# Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage

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# Design and Operation of Solution-mined Salt Caverns Used for Natural Gas Storage

## 1 Scope

This Recommended Practice (RP) provides the functional recommendations for salt cavern facilities used for natural gas storage service and covers facility geomechanical assessments, cavern well design and drilling, risk management, solution mining techniques and operations, including monitoring and maintenance practices, site security and safety, procedures, training, and abandonment.

This RP is based on the accumulated knowledge and experience of geologists, engineers, and other operations personnel in the petroleum and gas storage industries and promotes public safety by providing a comprehensive set of design guidelines. This RP recognizes the nature of subsurface geological diversity and stresses the need for in-depth, site specific geomechanical assessments with a goal of long-term facility integrity and safety.

This RP includes the cavern well system (wellhead, wellbore, and cavern) from the emergency shutdown (ESD) valve down to the cavern and facilities having significant impact to safety and integrity of the cavern system.

This RP does not apply to caverns used for the storage of liquid or liquefied petroleum products, brine production, or waste disposal; hydrogen, or compressed air, nor to caverns which are mechanically mined, or depleted hydrocarbon or aquifer underground gas storage systems.

This document is intended to supplement, but not replace, applicable local, state, and federal regulations.

## 2 Normative References

The following referenced documents are indispensable for the application of this document. For dated references, only the edition cited applies. For undated references, the latest edition of the referenced document (including any amendments) applies.

API Technical Report 5C3, *Technical Report on Equations and Calculations for Casing, Tubing, and Line Pipe Used as Casing or Tubing; and Performance Properties Tables for Casing and Tubing*

API Specification 10A, *Specification for Cements and Materials for Well Cementing*

API Recommended Practice 10F, *Recommended Practice for Performance Testing of Cementing Float Equipment*

ASTM D3967, *Standard Test Method for Splitting Tensile Strength of Intact Rock Core Specimens*

ASTM D4543, *Standard Practices for Preparing Rock Core as Cylindrical Test Specimens and Verifying Conformance to Dimensional and Shape Tolerances.*

ASTM D4645, *Standard Test Method for Determination of In-Situ Stress in Rock Using Hydraulic Fracturing Method*

ASTM D7012, *Standard Test Methods for Compressive Strength and Elastic Moduli of Intact Rock Core Specimens under Varying States of Stress and Temperatures*

ASTM D7070, *Standard Test Methods for Creep of Rock Core Under Constant Stress and Temperature*

# 3 Terms, Definitions, Acronyms, and Abbreviations

## 3.1 Terms and Definitions

For the purposes of this document, the following terms and definitions apply.

**3.1.1**
**abnormal operating condition**
Condition identified by the operator that may indicate a malfunction of a component or deviation from normal operations that may:

— indicate a condition exceeding design limits; or

— result in a hazard(s) to persons, property, or the environment; or

— indicate a potential downhole problem not related to design or hazard(s) but that may risk the integrity of the well or the reservoir.

**3.1.2**
**annulus**
Space between two lengths or strings of concentric pipe or between pipe and borehole.

**3.1.3**
**area of review**
The underground gas storage cavern and all wells associated with it, as well as all non-associated subsurface or surface structures, formations, or activities proximal enough that could impact or be impacted by the underground gas storage facilities and operation process.

**3.1.4**
**as low as reasonably practicable**
**ALARP**
Reducing the risk to a level which is ALARP involves objectively determining the balance where the effort and cost of further reduction measures becomes disproportionate to the additional amount of risk reduction obtained.

**3.1.5**
**base gas**
Volume of gas required in the cavern to maintain sufficient pressure to adequately support the cavern roof and walls.

NOTE Also commonly referred to as ‘cushion gas’ or ‘pad gas’.

**3.1.6**
**bedded salt**
Salt formation in which the original depositional structure of alternating salt and nonsalt beds is largely preserved.

**3.1.7**
**blanket material**
A fluid less dense than water and incapable of dissolving salt that is used during solution mining to protect the cavern roof from the injected water and prevent dissolving the salt of the roof and around the casing seat.

**3.1.8**
**borehole**
Shaft bored or drilled into the ground either vertically or horizontally.

NOTE Also commonly referred to as “wellbore”.

**3.1.9**
**bradenhead**
Wellhead component typically attached to the intermediate casing and from which the blowout preventers (BOPs) are affixed during drilling and the remainder of the wellhead components are affixed after drilling.

NOTE Also commonly referred to as "casinghead" or "starting head".

**3.1.10**
**brine**
Solution of water and a variable amount of salt, generally sodium chloride, produced during solution mining.

**3.1.11**
**buffer zone**
Area or interval outside the defined gas storage cavern, horizontally or vertically, to provide protection of the storage cavern from encroachments and losses.

NOTE Buffer zones accommodate geologic uncertainties in the exact location of the storage caverns

**3.1.12**
**caprock**
Anhydrite, gypsum, and calcite layer above many salt domes that is formed by consolidation, cementation, and alteration of insoluble residue left by salt dissolution.

**3.1.13**
**casing**
Any of several sizes and lengths or strings of steel pipe, most usually threaded together, placed in the borehole to support the sides of the borehole, prevent uncontrolled movement of fluids into or out of the borehole or annular space, and allow production into and out of the well.

**3.1.14**
**casing, conductor**
Relatively short length of large diameter steel pipe use to prevent the borehole from caving during the initial drilling of a well.

**3.1.15**
**casing, intermediate**
One or more strings of steel pipe placed in the borehole inside the surface casing as needed to support the section of the borehole beneath the surface casing and to seal off intermediate water or hydrocarbon zones.

**3.1.16**
**casing, liner**
Casing placed in the borehole that does not extend the length of the well and is hung from the bottom of the previous casing string.

**3.1.17**
**casing, production**
The last cemented string of casing placed in the borehole inside the intermediate casing and used to flow into and out of the well.

**3.1.18**
**casing seat**
Lowermost location where the casing is cemented to the rock formation.

**3.1.19**
**casing shoe**
Piece of equipment threaded or welded onto the bottom joint of a casing to facilitate the lowering of the casing into the borehole.

**3.1.20**
**casing, surface**
Steel pipe placed inside the conductor casing in the borehole to protect underground sources of drinking water and other shallow geologic formations.

**3.1.21**
**cavern**
Underground void developed by the solution mining of a salt formation.

**3.1.22**
**cavern chimney**
The initial section of the cavern in early development which becomes the main cavern interval during the solution mining process.

**3.1.23**
**cavern field**
Group of caverns within a salt dome or bedded salt formation.

**3.1.24**
**cavern system**
A group of components, cavern, wellbore, casings, and wellhead that function as a system.

**3.1.25**
**cementing**
Operation in which a cement slurry is pumped down the inside of the innermost casing, out the bottom of the casing and upward into the annular space behind the casing and the borehole or the previous casing.

**3.1.26**
**circulation, direct**
Pumping of raw water down the center and longer hanging string, into the cavern and returning brine to the surface through an outer and shorter string annulus.

**3.1.27**
**circulation, reverse**
Pumping of raw water down an outer and shorter string annulus, into the cavern and returning brine to the surface through the center and longer hanging string.

**3.1.28**
**collapse pressure**
Pressure that, when applied to the exterior of a casing or tubing, causes it to collapse or fail.

**3.1.29**
**core, slabbed**
Core that is cut parallel to the core axis for analysis of grain structure.

**3.1.30**
**consequence**
Outcome of an event affecting objectives

**3.1.31**
**creep**
The property of salt to flow slowly and deform permanently under the influence of shear stress.

**3.1.32**
**creep closure**
Reduction in size of a cavern due to the natural flow of salt under lithostatic, tectonic, or overburden pressures.

**3.1.33**
**domal salt**
Mound or column of salt resulting from upward flow of a salt formation into shallower rock and caused by the low density of salt relative to most sedimentary rocks.

NOTE Also commonly referred to as “salt dome”.

**3.1.34**
**dry drilling**
Drilling without significant fluid returns to the mud system at the surface.

**3.1.35**
**emergency shutdown valve**
Automated valve designed to stop the flow of gas upon detection of specific events.

**3.1.36**
**formation**
Body of rock forming a separate and identifiable geological unit based on the rock characteristics.

**3.1.37**
**functional integrity**
Total reliability of the storage system, including the physical integrity of the cavern and well components and the performance reliability assurance established by management systems employed by the storage operator.

**3.1.38**
**hanging string**
String of steel casing hung from the wellhead and inside the production casing and is not cemented.

**3.1.39**
**hazard**
A situation or condition that has the potential to cause loss, damage, or harm to a storage well, well site, or cavern and thus affect the functional integrity of the storage operation.

**3.1.40**
**hole section**
A section of the overall cavern well borehole.

**3.1.41**
**hydrate**
Crystalline solid made of a varying mixture of ice and gaseous hydrocarbons.

**3.1.42**
**hydraulic communication**
Movement of gas or fluid by several methods, including through porous or permeable rock, annular movement, or casing leaks.

**3.1.43**
**in-service date**
The date a newly constructed cavern system is available for gas injections and withdrawals.

**3.1.44**
**insolubles**
Minerals that do not readily dissolve in water.

**3.1.45**
**interface**
Surface formed by the contact between two immiscible fluids in a well or cavern.

**3.1.46**
**lithology**
The physical characteristic of a rock.

**3.1.47**
**log**
Recording of a variety of subsurface properties made by lowering detectors into the well or cavern.

**3.1.48**
**mechanical integrity**
Quality or condition of a well in being structurally sound with competent pressure seals by application of technical, operational, and organizational solutions that reduce the risk of uncontrolled release of formation fluids throughout the well life cycle.

**3.1.49**
**mechanical integrity test**
Pressure test that verifies a cavern can store natural gas within design limitations with no significant loss of gas.

**3.1.50**
**microfractures**
Small fractures at a microscopic level.

**3.1.51**
**overburden**
Geologic strata above the top of the salt deposit.

**3.1.52**
**p-seals**
Wellhead to casing sealing mechanisms installed into the bore of wellhead components allowing for bands to be energized against the casing by the injection of packing material.

**3.1.53**
**pillar**
Salt mass separating caverns and providing structural support to the cavern field.

**3.1.54**
**plan**
Documented explanation of the mechanisms or procedures used to implement a program and to achieve compliance with standards.

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

**3.1.55**
**plugged and abandoned well**
Well whose use has been permanently discontinued and filled with material and cement.

**3.1.56**
**pressure gradient**
Pressure at a given depth divided by the depth.

**3.1.57**
**pressure gradient, fracture**
**fracture gradient**
Pressure required to fracture the rock at a given depth in the wellbore.

**3.1.58**
**pressure gradient, operating**
Pressure gradient in the cavern system during normal cavern operation.

**3.1.59**
**procedure**
Documented explanation of action taken to achieve the steps of a process.

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

**3.1.60**
**process**
Systematic, ordered series of events directed to some end that comprise an approach or methodology to achieve an objective.

NOTE A process can describe workflow activity and quality standards for a wide range of procedures.

**3.1.61**
**program**
Overall approach to manage a functional activity or physical part of an asset.

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

**3.1.62**
**radius of influence**
The distance a cavern significantly changes the initial, in situ state of stress in the salt.

**3.1.63**
**raw water**
Untreated surface or ground water, ranging in salinity from fresh to sea water, used in solution mining to dissolve salt.

**3.1.64**
**risk**
The consequence's severity of a realized threat multiplied by the likelihood of its occurrence.

**3.1.65**
**risk analysis**
Process to comprehend the nature of risk and to determine the level of risk

**3.1.66**
**risk assessment**
Overall process of risk identification, risk analysis, and risk evaluation

**3.1.67**
**risk evaluation**
Process of comparing the results of risk analysis with risk criteria to determine whether the risk or its magnitude is acceptable or tolerable.

**3.1.68**
**risk identification**
Process of finding, recognizing, and describing risks.

**3.1.69**
**risk management program**
Coordinated activities to direct and control an organization with regard to risk

**3.1.70**
**rock salt**
Rock composed of halite (sodium chloride) and minor concentrations of other minerals that form a crystalline or granular aggregate.

**3.1.71**
**rubble, core**
Core that is crushed during coring.

**3.1.72**
**rubble, floor**
Collapsed, non-soluble beds within the salt structure having fallen to the floor of the cavern.

**3.1.73**
**safe work practices**
Written methods outlining how to perform a task with minimum risk to people, equipment, materials, environment, and processes.

**3.1.74**
**salt stock**
The columnar body of a salt dome.

**3.1.75**
**saltback**
The distance from the top of the salt to the casing seat.

**3.1.76**
**solution mining**
Process of dissolving salt by means of circulating raw water from the surface, through a well to the subsurface where the salt is dissolved and returning the fluid to the surface as brine.

**3.1.77**
**sonar survey**
Measurement of the internal dimensions of a cavern using an acoustic wave generating/receiving tool.

**3.1.78**
**sump**
The lower section of the cavern developed to allow for the settling of insolubles embedded in the salt structure and released during solution mining.

**3.1.79**
**tectonic salt**
A salt deposit that has been severely deformed by tectonic forces.

**3.1.80**
**threat**
Created by an encounter with or an activation of a hazard during the storage operation

**3.1.81**
**total gas storage capacity**
Maximum amount of gas that can be stored in the cavern in accordance with its design and operating procedures.

**3.1.82**
**tubing**
Smaller diameter steel pipe(s) inserted in the production casing used during solution mining for water or brine flow and during debrining for brine removal.

**3.1.83**
**turn**
Withdrawal and injection of the entire working gas capacity.

**3.1.84**
**wellhead**
Assemblage of surface equipment used to maintain control of the well and to permit access into the wellbore.

**3.1.85**
**working gas capacity**
Volume of gas that can be withdrawn from the cavern for delivery into the natural gas grid (equal to total gas storage capacity minus the base gas).

**3.1.86**
**wireline**
An electrically conductive wire used to run logging tools into a well.

**3.1.87**
**workover**
Maintenance activities performed on an active well.

### 3.2 Acronyms and Abbreviations

For the purposes of this document, the following acronyms and abbreviations apply.

| | |
|---|---|
| ALARP | as low as reasonably practicable |
| API | American Petroleum Institute |
| BHA | bottom hole assembly |
| BHC | borehole compensated [sonic] |
| BOP | blow-out preventer |
| BWOW | by weight of water |
| CBL | cement bond log |
| ESD | emergency shutdown |
| GR | gamma ray |
| $H_2S$ | hydrogen sulfide |
| ID | inside diameter |
| K | potassium |
| KCl | potassium chloride |
| MAOP | maximum allowable operating pressure |
| Mg | magnesium |
| $MgCl_2$ | magnesium chloride |
| MIT | mechanical integrity test |
| MOC | management of change |

| | |
|---|---|
| NaCl | sodium chloride |
| OCTG | Oil Country Tubular Goods |
| OD | outside diameter |
| OPP | overpressure protection |
| P&M | preventive and mitigative |
| ROP | rate of penetration |
| SCADA | supervisory control and data acquisition |
| SMRI | Solution Mining Research Institute |
| SP | spontaneous potential |
| TD | total depth |
| Th | thorium |
| Ur | uranium |
| USDW | underground source of drinking water |
| VSP | vertical seismic profile |

# 4 Overview of Underground Natural Gas Storage

## 4.1 General

The underground storage of natural gas is an integral component in the natural gas energy infrastructure and plays a vital role in maintaining the reliability of supply needed to meet the demands of the consumers of natural gas.

The need for natural gas is highly variable within a typical season, day or even hour. Underground natural gas storage acts to accept delivery of a produced natural gas while providing re-delivery at the variable flow rate required by the consumers of natural gas. Traditionally, natural gas has seen highest demand during the winter because of its use as a heating source. Due to the increasing amount of natural gas used in gas-fired electrical generation plants, demand for natural gas during the summer months is on the rise. Natural gas storage facilities also help pipelines, local distribution companies, producers, and shippers to avoid supply-to-delivery imbalances while optimizing the use of pipeline facilities.

## 4.2 Types of Underground Natural Gas Storage

There are three principal types of underground natural gas storage fields: depleted hydrocarbon reservoirs; aquifer reservoirs; human-made caverns (cavities) in salt formations. Each of these has distinct geographic and geologic availability and physical characteristics which govern the suitability to a particular type of storage.

Depleted hydrocarbon reservoirs are porous and permeable formations that have typically produced most or all their economic reserves. The existing wells in the reservoir are converted for gas storage use and additional wells are often drilled to add to the reservoir's gas injection and withdrawal capability. Gas storage in depleted hydrocarbon reservoirs is the predominant type of gas storage facility in the United States.

Aquifer reservoirs are similar to depleted hydrocarbon reservoirs in terms of the nature of the porous rock media used to contain the gas and the methodology for assessing the reservoir. The difference is that aquifer reservoirs were originally filled with water and did not contain oil or gas.

The third principal type of underground natural gas storage facility is human-made caverns in salt formations. Salt caverns are created through the planned solutioning (dissolving) of portions of naturally occurring salt formations.

