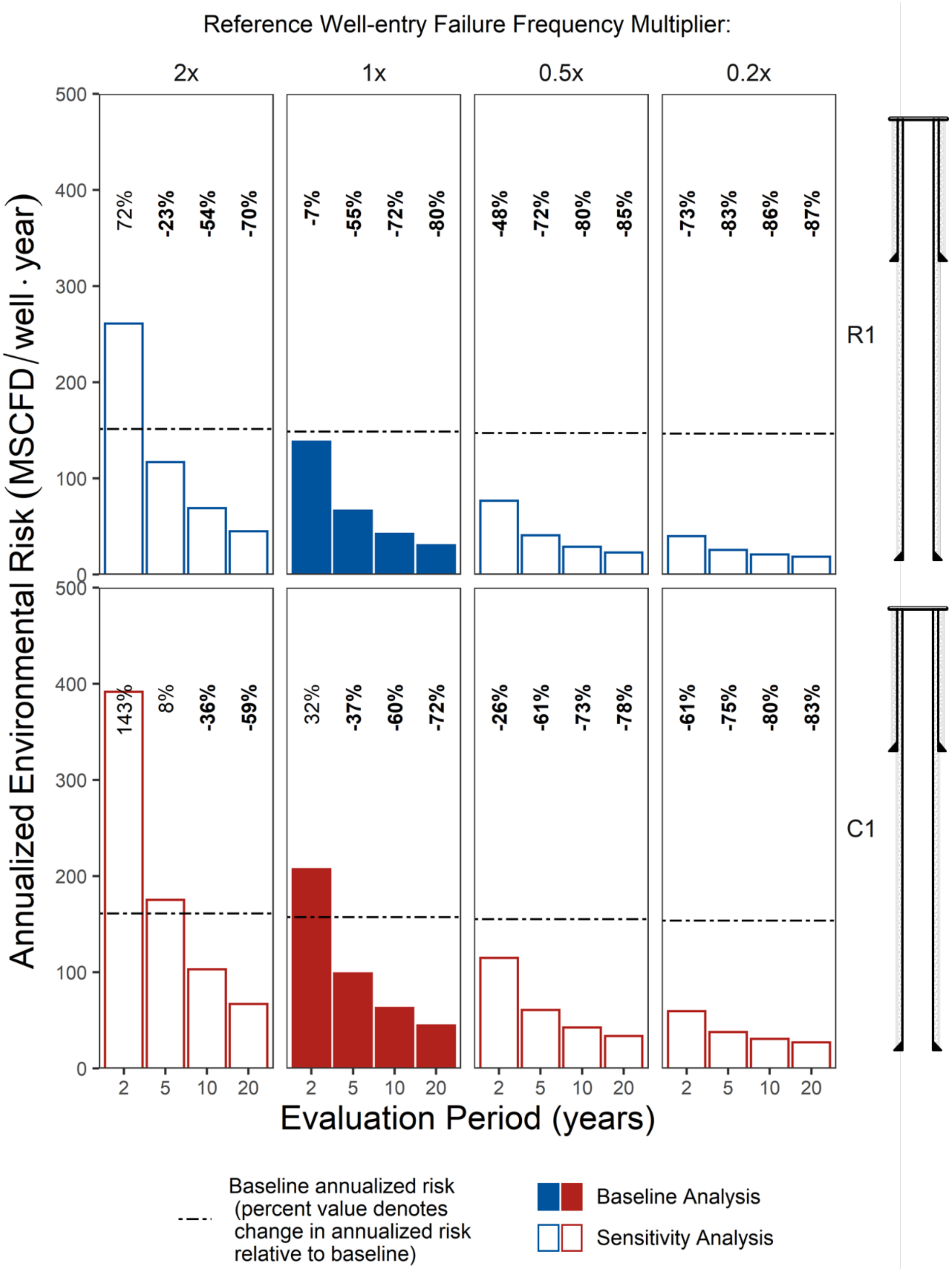

Figure 5.18 Entry Scenario 2b: Annualized Environmental Risk vs. Evaluation Period for R1 and C1

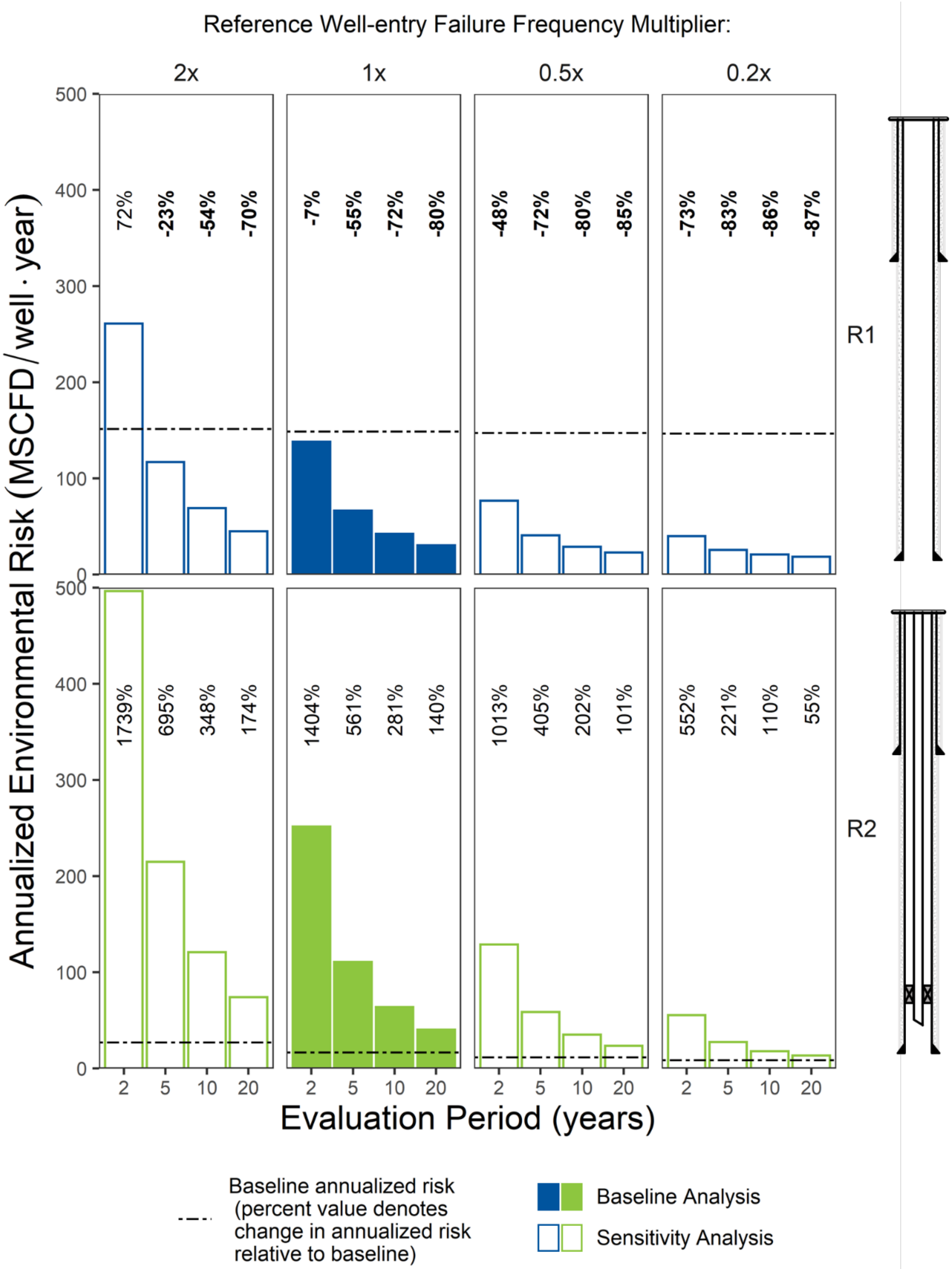

Figure 5.19 Entry Scenario 2b: Annualized Environmental Risk vs. Evaluation Period for R1 and R2

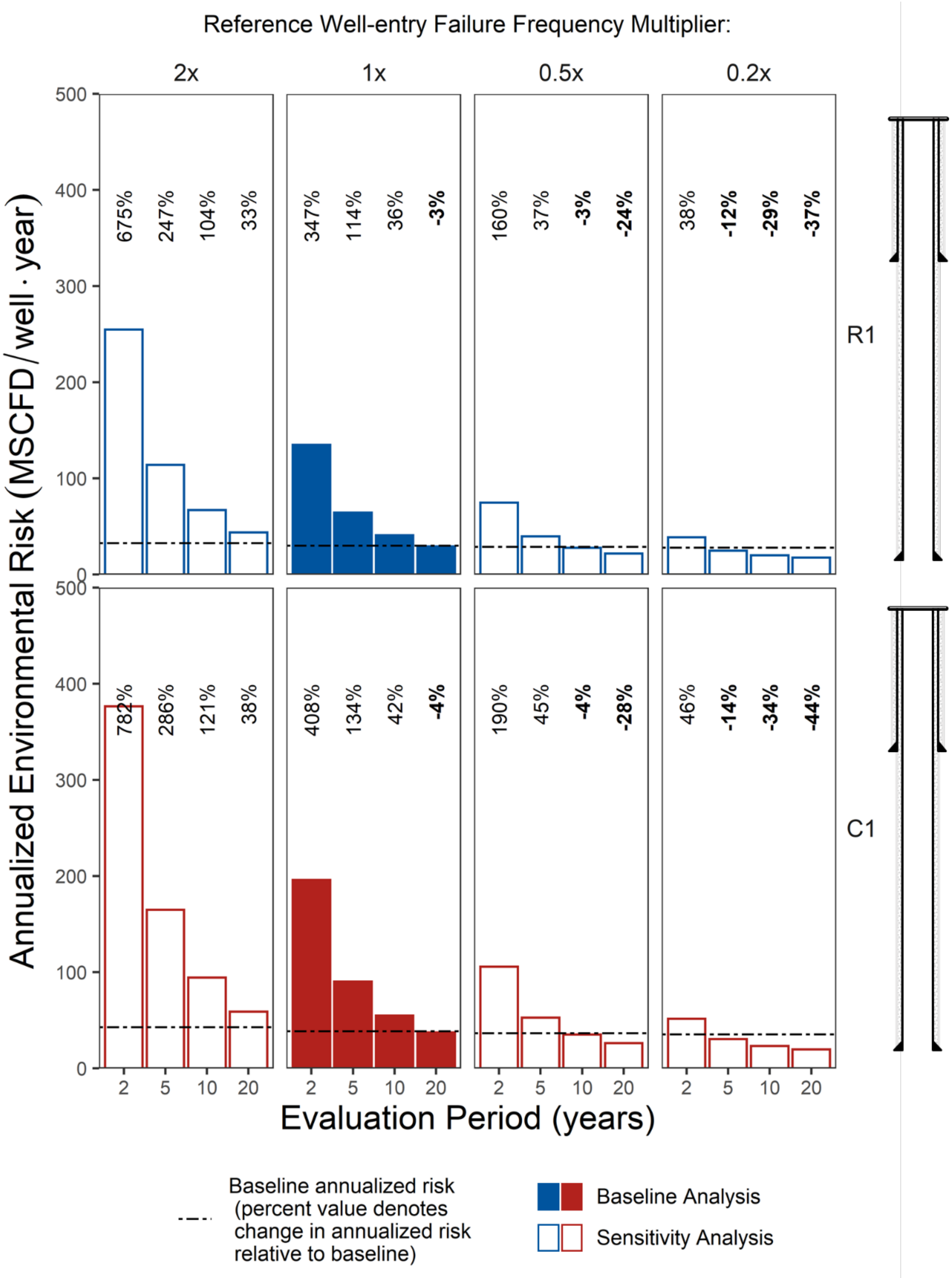

Figure 5.20 Entry Scenario 3: Annualized Environmental Risk vs. Evaluation Period for R1 and C1

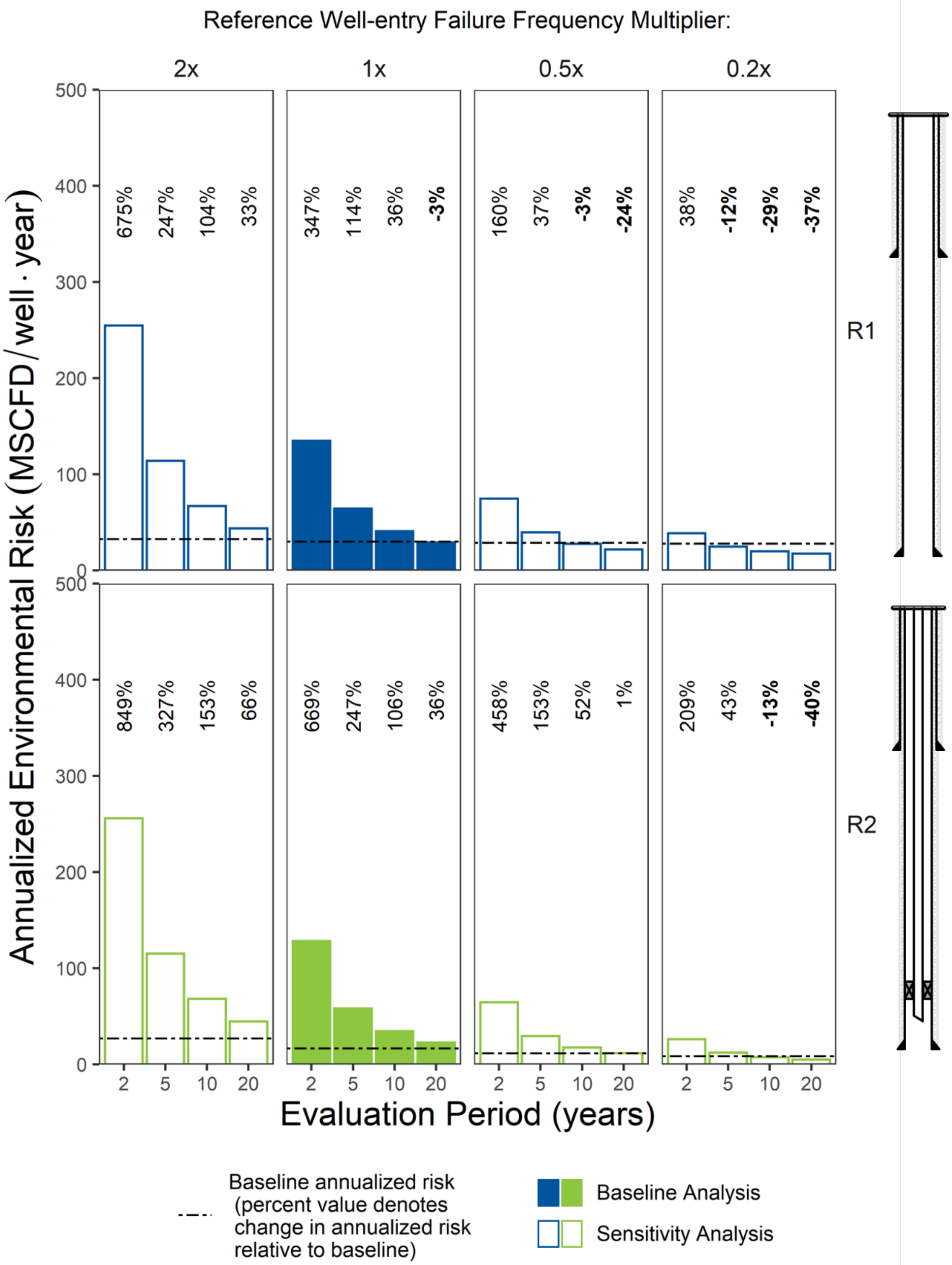

Figure 5.21 Entry Scenario 3: Annualized Environmental Risk vs. Evaluation Period for R1 and R2

5.6 Key Findings

The example QRA of selected reservoir and cavern well configurations supports the following directional findings:

General

- *Importance of assumed failure probabilities*. The results highlight the sensitivity of risk estimates to the assumed failure frequencies and failure mode splits for key well components and activities. The key items include wellhead failure during well entry or operation, and production casing failure during operation in cases where the production casing is the only downhole barrier.

- *Risk in cavern versus reservoir wells*. Cavern wells can be associated with both higher safety and environmental risk levels than reservoir wells. This is due, in part, to the fact that salt caverns are typically designed for higher operating flow rates, meaning that release rates resulting from well failure will be higher. Additionally, cavern wells are not subject to deliverability limits and flow throttling as reservoir wells are. In general, higher flow rates result in greater failure consequences, both for ignited releases resulting in higher safety risk and for unignited release volumes that lead to higher environmental risk.

Well Safety Risk

- *Public safety risks*. Typical reservoir and cavern wells do not pose a significant safety risk to the public unless routinely occupied locations are in close proximity to the wellhead.

- *Guidance on setback distances*. Setbacks on the order of 100 to 200 feet can achieve broadly acceptable levels of individual safety risk for typical reservoir and cavern wells in typical condition. However, explicit guidance is required to define appropriate setback distances that adequately account for the impact of key well attributes on thermal radiation hazard zone size. (Guidance could consist of a variation of the PIR formula currently used for identifying high consequence areas for gas pipelines (81). The current PIR model for gas pipelines can be adapted to UGS wells by replacing the gas release rate model with a model that adequately reflects the gas release characteristics of UGS wells, as controlled by well diameter, well depth and gas storage pressure.)

- *Well entry contribution to total risk*. Well entry was found to be the largest contributor to the annual safety risk, particularly for entry activities involving coiled tubing work or a well workover. Additional precautions during complex and invasive well entries involving coiled tubing work and, in particular, workovers on wells in close proximity to occupied areas may be warranted. For example, temporary setback distances could be defined for specified workover periods to ensure appropriate safety risk levels are met.

Well Entry Risk

- *Entry methods*. Well configurations that support the use of less complex and less invasive (and thereby less failure prone) well entry methods for inspection and remediation are generally associated with lower life-cycle operating risks.

- *Integrity management entries*. Well entry for integrity management purposes is most beneficial if efforts target components that serve as single barriers to a gas release. For example, production casing integrity enhancements are most beneficial when neither intermediate casing nor tubing and packer assemblies are present. The wellhead is also typically a component of a single-barrier pathway and management of wellhead integrity is, therefore, an effective means of risk management.

- *Frequency of periodic well entry*. Periodic well entry for inspection and remediation of production casing, when it is the sole downhole barrier, is difficult to justify on a frequent basis unless casing condition is known to be poor, such that its POF is significantly higher than average. If remediation work is to be performed, it should ideally be planned to maximize the time to the next required well entry.

- *Remediation of production casing*. Periodic well entry for inspection and remediation of production casing, when it is not the sole downhole barrier, is difficult to justify in typical situations due to the high failure probability associated with workover entries. This action may, however, become more justifiable if and when reliable casing integrity evaluation can be performed without removal of the tubing string, particularly for casing integrity confirmation in wells employing production tubing.

- *Well entry frequency optimization*. True optimization of well entry frequency requires methods and models that can convert downhole component condition and inspection data into defensible estimates of component reliability over time. An example would be a methodology for using data obtained from high-resolution casing corrosion inspection logs to estimate casing failure probability as a function of time with and without selected defect remediation. Such methods have been developed for use in the pipeline industry (73,74) and are adaptable to UGS wells; work in this area is ongoing (75).

6. SUMMARY AND RECOMMENDATIONS

6.1 Summary

The primary objective of this project was the development of guidelines for the risk assessment of UGS wells subject to periodic well entry. The focus of the guidelines is on the development and application of QRA methods and models, but the underlying concepts are also applicable to qualitative assessments. The guidelines are intended to provide UGS well operators with information to support the development, selection and application of risk-based models that will facilitate decision making with regard to well entry activities. They are also intended to provide regulators with information to support evaluation of the risk assessment methods and models used by industry.

The risk assessment guidelines address the following:

- Methods and models that can be used for failure frequency and failure consequence estimation, including discussion of the advantages and limitations inherent in the use of different methods and models;
- Risk measures required to provide a suitable basis for quantifying and evaluating the public safety and the environmental risks posed by UGS well operation and periodic well entry;
- The process required to integrate the failure frequency and failure consequence estimates, obtained separately for normal well operation and periodic well entry, into meaningful measures of combined well entry plus operating risk for the purpose of estimating the public safety and environmental risk levels; and
- Suggested approaches for evaluating the safety and environmental risk estimates developed, including a discussion of acceptance criteria for public safety risk and a risk-based framework for evaluating the environmental risk associated with different well entry scenarios for the purpose of determining the preferred course of action.

A secondary project objective was to illustrate the application of the QRA process to selected UGS well configurations subject to periodic well entry. In addition to demonstrating the application of a defensible QRA process, the directional findings of the example assessments are intended to support the development of best practices for the selection of preferred well completion configurations and the optimization of well entry practices.

The UGS well configurations considered in the demonstration analysis were selected to include a range of representative UGS well completion configurations that are applicable to typical wells serving depleted hydrocarbon reservoirs and salt caverns. The well configurations were made as simple as possible and the set of well components included in the assessments was limited, to the extent possible, in the interest of clarity of presentation.

Risk levels were calculated for each well configuration under both normal operating conditions and during well entry events. Risk levels under operating conditions were estimated as a function of well type and configuration on an annual basis. Risk levels associated with well entry were estimated as a function of well entry type on a per entry basis. A combination of historical incident data, analytical models and judgment was used to estimate both the frequencies and consequences of well failure required for risk estimation. The QRA framework described in the guidelines was then followed to estimate and evaluate the public safety risk and the environmental risk levels for each well type and completion configuration.

The results obtained from these analyses support the following directional findings:

General

- The risk estimates developed using a QRA process are highly dependent on the assumed failure frequencies and failure mode splits for key well components and activities. The key items include wellhead failure during well entry or normal well operation, and production casing failure during operation in cases where the production casing is the only downhole barrier.
- Cavern wells are shown to be associated with higher safety and environmental risk levels than reservoir wells. This is because salt caverns are typically designed for higher operating flow rates than reservoir wells and cavern wells, unlike reservoir wells, are not subject to the flow throttling effects of reservoir deliverability constraints.

Well Safety Risk

- Typical reservoir and cavern wells do not pose a significant safety risk to the public unless routinely occupied locations are in close proximity to the wellhead.
- Modest setback distances can achieve broadly acceptable levels of individual safety risk for typical reservoir and cavern wells. However, explicit guidance is required to define appropriate setback distances that adequately account for the impact of key well attributes on the thermal radiation hazard zone size (including production string diameter, well depth, and gas storage pressure).
- Well entry is typically the largest contributor to the annual safety risk posed by a UGS well, particularly for entry activities involving coiled tubing work or a well workover. On this basis, additional precautions during complex and invasive well entries on wells in proximity to occupied areas may be warranted.

Well Entry Risk

- Well configurations that support the use of less complex and less invasive well entry methods for inspection and remediation are generally associated with lower life-cycle operating risks.
- Well entry for integrity management purposes is most beneficial if efforts target components that serve as single barriers to a gas release. For example, production casing integrity enhancements are most beneficial when neither intermediate casing nor tubing and packer assemblies are present. The wellhead is also typically a component of a single-barrier pathway and management of wellhead integrity is, therefore, an effective means of risk management.
- Periodic well entry for inspection and remediation of production casing, when it is the sole downhole barrier, is difficult to justify on a frequent basis unless casing condition is known to be poor, such that its likelihood of failure is significantly higher than average. If remediation work is to be performed, it should be planned to maximize the time to the next required well entry.
- Periodic well entry for inspection and remediation of production casing, when it is not the sole downhole barrier, is difficult to justify in typical situations due to the reduced risk reduction benefit afforded by casing integrity enhancement when it forms part of a dual-barrier release pathway. This is particularly the case in wells employing production tubing where reliable casing inspection requires invasive well entry to remove the tubing string. Casing inspection in these situations may, however, become more justifiable if and when reliable casing integrity evaluations can be performed without removal of the tubing string.

6.2 Future Work

The literature review and research carried out during this project identified areas where further work is required to better enable the undertaking of defensible QRAs on UGS wells subject to well entry. The suggestions for further work, organized by topic area, are as follows:

Failure Frequency Estimation

- For QRA, failure frequency is most often estimated for well operation using historical component failure rate data. While significant amounts of such data are available, very little of it is specific to UGS wells. Where well entry is addressed as an integrity threat, the frequency of well failure during entry is most often estimated using historical data on entry-related failures that may or may not differentiate the type of well entry. Given the importance of this information, efforts should be made to expand the reporting and analysis of UGS well and UGS well component failure incident data. The reporting of failures of UGS wells has been a PHMSA requirement since 2017, with this data currently forming part of the Natural Gas Transmission and Gathering incident report (63). It is recommended that both the reporting requirements for, and the granularity of the information provided on, UGS well failures should be revisited.

Failure Consequence Estimation

- Central to all safety and environmental consequence modeling is release rate estimation. Accurate release rate estimation requires models that can explicitly account for the various flow conditions that develop along the length of each credible release pathway. It is recognized that the modeling of the gas flow upwards through the casing cement and/or the surrounding formation in the event of a casing breach is not well understood. Further work is required to better understand and properly estimate gas flow rates when a sub-surface casing breach is involved.

Setback Distances

- Current setback requirements for developments adjacent to UGS wells, where they exist, are inconsistent. This is problematic because the extent of the hazard zone for a given well is highly dependent on the maximum credible release rate, which in turn depends on key well parameters, including production string diameter, well depth and gas storage pressure. To enhance public safety and promote greater consistency in defining setbacks, explicit guidance is required to define well-specific setback distances that adequately reflect the possible extent of the thermal radiation hazard zone that would develop in the event of a credible worst-case release followed by gas ignition. Suggested guidance could involve the development of a simple formula that relates the required setback to selected key well attributes. It is suggested that the PIR formula, originally developed for the integrity management of natural gas pipelines in high consequence areas (see 49 CFR 192 (3)), can be adapted for use on UGS wells by replacing the underlying gas release rate model with a model that better reflects the gas release characteristics of such wells.

Risk Acceptance Criteria

- The guidelines include a discussion of safety criteria for both individual risk (IR thresholds) and societal risk (F-N curves), and they endorse a specific set of criteria for use in evaluating UGS safety risk. However, to facilitate the broader use of QRA for safety-based decision making, a widely accepted, consensus-based set of safety criteria is required. An effort should be made to assemble a group of informed stakeholders to review options and decide on what set of criteria should be adopted for use in assessing UGS well safety.

Well Entry Interval Optimization

- True optimization of well entry frequency requires methods and models that can convert downhole component condition and inspection data into defensible estimates of component reliability over time. An important application of this would be a methodology for using data obtained from high-resolution casing corrosion inspection logs to estimate casing failure probability, as a function of time, with and without selected defect remediation. Such methods, involving the use of structural reliability models, have been developed for use in the pipeline industry (73,74) and are adaptable to UGS wells. Work in this area is ongoing (75), but efforts to accelerate the development and application of such methods is warranted.

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APPENDIX A – INDUSTRY SURVEY

ATTACHMENT 1 – SURVEY FORM

C-FER Technologies
A SUBSIDIARY OF ALBERTA INNOVATES

SURVEY BACKGROUND

Introduction

Industry Survey in Support of PHMSA Research Project DTPH56-17-RA-00002 on Risk Assessment and Treatment of Underground Gas Storage Wells

https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=740

The U.S. Department of Transportation - Pipeline and Hazardous Materials Safety Administration (PHMSA) has awarded to C-FER Technologies (C-FER) a research project titled "Risk Assessment and Treatment of Wells". The objective of this project is to develop guidelines for the assessment of the risks associated with gas storage well entry using relative, qualitative, and probabilistic assessment approaches. The development of these guidelines will be based on an assessment of desirable risk model attributes related to accuracy, verifiability, transparency, practicality and fit within the decision making processes used by both operators and regulators.

The project will also evaluate the risks associated with well entry for selected entry procedures applicable to typical gas storage well configurations to provide a basis for the development of best practices for well configuration, entry procedures and risk mitigation actions.

This survey is intended for underground gas storage (UGS) facility operators, regulators and other industry stakeholders. It will be used by C-FER to help identify:

(1) the range and prevalence of existing UGS well configurations;
(2) possible new well configurations to be considered;
(3) the range and prevalence of current well entry activities that support the inspection, maintenance and efficient operation of these wells and the entry methods associated with these actions; and
(4) possible new or emerging well integrity and operational maintenance activities and associated well entry methods.

The survey also provides an opportunity (see last tab) for stakeholders to identify important considerations or key concerns that should be taken into account in developing and applying a risk-based approach to well entry optimization.

C-FER will take appropriate measures to protect the confidentiality of the information that respondents provide in this survey. PHMSA (and all survey respondents) will receive an aggregated and anonomized summary of responses and feedback gathered in this study.

Use of This Survey

(1) The use of this Excel workbook requires that macros be enabled.
(2) If you require more information about this survey, please contact C-FER via email or telephone at:

Josh Vani C-FER Technologies (1999) Inc. Email: J.Vani@cfertech.com Telephone: 1.587.754.2339, ext. 353	or	Dale Friesen C-FER Technologies (1999) Inc. Email: D.Friesen@cfertech.com Telephone: 1.780.450.8989, ext. 307

(3) When complete, please save this workbook and submit it to C-FER via email:

Submit Survey

Survey Structure

Section 1 - Company Information
Contact information and number of storage fields and wells.
Section 2 - Depleted Hydrocarbon Reservoir Storage Well Configuration Information
Configuration details for depleted hydrocarbon reservoir storage wells.
Section 3 - Aquifer Storage Well Configuration Information
Configuration details for aquifer storage wells.
Section 4 - Salt Cavern Well Configuration Information
Configuration details for salt cavern storage wells.
Section 5 - Depleted Hydrocarbon Reservoir Well Entry Information
Well entry details for depleted hydrocarbon reservoir storage wells.
Section 6 - Aquifer Storage Well Entry Information
Well entry details for aquifer storage wells.
Section 7 - Salt Cavern Well Entry Information
Well entry details for salt cavern storage wells.
Section 8 - Stakeholder Concerns
Details of specific well entry concerns faced by operators.

SECTION 1 - COMPANY INFORMATION	

Company Name:	
Contact Name:	
Contact Email Address:	
Contact Phone Number:	

For depleted hydrocarbon reservoir storage facilites owned/operated:

Total Number of Storage Fields:	
Total Number of Storage Wells:	

For aquifer storage facilities owned/operated:

Total Number of Storage Fields:	
Total Number of Storage Wells:	

For salt cavern storage facilities owned/operated:

Total Number of Storage Fields:	
Total Number of Storage Wells:	

Note: This survey only applies to underground natural gas storage. Liquid hydrocarbon storage facilities are excluded.

SECTION 2 - DEPLETED HYDROCARBON RESERVOIR WELL INFORMATION

• For each type of well configuration that your company currently operates in depleted hydrocarbon reservoir storage facilities, please indicate its prevalence and associated attributes in Table 2.A.
• If your company has storage wells that do not fit the typical configuration framework, please describe them separately in Table 2.B, along with any new well configurations currently being considered for future use.
• Note that the focus of this survey is on the configuration of the upper completion, excluding above ground equipment.
• Key components associated with two generic UGS well configurations are depicted in Figures 1 and 2.
• At a minimum, please describe your most common well configurations and any other well configurations that have been shown to be particularly problematic from a well entry perspective.

Number of Depleted Hydrocarbon Reservoir Storage Wells:	0	! This tab only applies to operators with depleted reservoir storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 2.A Typical well configurations:

							Production Casing	Intermediate Casing(s)		Surface Casing	
Prevalence (%)	**Well Direction**	**Tubing**	**Flow String(s)**	**Downhole Shut-off Valve(s)**	**Packer Isolation**	**Unperforated Liner †**	**Cement Height**	**Number**	**Cement Height ‡**	**Cement Height**	**Additional Relevant Details (optional)**

Add Row

†For the purpose of this survey, a liner or scab liner that acts as a barrier to prevent unintentional fluid flow.

‡If more than one condition applies, select the least cemented.