### 4.3 Natural Gas Storage in Salt Formations

Natural rock salt has been mined from the near surface since prehistory for consumption and food preservation. Conventional underground mining of salt may have begun in the Austrian region of Europe during the Stone Age. Solution mining was first used successfully in China thousands of years ago. In modern times, conventionally mined and solution-mined salt is used as an industrial chemical, in water conditioning, for highway de-icing, in agriculture, and as a food additive.

In contrast to historical salt production methods, the technique of solution mining a cavern or cavity in salt for storage is a relatively recent development, dating to the 1950s when liquefied petroleum gas was first stored in solution-mined salt caverns in Canada. Construction of the first solution-mined salt caverns in the United States created specifically for the storage of natural gas began in the Eminence Salt Dome in Mississippi in the late 1960s by Transcontinental Gas Pipe Line. As the benefits of natural gas storage in salt became more apparent, a period of significant cavern development occurred through the 1990s to the early 2010s, often in salt domes in the Gulf Coast States but also in bedded salt deposits in Michigan, Texas, Kansas, New York, and Virginia. As of 2014, there were over 100 caverns in the United States safely storing and re-delivering natural gas at more than 35 facilities on 30 salt domes or in bedded salt formations in seven states.

Solution mining a cavern is accomplished by drilling a wellbore into a suitable salt formation, dissolving the salt by circulating fresh or low-salinity water into the wellbore and withdrawing or returning the brine to the surface. As the salt is dissolved, the wellbore grows to form a cavern, or cavity, in the salt formation. When the cavern has reached its planned size, gas is injected into the cavern displacing and emptying the brine out of the cavern, making it ready for gas storage.

When properly located, designed, developed, and operated, salt caverns make excellent storage containers for natural gas. The walls of caverns formed in subsurface salt structures are effectively impermeable to natural gas, ensuring containment of the gas stored in a cavern. Salt caverns are well-suited to provide relatively high gas injection and delivery rates.

### 4.4 Functional Integrity

Functional integrity should be the goal of the design, construction, and operation phases of a cavern. Sound engineering practices such as those in this RP help guide operators with the goal of ensuring a safe facility for all stakeholders.

### 4.5 Overview of Major Steps in the Development of Gas Storage Caverns

Major steps in developing salt caverns for natural gas storage include:

— locating a salt structure suitable for cavern development;

— determining gas storage capacities and flow rate capabilities;

— determining a project schedule including in-service dates;

— designing, drilling, and equipping the cavern well;

— designing, drilling, and equipping water supply wells, circulating pumps, and brine disposal wells and facilities;

— designing, solution mining, testing, and placing the cavern into service;

— conducting a risk assessment;

— operating and maintaining the cavern well and cavern to ensure functional integrity.

Not all sedimentary basins in the United States contain salt deposits, limiting the areas available for cavern development. Selecting a site for solution-mined caverns involves many factors, including the suitability of a salt dome or salt formation's geological and geomechanical properties. These properties include the height and areal extent of salt, the percent of nonsalt material within the salt formation, depth and geothermal temperature of the salt, the internal structure of the salt, and the strength of the salt when subjected to forces of compression and tension. Drilling test boreholes and obtaining rock cores are among the ways these properties can be investigated. The geological characterization of the salt body can be accomplished through review of data from wells drilled in the area, as well as analysis of existing or newly acquired seismic data.

The total storage capacity of a cavern is the maximum amount of gas that can be stored in the cavern in accordance with its design and operating procedures. The total capacity is the sum of the working gas capacity and the base gas. The working gas capacity is the maximum amount of gas that can be withdrawn from the cavern for delivery in the natural gas grid. The base gas is the minimum amount of gas that remains in the cavern to provide the pressure required to meet the minimum design flow rate and to maintain the stability of the cavern roof and walls.

Once the storage capacities are determined, the size and shape of the cavern to store those volumes can be designed. In general, combinations of overall cavern height, diameter, and depth are compared.

Studies can be conducted on the mechanical strength of the salt to determine an effective, efficient, and stable cavern shape. The depth of the cavern also has a large impact on the size needed to store a given amount of gas. Deeper caverns allow higher gas pressures in the caverns, increasing the total storage capacity. Offsetting the larger volume that can be stored due to higher gas pressures is the generally increasing, naturally occurring temperature of the salt around the cavern. Increasing salt temperature heats the gas in the cavern, can increase the rate of cavern volume loss due to salt creep, and thus lowers the total amount of gas capable of being stored. Also, the amount of base gas increases with depth because the minimum pressure increases as the in situ stress around the cavern increases.

The required rate at which the gas is to be injected or withdrawn from the cavern system determines the size of the cavern well and surface equipment. These rates are expressed in flow units such as million standard cubic feet per day, where a standard cubic foot is the amount of gas (mass) that occupies a cubic foot at standard temperature and pressure conditions. Similar terms of flow capabilities are based on the time required to inject or withdraw the working gas in a cavern. An example is "annual turns", which quantifies a cavern system's capability for the number of injection and withdrawal cycles of the entire working gas capacity within a year.

With the flow rate requirements given, the size (diameter) of the well into the cavern can be established. The required flow rate influences the diameter of the well due to factors such as acceptable frictional losses and the potential for hydrate formation. Combinations of casing diameters, thicknesses and strengths can be reviewed to find an effective design. However, the final casing diameters are often determined by solution mining rates.

A project schedule including in-service dates are based on the time required to design, permit, and drill the cavern well, and to solution mine, test, and debrine the cavern. Once the facility design is completed, there can be significant lengths of time required to prepare and obtain the necessary regulatory permits and authorizations.

Drilling a cavern well to be used to develop and operate a cavern requires careful planning and execution. For cavern wells, the size of the holes bored in the earth are typically larger than required by other oilfield operations such as exploration and production activities. The number and setting depths of well casings is also different than found in other oilfield operations due to the unique geologic settings and operating conditions of salt cavern wells.

Water supply and returned brine disposal facilities can be designed to supply the water and dispose of the brine during cavern development. Pumps, filters, meters, flow lines, and other surface equipment can be designed and installed creating a flow path from the water supply, down the cavern well, into the cavern, up the cavern well to the surface, and to the brine disposal facilities.

After drilling the cavern well, multiple concentric tubular steel casing strings are lowered into the well and suspended or hung from inside the wellhead and into the wellbore. The water supply pumping equipment can be hooked up to the wellhead to inject the water down through the tubular strings where it contacts the salt formation. The salt dissolves into the water, turning the water to brine. The pumps circulate the brine to the surface where the brine exits the wellhead and flows to the disposal wells and facilities. During solution mining, it is critical that the roof of a cavern is prevented from dissolving by placing and floating a blanket material which does not dissolve salt (often gas, a liquid hydrocarbon, or mineral oil) on top of the water and brine in the cavern. Periodic monitoring of the size and shape of the cavern can be performed using sonar survey equipment.

Once solution mining has been completed, the cavern and well are prepared for conversion to gas service by installing a wellhead specifically designed for gas service and by performing a mechanical integrity test (MIT) of the cavern system including the wellhead and wellbore tubulars. After a successful MIT, debrining operations can commence to displace the brine from the cavern by the injection of natural gas. Once the brine has been removed, the cavern is ready for natural gas service.

To ensure long-term, reliable service and safety of the public and to the environment, the integrity of the well and salt cavern system need to be maintained and monitored. Periodic integrity assessments should include the condition of the wellhead, the cemented production casing, the size and shape of the cavern, and the ability of the cavern system to contain the gas stored within it. A key activity in understanding and managing the inherent risks associated with designing, building and operating a salt cavern facility is to conduct risk assessments. This assessment will aid in the design and development of the cavern and its well and with maintaining the long-term integrity of the storage facility.

All these objectives are associated with corresponding design and construction requirements. The design process seeks to find the most effective combination of performance objectives and design, construction, and operational requirements.

# 5 Geological and Geomechanical Evaluation

## 5.1 General Considerations

The first major step in developing salt caverns for natural gas storage is locating a salt deposit suitable for cavern development. Not all sedimentary basins contain salt deposits, resulting in limited areas of the United States that have suitable salt formations [1]. When selecting a site for solution-mined caverns, an operator considers several factors, including locating a salt dome or salt formation with suitable geological and geomechanical properties. These properties include the thickness and lateral extent of salt, the percent of nonsalt material within the salt formation, depth and geothermal temperature of the salt, the internal structure of the salt, and the strength of the salt when subjected to forces of compression and tension. Drilling test boreholes and obtaining rock cores are among the ways these properties can be investigated. The geological characterization of the salt body can be accomplished through review of data from existing wells drilled in the area, as well as analysis of existing or newly acquired seismic data.

## 5.2 Site Selection Criteria

### 5.2.1 General

Site selection for solution-mined natural gas storage caverns is based on numerous considerations, including at least the following items:

— a study of the geologic formation to be used;

— the availability of raw water for solution mining;

— opportunities for disposal of the produced brine;

— existing and planned use of the surface and subsurface.

If any of the key elements required for gas cavern construction and operation are not present at a particular site, cavern development at the site may not be practical or feasible.

### 5.2.2 Geologic Formation

The primary objective of the geological and geophysical site characterization is to determine the type (domal, bedded, or tectonic), geometry, and areal extent of the salt deposit and its ability to contain natural gas storage caverns safety and economically. Additionally, overlying, and adjacent formations should be studied as part of the overall geological investigation. The deformation and strength properties as well as the in situ conditions such as temperature and stress state are important geomechanical considerations in the selection of an appropriate geologic formation for gas storage caverns.

The salt deposit should have enough extent to ensure:

— the gas storage caverns are sufficiently remote from the edge of the dome or significant faulting in the case of bedded salts;

— the gas storage caverns are sufficiently remote from the property boundary and adjacent caverns;

— the gas storage caverns are sufficiently remote from the top and base of salt.

NOTE The determination as to whether the caverns are “sufficiently remote” depends on the expected operations in the caverns, the operations in existing or planned adjacent caverns, the geomechanical properties of the formations, and the in situ conditions in the formations.

### 5.2.3 Availability of Raw Water for Solution Mining

A source of raw water with sufficient quantity, quality, and delivery rate should be available for solution mining of the natural gas storage caverns. Approximately seven to 10 barrels of fresh water are required to develop one barrel of cavern space. If saline or brackish water is used for solution mining, the water requirements can be somewhat greater. In addition to the water volume, the rate of delivery is also an important site selection consideration. For example, if cavern volume is to be developed rapidly, associated high water delivery rates are required. Supply rate requirements of 3000 to 5000 gallons per minute for each cavern being solution-mined are common.

### 5.2.4 Opportunities for Brine Disposal

Opportunities for brine disposal in volumes and at rates slightly greater than the water supply volumes and rates should be available at or near the site. Brine produced in the solution mining of natural gas storage caverns can be provided to a brine user or disposed in a subsurface formation or in bodies of saltwater, if located at a practical pipeline distance. The number of brine disposal wells required to dispose of the produced brine at the desired rate depends on the formation permeability and porosity as well as other subsurface conditions, such as initial formation pressure, fracture gradient, proximity to faulting and formation thickness. The number of disposal wells can range from a low of just one or two to as many as 5 to 10.

### 5.2.5 Existing and Planned Infrastructure

Existing and planned caverns and surface infrastructure should be included in the site selection process.

Existing solution-mined caverns (for brine production, liquid hydrocarbon storage, or natural gas storage) can provide valuable information for site selection at a particular salt deposit. Internal faulting or shearing within the salt body and any potential irregularity in solution-mined cavern shapes can often be assessed by examining existing solution-mined caverns. Another key consideration in site selection is proximity to surface infrastructure (such as gas transmission pipelines, three-phase electrical power, and roads and highways) that is required for the development and operation of gas storage caverns.

## 5.3 Geologic Site Characterization

### 5.3.1 General

A geological characterization of the site provides a framework to sufficiently understand the site geology, potential risk factors, and project feasibility. It also aids in the selection of well locations and provides input to the engineering design. Although this document pertains primarily to salt caverns, site characterizations for salt cavern projects also require characterization of brine disposal and water supply if they rely on geologic sources.

A geologic site characterization should delineate the geometry, thickness, and internal petrophysical character of the salt deposit and, if applicable, the brine disposal reservoir and water supply aquifer. Geologic site characterization requires an understanding of the depositional and structural framework of the geologic formations. The geologic framework established by a site characterization provides the basis for prediction of the geologic conditions in the subsurface that allows for locating cavern wells and identifying or managing geologic uncertainties. Limited resolution or uncertainty in the geologic model can equate to some level of increased risk that may need to be resolved with additional data or planning.

### 5.3.2 Subsurface Geologic Data

#### 5.3.2.1 General

The data used in a geologic site characterization should incorporate subregional and site-specific data from all readily available sources. Initial feasibility studies rely upon existing available data, either proprietary or public domain. Geologic site characterizations are usually more detailed than feasibility studies, and acquisition of additional site-specific data can be required depending upon the quality and completeness of the existing data set. This additional data are commonly obtained by drilling exploration wells or acquisition of geophysical surveys.

Data can include, but are not limited to, the following:

— geologic literature and historic data (well records, geologic reports, scout tickets, driller’s logs, daily drilling reports, older maps, and similar data);

— open-hole well logs;

— core data;

— geophysical surveys.

#### 5.3.2.2 Geologic Literature and Public Domain Data

Geologic site characterization should include a review of the available geologic literature, historical reports, and published maps to provide information regarding the local geology, historical information, and regional geologic context of the area. Additional data can be found in drilling reports, scout tickets, driller’s logs, and similar sources of data. Much of the historical information predates geophysical well logs and can provide information for older wells where the original data are no longer available.

#### 5.3.2.3 Open-hole Well Logs

##### 5.3.2.3.1 General

A geologic site characterization should incorporate all available site-specific well logs that provide geologic data for the salt/reservoir/aquifers and overburden strata relevant to the project. Open-hole well logs acquired mainly during oil and gas exploration and exploitation activities form the basic data in most subsurface salt storage geologic investigations. Well log data can vary greatly in vintage, availability, type, quality, and density of coverage. Logs provide the basis for the correlation of formation tops used for mapping the subsurface geology and petrophysical data that are used to characterize the internal properties of the salt, caprock, and surrounding strata. Well logs can be obtained from company files, commercial sources, and some state agencies.

See Annex A for additional information about open-hole well logs.

#### 5.3.2.3.2 Well Logging Programs

An open-hole logging program to acquire useful and meaningful borehole data should be run in any new well drilled for the project. Log coverage should be continuous from the base of the surface casing to the total depth of the well unless logging an interval presents a risk to the well.

The specifics regarding log type and log intervals should be determined by the borehole geology, borehole conditions (borehole size and irregularity, drilling fluid, and similar characteristics), drilling program, and the data requirements of the project. A logging program should be designed to the specifics listed above and the log data reviewed as it is being acquired to make sure the header information is correct, and the log data are of good quality.

NOTE 1 The type of drilling fluid, large borehole size and borehole irregularity impact the quality of many open-hole well logs.

The log suite for geologic characterization of a salt deposit and the overlying strata should include gamma ray (GR), litho-density, neutron, dipole, or full-wave sonic, and caliper logs. This well log suite provides information on salt purity, nonsalt stringers or interbeds, and the presence of potassium-magnesium (K-Mg) salts that are highly soluble and creep prone. These logs are also useful to characterize any caprock and the strata overlying and surrounding the salt. Other types of wireline logs may be required as dictated by the local geology and the type of data required.

NOTE 2 Spectral gamma ray logs break down the gamma ray signature into components of potassium, thorium, and uranium (K, Th, and Ur) that can help distinguish K-Mg salts from other impurities such as clay.

Spontaneous potential (SP) and some type of resistivity log should be run in strata overlying the salt to help identify the base of fresh water and any hydrocarbon zones. Surrounding hydrocarbon or groundwater wells in a specific area often have a preferred log type such as resistivity, sonic or density. The preferred log type should also be run to provide the basis for correlation with surrounding well control.

NOTE 3 While resistivity logs are very useful for characterizing strata outside the salt (especially for identifying freshwater zones, permeable zones and hydrocarbon zones), they either do not work or are not particularly useful in salt. SP tools do not work in salt but can be used to indicate the presence of salt in historic well logs.

NOTE 4 Halite, anhydrite, gypsum, and clean sandstones are indistinguishable on gamma ray logs and require other data such as density or sonic logs to distinguish between them.

Check shot surveys and sonic logs can be useful to interpret or depth-convert seismic data.

While not an open-hole geophysical log, a mud or cuttings log can be useful for lithologic identification, for helping determine core or casing points prior to wireline logging, and for detecting the presence of gas while drilling. They are also useful for recording penetration rate, core intervals, and lost circulation zones.

#### 5.3.2.3.3 Modeled Mineralogy Logs

Modeled mineralogy logs are derived from wireline log data and may be used in salt to assist with solution mining simulations. The mineral components to be included in the model are determined by the geology of the interval being modeled and the available log data. A modeled mineralogy log is generated from well log data to identify the type and gross distribution of insoluble and impurity material within the salt. The more log types available, the more components that can be accommodated by the model.

Modeled mineralogy logs should be calibrated with core data such as weight percent insoluble material, X-ray diffraction, petrographic and wet chemistry data. These logs are non-unique solutions and proper calibration requires good core log integration.

#### 5.3.2.4 Core

##### 5.3.2.4.1 General

Salt cavern fields should have core data for the salt and any brine disposal zones. Core data from key units such as confining formations, caprock, and disposal zones, can also be of value depending upon the site geology and data requirements. A core is the geologic equivalent of “ground truth” for subsurface geology. Geologic information such as geomechanical properties, salt fabric, structural features, anomalous salt, and the actual distribution of insoluble material within the salt can only be determined from core samples. Most importantly, core test data provide the geomechanical properties of salt and other key rock units that are input into geomechanical models used to evaluate cavern stability, subsidence, and the operating pressures in a storage cavern. While some petrophysical data can be acquired from logs, petrologic and mineralogic analysis of both salt and nonsalt core can be used in the calibration of open-hole well logs and other geophysical data.

For brine disposal reservoir assessment, core data provide direct permeability data that cannot be obtained from well logs. Core samples also provide data on pore throat size and distribution, which are necessary to design and optimize brine injection filtering systems to prevent plugging of the disposal formation.

##### 5.3.2.4.2 Geologic Considerations for Core Acquisition

If not already available, a core can only be acquired with the drilling of a new wells. The depth interval and amount of core to be cut should be determined on a well-to-well basis depending upon the needs of the project and the site geology.

If data are not available from nearby wells, the core may be cut based on expected depth of the cavern interval and geology in the immediate area. The amount cored should be sufficient to anticipate the amount of material required for core testing and account for damaged core, rubble, lost core, anomalous salt, nonsalt interbeds and stringers, and other factors that may limit its usefulness for testing. As the core is only obtainable by drilling a well, it is better to cut more rather than too little. This is especially true for gas storage caverns whose operating pressure range is determined by geomechanical modeling that relies upon core testing. Poor sampling or insufficient core can result in skewed test results that could detrimentally impact the cavern operating conditions.

Salt core should be 4 in. diameter conventional core to be suitable for geomechanical testing. Sidewall cores (either percussion or rotary) are of little value in salt because percussion samples are highly damaged and rotary cores are too small to test for salt mechanical properties (see 5.4). Sidewall cores can be useful for obtaining petrologic data for nonsalt interbeds and brine disposal reservoirs.

If the geology indicates variable lithology or significant interbeds, sufficient core should be cut to sample the various major zones, especially weak points such as bed contacts. In domal salt where the internal banding is near vertical, different wells in a cavern field can exhibit significantly different properties and core samples should be recovered in each cavern well. In bedded salt if the salt is stratigraphically similar across the storage field, the entire cavern interval should be cored in the first well with spot coring in subsequent wells.

Liners or aluminum sleeves should be used to help maximize core recovery, properly locate rubble zones, and minimize or expedite core handling in the field. Reduced core handling in the field helps minimize core damage and exposure of salt to the elements while aiding in core transport, inventory, and reconstruction. Liners help with the recovery of rubble and maintain the rubble in its position relative to the rest of the core. In the field the liners can be cut into segments, end capped, and depth marked, minimizing exposure to the elements.

NOTE The location and amount of rubble can be the result of coring issues or can be an indicator of geologically problematic or anomalous salt. Having the rubble preserved in proper context can help identify geologically problematic zones within the salt.

#### 5.3.2.4.3 Initial Core Review

The core should be documented by a detailed core description and photography prior to any sampling or destructive testing. This provides a permanent record of the core intervals that were later removed for testing. Photographs and core descriptions allow assessment without pulling core out of storage.

The core should be reconstructed, cleaned, depth marked, and described in detail out of the weather under constant conditions of lighting. The fit or lack of fit between adjacent core pieces should be noted. A double red/black vertical line down the core axis aids in determining the up direction especially if core samples are removed.

A core gamma log may be run in the laboratory while the core is still in the liner or after it has been extruded and reconstructed. Core gamma logs are not useful for Gulf Coast domal salt where the primary non-halite impurity is anhydrite because anhydrite and halite have similar gamma ray signatures. However, in bedded salts or domal salt with impurities other than anhydrite/gypsum (for example, shale or potash), core gamma logs are useful for core-log correlation.

The core should be photographed in its entirety prior to any sampling. The photographs should be in constant lighting, out of the weather, and taken with a high-quality camera. Photographs should be high resolution with readily legible labels for the well name, API well number or serial number, date, core number, and depth interval of the core sample in the photo. The core photographs should also have depth scales and a color calibration bar. The photographs should be archived in the permanent project files so that they are available for review.

The core should be described in detail prior to any destructive testing or sampling. The core description should provide a record of the visual examination of the entire core including but not limited to core condition, lithology, color, fabric, grain size, grain orientation, impurity content, and other notable geologic features observed in the core such as faulting, fractures, rubble, dilated salt, zones of highly strained or sheared salt, and other anomalous features.

Describing whole core is more difficult and provides less detail than describing slabbed core. However, many core tests, especially on salt cores, can only be performed on whole core so caution should be used when deciding which intervals to slab. Slabbing often damages salt cores. Slabbing is not as detrimental to nonsalt cores and can aid with observing the details of the rock. Nonsalt core sample testing can often be done on plug samples or subcores if they are at least 1 $^7/_8$ in. in diameter (see 5.4.2.3).

#### 5.3.2.4.4 Core Sampling

Sampling of cores for testing from each type of salt should be done on visually similar salt cores regarding grain fabric and impurity content. After review of the core, different salt types can be identified based upon visual examination. Key discriminators in salt include grain fabric, grain size, and the type and distribution of impurity content. Salt cores of each major type of geologically representative samples should be selected for testing as determined by the geologist. The distribution and composition of impurity material can impact the geomechanical properties of rock salt. Grain fabric can be an indicator of deformational history or anomalous salt, both of which may be reflected in the geomechanical test results. Nonsalt core testing is determined based upon geologic and engineering considerations depending upon the type of information required.

Sufficient material for each salt type should be selected for geomechanical testing to allow one or more complete test suites as outlined in 5.4. Individual core pieces selected for testing should be at least one foot in length except for those selected for Brazilian indirect tension testing (see 5.4.2.4) which can be as short as four inches. Sampling should avoid features such as impurity stringers, large intraclasts, and structural anomalies that might localize deformation or potentially skew the creep and strength test results. Under-gauge core due to exposure to undersaturated brine. Core samples damaged during drilling should be avoided as test samples.

#### 5.3.2.4.5 Core Testing

The goal of the core testing program is to characterize the geomechanical and geologic properties of each of the identified salt types (i.e. facies) and nonsalt units within the radius of influence of the cavern. See 5.4 about geomechanical core testing and protocols.

Before testing, the prepared geomechanical test samples should be photographed to provide a record of the pre-test sample and sonic/density measurements may be made. Post-test photographs should also be taken to facilitate the review of sample failure/deformation to determine if the test results could have been influenced by nonsalt impurities or localized strain/failure.

Core testing should be done to help to characterize the insoluble content. This information can assist with the preparation of a solution mining plan, log calibration for modeled mineralogy logs, solids control of the brine stream, and evaluating potential for formation damage in brine disposal reservoirs.

Additional testing to characterize the insoluble content within the salt should include a determination of the weight percent of insolubles, X-ray diffraction to determine the mineralogy of the insoluble fraction within the salt, and particle grain-size analysis to determine the grain size of insoluble components. With regards to coordinating this testing with the geomechanical sampling, end cuts from the geomechanical test samples may be used for the above-mentioned tests.

In complex salts with high impurity content, dissolution testing may also be performed to obtain a dissolution rate relative to clean halite for input into the solution mining model.

#### 5.3.2.4.6 Core Log Integration

The first task of core log integration should be to reconcile the core depth (driller's depth) with the open-hole well log depth, which can differ by several feet or tens of feet. The typical method is to run a core gamma log in the laboratory. Core log integration often results in a bulk shift of the core depth to coincide with log depth. If individual core pieces exhibit lack of fit with the adjacent pieces (i.e. lost or missing core), this bulk shift can vary within the cored interval.

NOTE In clean domal salt it is often impossible to reconcile core depth and log depth using a gamma ray (GR) log because anhydrite/gypsum have similar GR signatures to halite. If impurity stringers or banding exist, they can be correlated with GR, density or sonic log data depending upon the type and amount of the impurities. In the case of some bedded salt with discrete, well-defined layers, the core log integration can be based strictly upon lithology without using a core gamma log.

The core should be used in conjunction with the full suite of available open-hole well logs. Once the core depth and log depth have been reconciled, individual core test data, core intervals, rubble zones and other significant features within the core can be directly located on the well logs for analysis. Good core log integration assists with the characterization of non-cored intervals based solely upon well log information.

### 5.3.2.5 Geophysical Surveys

#### 5.3.2.5.1 General

Geophysical surveys are remote sensing methodologies that can help resolve the subsurface geology where well data are sparse or insufficient. Geophysical surveys can be either specifically performed for a project or purchased or leased if non-proprietary commercial data for the locale are available.

#### 5.3.2.5.2 Purchase or Lease of Commercial Data

Commercial geophysical data may be available for purchase or lease. The quality of the data should be assessed by a knowledgeable geophysicist or geologist. Most of the commercially available data from two-dimensional (2D) and three-dimensional (3D) seismic surveys were originally acquired by oil and gas companies. The acquisition and processing parameters that were originally used in this data may not address the concerns or depth interval of interest for salt cavern storage and may be unsuitable or require reprocessing.

A geophysicist or geologist should be involved with the selection of methodology, survey design, acquisition, processing, and interpretation of any geophysical survey. Forward modeling prior to data acquisition can be useful to determine if a particular acquisition program or methodology is likely to provide satisfactory results.

#### 5.3.2.5.3 Data Acquisition and Processing

Acquiring new geophysical survey data may be necessary. This occurs in a later phase of the geologic investigation after sufficient work has been done to determine the existing data gaps and the nature of the data that need to be acquired.

The site geology, existing data coverage, depth of investigation, contrast of the geologic units of interest, geometry of the structure to be imaged and surface access should be evaluated prior to selecting a particular geophysical survey method. A geophysicist or geologist should determine the appropriate methodology, survey design, and processing of the data. It is important to consider the nature of the investigation and the local geology to determine if the selected methodology can adequately provide the resolution needed to image the interval of interest in the subsurface.

NOTE The geophysical resolution of a bed or structure in the subsurface usually depends upon the geometry (thickness, depth, and orientation) of the object being imaged, its contrast (sonic velocity or density) with other strata or rock types, and the acquisition parameters of the chosen methodology. When considering performing a geophysical survey, existing culture and terrain are important considerations.

Typical geophysical methods useful for underground storage in salt caverns are:

— 2D and 3D seismic surveys;

— borehole seismic surveys;

— gravity surveys; and

— borehole acoustic/radar surveys.

Regardless of the methodology, geophysical surveys should be calibrated and validated with well control and other “ground truth” data because the survey data are highly model and processing dependent.

#### 5.3.2.5.4 2D and 3D Seismic Surveys

Seismic reflection surveys measure the travel time of elastic waves through rock strata and currently are the most commonly used geophysical method for the subsurface mapping of salt structures in the United States. Because of the limitations of data coverage in two dimensions, 2D seismic is considered less useful than 3D seismic in geologically complex areas because 3D seismic provides complete coverage of the survey area. 3D surveys are also considered better for salt domes because they provide a larger data volume, do not require extrapolation between individual lines, and typically do a better job locating steeply dipping events into their proper locations.

Salt domes present several challenges with regard to seismic surveys because of the near vertical sides of the salt stock, the potential for salt overhangs, and the associated structural complexity. Both 2D and 3D seismic surveys usually need long offsets to image near vertical edges and steeply dipping strata. Multiple 2D seismic lines are often acquired in radial patterns to image the edge of salt. For steeply dipping and structurally complex structures, 2D seismic surveys often suffer from out of plane events.

Seismic data are acquired in time. A velocity model is required to convert the data to depth. The depth conversion is dependent upon the quality of the existing velocity model. Seismic interpretations should be tied to existing well data.

#### 5.3.2.5.5 Borehole Seismic Surveys

Borehole seismic can be a useful exploration tool for salt cavern projects. Borehole seismic surveys most commonly used for salt include check shot surveys, vertical seismic profiles (VSPs), salt proximity surveys, and cross-well tomography. All of these methods require access to one or more boreholes. The choice of methodology depends upon the objectives of the study, tool availability, well availability, borehole conditions, and local geology.

Check shot surveys are useful for acquiring velocity data in the borehole for velocity models and time-depth conversions of 2D and 3D seismic surveys.

VSPs can help locate the edge of the dome or salt deposit. They are sensitive to source/receiver placement and the geometry of the interface to be imaged. VSPs often suffer from the inability to image the salt flank at the cavern level due to geometric constraints unless the well in which the VSP is being acquired is much deeper than the depth being imaged. They may be able to image features within the salt deposit depending upon thickness, acoustic contrast, and geometry; however, other borehole data such as open-hole well logs and core are needed to characterize the geologic feature that created the VSP response. For cross-well tomography, the source and receivers are each placed in adjacent wells.

##### 5.3.2.5.6 Gravity Surveys

Because of salt's low density, gravity surveys can be useful for delineating salt deposits if there is a sufficient density contrast between the salt and surrounding rock mass. The ability of a gravity survey to resolve a salt body also depends upon the size and depth of the salt mass. While often useful to identify areas of more salt, potentially cleaner salt, or the general boundaries of a salt deposit, the resolution capabilities of gravity surveys are limited in terms of detail.

##### 5.3.2.5.7 Borehole Acoustic and Radar Surveys

Geologic structure within salt hundreds of feet from a borehole can be interpreted using borehole acoustic and radar surveys. Both methods use the reflection of waves transmitted from a single borehole to image internal structure if there are layers or bands within the salt that have suitable geometry, thickness, and contrast to be adequately imaged and resolved. The primary difference between the two methods is the frequency of the waves used in the surveys.

Acoustic surveys use waves in the kilohertz range, whereas radar surveys use ultrahigh-frequency radio waves. Borehole radar has been used in Europe in a similar fashion to VSPs, but tool availability may be limited in the United States.

### 5.3.3 Exploration Programs

After review of the initial assessment based upon the available data, it may be determined that additional subsurface data are needed for the feasibility study or site characterization.

Exploration programs should be designed based upon an assessment of the existing data and aim to acquire pertinent useful data in an effective fashion requiring consideration of the site-specific geologic setting, available geologic data (quality, distribution, and density), and the usefulness and limitations of the various methodologies considered. Typical exploration programs can include the drilling of test wells to acquire open-hole well log data, borehole geophysical surveys, core, and well test data for a specific location. Geophysical surveys such as 2D and 3D seismic can be used to cover larger areas away from known well control or where gaps exist in the well data.

### 5.3.4 Geologic Assessment and Integration

#### 5.3.4.1 General

Subsurface geologic maps are used to formulate and communicate geologic interpretations. They are used to establish project feasibility, design criteria, select well locations, and identify and manage potential geologic risk.

There are always interpretational options when constructing subsurface geologic maps, so mapping to concepts and using multiple lines of supporting data (drilling records, cavern sonar surveys, lost circulation, and similar sources of data) should be incorporated into mapping to constrain interpretational options.

Maps and other geologic displays should be adjusted with each other and be internally consistent. An accurate interpretation is often obtained by using a coordinated suite of maps and displays incorporating multiple horizons as opposed to a few stand-alone displays.

While the general approach is similar for all salt deposits, the exact methodology for geologic assessment and integration of data should be determined on a site-by-site basis depending upon the geologic setting and project requirements as well as the quality, type, and distribution of the available data. Salt dome characterizations generally emphasize edge (flank) definition, salt quality (mechanical and compositional), lateral salt variation, internal banding, shear zones, and differential salt movement. There is no stratigraphic component associated with salt domes as the original bedding has been destroyed and is replaced by internal shear banding. Bedded salt characterizations, while also concerned with salt quality, generally emphasize stratigraphy, dissolution fronts, bed thickness, strength, and competence of interbeds, and lithologic controls on solubility and cavern stability. Characterization of highly deformed, tectonic salt deposits includes a strong structural component as well as varying degrees of stratigraphic assessment.

#### 5.3.4.2 Geologic Uncertainty

A geologic site characterization should assess the uncertainty in the characterization based upon the existing data and current geologic model. The attributes and characteristics of this uncertainty should be part of the input into the risk management analysis conducted in Section 8.

Elements of uncertainty that pose risks in salt include, but are not limited to, the edge of salt, shear zones, faults, high impurity zones, K-Mg salts, weak zones, zones with high creep potential, dissolution or collapse zones, nearby wells, or other subsurface activities. The edge of salt is one of the primary elements of geologic risk for salt domes. Additional buffer should be assessed on a site-by-site basis by a geologist to account for uncertainty in locating the exact edge of salt and to allow for the possibility that salt quality regarding geomechanical strength properties and impurity content tends to degrade toward the edge of salt. Caprock on salt domes can contain lost circulation zones, faulting, and $H_2S$ that can pose risks to hole stability and safety during drilling and to long-term stability of well casing. In the case of brine disposal, potential risk factors include, but are not limited to, nearby wells and subsurface activities, the presence of hydrocarbons, faulting, limited reservoir volume, permeability pathways and barriers, potential leak paths, and proximity to underground sources of drinking water.