Table 2.B Atypical well configurations in use, or new well configurations being considered:

Label/Name	**Description**

Add Row

Typical well configuration reference figures:

Figure 1 Configurations without Production Tubing

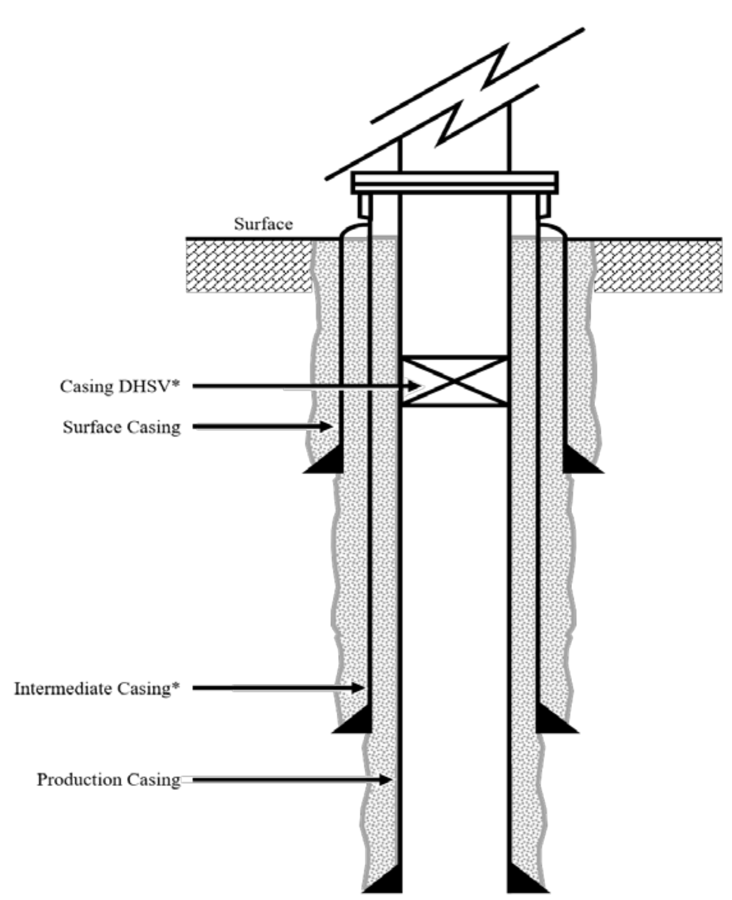
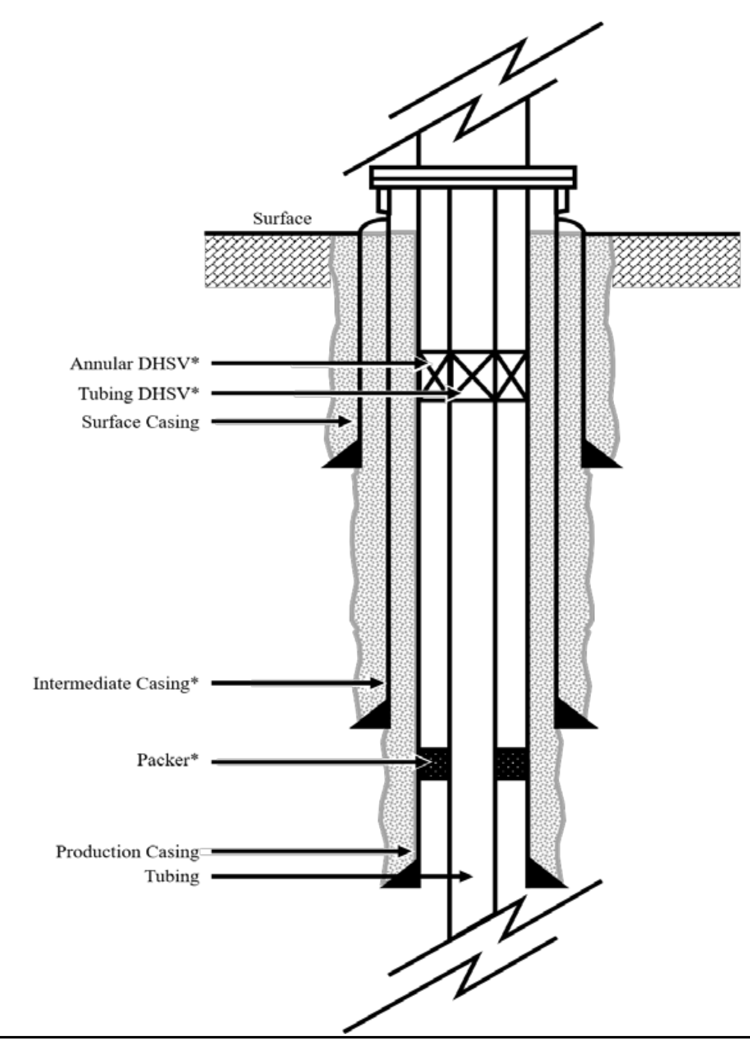


Figure 2 Configurations with Production Tubing



*Component may or may not exist. Please specify in Table 2.A.

SECTION 3 - AQUIFER WELL INFORMATION

• For each type of well configuration that your company currently operates in aquifer storage facilities, please indicate its prevalence and associated attributes in Table 3.A.
• If your company has storage wells that do not fit the typical configuration framework, please describe them separately in Table 3.B, along with any new well configurations currently being considered for future use.
• Note that the focus of this survey is on the configuration of the upper completion, excluding above ground equipment.
• Key components associated with two generic UGS well configurations are depicted in Figures 1 and 2.
• At a minimum, please describe your most common well configurations and any other well configurations that have been shown to be particularly problematic from a well entry perspective.

Number of Aquifer Storage Wells:	0	! This tab only applies to operators with aquifer storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 3.A Typical well configurations:

							Production Casing	Intermediate Casing(s)		Surface Casing	
Prevalence (%)	**Well Direction**	**Tubing**	**Flow String(s)**	**Downhole Shut-off Valve(s)**	**Packer Isolation**	**Unperforated Liner †**	**Cement Height**	**Number**	**Cement Height ‡**	**Cement Height**	**Additional Relevant Details (optional)**

Add Row

†For the purpose of this survey, a liner or scab liner that acts as a barrier to prevent unintentional fluid flow.

‡If more than one condition applies, select the least cemented.

Table 3.B Atypical well configurations in use, or new well configurations being considered:

Label/Name	Description

Add Row

Typical well configuration reference figures:

Figure 1 Configurations without Production Tubing

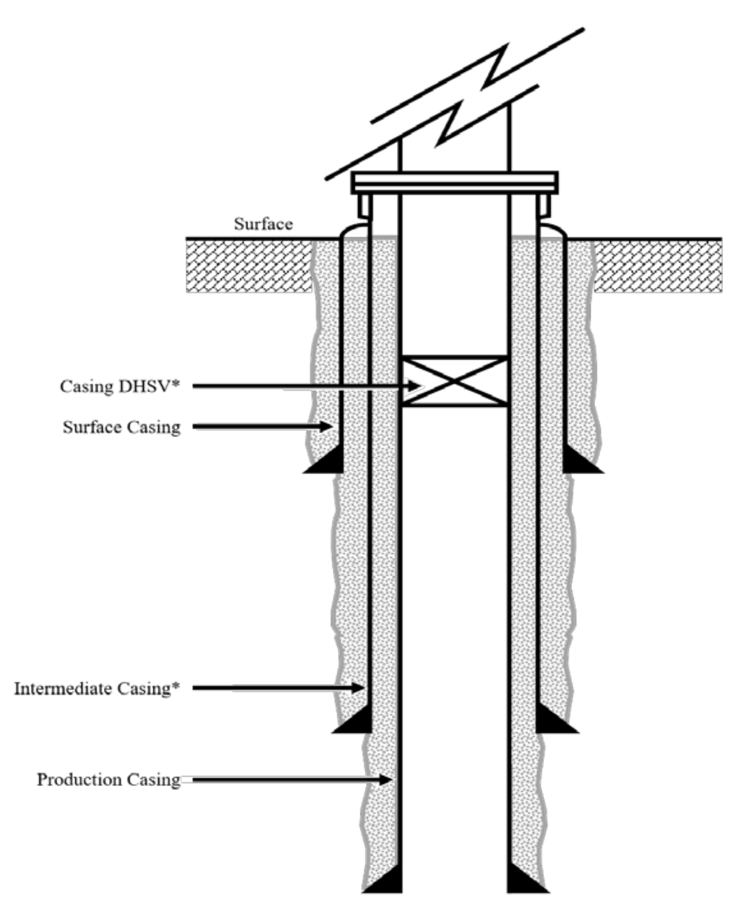
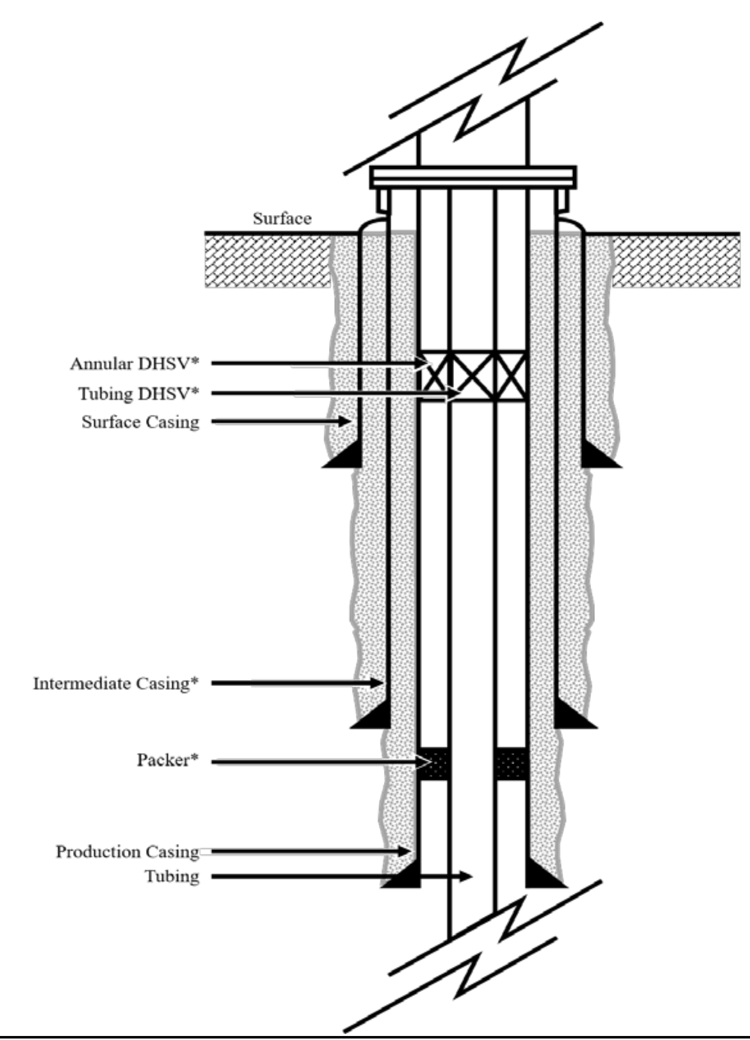


Figure 2 Configurations with Production Tubing



*Component may or may not exist. Please specify in Table 3.A.

SECTION 4 - SALT CAVERN WELL INFORMATION

• For each type of well configuration that your company currently operates in salt caverns storage facilities, please indicate its prevalence and associated attributes in Table 4.A.
• If your company has storage wells that do not fit the typical configuration framework, please describe them separately in Table 4.B, along with any new well configurations currently being considered for future use.
• Note that the focus of this survey is on the configuration of the upper completion, excluding above ground equipment.
• Key components associated with two generic UGS well configurations are depicted in Figures 1 and 2.
• At a minimum, please describe your most common well configurations and any other well configurations that have been shown to be particularly problematic from a well entry perspective.

Number of Salt Cavern Storage Wells:	0	! This tab only applies to operators with salt cavern storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 4.A Typical well configurations:

							Production Casing	Intermediate Casing(s)		Surface Casing	
Prevalence (%)	**Well Direction**	**Tubing**	**Flow String(s)**	**Downhole Shut-off Valve(s)**	**Packer Isolation**	**Unperforated Liner †**	**Cement Height**	**Number**	**Cement Height ‡**	**Cement Height**	**Additional Relevant Details (optional)**

Add Row

†For the purpose of this survey, a liner or scab liner that acts as a barrier to prevent unintentional fluid flow.

‡If more than one condition applies, select the least cemented.

Table 4.B Atypical well configurations in use, or new well configurations being considered:

Label/Name	**Description**

Add Row

Typical well configuration reference figures:

Figure 1 Configurations without Production Tubing

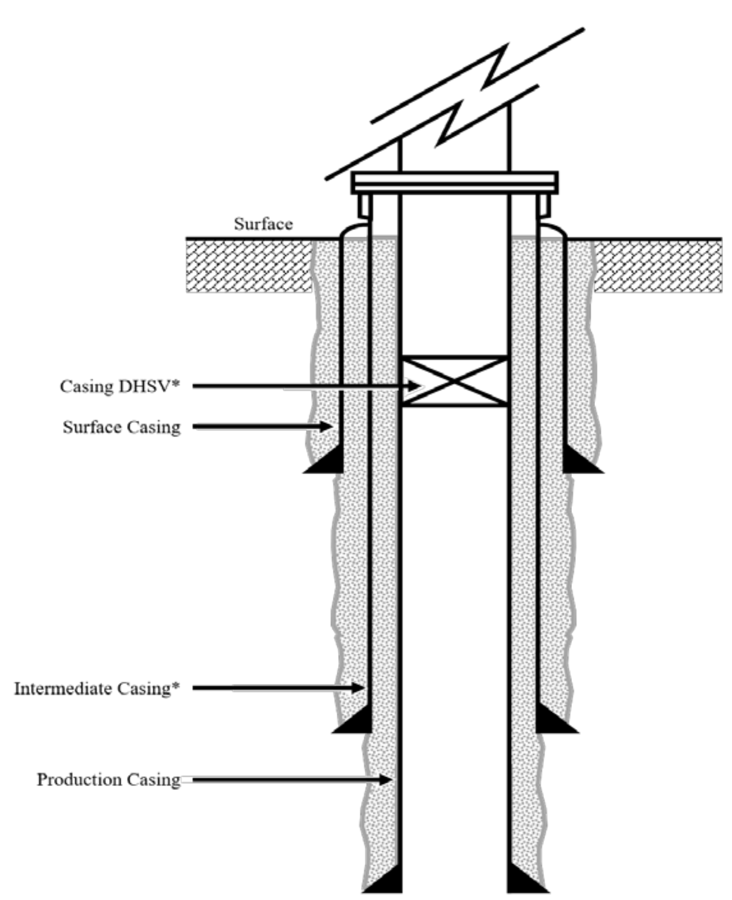
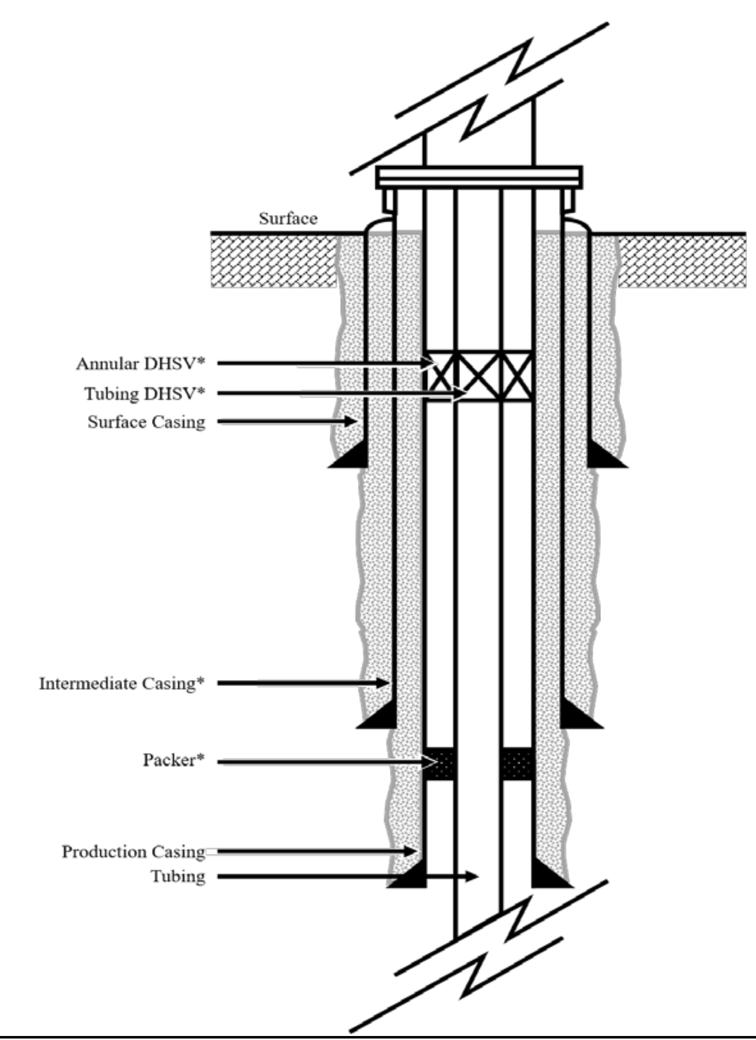


Figure 2 Configurations with Production Tubing



*Component may or may not exist. Please specify in Table 4.A.

SECTION 5 - DEPLETED HYDROCARBON RESERVOIR WELL ENTRY INFORMATION

For typical well entry activities that support the inspection, maintenance and efficient operation of wells in depleted hydrocarbon reservoir storage facilities, please indicate the main reason for well entry, the well entry method, and the key attributes of the entry procedure in Tables 5.A and 5.B. If your company utilizes atypical well entry methods (i.e. entry methods that differ from those listed in the 'Type' category), please describe them in Table 5.C, along with any new well entry methods currently being contemplated for future use.

! This tab only applies to operators with depleted reservoir storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 5.A Typical well entry activities (configurations without production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 5.B Typical well entry activities (configurations with production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 5.C Atypical well entry activities in use, or new well entry activities being considered:

Description

Add Row

SECTION 6 - AQUIFER WELL ENTRY INFORMATION

For typical well entry activities that support the inspection, maintenance and efficient operation of wells in aquifer storage facilities, please indicate the main reason for well entry, the well entry method, and the key attributes of the entry procedure in Tables 6.A and 6.B. If your company utilizes atypical well entry methods (i.e. entry methods that differ from those listed in the 'Type' category), please describe them in Table 6.C, along with any new well entry methods currently being contemplated for future use.

! This tab only applies to operators with aquifer storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 6.A Typical well entry activities (configurations without production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 6.B Typical well entry activities (configurations with production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 6.C Atypical well entry activities in use, or new well entry activities being considered:

Description

Add Row

SECTION 7 - SALT CAVERN WELL ENTRY INFORMATION

For typical well entry activities that support the inspection, maintenance and efficient operation of wells in salt caverns storage facilities, please indicate the main reason for well entry, the well entry method, and the key attributes of the entry procedure in Tables 7.A and 7.B. If your company utilizes atypical well entry methods (i.e. entry methods that differ from those listed in the 'Type' category), please describe them in Table 7.C, along with any new well entry methods currently being contemplated for future use.

! This tab only applies to operators with salt cavern storage wells, please advance to the next tab or go back to tab 1 and enter a value for number of storage wells.

Table 7.A Typical well entry activities (configurations without production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 7.B Typical well entry activities (configurations with production tubing):

Reason for Entry	Well Entry Method	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Minimum Number of Barriers	Additional Relevant Details (e.g., barrier types, typical hazards)

Add Row

Table 7.C Atypical well entry activities in use, or new well entry activities being considered:

Description

Add Row

SECTION 8 - STAKEHOLDER CONCERNS
The guidelines to be developed in this project are intended to assist operators with the selection and development of risk-based models for evaluating well entry methods with the aim being to minimize the lifetime operating risk of gas storage wells by optimizing the well entry schedule. Based on your experience, please identify any important considerations or key concerns that should be taken into account in developing and applying a risk-based approach to well entry optimization. The requested responses are divided into two categories: 1) concerns associated with risk model development and application in general (e.g. lack of data to support failure probability characterization for selected components, lack of well defined failure consequence measures); and 2) concerns specific to the risk analysis of well entry activities (e.g. lack of data to support characterization of failure probability increase during entry, sensitivity of entry-related well failure to factors not identified in this survey)

Risk Modelling Concerns	Description

Add Row

Well Entry Analysis Concerns	Description

Add Row

SUPPLEMENTARY INFORMATION - LISTS FOR DROPDOWNS

Tubing
Yes
No

Packer
Yes
No
N/A

Flow String(s)
Production casing
Tubing
Tubing and annulus
Annulus only

DHSV
None
Production casing
Tubing
Tubing and annulus
Annulus only

Unperforated Liner
Yes
No

Casing Cementing
Cemented to surface
Cemented above the adjacent shoe (of the outer casing string)
Cemented below the adjacent shoe (of the outer casing string)
Not cemented
N/A

Surface Casing Cementing
Cemented to surface
Cemented partway to surface
Not cemented

Number of Intermediate Strings
0
1
2
3+

Entry Activity*
Downhole sensor work
Wellbore stimulation
Casing integrity logs
Perforating
DHSV work
Well cleanout
Casing repair (e.g. patches, liners, remedial cementing)
Drilling
Milling
Fishing jobs
Hydraulic fracturing
Re-completion
Tubing removal
Wellhead valve replacement
Other (please describe in additional details field)

*List adapted from States First Underground Gas Storage Regulatory Considerations: A Guide for State & Federal Regulatory Agencies

Entry Types*
Wireline or slickline
Coiled tubing
Snubbing unit
Drilling rig and/or service-type pulling unit

Number of Barriers During Entry
1
2+

Tubing
Tubing in place during entry
Tubing pulled during entry

Well Directionality
Vertical
Slanted
Horizontal
All of the above

Entry Frequency
More than once per year
Once per year
Once every 24 months
Several times in the life of the well
Once or twice in the life of the well
Not usually carried out in the life of a well (but occasionally necessary)

ATTACHMENT 2 - SURVEY RESPONSES

SUMMARY INFORMATION

In the first section of the survey, background information such as the number of storage wells, the number of storage fields and the types of storage fields owned/operated was collected. This information is summarized in Table 1.

Field Type	Number of Storage Fields	Number of Storage Wells
Depleted Hydrocarbon Reservoir	75	5360
Aquifer	0	0
Salt Cavern	11	44
All	*86*	*5404*

Table 1 Summary of Survey Respondents' Assets

WELL CONFIGURATION

Two tables of well configuration data were collected. The first, presented in Table 2, characterizes depleted hydrocarbon reservoirs well configurations. The second, presented in Table 3, characterizes salt cavern well configurations. The following guidance was provided to survey respondents:

For each type of well configuration that your company currently operates, please indicate its prevalence and associated attributes. If your company has storage wells that do not fit the typical configuration framework, please describe them separately, along with any new well configurations currently being considered for future use. Note that the focus of this survey is on the configuration of the upper completion, excluding above ground equipment. At a minimum, please describe your most common well configurations and any well configurations that require unconventional well entry activities.

Approximate Number of Wells	Well Direction	Tubing	Flow String(s)	Downhole Shut-off Valve	Packer Isolation	Unperforated Liner	Production Casing	Intermediate Casing		Surface Casing
							Cement Height	Number	Cement Height	Cement Height
6	Horizontal	No	Production casing	None	N/A	No	To surface	0	N/A	To surface
103	Horizontal	No	Production casing	None	N/A	No	To surface	1	To surface	To surface
91	Horizontal	No	Production casing	None	N/A	No	Above the adjacent shoe	1	To surface	To surface
12	Horizontal	Yes	Tubing	None	Yes	No	To surface	0	N/A	To surface
367	Vertical	No	Production casing	None	N/A	No	To surface	0	N/A	To surface
507	Vertical	No	Production casing	None	N/A	No	To surface	1	To surface	To surface
250	Vertical	No	Production casing	None	N/A	No	Above the adjacent shoe	1	To surface	To surface
219	Vertical	No	Production casing	In casing	Yes	No	Above the adjacent shoe	1	Above the adjacent shoe	To surface
225	Vertical	No	Production casing	None	N/A	No	Below the adjacent shoe	1	To surface	To surface
438	Vertical	No	Production casing	None	N/A	No	Above the adjacent shoe	1	Below the adjacent shoe	To surface
88	Vertical	No	Production casing	None	N/A	No	Below the adjacent shoe	1	Below the adjacent shoe	Part way
131	Vertical	No	Production casing	None	N/A	No	Below the adjacent shoe	1	Below the adjacent shoe	Not cemented
1445	Vertical	No	Production casing	None	N/A	No	Below the adjacent shoe	0	N/A	To surface
526	Vertical	No	Production casing	None	N/A	No	Below the adjacent shoe	0	N/A	Not cemented
131	Vertical	No	Production casing	None	N/A	No	To surface	1	Below the adjacent shoe	Part way
219	Vertical	No	Production casing	None	N/A	No	To surface	1	Below the adjacent shoe	To surface
131	Vertical	Yes	Tubing	None	N/A	No	Below the adjacent shoe	1	Above the adjacent shoe	To surface
2	Vertical	Yes	Tubing	None	*	No	To surface	0	N/A	To surface
72	Vertical	Yes	Tubing	None	Yes	No	Above the adjacent shoe	0	N/A	To surface
366	Vertical	Yes	Tubing	None	Yes	No	To surface	0	N/A	To surface
25	Vertical	Yes	Tubing	In tubing	Yes	No	Above the adjacent shoe	0	N/A	To surface
6	Vertical	Yes	Tubing	In tubing	Yes	No	To surface	0	N/A	To surface

* Tubing cemented to surface instead of being set on packer

Table 2 Depleted Hydrocarbon Reservoir Well Configurations

Approximate Number of Wells	Well Direction	Tubing	Flow String(s)	Downhole Shut-off Valve	Packer Isolation	Unperforated Liner	Production Casing	Intermediate Casing		Surface Casing
							Cement Height	Number	Cement Height	Cement Height
5	Vertical	No	Production casing	None	N/A	No	To surface	1	To surface	To surface
11	Vertical	No	Production casing	None	N/A	No	To surface	2	To surface	To surface
11	Vertical	Yes	Production casing	None	No	No	To surface	2	To surface	To surface
1	Vertical	Yes	Production casing	None	No	No	To surface	3+	To surface	To surface
11	Vertical	No	Production casing	None	N/A	No	Above the adjacent shoe	0	N/A	To surface
2	Vertical	No	Production casing	None	N/A	Yes	Above the adjacent shoe	0	N/A	To surface
3	Vertical	No	Production casing	None	N/A	No	To surface	0	N/A	To surface

Table 3 Salt Cavern Well Configurations

WELL ENTRY

Survey respondents were asked to characterize their typical well entry practices as they apply to four facility types: 1) entry activities on depleted reservoir wells without tubing, 2) entry activities on depleted reservoir wells with tubing, 3) entry activities on salt cavern wells without tubing, and 4) entry activities on salt cavern wells with tubing. Each of these datasets are presented in Tables 4 to 7. The following guidance was provided to survey respondents:

For typical well entry activities that support the inspection, maintenance and efficient operation of wells in UGS facilities, please indicate the main reason for well entry, the well entry method, and the key attributes of the entry procedure. If your company utilizes atypical well entry methods (i.e. entry methods that differ from those listed in the 'Method' category), please describe them separately, along with any new well entry methods currently being contemplated for future use.

Attachment 2 - Survey Responses

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Wireline or slickline	Casing integrity logs	All	Several times in the life of the well	Wireline BOP and pack off on lubricator	Pulling out of rope socket, damage to well or master valve, tool getting stuck
Wireline or slickline	Casing integrity logs	Vertical	Several times in the life of the well	Wireline lubricator/BOP	Routinely log about 30 wells/year, each well having at least 2 log runs
Wireline or slickline	Casing integrity logs	All	Several times in the life of the well	Pressure control equipment (BOP, grease injector head), sometimes liquid for hydrostatic overbalance	
Wireline or slickline	Casing integrity logs	All	Several times in the life of the well	Lubricator, pack off, BOPE	
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)	All	Once or twice in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)				
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)	All	Once or twice in the life of the well	BOPE, Fluid	
Drilling rig and/or service-type pulling unit	DHSV work	All	Several times in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	DHSV work				
Wireline or slickline	DHSV work				
Wireline or slickline	DHSV work	All	Several times in the life of the well	Lubricator, pack off, BOPE	
Wireline or slickline	Downhole sensor (e.g. temperature, noise)				
Coiled tubing	Drilling	All	Occasionally necessary	BOPE	
Drilling rig and/or service-type pulling unit	Drilling	All	Once or twice in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Drilling	All	Several times in the life of the well	Pressure control equipment (BOP), liquid ("mud system") for hydrostatic overbalance	
Drilling rig and/or service-type pulling unit	Drilling	All	Once or twice in the life of the well	BOPE, fluid	
Coiled tubing	Fishing jobs	All	Once or twice in the life of the well	BOPE	
Drilling rig and/or service-type pulling unit	Fishing jobs	All	Occasionally necessary	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Fishing jobs				

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Drilling rig and/or service-type pulling unit	Fishing jobs	All	Once or twice in the life of the well	BOPE, fluid	
Snubbing unit	Fishing jobs	All	Occasionally necessary	Safety and snubbing BOPE	
Coiled tubing	Hydraulic fracturing	All	Occasionally necessary	BOPE	
Drilling rig and/or service-type pulling unit	Hydraulic fracturing				
Coiled tubing	Milling	All	Once or twice in the life of the well	Coiled tubing BOP stack	Damage to well or wellhead during operations, BOP failure, coiled tubing leak or rupture, getting stuck in the well
Drilling rig and/or service-type pulling unit	Milling	All	Once or twice in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Milling				
Drilling rig and/or service-type pulling unit	Milling	All	Once or twice in the life of the well	BOPE, fluid	
Wireline or slickline	Other (please describe in additional details field)	All	Once per year	Lubricator, pack off, BOPE	Mechanical plug setting, bottom hole pressure reads, well testing, temporarily abandoning subsurface safety valve
Wireline or slickline	Perforating	All	Several times in the life of the well	Wireline BOP and pack off on lubricator	Pulling out of rope socket, damage to well or master valve, tool getting stuck
Wireline or slickline	Perforating				
Wireline or slickline	Perforating	All	Once or twice in the life of the well	Lubricator, pack off, BOPE	
Drilling rig and/or service-type pulling unit	Re-completion	All	Once or twice in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Re-completion				
Drilling rig and/or service-type pulling unit	Re-completion	All	Once or twice in the life of the well	BOPE, fluid	
Drilling rig and/or service-type pulling unit	Tubing removal	All	Several times in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Drilling rig and/or service-type pulling unit	Tubing removal	All	Once or twice in the life of the well	BOPE, fluid	
Snubbing unit	Tubing removal	All	Once or twice in the life of the well	BOP on snubbing unit	BOP failure, dropping tubing, loss of well control, light pipe coming out of hole
Snubbing unit	Tubing removal	All	Once or twice in the life of the well	Safety and snubbing BOPE	

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Coiled tubing	Well cleanout	All	Once or twice in the life of the well	Coiled tubing BOP stack	Damage to well or wellhead during operations, BOP failure, coiled tubing leak or rupture, getting stuck in the well
Coiled tubing	Well cleanout	All	Once or twice in the life of the well	BOPE	
Drilling rig and/or service-type pulling unit	Well cleanout	All	Several times in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string
Drilling rig and/or service-type pulling unit	Well cleanout				
Drilling rig and/or service-type pulling unit	Well cleanout	All	Once or twice in the life of the well	BOPE, fluid	
Wireline or slickline	Well cleanout				
Coiled tubing	Wellbore stimulation	All	Once or twice in the life of the well	Coiled tubing BOP stack	Damage to well or wellhead during operations, BOP failure, coiled tubing leak or rupture, getting stuck in the well
Coiled tubing	Wellbore stimulation	All	Several times in the life of the well		
Coiled tubing	Wellbore stimulation	All	Once or twice in the life of the well	BOPE	
Drilling rig and/or service-type pulling unit	Wellbore stimulation	All	Several times in the life of the well	BOP and fluid	BOP failure, loss of fluid column, taking a kick, dropping work string
Drilling rig and/or service-type pulling unit	Wellbore stimulation				
Drilling rig and/or service-type pulling unit	Wellhead valve replacement				
Drilling rig and/or service-type pulling unit	Wellhead valve replacement	All	Several times in the life of the well	BOPE, fluid	
Wireline or slickline	Wellhead valve replacement	All	Once or twice in the life of the well	Wireline BOP and pack off on lubricator	Setting bridge plug as a barrier before removing wellhead valve, pulling out of rope socket, damage to well or master valve, tool getting stuck
Wireline or slickline	Wellhead valve replacement	Vertical	Once or twice in the life of the well	Wireline lubricator / BOP / 2 Retrievable bridge plugs	No set replacement schedule but have performed 100 replacements, with approximately 20 more scheduled in the next 2 years.
Wireline or slickline	Wellhead valve replacement	All	Several times in the life of the well	Lubricator, pack off, BOPE	

Table 4 Typical Well Entry Activities on Depleted Reservoir Wells Without Tubing

Attachment 2 - Survey Responses

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Drilling rig and/or service-type pulling unit	Casing integrity logs	Vertical	Tubing pulled during entry	Once or twice in the life of the well	BOP, hydrostatic head	Possible pressure increase in the formation during workover - injection on other wells in the field
Drilling rig and/or service-type pulling unit	Casing integrity logs	Vertical	Tubing pulled during entry	Several times in the life of the well	Workover fluid, workover rig BOPE	Workover hazards include: 1) loss of hydrostatic pressure above the storage zone, 2) failure to recognize a gas influx into the well during workover, 3) failure of the downhole workover assembly, 4) failure of the workover rig derrick structure, 5) high wind, 6) operator error such as crown out, 7) failure to run sufficient kill string, 8) failure of the workover BOPE if primary barrier is lost
Drilling rig and/or service-type pulling unit	Casing integrity logs	Vertical		Several times in the life of the well	Packer and on/off tool with tubing plug in place, service rig BOP on wellhead (pipe and blind rams)	
Drilling rig and/or service-type pulling unit	Casing integrity logs	All	Tubing pulled during entry	Several times in the life of the well		
Snubbing unit	Casing integrity logs	Vertical		Several times in the life of the well	Snubbing stack, tubing plug	
Wireline or slickline	Casing integrity logs	Vertical		Several times in the life of the well	Master valve, wireline BOPs, grease injection head	
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)	Vertical	Tubing pulled during entry	Once or twice in the life of the well	BOP, hydrostatic head	Possible pressure increase in the formation during workover - injection on other wells in the field
Wireline or slickline	Downhole sensor (e.g. temperature, noise)	All	Tubing in place during entry	Several times in the life of the well	Fluid, BOP	Pulling out of rope socket, damage to well or master valve, tool getting stuck
Wireline or slickline	Downhole sensor (e.g. temperature, noise)	Vertical	Tubing in place during entry	Once per year	Lubricator, stuffing box, bottom and top master valves	
Wireline or slickline	Downhole sensor (e.g. temperature, noise)	Vertical	Tubing in place during entry	Once per year	Wireline lubricator with grease injection and pack off, wireline BOPE	Wireline hazards include: 1) failure of grease injection/pack off to contain the well pressure 2) failure of the BOPE in the event of loss of primary seal, 3) failure of seal elements in the lubricator, 4) stranding of the wireline cable within the lubricator, 5) failure of the hoist equipment, 6) operator error. The work is typically conducted in an active pressure well.
Drilling rig and/or service-type pulling unit	Drilling	Vertical	Tubing pulled during entry	Once or twice in the life of the well	Drilling mud, drilling rig BOPE	Drilling hazards include: 1) loss of hydrostatic pressure above the storage zone, 2) poor cement job above the storage zone, 3) failure to recognize a gas influx into the well during drilling, 4) failure of the downhole drilling assembly, 5) failure of the drilling rig structure, 6) subsidence of the ground while drilling, 7) failure of the drilling BOPE if primary barrier is lost
Wireline or slickline	Other (please describe in additional details field)	All	Tubing in place during entry	Once per year		Plug setting, bottom hole pressure reads
Wireline or slickline	Other (please describe in additional details field)	Vertical	Tubing in place during entry	Several times in the life of the well	Slickline lubricator with pack off, slickline BOPE	Slickline is used to set tubing plugs and shift downhole sleeves. Slickline hazards include: 1) failure of pack off to contain the well pressure, 2) failure of the BOPE in the event of loss of primary seal, 3) failure of seal elements in the lubricator, 4) balling of the slickline cable within the lubricator, 5) failure of the hoist equipment, 6) operator error. The work is typically conducted in an active pressure well