Characterization of water supply includes not only understanding the hydrogeologic capabilities/limitations of the aquifer and local water use, but also the potential for contamination if the aquifer is not adequately isolated from the brine disposal reservoir and storage caverns.

#### 5.3.4.3 Geologic Maps and Displays

Correlating formations or marker horizons between wells using open-hole well logs and geophysical survey data allows creation of subsurface geologic maps, cross-sections, and other displays that are used to assess and characterize the site geology. Correlation markers may be presented on a type-log or cross-section. The type and number of geologic displays used depend upon the site geology, the data available, the scope of the assessment, the requirements of the project, and the type of information that needs to be communicated.

A geologic site characterization should utilize accurate well coordinates and a good quality basemap showing well locations, property boundaries, and land grid. All mapping and displays should conform to accepted standards and methodologies for subsurface geologic mapping. Maps and cross sections should be referenced to a suitable datum (usually mean sea level), properly annotated, and scaled appropriately. Datums, scales, orientation (usually North direction), contour intervals, map type, date of origin, and author should be clearly defined and legible. Key data (e.g. formation tops, contour labels, well identifiers) should be annotated and readily legible.

The most common map type for salt dome storage projects is the salt structure or top of salt map. Top of caprock and caprock isopach maps are also recommended if sufficient data are available. Profiles derived from the maps showing the cavern relative to both the caprock and salt can be useful to refine the interpretation and convey geologic information.

In the case of bedded salt, structure maps for both the top and base of the salt plus a salt isopach map should be developed if the data permits. If multiple salt layers and significant interbeds are present, structure and isopachs for each of the major units may be warranted. A series of cross-sections showing the continuity and variation of the salt and interbeds can also be useful.

NOTE When mapping a salt dome or salt deposit it is just as important to map where the salt is not encountered (negative well control) as it is to map the actual salt tops.

Brine disposal and raw water sources are also key components of a salt storage project. In addition to structure and isopach maps of key overburden or flank strata, additional maps may be warranted such as base of groundwater, porosity maps, net sand, lithofacies, and fault plane maps.

#### 5.3.4.4 Geologic Report

A geologic report should be prepared including all pertinent supporting data to document the basis for the geologic interpretation. The report should include a discussion of scope, data reviewed, methodology, analysis, conclusions, and recommendations with all supporting data and subsidiary reports supplied as appendices. All displays should be legible and annotated with the relevant data.

All supporting data should be referenced, and care should be taken when handling proprietary data. Many subsurface data are subject to confidentiality, copyright, and licensing agreements. This is especially true when using and presenting seismic survey data, the use of which is usually subject to licensing agreements and may require permission or redaction.

## 5.4 Geomechanical Site Characterization

### 5.4.1 General

Gas storage caverns in salt progressively decrease in volume because salt continuously deforms or creeps when subjected to the shear stresses induced by cavern development and operations. The stresses in salt redistribute as it creeps; if there are nonsalt units near the creeping salt, loads transferred from the salt accumulate in those units. Loads transferred to nonsalt units can cause them to fail if the loads exceed the strength of the nonsalt rock. Salt can also progressively microfracture and dilate if the shear stress exceeds its dilation strength. Microfracturing, also called “damage”, weakens the salt, and increases its permeability. The initial, in situ conditions in the salt and nonsalt rock surrounding a gas storage cavern strongly affect the rate of salt creep and the potential for salt damage and nonsalt failure.

To assess the structural stability and closure rate of a natural gas storage cavern, the mechanical properties of the various rock types and the in situ conditions should be determined in a geomechanical review and characterization of the site. These properties and conditions are key elements in developing a representative numerical model of a gas storage cavern.

The following site-specific geomechanical properties should be determined by laboratory testing of representative core samples:

— elastic and strength properties of both salt and nonsalt samples, and

— creep characteristics of salt samples.

In situ states of stress and temperature should be determined because accurate prediction of the creep deformation and potential for salt damage depends on these in situ conditions, especially in the depth interval of the storage cavern. If there are nonsalt units within the radius of influence of the cavern, the potential for their failure also depends on the in situ states of stress in them. In situ temperature has a minimal effect on the mechanical response of nonsalt rock types.

### 5.4.2 Laboratory Testing of Geomechanical Properties

#### 5.4.2.1 Testing Practices

The precision of laboratory tests is dependent on the competence of the personnel performing them and on the suitability of the equipment and facilities used. Agencies that meet the criteria of ASTM D3740 [2] or an equivalent standard, are considered capable of competent and objective testing, although compliance with D3740 does not in itself assure reliable testing. Reliable testing depends on many factors, and D3740 provides a means for evaluating some of those factors.

#### 5.4.2.2 Representative Samples

Both salt and nonsalt rock are inherently heterogeneous, and their mechanical properties can vary appreciably even within the same geological formation or member. Consequently, test specimens representative of each rock type under consideration should be selected from the available cores based on visual observations of mineral constituents, grain size and shape, and bedding and pore structure; measurements of bulk density and ultrasonic velocity; and correlation of specimen location to open-hole well logs.

Salt specimens from the cavern interval at the storage site should be used for testing of salt properties. Nonsalt specimens should be selected from within the cavern interval and from a distance of at least two cavern diameters above the cavern interval.

A sufficient number of specimens of each rock type should be tested to estimate average mechanical properties and to assess the variability in the properties. Although standard statistical methods are available to determine the number of tests required to obtain a specific confidence level, it may not be economically feasible to achieve statistically valid results for each property. The judgment of experienced professionals in rock mechanics may be required to supplement and interpret the laboratory test results.

#### 5.4.2.3 Sample Preparation

Cylindrical specimens shall be prepared for testing with procedures that meet or exceed ASTM D4543. For triaxial test specimens, this standard specifies that a specimen shall have a length-to-diameter ratio of 2.0 to 2.5 and a diameter of not less than 1 $^{7}/_{8}$ in. It is desirable that the diameter be at least 10 times the size of the largest mineral grain. However, this requirement may not be met for large, grained salt. The grain size of nonsalt rock generally is small enough that 2-in. diameter specimens satisfy this recommendation. For salt, a specimen diameter of nominally 4 in. should be considered the minimum necessary to satisfy the diameter recommendation of ASTM D4543 because large grain sizes are often encountered in rock salt.

Core retrieval, packing, shipping, unpacking, and specimen preparation can cause loosening of salt grains or formation of microfractures that can reduce the inherent dilation strength of salt specimens. Preconditioning test specimens for several days under hydrostatic conditions with axial and confining pressures of 3000 psi has been demonstrated to mitigate or heal preexisting specimen damage, yielding more repeatable and somewhat higher dilation strengths in triaxial compression tests [3].

#### 5.4.2.4 Brazilian Indirect Tension Tests

Tensile strength is obtained by the application of a uniaxial tensile load to a specimen with a cylindrical cross section. The application of a direct tensile load to a rock specimen is difficult and complicated for routine testing. Consequently, the Brazilian indirect tension test should be used to determine the apparent tensile strength of both salt and nonsalt samples because this test is simple and reliable.

When used, Brazilian indirect tension tests shall be performed and interpreted with a procedure that meets or exceeds the method specified by ASTM D3967. Although tensile strength is not typically used in geomechanical analyses because the loads around a natural gas storage cavern are, generally, compressive, the apparent tensile strength is a useful measure for comparisons between rock types and for comparing variations in rock strength from one location to another. If tensile stresses are predicted around a cavern, the apparent tensile strength may be used to estimate the rock's propensity for tensile failure.

#### 5.4.2.5 Triaxial Compression Tests

##### 5.4.2.5.1 General

In a triaxial compression test, a cylindrical specimen jacketed with a flexible, impermeable membrane is placed in a fluid-filled chamber that applies a confining pressure to the specimen's lateral surfaces and in a loading frame that applies a compressive axial stress. Triaxial compression tests are used to determine:

— static elastic moduli (e.g. Young's modulus and Poisson's ratio) of salt and nonsalt specimens;

— dilation strength of salt specimens; and

— compressive strength of nonsalt rock specimens.

These properties are used in numerical simulations, as well as for comparisons between different sites, rock types, and variations in properties from one horizon to another.

Triaxial compression tests shall be performed and interpreted with a procedure that meets or exceeds the method specified by ASTM D7012. This standard covers both uniaxial (unconfined) compression and confined compression tests. Although D7012 provides for testing at elevated temperatures, testing at room temperature should be adequate for determining the properties required in simulations of natural gas storage caverns.

##### 5.4.2.5.2 Elastic Moduli and Dilation Strength of Salt

Salt specimens should be tested in a confined state because salt has the propensity to microfracture at relatively small axial stresses in unconfined tests. In confined compression tests, the difference between the axial stress and confining pressure should be increased rapidly to minimize creep deformation during the tests (e.g. using a constant axial strain rate of $10^{-4}$ MPa per second). If unconfined compression tests are performed, they should only be used to determine index values for simple comparisons of salt properties from different locations and depths.

The static elastic moduli should be determined from the axial and radial strains measured during unload-reload cycles inserted into the loading path, as recommended in ASTM D7012 for rocks like potash and salt that undergo significant inelastic strains during triaxial compression tests. The elastic moduli are determined from the linear portions of the stress-strain responses measured during reloading.

ASTM D7012 covers the determination of the ultimate compressive strength of intact rock specimens. To determine the dilation strength of salt, the axial stress should be increased until inelastic, dilatant volumetric strain is measured. The onset of dilation (microfracturing) occurs at axial stresses substantially less than the ultimate strength of the salt. The axial stress at which inelastic dilation is observed is defined as the dilation strength at the confining pressure applied in the test.

NOTE For triaxial compression tests on salt, Mellegard and Pfeifle [4] recommend an alternate load path in which the mean stress in the specimen is maintained at a constant value by decreasing the confining pressure at twice the rate that the axial stress is increased. During conventional tests performed according to ASTM D7012, the confining pressure is maintained at a constant value while the axial stress is increased. By maintaining a constant mean stress during the course of the test, the elastic volumetric strain is suppressed, and the onset of inelastic dilatant strain is observed more definitively.

At least three confined compression tests should be conducted on similar salt specimens, each at a different confining pressure (or mean stress for constant mean stress testing), to define the variation of dilation strength of the salt as a function of mean stress. Replicate tests at the same conditions may be required to establish reliable trends in the dilation strength as a function of mean stress because of the heterogeneity typical in salt deposits and the scatter in the results that is often encountered.

#### 5.4.2.5.3 Elastic Moduli and Compressive Strength of Nonsalt Rock Types

The static elastic moduli and the unconfined and confined compressive strengths of nonsalt rock types within the radius of influence of natural gas storage caverns should be determined. The unconfined strength is particularly useful for comparisons between rock types and for evaluating variability within a nonsalt unit. In numerical simulations, deformation and strength properties determined from laboratory tests on nonsalt cores should be employed with proper judgment; laboratory values may not accurately represent rock mass properties that are influenced by joints, faults, inhomogeneities, and other factors absent in laboratory specimens.

The difference between the axial stress and confining pressure should be increased rapidly and at a steady rate during triaxial compression tests on nonsalt specimens. However, if the stress-strain response measured during initial loading exhibits significant nonlinearity, unload-reload cycles should be inserted into the load path to determine the elastic moduli in a manner similar to the methodology described for salt testing. ASTM D7012 specifies that the stress rate or strain rate should be selected to produce failure of a typical test specimen in unconfined compression in a test time between 2 minutes and 15 minutes. The selected stress rate or strain rate for a given rock type should be used for all tests of the rock type in the investigation.

ASTM D7012 specifies that at least three confined compression tests, each at a different confining pressure, should be conducted on essentially identical specimens of each rock type. Replicate tests at the same conditions may be required to establish reliable trends in the compressive strength as a function of confining pressure because of the heterogeneity that is inherent in rock and the scatter in the results that is often encountered. The unconfined and confined compressive strengths determined for each rock type should be reduced to a Mohr envelope that describes the variation of the rock type’s compressive strength as a function of confining pressure.

### 5.4.2.6 Triaxial Creep Tests of Salt

The predominant mechanism of deformation in salt surrounding natural gas storage caverns is time-dependent, viscoplastic deformation referred to as “creep.” The creep rate of salt is strongly dependent upon the Von Mises effective stress, which is a three-dimensional measure of shear stress, and upon the temperature of the salt. In a triaxial creep test, a constant temperature and effective stress (difference between axial stress and confining pressure) is applied to a cylindrical salt specimen, and the time-dependent creep deformations are measured. Triaxial creep tests are used primarily for deriving a creep model that describes the creep rate of a salt deposit as a function of Von Mises effective stress, temperature, and time. The creep model is used in numerical simulations of caverns in the salt, as well as for comparing different salts and variations in salt response from one location to another.

Triaxial creep tests shall be performed with a procedure that meets or exceeds the Triaxial Compression Method specified by ASTM D7070. Because of salt’s propensity to microfracture (dilate), salt should be tested in a confined state with a confining pressure greater than the difference between the axial stress and the confining pressure (equivalently, a confining pressure greater than one-half of the axial stress). Constant true-stress testing, in which the applied loads are adjusted to compensate for specimen deformation, should be used for triaxial creep tests on salt specimens because the creep strains often exceed 1 %.

The duration and procedure of a creep test should be adapted to the creep law that is used in numerical models. Multistage creep tests or constant effective stress tests may be implemented. The duration of a creep test at a constant effective stress and temperature should be sufficient for the axial strain rate to approach steady state. Typically, a creep test on a salt specimen requires 30 days or more to approach the steady-state creep rate.

At least three triaxial creep tests should be conducted on similar salt specimens, each at the same temperature but at different effective stresses, to define the variation in creep response as a function of effective stress. Replicate tests at the same conditions may be required to establish reliable trends in the creep response as a function of effective stress because of the heterogeneity typical in salt deposits and the scatter in the results that is often encountered.

The suite of triaxial creep tests should be performed at a temperature representative of the in situ temperature around the natural gas storage cavern. Alternatively, additional triaxial creep tests may be performed over a range of temperatures to determine the variation in creep response as a function of temperature.

#### 5.4.3 In situ Temperature

If available, a temperature log performed in a borehole through the cavern interval should be used to establish the in situ distribution of temperature. However, temperature logging performed soon after completion of a borehole consistently underestimates the in situ temperatures because the fluids circulated during drilling cool the borehole surface and the surrounding formations. Reliable measurements of the in situ temperature distribution require waiting days or even weeks for the fluid in the borehole to heat up to static conditions representative of the initial geothermal temperatures in the formations. Ratigan and Blair [5] recommend delaying temperature logging as long as practical, but for at least 3 days to 5 days after drilling is complete. Various techniques have also been used to correct a series of temperature logs in a borehole to static conditions by treating temperature as a transient function and extrapolating to steady-state conditions [6].

If reliable temperature logs are not available, regional databases of geothermal temperature and flux should be reviewed and used to develop preliminary estimates of in situ temperature. Interest in geothermal resources has yielded regional databases that include many of the salt deposits in the United States. However, regional geothermal data may not be representative of the conditions in salt domes because salt's thermal conductivity typically is two to three times greater than the thermal conductivities of the sedimentary deposits surrounding the dome. Many salt domes have also been investigated as hosts for heat generating, high-level radioactive waste repositories. Literature from these scientific investigations often includes measurements of the geothermal conditions in the salt domes.

#### 5.4.4 In situ Stress

The in situ distribution of vertical stress should be evaluated by integrating a formation density log from the ground surface through the depth interval of the natural gas storage cavern. In salt deposits, it is generally accepted that the in situ stress state is isotropic with the horizontal stress components essentially equal to the vertical stress because salt creep over geological time frames effectively removes any differences in the horizontal and vertical stress components. The stress regime can be anisotropic where the salt body is actively deforming.

In nonsalt units, significant differences between the vertical and horizontal stress components can be sustained over geological time frames because nonsalt rock types do not creep appreciably. Because the processes controlling the horizontal components of in situ stress (e.g. erosion, sedimentation, and tectonism) tend to be regional, reliable estimates of their principal values and directions may be available in regional literature and databases.

If reliable regional estimates of in situ stress are not available, the horizontal components of in situ stress should be established by hydraulic fracturing tests performed in the nonsalt units. Hydraulic fracturing for stress determination, also referred to as hydrofracturing or minifrac tests, shall be performed and interpreted with a procedure that meets or exceeds the method specified by ASTM D4645. Hydraulic fracturing tests may be performed in salt units to determine the fracture pressure gradient.

### 5.5 Assessment of Cavern Stability and Geomechanical Performance

#### 5.5.1 General

The structural stability and geomechanical performance of natural gas storage caverns in salt should be assessed using numerical models that represent the geometries of the caverns, their development history and operating conditions during gas storage, the geologic structure around the caverns, the mechanical properties of the salt and nonsalt units, and the preexisting in situ conditions. In particular, the numerical models should simulate the time-dependent creep deformation that is distinctive of rock salt and other evaporites.

The objective of the numerical simulations is to determine key parameters that maintain the structural stability and mechanical integrity of the caverns within their particular geologic setting. These key parameters include:

— cavern shape and size;

— cavern proximity to other caverns and edge of salt;

— key depths;

— wellbore and cavern roof design;

— minimum and maximum storage pressures and cycling; and

— surface subsidence estimation.