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Wireline or slickline	Perforating	Vertical	Tubing in place during entry	Once or twice in the life of the well	Lubricator, stuffing box, bottom and top master valves	
Drilling rig and/or service-type pulling unit	Re-completion	All	Tubing pulled during entry	Once or twice in the life of the well	Fluid, BOP	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole.
Drilling rig and/or service-type pulling unit	Tubing removal	All	Tubing pulled during entry	Several times in the life of the well	Wireline BOP and pack off on lubricator	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Snubbing unit	Tubing removal	All	Tubing pulled during entry	Several times in the life of the well	BOP on snubbing unit	BOP failure, dropping tubing, loss of well control, light pipe coming out of hole
Coiled tubing	Well cleanout	Vertical	Tubing in place during entry	Several times in the life of the well	BOP	Wellbore stimulation/cleanout is also done as part of workovers when the tubing is pulled. In that case, an additional barrier will be in place - hydrostatic column.
Drilling rig and/or service-type pulling unit	Well cleanout	All	Tubing in place during entry	Once or twice in the life of the well	Fluid, BOP	BOP failure, loss of fluid column, taking a kick, dropping work string, equipment failure, getting stuck in the hole
Coiled tubing	Wellbore stimulation	Vertical	Tubing in place during entry	Several times in the life of the well	BOP	Wellbore stimulation/cleanout is also done as part of workovers when the tubing is pulled. In that case, an additional barrier will be in place - hydrostatic column.
Coiled tubing	Wellbore stimulation	Vertical	Tubing in place during entry	Occasionally necessary	Coiled tubing lubricator with pack off, coiled tubing BOPE	Coiled tubing hazards include: 1) failure of pack off to contain the well pressure, 2) failure of the BOPE in the event of loss of primary seal, 3) failure of seal elements in the lubricator, 4) parting or leaking of the coiled tubing above the injector head, 5) failure of the hoist equipment, 6) failure of the injector head which can cause tubing to be blown from well, 7) operator error. The work is typically conducted in an active pressure well.

Table 5 Typical Well Entry Activities on Depleted Reservoir Wells With Tubing

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Wireline or slickline	Casing integrity logs	Vertical	Several times in the life of the well	WR plug, master valve, rig BOP, wireline BOP	
Drilling rig and/or service-type pulling unit	Casing integrity logs	Vertical	Several times in the life of the well	BOP stack, hydrostatic - cavern will be water filled	Some casing integrity logs (some corrosion logs are run as part of the workovers)
Wireline or slickline	Casing integrity logs	Vertical	Several times in the life of the well	Wireline lubricator/BOP	
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)	Vertical	Occasionally necessary	Multiple bridge plugs, BOP stack	
Snubbing unit	Casing repair (e.g. patches, liners, remedial cementing)	Vertical	Several times in the life of the well	BOP stack	Snubbing operations are typically carried out to run and remove a hanging string in the wellbore prior to water/gas fill operations
Drilling rig and/or service-type pulling unit	Casing repair (e.g. patches, liners, remedial cementing)	Vertical	Once or twice in the life of the well	BOP stack, hydrostatic - cavern will be water filled	Cavern will be water filled before being worked over using a drilling/workover rig
Wireline or slickline	Downhole sensor (e.g. temperature, noise)	Vertical	More than once per year	Lubricator, wellhead valves	Temperature, noise, downhole video and some casing inspection logs
Snubbing unit	Other (please describe in additional details field)	Vertical	Several times in the life of the well	BOP / bridge plugs / fluid in tubing	Performed after initial well construction and prior to, and after, a major cavern workover (typically every 15 years)
Drilling rig and/or service-type pulling unit	Other (please describe in additional details field)	Vertical	Several times in the life of the well	Fluid filled cavern	Rigs are used to pull hanging strings in a water filled cavern as part of a 15-year major workover that includes casing inspection logs and new wellhead
Snubbing unit	Tubing removal	Vertical	Once or twice in the life of the well	Multiple bridge plugs, BOP stack	

Table 6 Typical Well Entry Activities on Salt Cavern Wells Without Tubing

Well Entry Method	Reason for Entry	Applicable Well Direction(s)	Tubing Status During Well Entry	Typical Frequency	Barrier(s) in Place	Additional Relevant Details (e.g. typical hazards)
Wireline or slickline	Other (please describe in additional details field)	Vertical	Tubing in place during entry	Several times in the life of the well	Wireline lubricator/BOP	Pressure and temperature logging for MIT and inventory verification.

Table 7 Typical Well Entry Activities on Salt Cavern Wells With Tubing

Survey respondents were also asked for any well entry activities not included in the original dropdown list. Additional well entry activities provided by survey respondents included:

- setting tubing plugs and shifting downhole sleeves,
- sidetracking,
- well plugging and abandonment, and
- wellhead replacement.

STAKEHOLDER CONCERNS

Finally, survey respondents were asked for their key concerns as they relate to this research area. Key concerns provided are presented in Tables 8 and 9. The following guidance was provided to survey respondents:

The guidelines to be developed in this project are intended to assist operators with the selection and development of risk-based models for evaluating well entry methods with the aim being to minimize the lifetime operating risk of gas storage wells by optimizing the well entry schedule. Based on your experience, please identify any important considerations or key concerns that should be taken into account in developing and applying a risk-based approach to well entry optimization. The requested responses are divided into two categories:
1) concerns associated with risk model development and application in general (e.g. lack of data to support failure probability characterization for selected components, lack of well-defined failure consequence measures); and
2) concerns specific to the risk analysis of well entry activities (e.g. lack of data to support characterization of failure probability increase during entry, sensitivity of entry-related well failure to factors not identified in this survey)

Concern	Description
Data requirements	Lack of clear understanding of data requirements to support risk assessment efforts - especially more quantitative work.
Data integration	Often stand-alone database, spreadsheets, paper copies, etc. are current source of data to conduct risk assessment. They are not easy to import into risk assessment framework and integration is a challenge.
Internal process improvements/integration	Developing an internal process to implement and sustain risk assessment methodology to be a living process rather than one-time effort.
Lack of data for failures of individual components and barrier systems that could lead to a loss of well control. Industry data could be used to determine the probability of all barriers failing.	The main concern in a well intervention is loss of well control and not typically a leak. Multiple barriers or barrier systems would need to fail and ultimately the BOPE for a loss of well control. By nature of gas storage, the wells are high flow rate and consequence of loss of well control is high. In addition, the analysis should consider that well interventions require personnel in the direct vicinity of the well, thus injury/death consequence are higher during well interventions.
Lack of data	Lack of data to support failure probability characterization for casing or tubing. For example, as logging tool technology advances, our casing appears to have defects disappear.
Lack of data	Lack of data to support failure probability characterization for packers.
Lack of data	Lack of data to support failure probability characterization for subsurface safety valves.
Lack of data	Lack of data to support failure probability characterization for master valves.
Characterization	Lack of well-defined failure consequence measures - Very dependent on individual well characteristics! Such as absolute open flow, wellhead pressure, casing/wellhead size, etc.
Records	Some companies have very good equipment failure records to work with, others have none. Industry needs to start a process to collect this data in a similar manner to be consistent.
Lack of data	Lack of data to support failure probability of wellhead components
Qualitative and quantitative aspects	Ultimately, risk models should be quantitative and probabilistic. In the US (which is sponsoring this research study), PHMSA already has signaled to industry (specifically to pipeline integrity management) that the goal in risk model continual improvement is to move toward quantitative, probabilistic models. See PHMSA, 2018 - Pipeline Risk Modeling - Overview of Methods and Tools for Improved Implementation. The case for well entry risk needs to be made using quantitative comparisons leveraging oil and gas industry well entry risk (loss of control) information. The reason for well entry must lead to a potential risk reduction benefit that is at least equal to, but preferably greater than, the risk of loss of control due to well entry. PHMSA would like to see the industry enabled to speak to the cost/benefit of risk reduction measures, and one way to do this is to assemble data from industry contributors into a central data warehouse, managed and analyzed by a third-party, showing among other risk management performance items the number of well entries and approximate costs for inspections, monitoring, rehabilitation, etc. and the perceived risk reduction. Risk of a loss-of-well-control event is fairly well known in the oil and gas industry and can be bracketed to a good level of confidence in order of magnitude ranges. So, for example, if the risk of loss of control is 1 in 1000 to 1 in 10,000 per well entry, and we know the distribution of how many days it takes to bring a well back under control, and the distributions of chances of injury to well site workers and/or environmental consequences, then we can fairly bracket the general well entry loss of control risk. We also can estimate the risk of further necessitating well entry for every well entry that we do. With good literature-mining, these sorts of rates and distributions are known based on the wider oil and gas industry experience (and the storage industry is no different). The ultimate end of risk management around well entry risk: reduce the number of reasons to enter the well, and well entry risk decreases and in fact is minimized; increase the number of reasons to enter a well, and well entry risk event likelihood increases - both due to the number of entry events as well as to the pervasive weakness in human and organizational systems (see concern below labelled *Human and organizational factors involved in well entry accidents*).

Table 8 Risk Modeling Concerns

Concern	Description
Lack of data	Lack of data to support characterization of failure probability increase during entry
Records	Lack of consistent/similar data across industry to support characterization of failure probability increase during entry
Records	Inconsistent record keeping across industry to support calculation of probability of failure
Characterization	Well entry work can vary slightly from contractor to contractor, as well as in different parts of the country. Additionally, how a well is constructed/completed can change how a well entry is done. To state that pulling tubing has a certain probability of failure would be a very generalized assumption.
Maintenance records on well control equipment from vendors	Getting access to all the historical maintenance, test and certification records is a challenge when using third-party well control equipment.
Requirement of double barriers in storage wells	Much discussion has been had recently that all gas storage wells should eventually be configure for a double-barrier pressure containing capability most often seen as tubing set on a packer inside production casing. While this seems to be a logical statement that all gas storage operators should agree to, this is not the case. From years of operating experience, our company can show that having a wellbore that is only the production casing is the safest configuration for a gas storage well. Having a production-casing-only configuration (i.e. without tubing and/or packer) allows an operator full flexibility to easily rig up on the well and run any number of casing assessment tools, including MFL-type, caliper, temperature, neutron, noise assessments. If an abnormal condition is found in the production casing, the operator can immediately run and set an isolation bridge plug to separate the anomaly from the pressurized gas storage formation. Unfortunately, a tubing/packer configuration inhibits an immediate response as removing a tubing/packer configuration to allow access to the production casing often requires a significant well workover or intervention operation. Often operators using tubing/packer configurations will monitor the A-Annulus pressure. An unexpected increase in A-Annulus pressure is a lagging indicator (pressure is only seen after a problem has already happened). A production-casing-only configuration allows for leading-indicator type inspections (MFL, temperature logs, etc.). Double barriers are not a requirement for the US pipeline grid and the mileage of pipelines close to high consequence areas is much higher than vertical wellbore piping, so why isn't the pipeline industry required to have double barriers?
Reasons for entry	Prescriptive regulations mandating certain frequencies for entry increase well entry risk by increasing (by force of law) the number of times an operator must enter a well to perform some function. The storage industry consistently has argued for risk-based monitoring and inspection in order to avoid unnecessary well entries. There currently are uneven regulations and standards with respect to well entry frequency. For example, CSA Z341 requires certain minimum frequencies for casing inspection, whereas API 1170-1171 does not. California storage regulations require relatively frequent entries for inspection and monitoring, whereas US federal regulations do not, nor do the regulations of many other US states, where such states have specific storage regulations. Risk modeling should account for differences in regulatory requirements, as in some jurisdictions the storage operators must enter wells with certain minimum frequencies.
Reasons for entry	More "non-passive" mechanical equipment and components within the well barrier system will mean more well entries for service to inspect/restore functionality or replace equipment. "Passive equipment", or a "passive barrier" (that is, a "technical passive barrier"), can be defined as a component that functions all the time and at some (initial) design condition - so this includes casing and cement sheaths and can include natural barriers (caprock, impermeable formations, etc.). Technical active barriers could include those components that need to be energized (such as wellhead seals, packer and tubing seals, and the like, which require ongoing energization or an initial energization (pressure, tension, or other) to set and hold. However, another class of "technical active barriers" includes items that are installed but perform on demand, such as emergency/safety shut down valves, lift devices, etc. Then, a well barrier system also could add "technical control barriers," such as surface and/or downhole monitors and alarm systems for pressure, temperature, rate, composition, fluid cut, etc.). So there are several points: 1) As complexity of the well barrier system increases by adding components, the difficulty of well entry increases - difficulty as expressed by more complex procedures, higher skill requirements for workers and supervision, and more issues with parts, service, and availability; and 2) As the number of non-passive technical barriers increases, the reasons for well entry will increase because each of the components have expected lifetimes, as well as potential functionality problems (so both engineering reliability problems as well as lifecycle term uncertainties - but in both instance these issues are greater than for technical passive barriers such as casing and cement - which, with proper engineering design, installation, and monitoring, have much longer lifespans and very little reliability issue as compared to technical active barriers and technical control barriers. Therefore, the risk modeling should reflect the increased need for well entry due to increasing complexity of components (more components and more of the "active" and "control" components, as compared to the passive technical components.
Human and organizational factors involved in well entry accidents	Human and organizational factors and their place in well entry loss-of-control events is somewhat understood, but in general, human and organizational factors is a fledgling field of study (see SPE TR 170575 "The Human Factor - Process Safety and Culture" - March 2014). An ongoing concern is that the level of maturity in management systems, process safety management, and related topics, is at a low level in much of the oil and gas community and in particular in the storage community. Creating means and reasons for increasing well entry frequency at a time of insufficient maturity in process safety management in the storage industry, especially with respect to human and organizational factors, is begging for increased loss-of-control events. Part of the risk analysis should involve maturity and efficacy (operational discipline and evidence of continual improvement activities) assessment of process safety management systems. Again, API has a number of standards that can be adopted/adapted to storage, including API 1173, API 754, etc.

Table 9 Well Entry Analysis Concerns

APPENDIX B – RISK ASSESSMENT IN OTHER INDUSTRIES

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B.1. BACKGROUND AND CONTEXT

Risk assessment methodologies currently in use in other industries were surveyed to complement the information gained from a similar review of methods and models currently employed for wells and associated with underground gas storage (UGS) facilities. The other industries considered include:

- Pipeline,
- Nuclear,
- Offshore oil and gas,
- Aviation, and
- Power transmission.

Much of the information in this review of risk methods and models used in other industries was adapted from a review carried out as part of a previous project for the US Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA) by C-FER Technologies (1999) Inc. ("C-FER") that produced guidelines for the development and application of risk assessment models for pipelines (1). In addition, C-FER's background expertise in performing quantitative pipeline risk assessments was used to augment the information in the reviewed literature.

Given that well entry risk is the focus of the current project and that risks due to well entry are potentially highly influenced by human factors, extra attention was paid to the human factor component of risk assessment as developed and applied in other industries.

B.2. PIPELINE INDUSTRY

B.2.1 Risk Analysis

B.2.1.1 Overview

Risk analysis is a sub-process of a more comprehensive risk management process (see also Figure B.1.1) that involves:

- System definition,
- Threat identification,
- Failure frequency estimation,

- Failure consequence estimation, and
- Risk estimation.

Each component of risk analysis is discussed separately in the following sections.

B.2.1.1.1 System Definition

With respect to system definition, pipeline risk models are typically focused on the pipe itself, though occasionally other equipment, such as valves, appurtenances, pumps, seals, and flanges, are addressed (2,3).

B.2.1.1.2 Threat Identification

ASME B31.8S (4) contains a list of nine threats, which are the basis of most risk models. A screening process based on historical data and/or subject matter expert (SME) opinion can be used to eliminate non-applicable threat categories (3,5,6). Interacting threats may also be considered (6), which include coincident defects (e.g. coincident crack and dent features), coincident threats (e.g. ground movement at the location of a crack), and interacting common-mode conditions that may result in coincident defects (e.g. coating holidays leading to external corrosion and stress corrosion cracking (SCC)). Threats may also be identified based on historical information, though this may lead to underestimation of risks of rare or unobserved threats.