### 5.5.2 Cavern Shape and Size

Cavern size should be established to provide the needed working gas capacity while considering the safe maximum and minimum storage pressures of the cavern and the maximum and minimum storage temperatures for the gas during the expected cavern pressure cycle. Sharp corners or ledges produce stress concentrations and should be avoided by designing an arched roof and smooth cavern shoulders and walls. Once a desired cavern size and shape is established, numerical modeling should be used to investigate areas known to create concentrated stresses.

### 5.5.3 Cavern Proximity to Other Caverns and Edge of Salt

Geomechanical modeling should be used to determine adequate salt thickness between the cavern and existing or planned additional caverns and between the cavern and the edge of the salt stock. The modeling should include expected operating pressure scenarios in the gas storage caverns as well as in adjacent caverns.

Industry experience has shown that salt pillar widths of two to three times the average maximum diameter of adjacent caverns have satisfied mechanical modeling evaluations to determine safe cavern spacing for given pressure operating scenarios. This spacing range has also been proven to provide adequate salt pillar width for safe, ongoing natural gas storage operations.

Distance from the edge of the salt stock should be evaluated when planning the size and location of the cavern. The level of confidence in determining the edge of the salt stock is dependent upon the quality of the available data. Additionally, there can be a higher potential for degraded salt properties and impurities near the edge of the salt which can result in higher shear stresses and the possibility of preferential solutioning.

### 5.5.4 Key Depths Determination

The cemented casing should be set at a depth below the top of the salt that provides for the structural integrity of the casing and the cement bond. The salt interval provides the environment for a good pipe-cement-salt bond and enhances the integrity of the casing seat for gas storage operations.

Design depths for wellbore casings and for cavern roof and bottom are influenced by the following factors:

— top of salt depth,

— maximum and minimum pressures,

— cavern diameter and height, and

— insoluble settlement.

Analysis of overburden density logs and fracture gradient testing should also be used in the cavern design. These studies help determine the safe maximum pressure at the casing seat.

The cavern diameter should be determined by evaluating the spacing between adjacent caverns and proximity to the edge of the salt dome and facility property boundaries. Cavern height should be determined by evaluating the design storage capacities, the maximum and minimum storage pressures, and the cavern diameter.

Estimates of insoluble percentage in the salt mass should be determined from core samples and open-hole well logs acquired during the drilling phase. Insoluble impurities, usually anhydrite, are present in most salt masses and the bulk volume of these insolubles upon settlement is greater than their original volume. During planning of the total drilling depth for the cavern, the expected volume of insoluble settlement in the lowest portion of the cavern, known as the sump, should be evaluated because several hundred feet of the initial cavern interval can be lost during the solution mining process.

Salt creep rates and surface injection pressures are constraints that should be evaluated for determination of total cavern depth. Salt creep rates increase with depth due to increasing in situ stress and temperature. Additionally, pressures for water injection during solution mining and for gas injection during debrining increase as cavern depth increases, affecting the design and cost of associated surface facilities.

#### 5.5.5 Wellbore and Cavern Roof Design Considerations

The distance from the bottom of the cemented casing to the cavern roof shall be sufficient to prevent roof strains from affecting the integrity of the cemented casing and casing connections. Subsequently, geomechanical modeling should be used to evaluate the effects of the pressure cycling and salt creep in this interval. This distance can be greater than one- half the cavern diameter depending upon salt thickness, salt properties, and pressure cycling scenarios. The cemented casing seat is subjected to varying levels of stresses and deformation because of the wide range of pressure cycling that occurs during typical natural gas storage operations. Proper design of the uncased wellbore section and the cavern roof mitigates the stress and creep strain placed on the casing seat and casing connections, reducing the risk of casing damage or loss of integrity in the cement bond at the casing seat.

#### 5.5.6 Minimum and Maximum Storage Pressures and Cycling

Maximum pressure shall be limited to a value whereby gas containment is ensured. Maximum pressure shall be determined by evaluating or estimating the fracture gradient of the salt stock and the design depth of the casing seat. Since caverns are susceptible to creep closure and to salt damage and spalling if the salt's dilation strength is exceeded, the minimum pressure should be set to minimize these effects. The operating pressure range and the cycling frequency are important factors to consider during cavern design. These factors are key elements affecting the long-term stability and integrity of the cavern.

Geomechanical simulations should be used to help determine a cavern's allowable operating pressure range and safe cycling frequency. The simulations should include the properties of salt and nonsalt units for the cavern location and should also include the expected operating pressures in adjacent existing or planned caverns. The assessment may also include the effects of gas thermodynamics, heat transfer, and thermo-mechanical stress and deformation.

Pressure cycling scenarios in the geomechanical simulations should be at least as rigorous as the planned commercial utility of the cavern. The simulations should also include a scenario that evaluates the cavern closure, stresses and strains in pillars, and ground subsidence rates when the cavern is maintained at or near its minimum pressure for an extended period, to evaluate the potential effects of an abnormally long period of low-pressure operation.

#### 5.5.7 Surface Subsidence Estimation

Geomechanical modeling should be used to provide a prediction of the expected rate of surface subsidence based on:

— depth, spacing, height, and volume of the cavern and adjacent caverns;

— pressure ranges and cycling frequency of the cavern and adjacent caverns;

— geomechanical properties of the salt and nonsalt units above and surrounding the caverns.

### 5.6 Periodic Review

As new data become available during the operation of a storage facility or there is a change in cavern operating parameters, the updated information should be incorporated into a risk assessment to determine if any new geological or geomechanical assessments are required. The results of these assessments may result in the adjustment of cavern operations or preventative and mitigative measures.

## 6 Well Design

### 6.1 General

Design of the storage well system shall ensure the confinement of the stored gas to the cavern system (see Figure 1). Major components of well design include:

— hole section design,

— casing design, and

— wellhead design.

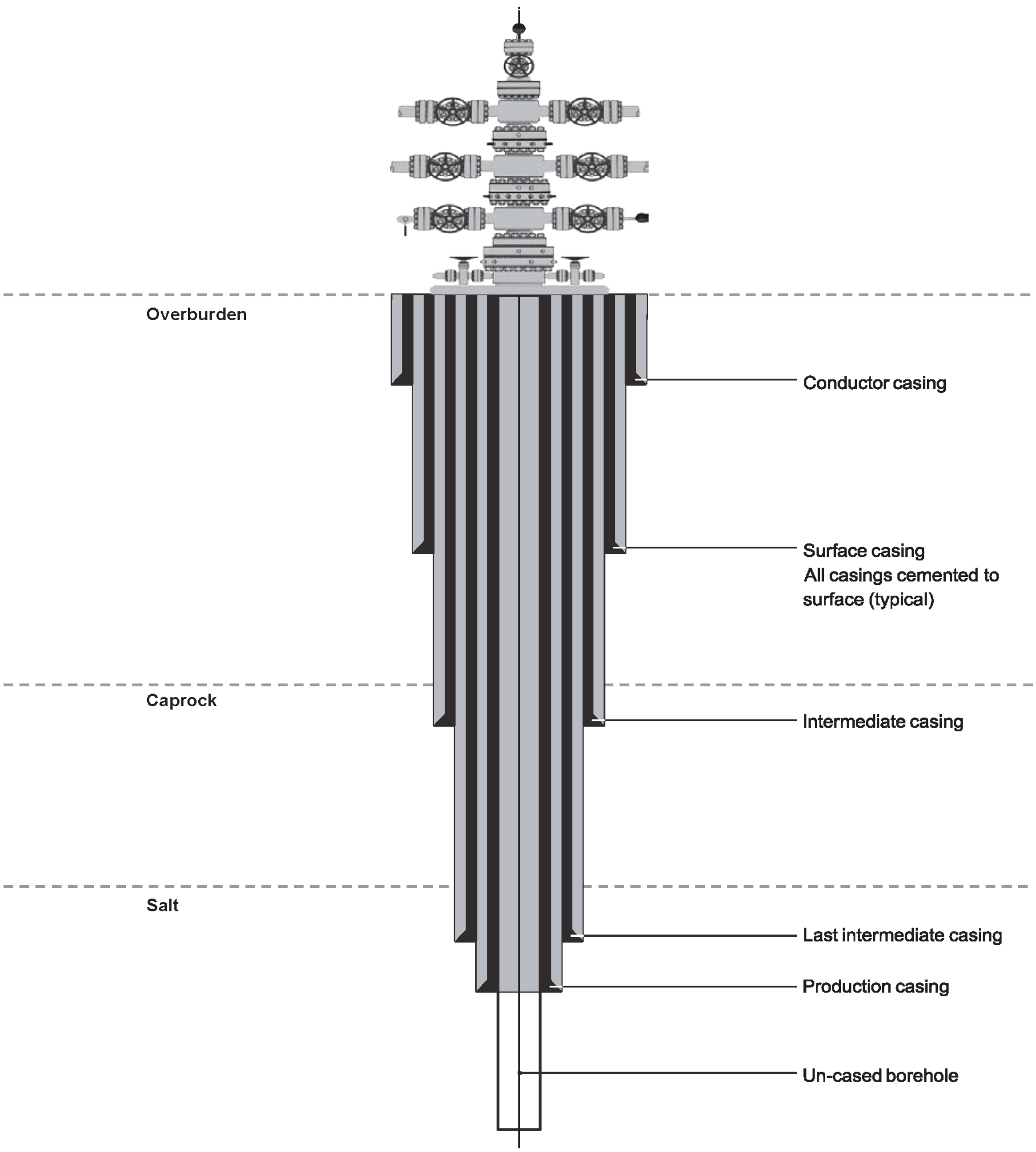


**Figure 1—Typical Cemented Casing Program for Domal Salt**

## 6.2 Hole Section Design

### 6.2.1 General

A hole section is a vertical length of the well having a discrete function in the cavern system. Design of each hole section should consider the diameter and depth needed to allow for the installation of the final cemented production casing.

Typically, the progression by **depth** and diameter of hole sections is:

— conductor casing hole section;

— surface casing hole section;

— intermediate casing hole section(s);

— production casing hole section;

— cavern hole section.

### 6.2.2 Conductor Casing Hole Section

When used, the conductor casing hole section is the first section to be developed and shall be lined by the conductor casing. Conductor casing or drive pipe is used as the foundation for the well and the prevention of near-surface soils from caving into the wellbore and undermining the drilling rig.

The setting depth of this string is dependent on the competency of near-surface formations.

### 6.2.3 Surface Casing Hole Section

The surface casing hole section functions to isolate the lower portion(s) of the wellbore from the underground sources of drinking water (USDW).

Setting depth is determined by the depth of the lowest USDW and should be confirmed using an open-hole resistivity log.

### 6.2.4 Intermediate Casing Hole Section(s)

When drilling out below the surface casing, zones that lead to drilling problems may be encountered including unstable or unconsolidated zones, lost circulation zones, and pressurized production zones. The intermediate casing hole sections function to isolate these problem zones, enabling the deepening of the well.

Use of a contingent intermediate casing string above the salt should be evaluated if severe loss of circulation is anticipated.

NOTE The conductor and surface casing sections are often sized to allow for a contingency casing string to be set.

In domal salt wells, two casing strings shall be set into the salt. These casing strings are the last intermediate casing, and the production casing strings. Experience has shown that setting the intermediate casing 150 ft to 200 ft into the salt may be necessary for isolation of the caprock.

### 6.2.5 Production Casing Hole Section

The production casing hole section is drilled to allow the running, setting, and cementing of the production casing which is the final cemented casing string in the well.

The setting depth of the production casing is influenced by the need for saltback distance, or the distance from top of the salt to the casing seat. Geomechanical analysis should determine adequate saltback distance.

Often the setting depth is determined by pressure considerations at the casing seat for future gas storage volumes. The production casing should be set in a section of salt determined competent to provide a pressure-containing casing seat.

In bedded salt, the casing seat should be within the cavern salt or an overlying salt bed (see 9.10.2.4).

### 6.2.6 Cavern Hole Section

The cavern hole section is below the final cemented production casing and includes the cavern neck, cavern interval, and sump.

## 6.3 Casing Design

### 6.3.1 General

Casing is used to maintain borehole stability, prevent contamination of subsurface formations and control pressures during drilling, mining, and gas service operations. Casing also provides points of attachment for the wellhead and blowout prevention equipment.

### 6.3.2 Design Considerations

Each section of casing should be designed with consideration to the physical forces acting on it. Physical forces include the loads acting to collapse, burst, compress, or pull apart (axial compression and tension). Forces acting on the casing change over time from when the casing is cemented, solution-mined, debrined, placed in gas service and throughout the service life of the well. Once the ranges of physical forces are determined, the worst-case set of conditions should be designed for. Safety factors should be applied to design calculations to provide a level of additional margin of mechanical strength.

Diameters should be chosen which allow for adequate space between the outer and inner strings for successful cement jobs. Because the space between the outside of the casing and the wellbore wall is cemented, sufficient annular area is required for the cement to adequately fill and ultimately seal-off this space. Experience in running and cementing large diameter casings has shown that a hole diameter six inches greater than the diameter of the next inner casing is an optimum annuli; for example, 20 in. casing should be set in a 26 in. hole, where feasible.

The casing strings are often larger in domal salt wells than in bedded salt wells and may require the use of line pipe in lieu of oil country tubular goods (OCTG) casing. Differences between line pipe and OCTG should be taken into consideration, including:

— different ovality tolerances;

— different metallurgy;

— different connection methods; and

— applicability of casing design equations for large outside diameter (OD) line pipe.

All casing should be cemented in-place from the bottom of the casing to the surface.

All casing shall be supplied with material test reports which shall be kept for the life of the well.

NOTE Hanging string design is addressed in 9.4.2.

### 6.3.3 Conductor Casing or Drive Pipe

The conductor casing is either driven into the ground to refusal or is drilled with an auger, set in-place, and cemented.

If driven, collapse design shall be calculated to withstand lithostatic pressure at the anticipated setting depth. Maximum buckling forces expected during pipe driving shall be evaluated. A reinforced drive shoe should be used. If driven, the pipe is not cemented.

If augered, collapse design shall be calculated to withstand the differential pressures encountered during cementing. Burst and tensile loads are generally not factors due to the typically shallow setting depths.

### 6.3.4 Surface Casing

Collapse design shall be calculated to withstand the pressures encountered during cementing of the surface casing.

If encountering a gas-bearing formation is anticipated during the drilling of the intermediate hole section, burst design shall consider the expected gas pressure.

Due to the usual shallow setting depths of the surface casing in domal salt, compressive and tensile loads are generally not a factor.

In bedded salt well design, there may not be an intermediate casing and the Bradenhead is installed on the surface casing. In this case, burst design for the top of the surface casing shall be based on maximum operating pressure without allowance for pressure containment due to cement sheath or hydrostatic head outside of the surface casing. Burst design for the bottom of the surface casing shall be based on the cementing differential pressures to be encountered. Since the production casing and the solution mining hanging string loads are exerted on the surface casing, maximum compressive loads shall be used.

#### 6.3.5 Intermediate Casing

In domal salt well design, the intermediate casing's main function is to bridge the hole sections through the unconsolidated overburden, the caprock, and into the top of the salt. Drilling issues may require multiple intermediate casings.

The bradenhead should be installed on the last intermediate casing, which allows for the setting of the production casing and the remainder of the wellhead.

Collapse design shall be calculated using intermediate casing cementing pressures.

Burst design should be calculated differently for the top and bottom sections of the last intermediate casing string. Burst design for the top of the intermediate casing string shall be based on maximum operating pressure without allowance for pressure containment due to cement sheath or hydrostatic head outside of the intermediate casing. Burst design for the bottom of the intermediate casing string shall be based, at a minimum, on the cementing differential pressures to be encountered.

During the cementing of the production casing, cement at the surface could settle down the annulus, causing an open annular area between the casings. During gas operations, gas could pass through the wellhead seals into the void space created by cement settlement. Experience indicates that welding the upper 200 ft to 400 ft of intermediate casing can eliminate gas leakage through threaded casing connections.

Welding and inspection procedures shall be developed with consideration to wall thickness and grade. Welded connections shall be inspected using X-ray or an equivalent non-destructive test method.

#### 6.3.6 Production Casing

Production casing shall have adequate tensile strength for the setting depth.

Collapse design shall be based on full lithostatic load externally and atmospheric pressure internally.

Burst design shall be calculated using the maximum operating pressure without allowance for pressure containment due to cement sheath or hydrostatic head outside of the production casing.

Due to the forces applied to the production casing by thermal cycling during gas storage operations and the tendency for leak paths to develop in threaded and coupled connections, production string shall have welded connections.

If a casing string of varying wall thicknesses is called for, one joint of the smallest internal diameter pipe should be run as the last (shallowest) joint in the hole. This prevents tools or equipment from being run and stuck downhole in the smaller ID pipe.

Welding and inspection procedures shall be developed with consideration to wall thickness and grade. Welded connections shall be inspected using X-ray or an equivalent non-destructive test method.

## 6.4 Wellhead Design

### 6.4.1 General

The wellhead is used to contain the gas stored in the cavern system and to allow controlled flow into and out of the cavern system.

New or replacement wellhead equipment, including associated fittings, flanges, and valves, should conform to API Specification 6A [18], API Specification 6D [19], or equivalent standard.

### 6.4.2 Design Considerations

Two separate wellheads are typically used during the service life of a cavern system: one for solution mining development, one for gas storage service.

All wellhead components shall be steel and shall be of sufficient strength to withstand the maximum operating pressure. Safety factors should be applied to design calculations to provide a level of additional margin of mechanical strength.

Appropriate materials for the service and temperature range to be encountered shall be selected for wellhead components and seals.

Outlets shall be sized for anticipated flow rates.

Ring type joint flange connections shall be used as opposed to raised face flange connections. On ring type joint connection between flange faces, stainless steel ring gaskets should be used and should be replaced after each use.

### 6.4.3 Wellhead Considerations for Solution Mining Service

The solution mining wellhead is installed during the completion of well drilling and remains in place through the end of cavern solution mining operations (see Figure 2).

The solution mining wellhead should be designed to allow the injection of pressured raw water from the surface, down the well, and into the salt formation for salt dissolution and return of the brine solution to the surface for processing or disposal. The solution mining wellhead equipment is also designed to allow for injection of a roof protection blanket into the production casing annulus.

The design of the wellhead should take into account site-specific considerations, such as brine and corrosive gases. The equipment should have internal coatings to resist corrosion or adequate corrosion allowances during solution mining operations.

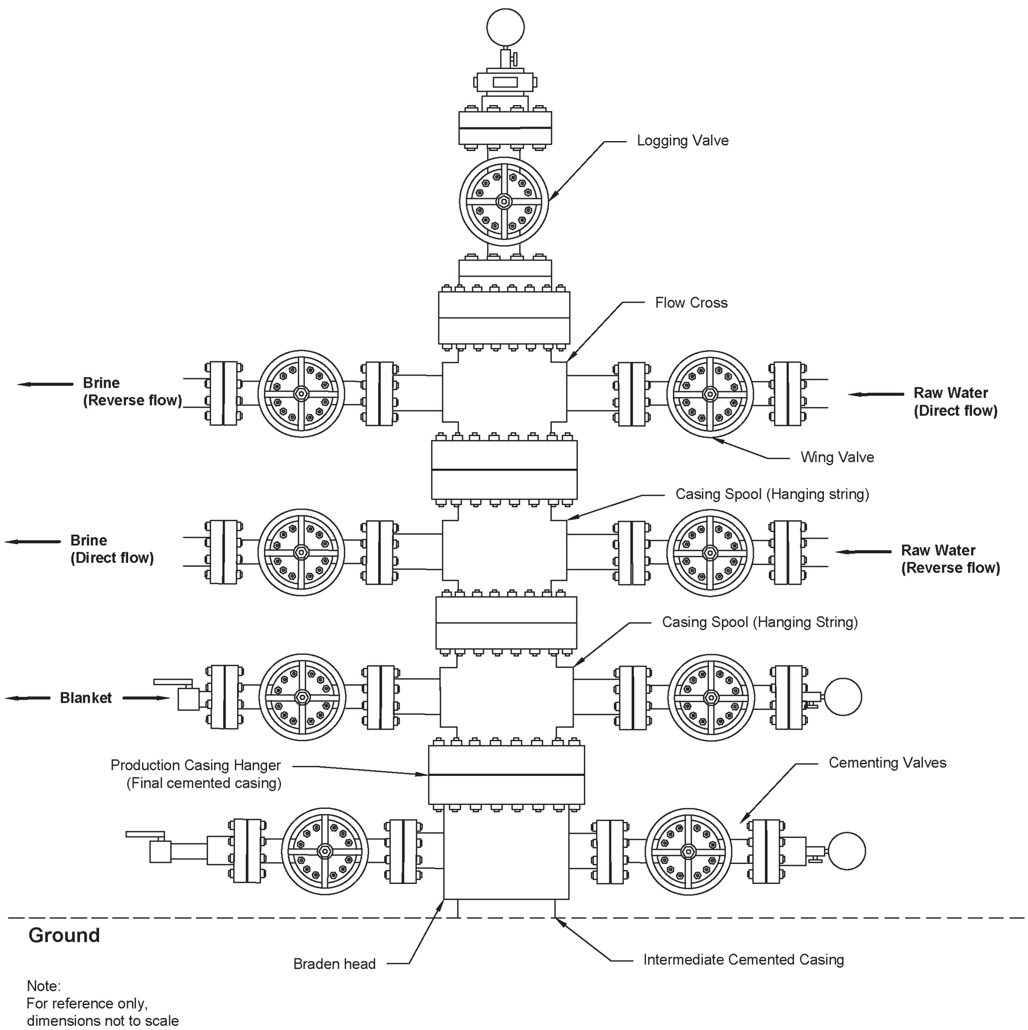


**Figure 2—Typical Solution Mining Wellhead**

### 6.4.4 Wellhead Considerations for Gas Storage Service

The storage wellhead is installed after the completion of solution mining and cavern development activities and prior to the commissioning MIT (see Figure 3 and Figure 4).

The wellhead equipment shall be designed for gas injection and debrining operations.

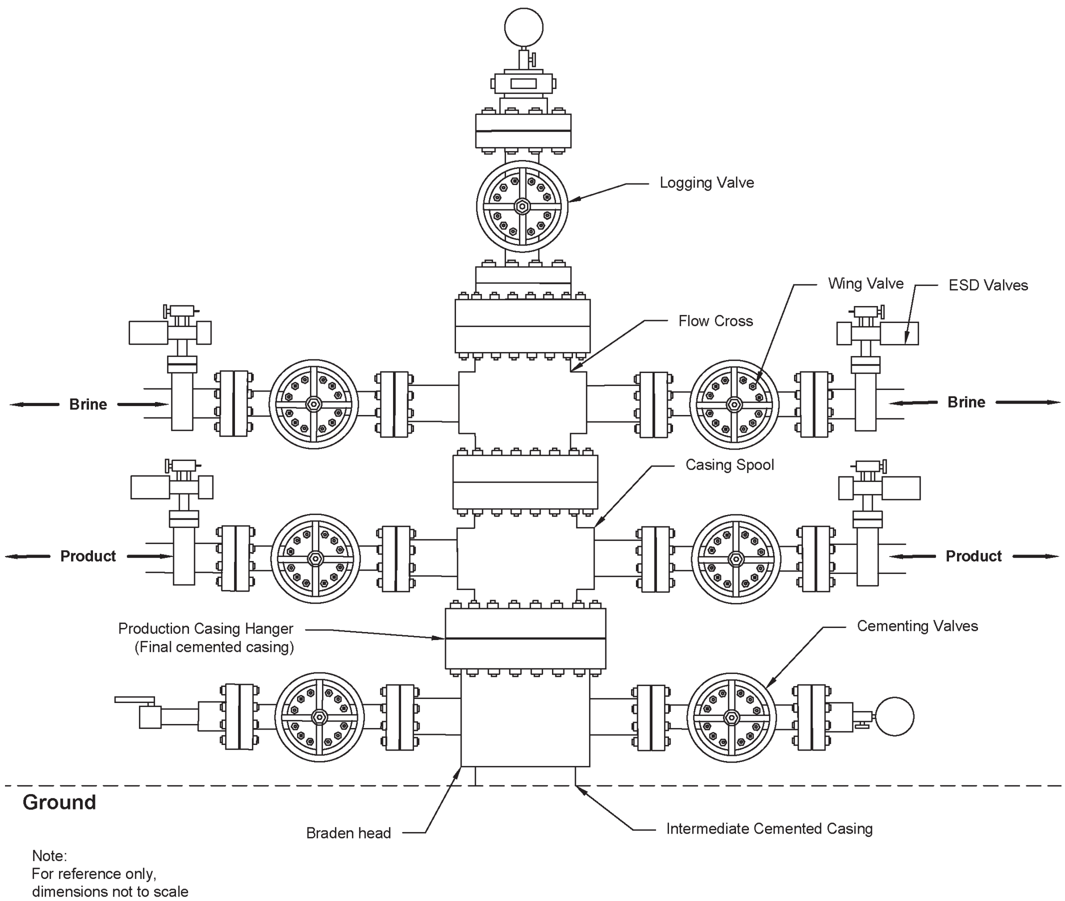


**Figure 3—Typical Gas Storage Wellhead with Hanging String**

### 6.4.5 Bradenhead

The Bradenhead, also known as the starting head, is typically installed on the last intermediate casing and is the foundation for the remaining wellhead equipment.

The size of the Bradenhead is determined by the size of the last two cemented casing strings.

The Bradenhead should have two side outlets and be sized to allow adequate flow rate of returns during the cementing of the last cemented string.

Slip-on welded type Bradenheads should be used. This weld should be made under controlled fabrication shop conditions where the weld can be gas tested.

The Bradenhead with the casing stub is butt welded in the field to the last intermediate casing. Welding and inspection procedures shall be developed with consideration to wall thickness and grade of the pipe being welded. The welded connection shall be inspected by X-ray or an equivalent method.

### 6.4.6 Casing Hanger for Casing Strings

A slip-type or mandrel casing hanger should be used to hang off the production string in the Bradenhead. The casing hanger shall be designed to fit in the bowl of the Bradenhead and fully close around the OD of the production casing. The hanger shall be designed to support the entire weight of the casing string.

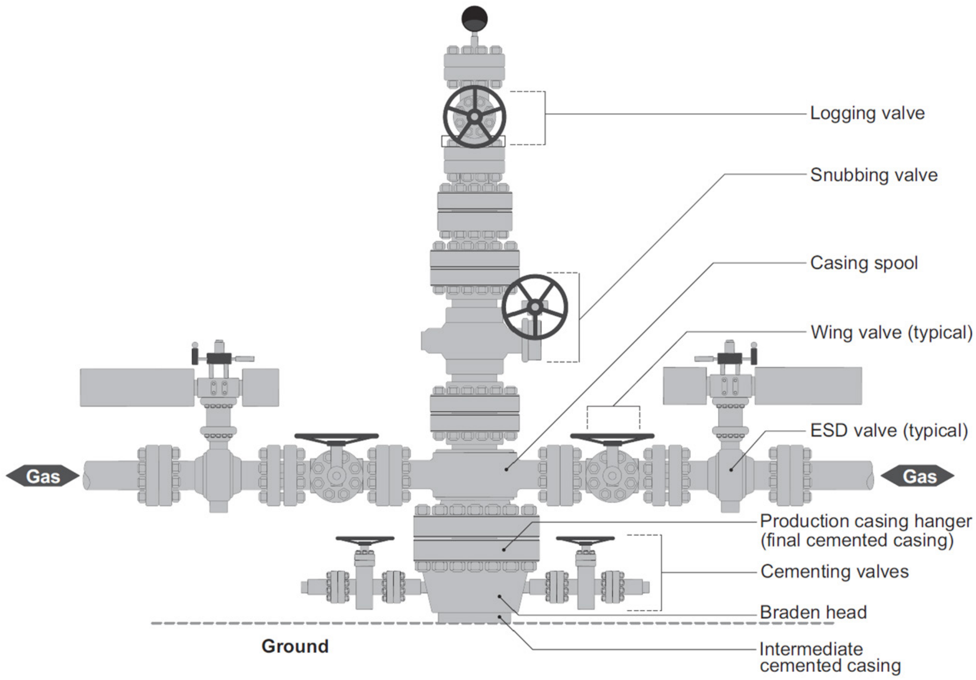


**Figure 4—Typical Gas Storage Wellhead without Hanging String**

### 6.4.7 Double Studded Adapter Pack-Off Flange

If the Bradenhead flange has a lower pressure rating than the wellhead components above it, a double studded adapter pack-off flange shall be used to transition pressure ratings between the Bradenhead flange and the bottom flange of the casing spool immediately above it.

The double studded adapter pack-off flange should have studded, flanged connections with ring joint gaskets adapting to the Bradenhead and the spool component immediately above it.

Double elastomeric p-seals in the double studded adapter pack-off flange should be used for a seal on the production casing stub above the slips. There should be a minimum of two ports per seal to allow for placement of packing material. Test fittings should be placed between and below the p-seals to test for adequate sealing.

### 6.4.8 Casing Spool

The wellhead will have one or more casing spools, depending on service. The casing spool allows for the landing of a hanging string and forms a seal on the casing string below.

During the solution mining process two casing spools are needed to hang the long and the short hanging strings and to allow the flow of raw water into the well and brine out. The side outlets should be sized to provide adequate flow area for the maximum flow rates at a minimal pressure drop. The bottom flange of each spool should have an elastomeric p-seal to seal around the hanger neck of the previous hanging casing, preventing hydraulic communication.

During gas storage operations there is typically only one casing spool that is needed to suspend the debrining casing and allow the maximum gas flow through its side outlets and brine through the debrining casing.

The casing spools should be designed with a bowl to accept the mandrel casing hanger. The top flange of each casing spool should be fitted with lock down pins that help activate the mandrel hanger body seal and hold the mandrel hanger in place.

### 6.4.9 Casing Hanger for Hanging Strings

Casing hangers designed for solution mining and gas cavern operations are typically of the mandrel type. A mandrel hanger has a solid body with a through-bore ID the same as the attached tubing or casing. The mandrel hanger is designed to withstand the tensile loading of the attached hanging string. The mandrel hanger generally has elastomeric seals on the OD of the hanger that seals against the hanger bowl. The mandrel hanger neck should be sized for the elastomeric p-seal of the flange immediately above.

### 6.4.10 Flow Cross/Flow Tee

The section above the top casing spool can be a four-way fitting (flow cross) or a three-way fitting (flow tee). The outlets should be sized to allow adequate flow area for the maximum flow rates at a minimal pressure drop.

### 6.4.11 Manual Wellhead Valves

Manual solution mining valves, either gate or ball, shall be placed directly on the side outlets of the various casing spools of the wellhead and are used during cavern development operations. These valves are designed to allow high pressure raw water to be injected into the salt formation and brine to be displaced to the surface. Valves of suitable pressure rating shall be installed for safe injection and removal of blanket materials and are designed to safely operate at solution mining pumping pressures as well as blanket containment pressures. Appropriate materials for the service to be encountered should be selected for valve bodies, trim, and seals.

Manual gas storage valves, either gate or ball, shall be placed on the storage wellhead during the gas storage conversion workover. These valves are designed to allow for the injection and withdrawal of high pressure gas and for debrining operations. In addition to the rated working pressure of wellhead valves, appropriate materials for the service to be encountered should be selected for valve bodies, trim, and seals. See 9.4.1 and 10.2.2 for ESD equipment.

A crown or logging valve should be installed on top of the upper flow cross. Future operations through this valve, such as logging and snubbing, should be considered when sizing this valve.

# 7 Drilling

## 7.1 Rig and Equipment

### 7.1.1 Rig Selection

The selection of the drilling rig shall be made in accordance with the well design tubular loads and diameters.

The hook load capacity shall be evaluated based on the casing with the largest total string weight and contingent over-pull.

The minimum rotary beam opening shall be based on the diameter of the largest non-conductor casing.

The rig floor height above ground level shall provide enough clearance for the stack-up of the above ground casing, Bradenhead, temporary adapter/cementing spools and blowout preventer (BOP) equipment. Sufficient rig floor height shall be provided to allow the make-up below the rig floor of any hole-openers having larger diameter than the rotary table.

The rig substructure should have the rotary capacity to suspend the heaviest casing string load plus (simultaneously) a rack-back capacity of supporting the maximum drill pipe and bottom hole assembly (BHA) loads.

Available drill pad area shall accommodate the drilling rig chosen for the job along with the ancillary equipment specific to that rig. A typical pad area for a large bore drilling rig is 400 ft by 300 ft. The rig provider should be consulted for the pad area required and acceptable rig layout drawings.

### 7.1.2 Fluid and Cuttings Handling Equipment

The rig pumps should be equipped to supply adequate pump pressure and flow rates to transport cuttings to the surface. To prevent washing out the near surface borehole, it is recommended that low flow rates along with sufficient mud viscosity be used to lift the cuttings.

Due to the volume of drill cuttings produced during large bore drilling and hole opening, proper removal of drill cuttings is essential. Removal of the cuttings prevents loading of the wellbore annulus and mitigates a possible lost circulation condition by reducing equivalent circulating density.

The minimum flow line diameter should be designed for the mud flow and volume required for proper removal of the cuttings. A typical flow line diameter is 10 in. to 12 in. To keep the flow line clear of cuttings, it is good practice to install a fresh water jet line into the flow line to circulate clean drilling fluid or fresh water.

The fluid handling system consists of hopper, suction tank, water tank, trip tank, gas buster, shaker tank, and choke manifold.

Multiple, cascading shale shakers should be evaluated. One extra shale shaker should be installed to allow for screen maintenance and redundancy. Several screen sizes are usually required for solids removal, depending on which hole section is being drilled.

The desander, desilter, mud cleaner, and centrifuge are additional solids control equipment that should be used for removal of finer solids.

A closed loop system may be used for the handling and disposal of the drill cuttings, eliminating the need of the collection of the drill cuttings in an earthen pit or reserve pit. If used, cuttings should be collected in open top cuttings tanks that allow a track hoe to access the cuttings for loading into dump end trucks to haul to disposal. An auger tank can be used for loading dump end trucks instead of using a track hoe.