B.2.1.2 Failure Frequency Estimation

Failure frequencies in the pipeline industry are estimated using SME opinion, historical data, and analytical models. Depending on the level of complexity of the failure models, the available data and the level of expertise of SMEs, failure frequencies may be independently defined for leak (which are sometimes further delineated into “small” or “pinhole” versus “large”) and rupture failure modes. Sutherby et al. (7) estimated the failure frequencies for small leaks, large leaks and ruptures. Kariyawasam et al. (6) estimated the failure frequencies based on an “equivalent rupture ratio”, which equates 20 leaks to a rupture. WorleyParsons (3) estimated the frequency of leaks and ruptures as a fraction of the total failure frequency. Mitchell et al. (8) reported only the frequencies of full-bore ruptures for the threats considered. Mangold et al. (2) and Perez et al. (5) estimated the total failure frequency and did not separate failure frequencies for leaks and ruptures.

Failure frequency estimates based on engineering models often define mathematical relationships to distinguish leaks from ruptures. Where SME opinion and historical data were used, the failure frequency estimate was often not divided between leaks and ruptures. Since the consequences associated with small leaks, large leaks, and ruptures differ significantly, calculating separate failure frequencies for each failure mode is preferred whenever possible. Considering all failure events as ruptures leads to an overestimation of the total risk due to an overestimation of failure consequences, while ignoring leak events and considering only rupture events leads to an underestimation of the total risk (particularly for hazardous liquids where leaks can have a significant environmental impact).

B.2.1.2.1 SME Opinion

Failure frequency estimates based on the judgment and experience of SMEs are often used to bridge the gap between qualitative and quantitative risk assessments for pipeline assets. These models are sometimes referred to as semi-quantitative for their blending of qualitative decision making with quantitative mechanisms. For example, an SME can be used to identify parameters that influence failure and estimate failure frequencies based on a qualitative assessment of these parameters (e.g. Cicansky and Yuen (9) and Perez et al. (5)). Other examples include converting a qualitative risk index score to a quantitative failure frequency (e.g. Mangold et al. (2)), or using a structured questionnaire to elicit SME scores and converting the scores to failure frequencies through a consistent set of rules (e.g. Esford et al. (10) and WorleyParson (3))

Using SME opinion is advantageous when system-specific knowledge can be used to fill-in data gaps (Cicansky and Yuen (9), Perez et al. (5), Solis et al. (11), Mangold et al. (2)), or for threats that are not well represented in historical data and are not amenable to analytical modeling (Esford et al. (10), WorleyParsons (3)). However, the level of subjectivity in SME opinion can lead to biased estimates of failure frequencies and, thus, SME is not a suitable method for estimating failure frequencies of new threats where little pipeline-specific expertise exists. Potential bias can be reduced by requesting opinions from several SMEs and applying a structured communication technique, such as the Delphi technique (12) to reconcile them.

B.2.1.2.2 Historical Data

The use of historical data to estimate baseline failure frequencies due to specific threats on one system as a proxy for the failure frequencies on another is one way of developing quantitative failure frequency values. One limitation of this approach is that the estimated failure frequencies are often developed from generic incident databases and do not necessarily reflect the condition (e.g. differing pipeline-specific attributes) and environment (e.g. corrosion vulnerability) of the pipeline system in question.

This limitation is addressed by modifying the baseline frequencies, using either multiplicative adjustment factors (3,7,13,14,15,16,17) or mathematical functions based on regression (6,18).

Failure frequency estimates based on historical data generally offer more confidence than those developed using SME opinion due to the use of empirical data. However, this method is not completely divorced from the subjectivity involved in SME opinion, as SME opinion is often used to develop the adjustment factors used to tune baseline frequency estimates to a specific system. Furthermore, historical failure frequencies are only as good as the data upon which they are based. Inconsistent incident reporting may lead to inaccuracies in the calculated failure frequencies, and the lack of historical failure data for newly-identified threats or novel designs prevents the application of this approach in these scenarios. Historical data also reflects the design, construction and operational practices of the time during which the data was collected and, thus, it is important that these practices are reflected in the pipeline system for which a given risk assessment is being performed.

B.2.1.2.3 Analytical Methods

Analytical models can be broadly categorized as structural reliability methods (e.g. Monte Carlo simulation), probabilistic graphical models (e.g. fault tree methods and Bayesian networks), and fuzzy logic models.

Structural reliability methods are used to estimate failure frequencies by considering the uncertainties in the parameters and models that govern pipeline failures. Given a deterministic failure model, and the probability distributions of the model input parameters and model error factors, standard reliability methods such as Monte Carlo simulation (19) can be used to estimate the frequency of failure.

Graphical models are probabilistic models that expresses the dependence structure between random events. Fault tree methods are a logical representation of all possible basic event combinations leading to a failure event. Basic events are connected using 'AND' and 'OR' gates, and probability theory is used to compute the frequency of the top event (i.e. failure) as a function of the probabilities of the basic events. Bayesian networks are similar to fault tree models, except that the relationships between the basic events are defined through conditional probabilities rather than the 'AND' and 'OR' relationships.

Recently, fuzzy logic, which is a non-probabilistic method for addressing uncertainty, has been used to estimate the failure rates of onshore pipelines (20,21,22,23). Fuzzy logic methods are based on fuzzy set theory, in which an element may be in both failure and success categories with different degrees of membership. Fuzzy logic allows for modeling linguistic representations of imprecision (e.g. labels such as 'poor', 'fair', 'excellent') and uncertainty (e.g. lack of knowledge about the coating condition being either 'poor' or 'fair'). Fuzzy logic does not have the well-established mathematical and theoretical basis that underpins probabilistic models and, thus, the application of fuzzy logic methods has not gained wide acceptance.

Taken together, analytical models have the advantages of being capable of directly estimating pipeline-specific failure frequencies, the influence of input variable uncertainty, and the differentiation between failure modes. Furthermore, the ability to address rare and interacting threats is only limited by model development, and not necessarily data collection. Analytical models do, however, require greater resources and expertise to characterize input parameters and compute failure frequencies, and the complexity of probabilistic models associated with analytical methods may be a barrier to their adoption.

B.2.1.3 Consequence Estimation

B.2.1.3.1 Natural Gas

Most consequence models developed for pipelines carrying natural gas focus on estimating the impact on life safety of jet fires or crater fires, as these are the most significant hazards associated with natural gas release.

Several models used to quantify the life safety consequence resulting from a natural gas release have been developed into software packages. PipeSafe considers gas outflow and dispersion, as well as thermal radiation effects of initial fireballs and steady-state fires. A review of the mathematical models and subsequent updates underlying the software package are available in Acton et al. (24,25,26). PHAST is proprietary software developed by Det Norsk Veritas Ltd. (DNV) and is used to estimate the life safety consequences of natural gas releases from pipelines. PHAST has been shown to produce realistic thermal radiation zones based on comparison with real-world events (27). The potential impact radius (PIR) formula developed by Stephens et al. (28) estimates the distance from the fire source at which the thermal radiation dosage results in a 1% chance of mortality. Estimates of the safety consequences and damage zones calculated by the PIR formula have shown to be comparable to those produced by PipeSafe (29,30). Other simplified analytical approaches to estimate life safety consequences due to release of natural gas have been developed by Jo and Ahn (31), Jonkman et al. (32), Francis et al. (33), and Kraus (34).

B.2.1.3.2 Liquid Products

For pipelines carrying liquids, the vapor pressure of the liquid being transported plays an important role in determining the likelihood of various release outcomes. Non-volatile low vapor pressure (LVP) liquids, such as crude oil, have a low ignition probability and, thus, release consequences relate mainly to ground and water contamination. Volatile LVP liquids, such as gasoline, present the possibility for a pool fire in addition to environmental contamination. Consequence models involving the release of high vapor pressure (HVP) liquids include flash fires or vapor cloud explosions.

Models to quantify life safety consequences due to the release of flammable liquids are typically developed as part of proprietary software packages such as CANARY and PHAST and are not described in detail in the public domain. Other models developed using computational fluid dynamics (CFD) to model pool fires are described in Sun et al. (35) and Jujuly et al. (36).

Models to quantify the environmental impact of spills estimate release volume, spill trajectories, potential for surface water and ground water contamination, the potential for the spill reaching an environmentally sensitive area, spill cleanup effectiveness, and/or time to habitat recovery. Simplified models that quantify the environmental consequences of a liquid release have been developed by Nessim et al. (37), who consider release volumes that are modified to account for the damage sensitivity of a spill area, and Etkin (38), who expresses environmental consequences in terms of dollar amounts. More environmental consequence are described in the following sources:

- Zuczek et al. (39) demonstrated the application of a digital elevation model to predict overland oil spill trajectories.

- WorleyParsons (3) conducted a detailed risk assessment for the Northern Gateway Pipelines project. The assessment used a model called "OILMAP Land" that determines the spill trajectories on land based on the steepest descent path as obtained from a digital elevation model. The velocity of spill flow in water was determined by the speed and direction of surface currents.

- Green et al. (40) provided a summary of the approach used to assess the ecological and human health risks associated with a hypothetical oil spill from the proposed Northern Gateway Pipeline. In addition to the spill trajectory modeling, the framework considered the behaviour of hydrocarbons in water, and the acute and chronic effects of the spill on ecological and human receptors.

- Humber et al. (41) quantified the potential impact due to an oil spill through detailed fate (i.e. natural degradation of hydrocarbons in the environment) and transport (i.e. pathways for oil movement) modeling for Trans-Northern Pipelines. The modeling included spill volumes; overland spill trajectories, including the effects of terrain, barriers and conduits; and risk receptor identification.

- Bonvicini et al. (42) defined the environmental damage due to an oil spill in terms of the expected cleanup and remediation costs, as well as the contaminated soil and ground water volumes. The "Hydrocarbon Spill Screening Model" (HSSM) developed by the US Environmental Protection Agency (EPA) was used to estimate the extent of contamination. Numerical models based on the finite element and finite difference methods were listed as widely applied general-purpose models for simulating the fate and transport of contaminants.

- A supplemental environmental impact study for the proposed Keystone XL Pipeline (43, Appendix T) used the HSSM model to estimate the potential for ground water contamination due to an oil spill. The same document (43, Appendix P) also included a detailed environmental risk assessment that considers the impact on soil, vegetation, wildlife and water resources, where water resources included ground water, flowing surface waters, aquatic organisms, wetlands/reservoirs and lakes.

Models to estimate financial impact are not generally available in the public domain. Examples of the failure cost components cited in the literature include:

- Product loss, repair cost, and shutdown cost (2,18);
- Costs due to customer impact, public perception and reputation damage; cost of increased regulatory oversight (i.e. other than the cost to implement immediate risk reduction measures); and cost to restore operational confidence (7,11,13);
- Impact on adjacent property, lost revenue and fatality compensation (13); and
- Cleanup costs (2).

B.2.1.3.3 Risk Estimation

Most risk models reviewed were either used as part of a pipeline integrity management process (6,7,9,10,13,44,45) or to demonstrate regulatory compliance (2,8,9,11,33,46).

In most cases, risk is measured using monetary units by converting the consequences related to safety, environmental sensitivity and financial impact to a dollar value (2,5,11,18). Other measures of life safety risk include 'individual risk' and 'societal risk'. Societal risk has been expressed as an F-N plot, which is a plot of the frequency (F) of incidents causing N or more of fatalities (47), or casualties (i.e. fatalities and injuries) (7). Societal risk has also been expressed in terms of the expected number of fatalities per km-year (13). Environmental risks have been quantified in terms of a sensitivity score (3) and an effective spill volume (37), which is defined as the spill volume, adjusted by a factor that accounts for the environmental sensitivity of the spill site. The use of consistent units for all consequences allows for a consistent comparison between assets; however, the conversion of life safety consequences to a dollar value requires a realistic valuation of a human life. This conversion becomes controversial as assigning a monetary value on human life opens the operators up to the risk of litigation and public outrage.

B.2.1.4 Human Factors

There is only very general coverage of human factors in risk assessments in the pipeline industry. Some hazards identified within ASME B31.8S (4), such as third-party damage and incorrect operations, may have a human error component. However, the impact of these hazards are mainly manifested in pipeline asset risk assessments through historical failure frequency estimates. This approach aggregates all sources of error for each failure event, and fails to delineate those contributions specifically attributable to human error, such as cognitive factors and the working environments that may influence them.

B.3. NUCLEAR INDUSTRY

B.3.1 Risk Analysis

The US Nuclear Regulatory Commission (NRC) is the main regulating body responsible for developing and enforcing regulations that ensure risks to public health and safety associated with the design, construction, and operation of nuclear power plants (NPPs) are minimized. One of the main tools used in this capacity is the probabilistic risk assessment (PRA)[1], which is used to quantify the frequency and severity of adverse events, as well as suggest improvements to NPP design and operation.

A PRA is composed of the following steps:

1. **Hazard specification** – defining the outcomes that are to be prevented. In NPPs, this is centered around preventing damage of fuel in the reactor core and the release of radioactive material to the environment.

2. **Identify initiating events** – defining a spectrum of events that could possibly lead to the hazard.

3. **Frequency estimation** – quantifying the frequency of initiating events using input from SMEs, historical data, simulations, or some combination thereof.

For each initiating event, a risk analyst will calculate the likelihood that a combination of failures, or sequence, will lead to the adverse outcomes defined in the hazard specification. This is done for all possible sequences leading to a given outcome and produces an overall likelihood for that outcome. Several techniques are used to accomplish this task:

- **Event trees** – used to model the success or failure of mitigating systems in NPPs.

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[1] The PRA is a method for determining quantitative failure probabilities in NPP operation, and is the primary method of evaluating overall risk in the nuclear industry. Use of PRA dates back as early as 1975 and, thus, the use of QRA methods in the nuclear industry is relatively mature compared to most other industries. As a result, risk assessment guidelines in the nuclear industry are primarily quantitative, though qualitative elements do occur in certain components, such as hazard identification and human reliability analysis.

- **Fault trees** – used to model NPP mitigating systems in detail to calculate the overall probability of failure of each system. The outcomes of fault trees are used to determine the probabilities of different sequences on the event tree, and form part of the calculation of failure frequencies of the NPP overall.

- **Human reliability analysis (HRA)** – used to evaluate and quantify the contribution to NPP system failure frequency caused by human errors considering factors such as training, procedures, and expected plant conditions during initiating events.

The NRC specifies three levels of PRA analysis, which represent sequential stages required for a full QRA that covers NPP core damage, subsequent release of radioactive material, and potential harm to the public and the environment.

- **Level 1 PRA** – estimates the frequency of accidents causing damage limited to the NPP reactor core (commonly referred to as core frequency damage). This is done using the event and fault tree approach illustrated in Figure B.2.1, with all sequences terminating with reactor core damage. Such sequences are typically referred to as "severe accidents". Frequencies for each severe accident are summed to calculate the total core damage frequency, which serves as an input for a Level 2 PRA.

- **Level 2 PRA** – models the NPP response to the severe accident sequences developed in a Level 1 PRA (e.g. given core damage, do tubes in the steam generator rupture). A Level 2 PRA analyzes the progression of a severe accident through the NPP based on the status and condition of containment structures and systems. Once the progression has been characterized, the amount and type of radioactivity released is determined, which is used in the Level 3 PRA.

- **Level 3 PRA** – models the consequences of a release in terms of adverse effects on human health and economic losses due to release of radioactive material into the environment.

Each PRA level is evaluated against an acceptance criterion. The hierarchical nature of the risk acceptance criteria and the requirement for different criteria to evaluate the system's safety and to define consequence reduction measures are discussed in Mitra et al. (48). The NRC report by Mitra et al. (48) also provides a more detailed discussion of the data requirements and uncertainties associated with the PRA levels.

The NRC assesses only the consequences associated with the health of the population. The consequences resulting from the Fukushima accident in 2011 have highlighted the importance of considering the costs associated with socio-economic and environmental effects. Silva et al. (49) include these effects and provide a consequence severity index based on the total costs of failure.

The degree of uncertainty in a PRA increases from Level 1 to Level 3 PRAs, not only due to the compounding effect of uncertainty of each individual level, but also due to the nature of probabilities being estimated. For example, Level 1 PRAs involve relatively well-established models and failure frequency estimates for plant components, while Level 3 PRAs involve highly variable weather patterns. Efforts by the NRC to reduce the uncertainty inherent in PRA include research into the advancement of physical models and the collection of data. Uncertainty reduction is also an active field of academic research. Some examples include the development of detailed guidelines for eliciting SME opinion to estimate equipment failure rates (50) and methodologies to reduce uncertainties that result from a lack of knowledge, as opposed to inherent randomness (51). Computer modeling methods, such as Monte Carlo simulation and Latin Hypercube sampling, can also be used to quantify the interaction between uncertainties of different PRA components include.