### 7.1.3 BOP System

#### 7.1.3.1 General

A BOP system is a set of hydraulically operated equipment used to isolate the well while drilling in the event of an unexpected pressure event, or kick. The BOP is also used to seal the wellbore in the event no drill pipe or casing is in the well.

A BOP shall be used during drilling of the pilot hole of each hole section to maintain well control. During hole opening operations, a BOP should be used if available in sufficient size.

API Standard 53 [7] recommends that the minimum working accumulator volume should be equal to three times the volume required to close the annular preventer and one pipe ram. The BOP system shall be pressure tested and function tested (both high and low pressure) prior to spudding the well and periodically, while drilling, to verify integrity. Each time any pressure containment seal on the stack is disconnected, the BOP system should be pressure tested to a high and low pressure.

#### 7.1.3.2 Ram BOPs

For hole sections 13 $^5/_8$ in. or less, ram BOPs should be used.

Ram BOP systems should be function and pressure tested after every installation. This test should be timed, and the closing time recorded on the daily drilling report. The function test should also be performed from alternating panels on the rig.

#### 7.1.3.3 Annular BOPs

For hole sections greater than 13 $^5/_8$, annular BOP systems may be used.

Annular BOPs should be function tested after every installation. This test should be timed, and the closing time recorded on the daily drilling report. The function test should also be performed from alternating panels on the rig.

#### 7.1.4 Drill Pipe, Drill Collars, and Crossovers

Drill collars give the primary weight and rigidity for the BHA. Drill collars also help maintain sufficient annular velocity of the drilling fluids and cuttings.

The drill pipe size, weight, grade, and threads shall be determined by depth of hole required, geologic formation drilled, required mud flow and drill bit/hole-opener torques.

To help avoid drill pipe or drill collar failures, inspections should be performed on a periodic basis depending on drilling conditions. When a rig arrives on location, the inspection papers of the drill pipe and drill collars should be verified.

#### 7.1.5 Drill Bits, Hole Openers, and Under-Reamers

Hole openers are used to enlarge the wellbore after the pilot hole has been drilled and logged. Based on the construction of the hole opener, the maximum size for the next pass with a hole opener should be 10 in. Because of the large volume of formation being drilled and removed with a hole opener and because of the high torque that is generated with a hole opener, consideration should be given to limiting the subsequent hole opener size.

The torque on the BHA should be monitored. Excessive torque, due mainly to loose cutter cones, can result in a drill pipe or drilling tool failure.

To help mitigate the chance of backing off the guide from below the hole opener, the guide and the hole openers can be welded, or strapped with a piece of metal plating.

Under-reaming in the caprock should be avoided. However, under-reaming in the salt section of the well is a common practice.

#### 7.1.6 Shock Subs

Shock subs should be used in the drill string while drilling the caprock formation. Shock subs help keep the drill bit or hole opener in contact with the formation being drilled. This reduces the produced vibration in the drill string and the surface rotary equipment.

#### 7.1.7 Mud Motors

When maintaining a vertical hole is important, mud motors in conjunction with vertical steering devices should be used to drill the cavern salt section. Motors are not commonly used in the unconsolidated portion of the well or the caprock section.

### 7.2 Drilling Fluids

#### 7.2.1 Surface Casing Hole Section

Freshwater based drilling fluid systems should be used to drill the surface hole section.

Control of the viscosity, density and solids content is essential to prevent lost circulation, to maximize drilling rate of penetration (ROP), and to maintain overall borehole stability. Bentonite and other additives can be introduced into the make-up water to produce increased viscosity and assist with filter cake production and lifting of the drill cuttings.

### 7.2.2 Intermediate Casing Hole Section

Freshwater based drilling fluid can be used to drill the intermediate hole section of a storage well, until the salt formation has been reached. Due to salt dissolution and washout potential in bedded or domal salt formations, a freshwater based drilling fluid should not be used for drilling salt. Potassium chloride (KCl) or sodium chloride (NaCl) may be required to maintain the desired mud properties, as different formations are encountered.

Depending on the specific casing program of the well to be drilled, and the availability of brine, it may be desirable to convert to a salt saturated drilling fluid system prior to drilling the intermediate hole section. Otherwise, the system should be converted from freshwater based to salt saturated before encountering the salt formation. Chloride concentration should be at or near saturation to minimize dissolution of the salt and maintain a consistent borehole profile. Continued control of the viscosity, density and solids content of the drilling fluid is critical to prevent lost circulation, to maximize drilling ROP, and to maintain overall borehole stability.

Oil based drilling fluid systems can be used in the intermediate hole section if potassium or sodium chloride inhibition is insufficient for formations encountered. If potassium chloride stringers are encountered, the oil-based drilling fluid system maintains borehole stability and profile by minimizing or eliminating washout of the highly soluble salt. If a formation in the intermediate hole section is sub-pressured, oil-based drilling fluid may be an appropriate solution. The formation evaluation logging technique may require modification if oil-based drilling fluid is used.

### 7.2.3 Production Casing Hole Section

A salt saturated drilling fluid shall be used when drilling halite formation. The use of this drilling fluid maintains a reasonable borehole profile, which is more conducive to achieving quality wireline logging and cementing job. Control of the viscosity, density and solids content is critical to maximize drilling ROP, and to maintain overall borehole stability.

If highly soluble salts such as KCl and magnesium chloride (MgCl2) are present, sodium chloride saturated drilling fluids can induce further dissolution and therefore shall be avoided. Oil based drilling fluids may be used in the production hole section of a storage well if potassium or magnesium chloride inhibition is insufficient. If highly soluble salt stringers are encountered, the oil based drilling fluid system maintains borehole stability and profile. The formation wireline logging evaluation may require modification if oil-based drilling fluid is used.

### 7.2.4 Cavern Hole Section

For drilling any halite formation, the use of sodium chloride saturated drilling fluid shall be required. The use of this drilling fluid maintains a borehole profile that allows for higher quality wireline logging.

Monitoring of the density and solids content is critical to maximize drilling ROP, and to maintain overall borehole stability. If the salt formation contains high potassium content, sodium chloride saturated drilling fluids can induce further dissolution of the highly soluble salts and should be avoided.

Oil based drilling fluids may be required in the cavern interval of a salt storage well if the salt has a high potassium content. Oil-based drilling fluid systems maintain borehole profile by minimizing or eliminating washouts in the salt. Wireline logging evaluation techniques may require modification if an oil based drilling fluid is used.

### 7.2.5 Lost Circulation

Lost circulation is a decrease in the volume of drilling fluids returning to the surface. This can be due to drilling through relatively low pressure, highly porous, fractured, or vugular formations. The loss of circulation can be encountered almost anywhere in the borehole above the top of the salt. Most commonly in domal salt drilling, it is encountered at the top of the caprock, within the caprock, or at the caprock-salt interface. Precautions should be taken to maintain the drilling fluid weight as low as possible. If lost circulation does occur, steps to alleviate the problem should be initiated immediately. The use of nut shells and other interlocking fibrous additives have been found to help re- establish circulation. Setting a cement plug across the lost circulation zone is another method that has been successfully employed.

Operators should prepare a detailed lost circulation plan prior to drilling a well to ensure a timely and effective response. Lost circulation issues can result in loss of borehole stability, loss of pressure control, and in severe instances, loss of the well.

## 7.3 Drilling Guidelines

### 7.3.1 General

The following sections include general guidelines and practices that have proven successful throughout the industry when drilling gas storage wells in salt.

### 7.3.2 Hydrogen Sulfide ($H_2S$)

Due to geological conditions, $H_2S$ may be encountered during drilling. If $H_2S$ is known in the area, the operator shall develop and implement a plan to monitor for and to mitigate the risks posed by $H_2S$ during the drilling and completion operations.

### 7.3.3 Driven Conductor Casing

Prior to driving this pipe, an external drive shoe should be installed on the bottom of the first joint to assist the operation. The drive shoe helps ensure that the casing does not collapse during driving operations.

Care should be taken at the start of driving this pipe to be certain that it is being driven as vertical as possible, even to the point of starting over if it begins to deviate.

Typically, drive pipe is driven using a crane to hoist the pipe and the drive hammer. In some instances, this pipe is driven after the drilling rig has been rigged up.

The drive hammer shall be sized properly to assure that the pipe is driven to the desired depth and that the pipe is not fatigued during the hammering process.

### 7.3.4 Surface Casing Hole Section

Shallow formations are often unconsolidated, and therefore drilling can typically be accomplished quickly. However, high ROP could overload the solids handling equipment due to the large volume of cuttings produced. To avoid loading up the hole and overloading the solids handling equipment, the ROP should be limited to the capabilities of the solids control equipment.

A high viscous sweep should be performed regularly to clean the cuttings from the wellbore and to keep from loading up the hole with cuttings and causing loss of circulation.

### 7.3.5 Intermediate Casing Hole Section

The use of a shock-sub while drilling the caprock portion of the well can reduce axial impacts to the BHA and can help to protect the rig from excessive vibrations.

When drilling through cap rock typically found above domal salt structures, the dry drilling method may be used. In this method, drilling is continued without fluid returns to the surface. During dry drilling, high viscous sweeps should be performed regularly to clean the cuttings from around the BHA, reducing the potential for sticking the BHA.

### 7.3.6 Production Casing and Cavern Hole Sections

Common practice is to drill to final cavern total depth (TD) after setting the intermediate casing. This allows for the operator to define the salt section more accurately, thereby providing more optimal selection of the production casing seat and cavern total depth.

To assure that the solution-mined cavern is developed in a symmetrical manner, a vertical-hole automated drilling system should be used in drilling the production casing and cavern hole sections. This also facilitates a good cementation of the production casing and decrease stresses on the hanging strings at the production casing shoe.

## 7.4 Logging

### 7.4.1 General

When specifying the logging program to the logging company, the types of drilling fluids planned to be in the wellbore during the logging operations should be communicated.

The overall length of the logging tools and the position of the first readings from each tool should be obtained from the logging company. These measurements should be used in determining the optimum depth to drill each section of hole. By drilling the section of hole to this optimum depth, the most complete amount of geological data can be obtained including the base of USDW, the top of caprock, and the salt-caprock interface.

To ensure sufficient clearance for all logging tools, the internal diameter of the tubulars, wellhead spools, and valves should be evaluated.

### 7.4.2 Open-Hole Logs

To properly evaluate the geological formations penetrated during the drilling operations, a suite of open-hole logs should be run. The recommended formation evaluation logs are discussed in more detail in and 5.3.2.3 and Annex A.

In addition to these formation evaluation logs, a gyroscopic log should be run for each hole section to determine the exact wellbore path and the bottom-hole location of the wellbore in relation to the surface-hole position.

A caliper log in the open borehole shall be run to determine the approximate volume of cement required to fill the annulus for each casing string cemented. During this caliper log, the tool should be pulled some distance inside of the previously set casing to verify the accuracy and calibration of the tool.

A static temperature log should also be run once the well has been drilled to TD to establish a pre-operating temperature profile of the entire wellbore.

### 7.4.3 Production Casing Logs

A casing inspection log which uses either magnetic flux leakage or ultra-sonic measurements to establish the production casing's wall thickness baseline for future comparison should be run. The magnetic flux leakage log can differentiate between internal and external metal-loss (corrosion), metal-gain (external hardware), and can also distinguish between general corrosion and isolated pitting.

A multi-finger caliper log should be run to establish a baseline internal diameter to identify possible casing wear, scale build-up, and ovality.

An acoustic or ultrasonic cement bond log on the production casing should be run, provided the tool response is adequate for the size of casing to be logged. Sufficient time after cementing shall be given before running this cement bond log. By waiting to run the cement bond log (CBL) until the well is being completed, the salt saturated cement around the production casing will have almost reached its ultimate compressive strength. Cement bond logs may be run on all cemented casings.

## 7.5 Casing Handling and Running

On threaded and coupled casing strings, the bottom few joints of casing run into the well are usually thread-locked (permanently sealed together with an activated epoxy-like material) to avoid the possibility of unscrewing during subsequent drilling operations.

Refer to 9.4.2 for additional information on handling of threaded casing hanging strings.

A pick-up, lay-down machine should be used whenever tubulars are picked up from the pipe rack, size permitting.

When the casing is welded, two joints may be welded on the ground prior to running into the well. Derrick opening height and width shall be considered when these two joints are lifted and positioned over the wellbore. Due to the weight and the length of the double jointed pipe, the lifting of these joints into running position should be done with a crane.

## 7.6 Cementing

### 7.6.1 General

The cement program shall be designed to provide isolation of the storage zone from all sources of porosity and permeability and secure the casing in the borehole. All cemented casing strings should be circulated to surface. Float equipment and cement quality and testing shall meet or exceed API Recommended Practice 10F and API Specification 10A, respectively, or equivalent standards.

Laboratory testing should be conducted on all proposed cements and actual mix water. Nonsalt saturated cements should include tests for 24-, 48-, and 72-hour compressive strengths at temperatures expected. Salt saturated cements should include tests for 24-, 48-, and 120-hour compressive strengths at temperatures expected.

Additives to control free water and fluid loss along with possible expanding agents should be evaluated.

An excess cement volume shall be determined following the evaluation of an open-hole caliper log of the wellbore.

The amount of time to wait after cementing and before any drilling activity can take place inside of the cemented casing is dependent on the development of compressive strength of the cement. Refer to subsequent sections on casing, below, for more information.

### 7.6.2 Hardware

The proper casing hardware is essential in facilitating a successful casing and cement placement.

A float shoe should be used rather than a guide shoe as a float shoe contains a minimum of one internal back pressure valve. A down-jet float shoe should be used if there is a concern that getting the casing to bottom may be a problem.

A float collar should be run one casing joint length above the shoe and should contain a minimum of one internal back pressure valve.

For cementing down casing sizes greater than 13 $^{3}/_{8}$ in., the inner string placement method should be used (see 7.6.5.1), which requires a stab-in type float collar. A standard float collar can be used with casing sizes 13 $^{3}/_{8}$ in. or less and if the displacement placement method is used.

Casing centralization shall be used to achieve the placement of the cement around the casing. The goal is to place the casing as centered as possible in the wellbore to maximize the flow area for cement evenly around the casing. The recommended minimum goal for standoff is 75 % to 85 %. Casing standoff should be modeled so that the centralizer number and placement can be determined.

There are two main types of centralizer design:

— bow spring type, and

— positive/rigid type.

A bow spring type centralizer is often run in a vertical well and in open wellbore sections where they help reduce casing drag on the wellbore during casing running operations. Bow spring centralizers are designed with restoring forces necessary to achieve maximum wellbore standoff to prevent fluid channeling due to casing eccentricity. The bow spring centralizer can be run through hole restrictions in the wellbore or through smaller casing strings that are cemented in the well, thereby centering the casing below the restriction.

A positive/rigid centralizer is mainly used in deviated wells where it is not conducive to use bow spring type centralizers because their restoring force can be exceeded.

#### 7.6.3 Primary Cement Slurry Design

The primary cementing is the original cementing operation performed after the casing has been run in the hole. Primary cement slurries should be designed to be either neat, those without additives, or with additives for specific purposes (e.g. lost circulation, accelerated setting times, lightweight, water loss properties, gas block properties, rheological properties, expansion properties).

The cement slurry for a particular well can be designed with either one type of cement or with multiple types, pumped in stages, i.e. lead (first pumped) and tail cements (last pumped).

Slurry properties including rheology and compressive strength development should be tested for placement of the cement slurry and the resulting cement sheath.

A salt saturated cement slurry has 37.2 % salt by weight of water (BWOW). The salt should be dry blended with the cement. It is not recommended to mix the dry cement with brine to create the salt saturated slurry.

The compatibility of the make-up water with the various cement slurries should be tested.

An excess cement volume shall be determined following the evaluation of an open-hole caliper log of the wellbore. A minimum range of 1000 psi to 1500 psi cement compressive strength is recommended at the casing shoe prior to testing or drilling out the shoe.

#### 7.6.4 Spacers and Flushes

Drilling mud can contaminate and weaken cement. Spacers and flushes should be used ahead of the cement slurry to displace a freshwater, saltwater, or oil-based drilling fluid, leaving the casing and formation water-wet (free of oil). Conditioning the annular area increases the chances of a good cement bond and decreases the likelihood of cement remediation due to poor cement bond. In addition, spacers and flushes separate the drilling fluids from the cement slurry to prevent cement contamination with the drilling fluid.

Spacers are used to displace drilling or formation fluids from the wellbore and have enhanced rheological properties.

Flushes are used to thin and disperse drilling-fluid particles and do not have enhanced rheological properties. Spacer performance depends on:

— rheological properties at wellbore temperatures;

— compatibility with the mud and cement;

— volumes needed for adequate separation between the mud and cement; and

— contact time, with regard to pump rates, and proper annular heights for drilling fluid removal.

### 7.6.5 Placement Methods

#### 7.6.5.1 Inner String Method

Due to the larger diameter casings used in cavern construction, cementing down the inside of large casing (greater than 13 $^3/_8$ in.) often requires the entire volume of cement be pumped prior to the cement reaching bottom, which can limit the ability to make real-time changes to the cementing procedure. In these cases, the inner string method of cement placement should be used. Inner-string cementing allows cementing through drill pipe or tubing, using a stab- in type float collar.