B.3.2 Human Factors

The use of HRA has a long history in the nuclear industry as one component of PRA. The HRA process generally entails the identification of human failure events (HFEs), which are those basic events that can be influenced by human activities where a fault in the event would influence NPP performance at the functional, component, or system level (52). A human error probability (HEP) is associated with each HFE, typically using expert estimation (although Bayesian approaches, historical data, and simulations have been used to inform HEPs as well; see Boring (53,54)). Once the HFEs have been identified and their corresponding HEPs estimated, they are then incorporated into a broader PRA program utilizing event and fault trees.

Performance-shaping factors (PSFs) are environmental factors that might increase or decrease HEP values, and are used to scale HEPs based on plant- or task-specific conditions. A sample of standardized PSFs are listed in Table B.2.1 (55).

Training and experience	Human-system interface
Procedures and administrative controls	Environment
Instrumentation	Accessibility/operability of equipment
Time available	Need for special tools
Complexity	Communications
Workload/time pressures/stress	Special fitness needs
Team/crew dynamics	Available Staffing

Table B.2.1 Examples of Performance Shaping Factors

There are currently at least 39 distinct HRA methods in use in the nuclear industry (56). Most of these follow some variant on the following steps, which form the basis of the Technique for Human Reliability Analysis (THERP), the first HRA model used in the nuclear industry (52):

1. Determination of a nominal HEP, which is what would be expected in the absence of any mitigating/exacerbating circumstances.

2. Calculation of the basic HEP, which modifies the nominal HEP for plant-specific conditions and PSFs.

3. Calculation of the conditional HEP, which modifies the basic HEP to account for the influences and interaction of other tasks or events.

A recent study by Boring (52) identified several HRA models that are in common use in NPPs today, and that may be viable for use in the oil and gas industry. These are described below.

THERP (57) was the first HRA model adopted for use in PRA by the US Nuclear Regulatory Commission (USNRC). An outline of the basic steps involved in THERP is shown in Figure B.2.1. It is among the most well-known and widely-used HRA methods (53). In THERP, it is assumed that errors associated with human activities occur at constant baseline rates. Human activities are divided into subtasks (i.e. HFEs) with associated probabilities of success/failure (i.e. HEPs) and arranged into a system of tables that can be matched to certain scenarios. For this reason, it is sometimes referred to as a "scenario matching method" (52). Consideration is given to environmental factors using PSFs which modify HEPs. This model has been validated by Kirwan (58,59) and Kirwan et al. (60) using historical data.

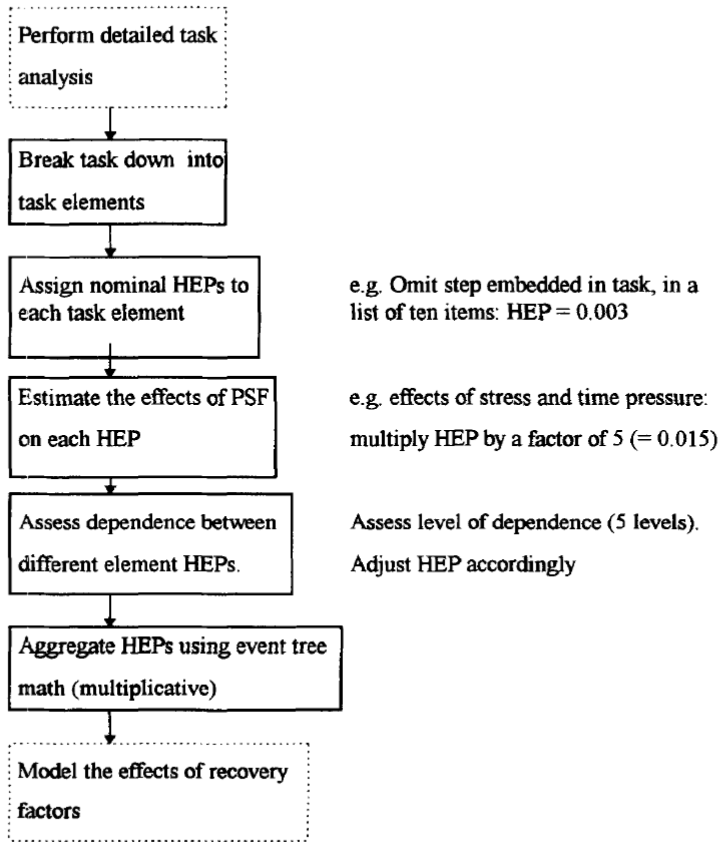

Figure B.2.1 The THERP quantification process from Kirwan (58)

SPAR-H (61) simplifies THERP by allowing greater flexibility in developing HFEs, which are broadly categorized into either diagnostic activities, which refer to the determination of the likely causes of abnormal events (e.g. determining the cause of an erratic instrument reading), or action activities, which refer to tasks that are typically the required response to a correct diagnosis (e.g. starting a pump). Diagnosis and action activities are assigned HEP values of 1.0×10^{-2} and 1.0×10^{-3}, respectively. SPAR-H also places greater emphasis on the impact of human behavior in HRA by relying on the following eight formalized PSFs:

- Available time,
- Stress and stressors,
- Experience and training,
- Complexity,
- Ergonomics,

- Procedures,
- Fitness-for-duty, and
- Work processes.

These PSFs generalize HEPs across the spectrum of human performances (Figure B.2.3) and were derived from the consideration of behavioral sciences literature in the context of NPP operation (62).

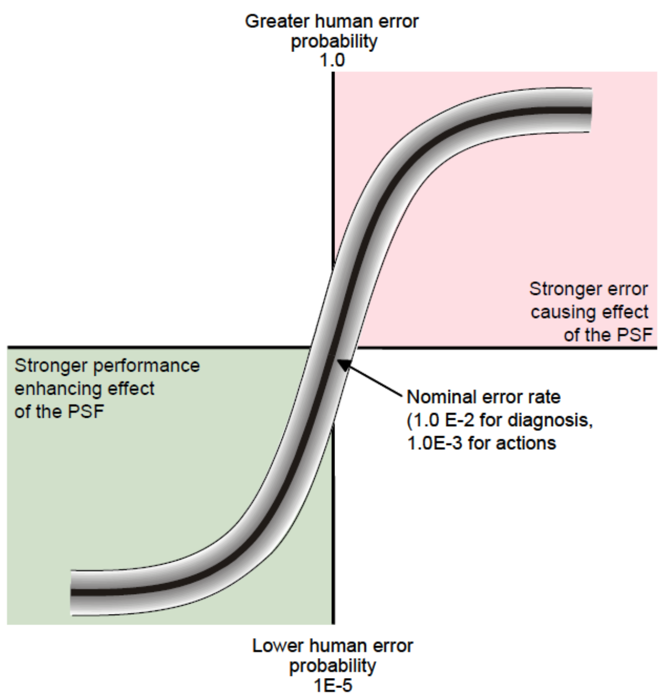

Figure B.2.2 HEP Values from Gertman et al. (61)

ATHEANA (63) was developed in response to the inadequacy of other HRA models in addressing errors of commission, which are those errors that arise from taking the wrong action. ATHEANA identifies "error forcing contexts" (EFCs), which are situations in which human error is likely to occur, such as situations outside of existing procedures and training. Error probabilities are assigned to those contexts which might force a human error (i.e. the EFCs), as opposed to the human actions themselves. ATHEANA is composed of two main stages:

- **Identification and Definition** – As in THERP and SPAR-H, the identification stage begins with identifying HFEs as the basic events that are incorporated into a broader PRA. Unsafe actions (UAs) are then identified and the EFCs in which those actions may occur are then identified.

- **Quantification** – This stage estimates HFE probabilities. This is achieved by first estimating the relative frequency of EFCs, which is informed by estimates of non-nominal plant conditions and associated PSFs. The next step is estimation of the probability that a human will make an error given the specific EFC. This process is done through a facilitated discussion between a multidisciplinary panel of experts. In terms of quantification, each expert selects upper and lower probability bounds, which are combined to produce a composite error on failure probability.

One key factor that differentiates NPPs from UGS wells is the setting in which the work is performed. Normal operations in an NPP are controlled by a centralized crew of reactor operators, whereas UGS well entry is much more decentralized. Furthermore, NPP operators follow detailed step-by-step procedures, whereas such procedures may not be available for UGS well entry. Boring (52) notes that applying procedure-related PSFs from a nuclear power HRA method to an HRA developed for applications in the oil and gas industry could result in unrealistically high HEPs (52).

There are, however, scenarios in NPP operation where the nature of the work is potentially more closely aligned with that performed during UGS well entry. Heo and Park (64) propose a framework for quantifying the effects of human errors related to maintenance tasks in the Balance of Plant (BOP, which refers to those parts of a NPP that exclude the nuclear steam supply systems) in NPPs, and Asadzadeh and Azadeh (65) propose an integrated systemic model that uses functional resonance to optimize condition-based maintenance programs.

B.4. OFFSHORE OIL AND GAS INDUSTRY

B.4.1 Risk Analysis

The main documents reviewed that give guidance on risk assessments for offshore oil and gas (O&G) facilities include risk assessment guidance notes published by the American Bureau of Shipping (66), the Marine Risk Assessment (MRA) guidelines prepared by DNV for the UK Health and Safety Executive (HSE) (67), and the HSE information on risk assessment for offshore installations (68).

B.4.1.1 ABS Guidance Notes

The ABS guidance notes (66) presents a framework to assess the risk associated with marine hazards in production and shipping of offshore O&G facilities that uses four basic steps:

1. Hazard identification,
2. Frequency assessment,

3. Consequence assessment, and
4. Risk evaluation.

Several techniques for hazard identification are described, including what-if analysis, hazard checklists, the hazard and operability (HAZOP) analysis technique, and failure mode and effects analysis (FMEA). The use of historical data, event trees, fault trees, common cause failure analysis, and human reliability analysis are all suggested as techniques for failure frequency estimation. Consequence assessment includes characterization of the source of the hazard, estimating the transport of material and/or energy released due to failure, and the identification and quantification of the effects of release on selected targets of interest. The selection of a risk evaluation method is dependent on the nature of the risk assessment (i.e. is it qualitative or quantitative), the level of detail of the risk assessment, and the availability of data. A listing of qualitative and quantitative approaches to risk assessment and the factors affecting their selection is provided, and includes risk matrices, F-N curves, risk profiles, risk isopleths, risk density curves, and risk index methods.

B.4.1.2 Marine Risk Assessment Guidelines

The MRA guidelines (67) focus on the selection of an appropriate risk assessment approach (i.e. qualitative versus quantitative) based on the following criteria:

- **Life-cycle stage** – The stage of a facility in its design life (spanning feasibility studies, front-end design, detailed design, operation, and abandonment) determines the information available for a risk assessment (e.g. design parameters versus historical and operational data), and the degree of flexibility available to change design elements (i.e. design parameters cannot be changed during operations). The type and quality of information related to design and operational details also influences the selection of the risk assessment approach.
- **Hazard potential** – The presence of high consequence events increases the degree of rigor required in the selected risk assessment process.
- **Decision context** – A decision context with higher elements of novelty, uncertainty or stakeholder concern requires greater detail.

The document also provides guidance on the hazard identification process. The use of combined SME opinions is encouraged to get diverse input; however, structure and a clearly defined scope are also essential to focus the analysis. Several techniques are also described, including:

- Hazard checklists;
- Failure mode, effects, and criticality analysis (FMECA);
- HAZOP studies; and

- Structured what-if checklists (SWIFT)

The guidelines also include several worked examples for a contextual demonstration of the ideas discussed therein.

B.4.1.3 Guidance on Risk Assessment for Offshore Installations

This report (68) provides guidance for asset managers and safety engineers intended for risk assessments of offshore installations in the context of the legal requirements set out in UK regulations. These require that the following be demonstrated:

- All hazards with the potential to cause a major accident have been identified;
- All major accident risks have been evaluated; and
- Measures have been or will be taken to control the accident risks to ensure compliance with relevant statutory provisions.

Three levels of rigor for risk assessments are defined as:

- **Qualitative (Q)** – frequency and severity are both qualitatively determined
- **Semi-quantitative (SQ)** – where frequency and severity are approximated within quantifiable ranges
- **Quantified[2] risk assessment (QRA)** – full quantification of frequencies and severities

The choice of which level of rigor to use for a given risk assessment should be guided by the amount of value provided by each level and the complexity of the system under investigation. Q and SQ assessments are generally considered screening tools to determine the most significant threats and hazards to be further analyzed by a full QRA. Regardless of the level of the assessment, assumptions and their justifications must be documented during the risk assessment process.

Once risks have been calculated, the next step is evaluation. The goals of risk evaluation are to list hazards that pose the greatest risk, determine which are most critical, and develop ways in which those hazards may be addressed. Risk matrices are recommended as suitable for risk evaluation in Q and SQ assessments, while quantitative targets are used for QRA. Hazards that pose intolerable risks are to be reduced until they become tolerable or are as low as reasonably

[2] The HSE guidelines use the term quantified risk assessment rather than quantitative risk assessment, but the interpretation is the same.

practicable (ALARP). It is recommended Q and SQ assessments be used where risks are low enough that risk is not expected to be intolerable.

B.4.1.4 Risk Modeling Techniques

Several risk modeling techniques are common to the reviewed guidelines and are described in more detail below:

- **Analysis of historical data** – ABS (66) recommends that an analyst using historical data for frequency estimation should consider the source of the data, the statistical quality of the data (e.g. as sample size), the reporting accuracy, and the relevance of the data to the event under consideration. Example applications of historical data analysis for offshore marine accidents are provided in DNV (67).
- **Event/Fault tree analysis** – Recommended by both DNV (67) and ABS (66), these are widely used techniques across many industries, with the main limitation being the assumption of independence between basic events, which can lead to common cause failures being overlooked.
- **Bow-tie analysis** – A bow-tie analysis is typically a combined fault tree and event tree analysis, with all the initiating events that lead to a release event on one side and all the potential hazard scenarios resulting from the release on the other side. Elements preventing the release are also called "prevention/control barriers" and those that reduce the consequences are called "mitigating barriers". The barriers are also referred to as "layers of protection" or "lines of defence".
- **Common cause failure analysis** – ABS (66) recommends this approach for examining the sequence of events proceeding from multiple incidents arising from the same root cause. SME opinion is employed to develop the probability of failure for each event conditional on the common cause.

B.4.2 Human Factors

Four sources exploring the use of human factors in risk assessments and safety systems in the offshore O&G industry were reviewed (two of which were also discussed in Section B.4.1 above). Descriptions of the consideration of human factors in these guidelines and documents are reviewed below:

B.4.2.1 ABS Guidance Notes

ABS (66) gives guidance on the consideration of human factors in the hazard identification procedure. The guidelines encourage risk analysts to be trained to spot potential for human error to contribute to risk. This requires identification of both explicit human interaction (e.g. an operator must shutdown a boiler valve following an alarm) and implicit human interaction (e.g. a pressure relief valve installed to relieve boiler pressure must have been installed properly by maintenance personnel). The guidelines also identify HRA as an approach to estimating the probability of human errors. The HRA is performed in the following steps:

1. **Selection of risk scenarios to analyze** – generally high-risk scenarios are a pre-requisite for an HRA. Such scenarios are re-examined to assess the impact an individual could have while completing a scenario-related task.

2. **Task analysis** – determination of what specific tasks an individual must perform in a given scenario.

3. **Error identification** – determination of potential errors made by an individual while performing a task. This could be due to poor ergonomics, training, or procedure definition.

4. **Determine error likelihood** – this can be done using quantitative or qualitative values informed by human failure databases.

5. **Develop error reduction strategies** – strategies for minimizing error likelihoods are developed and ranked in terms of cost-effectiveness.

6. **Document results** – all assumptions and justifications are to be recorded.

7. **Integrate with overall risk assessment** – the errors identified should be created to allow seamless integration with the structure of the overall risk assessment.

B.4.2.2 Marine Risk Assessment Guidelines

The MRA guidelines (67) distinguish between HFA and HRA.

An HFA defines human factors as the environmental, organizational, and job factors, as well as human characteristics, that influence human behavior at work in a way that can affect health and safety. For a risk assessment to be comprehensive, an HFA should be performed, which considers:

- **Activity** - tasks should be designed in accordance with ergonomic principles to achieve a physical and mental match with people's capabilities.

- **Individual** - people should be recruited and trained so that they are competent in performing the job.

- **Organization** - the company should establish a positive health and safety culture.

Four stages in an HFA are described:

1. An inventory of all operating tasks carried out for a given activity is performed using high-level task analysis, which identifies the main human tasks needed to meet operational goals. This process considers normal operations, emergency procedures, maintenance, and recovery measures.

2. The task inventory is screened for safety-critical tasks, which are defined as those with the greatest risk impact. For guidance on assigning task criticality, the reader is referred to a report developed for the UK HSE by Human Reliability Associates (69).

3. Specific human errors and their consequences that may arise in tasks listed in Stage 2 are identified. This may require a more detailed hierarchical task analysis, as well as hazard identification techniques, such as hazard checklists, procedural HAZOP, or predictive human error analysis (69). Errors are classified in terms of potential for error-recovery and consequences, with the aim being to focus on what can be done to reduce risks.

4. Appropriate risk control measures are selected, usually using SME opinion. This could include improved ergonomic design, provision of competent individuals, and implementation of positive safety culture practices.

An HRA consists of various techniques to estimate probability of human error. It begins with task analysis and predictive human error analysis and uses various methods to estimate the probabilities of human errors for a specific activity. An HRA is appropriate for activities where large risks are sensitive to human errors or quantitative treatment of human error is required for integration into QRA.

B.4.2.3 Identification of the Human Factors Contributing to Maintenance Failures

Antonovsky et al. (70) used the Human Factor Investigation Tool (HFIT) to identify patterns of human factors that recurred most frequently in maintenance-related failures. Interviews of 38 maintenance personnel on gas platforms, floating production, storage, and off-take (PFSO) vessels, and gas liquefaction process plants were performed. The interviewers found that the most frequent HFIT codes reported in the failure interviews related to the crew making unfounded assumptions in response to unforeseen problems or issues, the avoidance of maintenance practices made inconvenient due to poor facility design, and workers not seeking proper clarification of instructions. The authors identified HFIT as a useful instrument for identifying the pattern of human factors most common to maintenance related failures.

B.4.2.4 The Human Factor: Process Safety and Culture

This report (71) is the result of a two-day summit that was held by the Society of Petroleum Engineers (SPE) in response to a report by the US National Commission on the Deepwater Horizon

Oil Spill. The focus of the summit was discussing the role of human factors in exploration and production (E&P) operations. The intent was to develop a methodology to address human factors in process safety (both onshore and offshore) similar to what is done in the aviation and nuclear industries.

Participants included a group of SMEs representing small and large operators, contractors, regulators, universities, and consultants. Three human factors risks identified as "low hanging fruit" represent areas where immediate implementation is most feasible are described below.

B.4.2.4.1 Leadership and Culture

The challenge in creating a safety culture is creating an atmosphere where hazardous activities that do not typically result in high-consequence outcomes are not accepted as the norm. Safety culture must first be benchmarked. One suggested method of evaluating the state of a safety culture is defined by the O&G Producers (OGP) Association (72), which describes a five-point culture scale ranging from "Pathological" (i.e. hardly any interest in safety) to "Proactive and Generative" (i.e. beliefs and behaviors are strongly supportive of safety). Evaluation of culture can be performed using interviews at all organizational levels. The main value in interviews is identifying weaknesses and trends, as this medium does not lend itself to pass/fail analysis.

Leadership also plays a role in defining culture. Leaders can be trained to look for those behaviors that have the most impact on process safety during site visits. The activities of looking for specific activities and questioning workers about these activities send a clear message about the priorities of those in leadership positions.

Regulation can also affect organizational culture. An approach to regulation where performance goals are set collaboratively between regulators and operators is preferred over defining minimum prescriptive requirements. The former encourages continual introspective examination of safety performance, whereas the latter can lead to a mindset where regulatory compliance is conflated with overall safety.

B.4.2.4.2 Perception of Risk and Decision Making

Cognitive limits, physiological factors (e.g. impairment due to drugs, injury, or fatigue), and organizational conditions all affect how workers make safety-critical decisions. Considerable scientific literature is available regarding how these factors cause otherwise skilled and experienced individuals to make poor decisions:

- **Decision-making processes** – the distinction between rational decision making (involving conscious and deliberate comparison of options when sufficient time and information is available) versus sub-conscious decision making (where decisions are made automatically, which may be problematic in safety-critical situations)

- **Confirmation bias** – the perception of new information which is affected by our own biases
- **Perception of risk** – the tendency to misjudge probabilities, and how the framing of those probabilities (e.g. 90% chance of success versus 10% chance of failure) affects their perception
- **Group decision-making factors** – group-based decision making can be advantageous when it draws on a diversity of experiences, but must allow for freedom of expression without fear of social pressure
- **External situations and decision making** – time pressure, poor or ambiguous information, and conflicting goals are all environmental influences that influence quality of decisions made by personnel

Despite active research in these fields, the application of these factors to process development in the O&G industry is inconsistent and rare.

B.4.2.4.3 Individual and Team Capacity

It is recognized that both technical and non-technical training are required for safe process operation. While there is a general common understanding of the technical competencies for specific jobs, there are no industry-wide definitions of these competencies. Furthermore, these competencies must be continually updated to keep up with the pace of advancing technology.

There is no industry agreement regarding non-technical skills required for specific jobs. The nature of O&G E&P includes wide variation in personnel roles and dynamic processes. These factors, along with complex contractual relationships, represent barriers to the adoption of non-technical training programs compared with other industries.

Upstream E&P operations involve worksites that are remote in time and space from their planning and organization groups, which hampers communication between these two functional groups. There is little formalization in the E&P industry regarding the workflows, communication protocols, decision-making rights, competencies and training programs. In most cases, practices have evolved over time and are seldom documented or integrated into formal training. This leads to significant variation in practices within and across companies and worksites. The use of operational control of work (OCW) addresses these issues in the following ways:

- Setting out workflows, communication protocols, decision-making rights, competencies and training programs necessary for the safe and efficient execution of operations;

- Describing ways in which designs are translated into on-site executable instructions, and how the process is monitored for deviations; and
- Providing a framework across an organization that can be used to educate, train, and assess staff.

B.4.2.4.4 Additional Human Factors

Seven additional human factors were identified in this document. While these factors are not all independent, they are described individually to emphasize their individual significance:

- **Communication of Risk** – Everyone involved in safety-critical operations needs to be mindful of "weak signals" indicating that risks are increasing, and need to be willing and able to communicate assessments to immediate leaders.
- **Human Factors in Design** – Critical systems need to be designed to recognize the possibility of human error such that when they occur, they are likely to be caught before they can lead to serious consequences.
- **Collaborative and Distributed Team Working** – O&G operations rely on communication between distributed groups of people working in disparate locations and time scales. Technological, organizational, procedural, legal, and commercial mechanisms to support and encourage effective distributed team operations need to be proactively established.
- **Commercial and Contractual Environment** – O&G activities are carried out in complex commercial and contractual environments where different parties often have competing interests in terms of decision-making priorities. Adequate controls need to be in place to ensure each stakeholder is aware of the contribution they make to ensuring safety-critical human performance.
- **Workload Transition** – This refers to situations when people are expected to transition quickly from "normal" to "abnormal" (i.e. emergency) situations involving high workloads and significant challenges (see Huey et al. (73)).
- **Assurance of Safety-critical Human Activities** – Despite improvements in task automation, the O&G industry still relies on people to perform activities fundamental to safe and environmentally sustainable operations.
- **Investigation and Learning from Incidents** – This refers to the pursuit of a deeper understanding of why human errors occur beyond simple human involvement. The development of investigative tools and techniques to support identification of underlying human and organizational causes of incidents is still relatively uncommon in the O&G industry.

B.4.2.4.5 Integrating Human Factors into IT Development

Information technology (IT) systems also play a role in human factors related to risk critical processes. Increased data availability (i.e. information overload), an over-emphasis on presenting raw figures as opposed to synthesized information, and a lack of integration between data sources are all identified as areas where human factor issues related to risk-critical IT systems are an issue. These issues are exacerbated during emergency situations where human-machine interfaces add another potential layer of confusion.

Several suggestions were made to improve IT design and development, including:

- Make human factors an integral part of the initial IT system design;
- Use a mental modes approach to IT system design, where IT systems are designed to reflect optimal mental models (e.g. crew resource management, a human factors methodology used in the aviation industry), rather than have IT systems training focus on how those systems work;
- Make use of intelligent systems to process data to support cognitive capacities of the operational environment under critical conditions. This would include designing IT systems around the paradigm of decision support as opposed to directing operator actions; and
- Adoption of extensive safety automation systems (as is done in the nuclear industry). This can be costly in drilling when unnecessarily triggered, causing operation downtime. Also, drilling IT systems require more sophistication because they are highly dynamic.

B.5. AVIATION INDUSTRY

B.5.1 Risk Analysis

The risk assessment guidelines for the aviation industry, examined in this review, can be generally separated into those concerned with reducing risks inherent in aviation operations (i.e. operational safety) and those concerned with structural integrity.

B.5.1.1 Operational Safety

Operational safety guidelines for operational safety address hazard identification, risk assessment, and risk mitigation measures for operational errors that may occur in aircraft carriers, aerodromes, and air traffic control centers. The primary sources of information reviewed related to risk assessments of operational safety include guidelines from the Global Aviation Information Network (GAIN) (74), Civil Aviation Authority (CAA) in the UK (75), and Federal Aviation Administration (FAA) in the US (76).

In these documents, hazard identification is primarily linked to data collection during operations (e.g. flight, ground, and airport facility operations) and maintenance reports. GAIN (74) provides guidance on tools for and methods of data collection in four main categories:

- Flight safety event reporting and analysis systems;
- Flight data monitoring, analysis and visualization tools;
- Human factor analysis tools; and
- Special purpose analytical tools for accident investigation, data mining, and risk analysis.

Reliability models described for use by Martinez-Guridi and Samanta (76), Cacciabue et al. (77), and CAA (75) all recognize the importance of collecting operational data for hazard identification and, therefore, standardized data-collection processes and software systems have been developed for industry-wide data collection and sharing.

With respect to approaches to risk assessment, CAA (75) uses a qualitative assessment of the likelihood of failure and failure consequences, while those provided by GAIN (74) and Martinez-Guridi and Samanata (76) recommend quantitative methods, including fault tree, event tree, and bow-tie analyses. Cacciabue et al. (77) presents a comprehensive risk assessment methodology called Risk Assessment Methodology for Company Operational Processes (RAMCOP), which is a combination of a bow-tie analysis and the aviation risk management solutions (ARMS) model, which uses expert judgment in determining probabilities and consequences of events. RAMCOP aims to augment ARMS by offering more accurate methods of evaluating event probabilities when expert judgment is considered insufficient.

B.5.1.2 Structural Integrity

Risk assessments of structural integrity in the aviation industry are principally concerned with the failure frequency of aircraft components. Tong (78) performed a review of structural risk and reliability methods used to quantify failure frequencies, and probabilities for aircraft components due to fatigue crack growth in welds and SCC.

The review presents an overview of structural reliability methods, which include the strength-load interference method, the conditional probability technique, Monte Carlo simulations, and first- and second-order reliability methods (FORM/SORM). Probability distributions are used to quantify the variability in material properties, initial crack size distribution, time to crack initiation, crack growth rate, and reliability of inspection, which are all key input variables to the above described structural reliability methods.

The review discusses two methods for presenting the risk associated with component failure due to crack growth: cumulative failure probability over the safe life period of an aircraft (termed "cumulative risk"), and the probability of failure averaged within a specific time frame within the safe life period (termed "instantaneous risk"), which is calculated as the rate of change of the cumulative risk. The report recommends the latter, expressing the average probability of failure as a "failure rate per hour of flight", with a recommended maximum value of 1.0×10^{-7} failures per flight-hour.

B.5.2 Human Factors

The influence of human factors on flight safety risk are also identified for special consideration by several of the sources used in this document.

Cacciabue et al. (77) identifies human reliability and procedures involving human-machine interactions as key components of a risk assessment. The Tecnica Empirica Stima Errori Operatori (TESEO) (79) and THERP (57) are suggested as possible models to address these components.

GAIN (74) identifies several free and commercially-available tools for the recording and analysis of individual incidents involving human error. These tools aim to allow operators to understand the key underlying cognitive and environmental factors that may have led to the incident. Several of these tools are adapted from James Reason's (80) model of accident causation (sometimes called the "Swiss Cheese" model), which was originally developed for use in NPPs.

In particular, the Human Factors Analysis and Classification System (HFACS) (81) differentiates between active and latent failures. Active failures refer to willful violations of rules and regulations by pilots or other aircrew that ultimately lead to the accident. Latent failures are those organizational conditions that may lay dormant for a long time but ultimately allow active failures to happen. Three levels of latent failures are identified as preconditions for unsafe acts, unsafe supervision, and organizational influences. Taken together, these four layers of potential sources of human error are considered sufficiently comprehensive to identify and classify most human errors occurring in aviation operations.

B.6. POWER INDUSTRY

B.6.1 Risk Analysis

Risk guidelines associated with power transmission are primarily associated with loss of service, which occurs due to failures of structural components and operational procedures. Loss of service can occur due to the failure of these components and procedures alone, or because of their interdependence.

The Risk-Assessment Working Group (82) for the North American Electric Reliability Council provides a basic framework for qualitative and quantitative risk assessment approaches. These approaches are intended to allow organizations to protect themselves against security vulnerabilities and estimate consequences of adverse events. The following steps for a generic structured risk assessment are outlined as follows:

1. Identify and characterize the assets.
2. Identify and characterize the threats.
3. Identify and characterize the existing protective and mitigation factors.
4. Identify and characterize the vulnerabilities.
5. Estimate the probabilities of failure and consequences of failure.
6. Estimate and evaluate the risk.

Additional guidance is given on the following elements of the risk assessment framework:

- Scope and objectives;
- Risk assessment team selection;
- Methods of gaining stakeholder input for data collection;
- Characterization of threats, vulnerabilities, probabilities, and consequences; and
- Presenting the results of the risk assessment, and peer review of the assessment team's results

A white paper by the North American Electric Reliability Corporation (NERC) (83) recommends different risk assessment models based on the severity of the event involved. A full QRA is recommended for high frequency and low consequence events as a way to perform a cost-benefit analysis of different risk management strategies. Scenario-specific analyses and extreme value theory models are recommended for low frequency, high consequence events.

Other sources reviewed were primarily associated with characterizing the risk of service loss due to seismic hazards (84), high winds (85), and hurricanes (86,87,88).

B.6.2 Human Factors

The guidelines set out by NERC (83) include human factors as a potential cause of failure in power transmission operations, but do not elaborate on models that may be used to address these factors. No other sources related to risk assessments in the power industry specifically address human factors as part of an overall QRA.

B.7. SUMMARY AND CONCLUSIONS

The review of the methods, models and guidelines for risk assessment, with special consideration of human factors, as developed and applied in the nuclear, offshore, aviation, and power transmission industries is summarized as follows:

- Pipeline industry:
  - The published literature pertaining to the pipeline industry indicates that quantitative risk methods are used extensively. There are several established models for key threats, including corrosion and mechanical damage. However, since engineering and probabilistic models are less established or unavailable for some threats (such as geohazards, incorrect operations, or manufacturing defects), these threats are typically incorporated into QRAs through SME opinion and/or historical data.
  - Human factors in pipeline risk assessments are addressed only in a very general sense. Potential hazards arising from human error are manifested mainly through historical data, where specific human components of these hazards are not delineated.
- Nuclear industry:
  - The nuclear industry has used PRAs as part of a program to ensure the safe operation of NPPs. PRAs are defined at three different levels that address different domains, which are the NPP reactor core, the NPP containment system, and the public and surrounding environment. The uncertainties involved in each PRA level heavily influence acceptance criteria. Modern PRAs draw from a wide range of quantitative techniques, including event trees, fault trees, and Monte Carlo methods to quantify risk.
  - The use of HRA in the nuclear industry has a long and well-established history. Models such as THERP, SPAR-H, and ATHEANA describe systematic methods for identifying activities that are vulnerable to human error during NPP operation, as well as quantifying the specific effects of human cognition and working conditions on the frequencies of those errors.
  - Many of the original HRA models developed for use in the nuclear industry have been successfully adapted to other industries. One likely barrier to the application of HRA models to UGS wells is the highly controlled and procedural nature of work in an NPP control room versus on-site in a UGS well. Recent development of HRA models for use in maintenance operations at NPPs may be more relevant to UGS well entry.
- Offshore O&G industry:
  - Hazard identification plays a key role in the risk assessment process in the offshore industry, and several formalized methods of hazard identification are used in the development qualitative and quantitative risk assessments.

  - Several common and effective modeling techniques are used to quantify risk, including event trees, fault trees and bow-tie analyses, which effectively combine event and fault trees.
  - The guidelines reviewed identify HRA as a key component to a comprehensive risk assessment, though guidelines emphasize key components of HRA as opposed to specific models.
  - The Human Factors summit report published by SPE (71) identified several human factors associated with process safety, along with guidelines on how to move the industry forward in these areas.
- Aviation industry:
  - As demonstrated in the aviation industry's FAA and EASA guidelines, the aggregation of industry-wide data using well-defined formats facilitates data sharing and improves the process of hazard identification. Data collection in the aviation industry is further facilitated by incorporating it into operational processes.
  - The aviation industry has many well-established tools available for the documentation and analysis of incidents involving human error. These tools allow operators and risk analysts key insights into the role of cognitive and environmental factors leading to operational incidents.
- Power industry:
  - The guidelines reviewed in the power industry describe structured approaches to generic risk assessments.
  - The level of detail involved in a risk assessment model is largely informed by the probability of potential events severity of their consequences.
  - The sources in this review only mention HRA as one possible component in a larger risk assessment, though there is no elaboration of HRA methods or models.

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