The inner-string cementing method provides the following advantages:

— large-diameter cementing plugs are not required;

— by pumping through the smaller inner string, cement contamination resulting from channeling inside the casing can be reduced;

— cement is discharged outside the casing much faster after mixing, reducing the risk of the cement slurry within the casing having a highly-accelerated setting time;

— reduces the amount of cement that has to be drilled out of large-diameter casing;

— less circulating time is required with inner-string cementing.

However, the inner string method does not allow for the casing to be reciprocated or rotated during the cementing job, techniques that have proven to facilitate circumferential cement placement and bonding.

A stab-in sub (sealing adapter) is made-up onto the bottom of the drill pipe and is used to stab into the built-in sealing sleeve of the float equipment for sealing the annular space between the drill pipe and casing.

When using this method, a centralizer should be placed on the inner-string directly above the sealing adapter to help ensure that the adapter enters into the sealing sleeve properly.

A cementing/pack-off head with a pump-in sub should be used at the surface to seal the annular space between the drill pipe and the casing being cemented in place. The head also assists in preventing the collapse of the casing during the cement placement.

#### 7.6.5.2 Displacement Method

For cementing conventional sized casings (13 $^3/_8$ in. or less), a single stage displacement type cementing method can be used. In this method, cement is pumped directly down the ID of the casing.

The displacement cementing method provides the following advantages:

— reduction in rig time to prepare for the cement slurry placement;

— allows the manipulation of the casing during the placement of the cement slurry;

— allows for higher cement slurry pumping rates.

With a cementing head installed, the casing should be circulated clean before the cementing operation begins with at least one casing volume circulated. The first cement plug should be a wiper plug, which is pumped down ahead of the cement to wipe the inside of the casing clean. The flush or spacer is then pumped into the casing. The spacer is followed by the cement slurry, which should be followed by the second, shut-off plug.

When the bottom wiper plug reaches the float collar its rubber diaphragm is ruptured, allowing the cement slurry to flow through the plug, around the shoe, and up into the annulus. At this stage the spacer is providing a barrier to mixing of the cement and drilling fluid. When the solid, shut-off top plug reaches the float collar it lands on the bottom wiper plug and stops the displacement process. The pumping rate should be slowed down as the shut-off top plug approaches the float collar and the shut-off top plug should be gently bumped into the bottom wiper plug. The casing is often pressure tested at this point in the operation. The pressure is then bled off slowly to ensure that the float valves, in the float collar or float shoe, are holding.

#### 7.6.6 Topping Off

A top-off cement is a cement slurry that is used to fill the annular volume behind the casing near the surface. If the primary cement dropped back down the hole, any voids should be topped off when cementing the large diameter cavern wells to add structural support and near surface corrosion resistance.

#### 7.6.7 Surface Casing Cementing

Lightweight freshwater cement slurries can be used as a lead cement for filling the cased hole and open-hole sections with low fracture gradients, followed by a denser tail slurry. Heavier neat freshwater slurries, those without additives, can be used as the tail slurry across the base of the USDW.

#### 7.6.8 Intermediate Casing Cementing

The primary function of the intermediate casing cementing is to secure and support the casing through usually unconsolidated overburden and into a caprock or other confining formation(s) to prevent undesirable migration of fluids from other formations through the annulus formed by the borehole and the outside of the casing. Lightweight freshwater cement slurries can be used as a lead cement for filling the cased hole and open-hole sections with low fracture gradients, followed by a denser tail slurry. Heavier neat freshwater slurries, those without additives, can be used as the tail slurry across the top of the caprock or isolation barrier.

#### 7.6.9 Production Casing Cementing

The primary function of the production casing cementing is to secure and support the casing through overlying layers and rock salt to above the cavern roof to prevent undesirable migration of fluids or gases from the cavern through the annulus formed by the borehole and the outside of the casing.

The location and quality of the cement bond or seal between the production casing and formation shall be evaluated to determine whether adequate formation and pipe bonding has been achieved to prevent the migration of gas and fluids between zones.

Lightweight salt saturated cement slurries can be used as a lead cement for filling the cased hole and open-hole sections with low fracture gradients, followed by a denser, low permeability salt saturated tail slurry.

A minimum of 95 % of the 120-hour compressive strength is recommended at the casing shoe prior to testing or drilling out the shoe. The minimum wait on cement time before drilling out is dependent on compressive strength laboratory test results of the salt saturated slurries used.

A pressure test of each casing string should be completed prior to drilling out or perforating.

#### 7.6.10 Pump Rates

Pump rates should be designed to create turbulent flow and should be based on the fracture gradients of the open-hole formations, buoyant forces exerted on the casing, and if applicable on the cementing string.

#### 7.6.11 Sampling

To allow for future testing of cement quality, dry and wet samples should be collected.

Dry samples should be caught while loading at the cement bulk plant, and while performing the cement mixing on the well location.

Wet samples should be caught intermittently during the beginning, middle, and end of the cementing job.

### 7.7 Completion

Prior to running the hanging strings, all the drilling fluid in the wellbore shall be completely displaced with clean, fully saturated brine water.

Because of the weights of the hanging strings, the normal practice is to have the drilling rig run these two strings rather than a completion rig.

## 8 Risk Management for Gas Storage Operations

### 8.1 General

This section addresses risk management for surface and subsurface facilities that includes the underground gas storage cavern, all wells associated with the cavern, the areas of review and buffer zones, but excludes pipelines and compressor stations. Figure 5 has been incorporated to provide an operator an overview of a Risk Management Program and process as contained in this section.

NOTE References [27] through [32] provide further references that various industries, including pipeline and storage operators, employ in the application of risk or asset management.

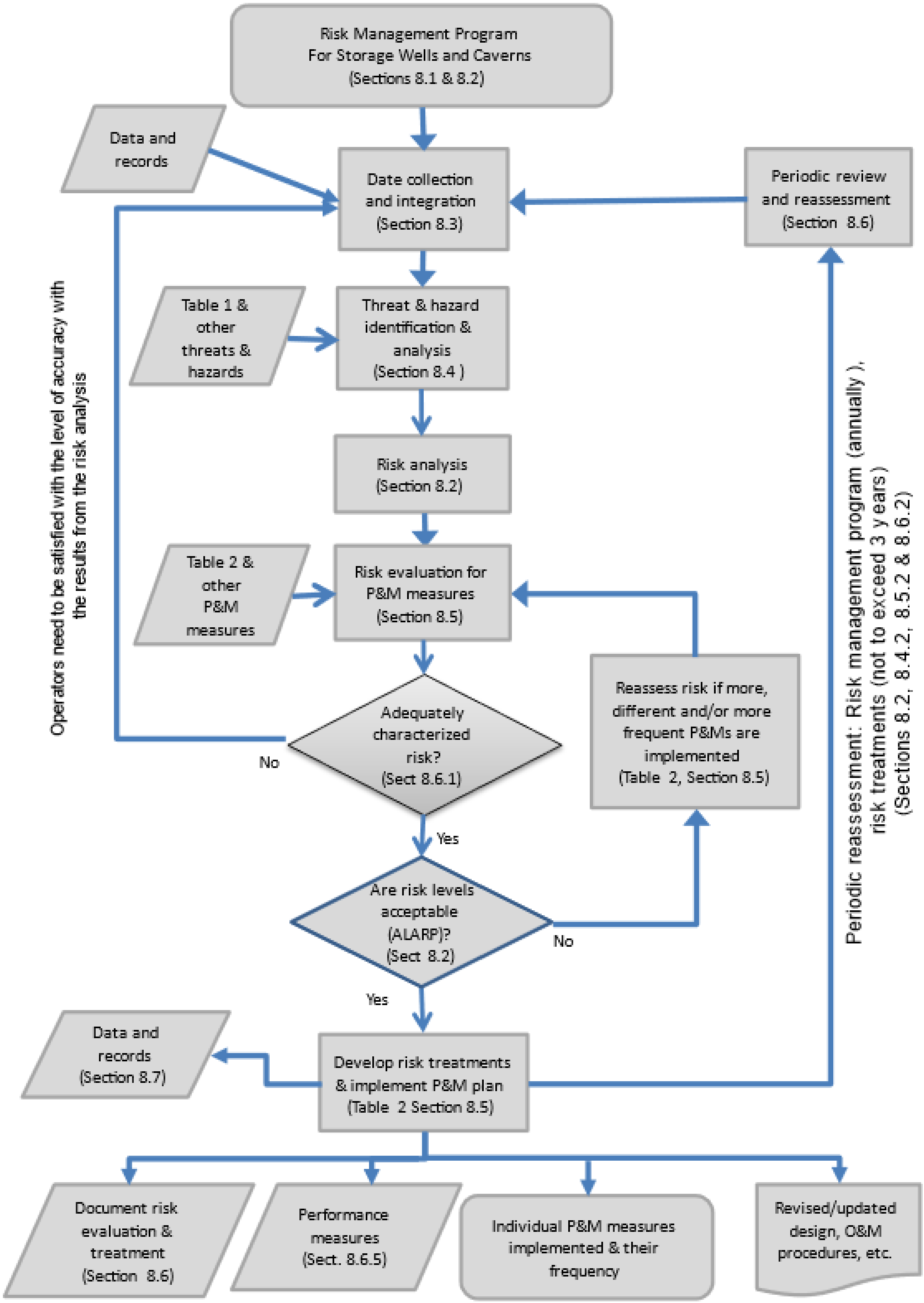


**Figure 5—Risk Management Program Flowchart**

## 8.2 Risk Management Program

The operator shall develop, implement, and document a program to modify risk that includes:

— data collection;

— potential threats and hazards;

— risk assessment;

— preventive and mitigative measures;

— periodic review; and

— record keeping.

Operator shall conduct an annual review of the risk management program.

The operator should follow the process of ALARP (as low as reasonably practicable) or equivalent risk reduction protocol, as a technique of risk management in the areas of facility design, construction, operation, and decommissioning.

### 8.2.1 General

Risk assessment is the overall process of risk identification, risk analysis and risk evaluation that ultimately leads to managing risk. It uses a variety of tools and techniques that evaluate and prioritize risks to direct risk management activities toward promoting functional integrity of the storage operation, recognizing that the storage facility and operation can impact, or be impacted, by its own operation or non-associated third-party activities within the areas of review or buffer zones.

The operator shall assess risk related to the storage operation and third-party activities within the areas of review, and buffer zones using a consistent process.

The operator shall define the roles and responsibilities of those involved in the managing of the risks.

### 8.2.2 Risk Assessment Process

A risk assessment process shall minimally include the following steps:

— identification and collection of information relevant to the storage field as part of risk assessment (data collection);

— identification of potential threats and hazards (Table 1) to the storage facility from within the areas of review and buffer zone (risk identification);

— evaluation of the likelihood of events and consequences related to the events (risk analysis);

— determination of risk ranking to develop P&M measures (Table 2) to monitor or reduce risk (risk evaluation);

— documentation of risk evaluation and decision basis for P&M measures (record keeping);

— periodic evaluation of risk assessment and determine of need to escalate the implementation or modification of P&M measures;

— evaluation of risk management program using performance measures.

## 8.3 Data Collection and Integration

### 8.3.1 General

Identifying and collecting the information relevant to a storage field is part of risk management. Data review and integration can highlight conditions in need of attention or additional information collection, assist in threat and hazard identification and risk analysis, and contribute to the continual improvement process.

### 8.3.2 Data Sources

The operator shall use available information such as performance data collected through the integrity monitoring and field history to determine susceptibility to threat and hazard-related events and to assess threat and hazard interaction.

The operator should identify data sources to be used in the risk analysis. Examples may include:

— cavern studies;

— drilling and workover records;

— material records;

— cavern system performance data;

— well logs;

— published industry; and

— research information.

The operator should validate identified data used in the risk analysis to ensure data accuracy.

The operator should establish the process for retaining data until the next risk analysis is performed.

There can be additional risk introduced into the risk assessment when there is a lack of records regarding cavern system integrity on one or more cavern system attributes. Operators should account for this in their risk assessments.

## 8.4 Threat and Hazard Identification and Analysis

### 8.4.1 General

The section discusses the common threats and hazards associated with gas storage operations. Operators shall identify those threats and hazards which may impact the functional integrity of the operations. Those identified threats and hazards shall be included in the operator's risk assessment process.

The operator may determine that some storage facilities are not susceptible to specific threats based on existing information, in which case the operator can provide justification and documentation for the exclusion of a specific threat from the risk assessment. A lack of data or information should not be used as justification to exclude a specific threat.

### 8.4.2 Analysis of Threats and Hazards

The operator shall analyze the potential threats and hazards impacting storage the cavern system. The operator should refer to the list of common threats and hazards in Table 1 and may supplement the list in Table 1 with other hazards or threats identified by site-specific assessments.

The operator should use data and records to ensure that all known threats and hazards have been considered for inclusion in the analysis.

The operator should incorporate the operating history of the cavern system in the risk analysis to ensure that all known threats and hazards have been considered for inclusion in the analysis.

The operator should estimate the risk to cavern systems based on threats and consequences of failure annually and consider changes to risk, including changes in threats, likelihood of failure, and consequences of failure.

The risk assessment should address not only individual threats, but also potential threat interactions, such as casing damage during service work that could exacerbate internal corrosion threat.

**Table 1—Potential Threats, Hazards, and Consequences**

| Category of Review | Threat or Hazard | Threat/Hazard Description | Potential Consequences |
|---|---|---|---|
| Wells | Well integrity (corrosion, material defects, erosion, equipment failure, annular flow, demonstrate casing seat stability) | Gas containment failure due to inadequately sealed storage well(s), e.g. casing corrosion, cement bond failure, material defect, valve failure, gasket failure, thread leaks, etc. | — Loss of stored gas inventory<br>— Damage to well site facilities and equipment<br>— Safety hazard to company personnel and the public<br>— Loss of use of water sources or wells<br>— Loss of storage cavern utility |
| | Design | Gas containment failure due to inadequately completed wells, sealed plugged well(s), failure of cement stage tool, pressure rating of components, etc.; lack of records on existing or plugged wells, improper set depth of hanging string | — Release of gas to the atmosphere and environmental hazards<br>— Damage to well site facilities and equipment<br>— Safety hazard to company personnel and the public<br>— Loss of use of water sources or wells<br>— Loss of stored gas inventory<br>— Decrease or loss of performance |
| | Operation and maintenance activities | — Inadequate procedures<br>— Failure to follow procedures<br>— Inadequate training<br>— Inexperienced personnel or supervision<br>— Inadequate casing inspection due to hanging string<br>— Use of incorrect data to perform a field operation | — Damage to well site facilities and equipment<br>— Safety hazard to company personnel and the public<br>— Loss of use of water sources or wells<br>— Loss of storage cavern utility<br>— Getting tools stuck or lost in hole<br>— Exceeding pressure limitations |
| | Well intervention | Gas containment failure due to loss of control of a storage well while drilling, snubbing, reconditioning. Lack of a full-bore master valve, inadequate sized hanging strings for snubbing equipment and operations. | — Damage to drilling rig or service rig<br>— Loss of tools in wellbore<br>— Hazard to operator and service company personnel on well site<br>— Safety hazard to public<br>— Loss of well control because of not having a full-bore valve during well intervention<br>— Loss of well control during well intervention/ workover/snubbing operations<br>— Loss of storage cavern utility<br>— Loss of well |

## Table 1—Potential Threats, Hazards, and Consequences (Continued)

| Category of Review | Threat or Hazard | Threat/Hazard Description | Potential Consequences |
|---|---|---|---|
| Wells | Third-party damage (intentional/ unintentional damage) | Accidental impact by moving objects (e.g. farm equipment, cars, trucks, etc.), vandalism, terrorism that could result in damage to facilities | — Loss of ancillary facilities<br>— Well on/off status change<br>— Impact to service reliability<br>— Loss of storage cavern utility<br>— Damage to well site facilities and equipment<br>— Safety hazard to company personnel and the public<br>— Loss of stored gas inventory<br>— Impact to neighboring public |
| | Outside force—natural causes | Weather related and ground movement | — Weather conditions, earth movements, groundwater table changes, subsidence, etc. that could result in:<br>— Damage to facilities/impact to service reliability<br>— Loss of stored gas inventory |
| Cavern | Third-party damage (third- party well operations subsurface encroachment) | Third-party drilling, storage, and leaching activities | — Drilling adjacent to the storage cavern could result in loss of containment<br>— Production well stimulation damages to storage well<br>— Loss of stored gas inventory<br>— Safety hazard if operating pressure of adjacent storage caverns are not similar to storage pressure of a third-party cavern<br>— Damage to third-party/public property and personnel |
| | | Third-party production, injection, or disposal operations in close proximity to a cavern, or without geo-mechanical study with safety factor; Difference in pressure profiles (liquid to gas) and operating pressures | — Decrease in field performance (both working gas cycling and deliverability)<br>— Loss of stored gas inventory<br>— Safety hazard if pressure rating of production facilities are not as high as storage pressure<br>— Inability to meet design performance requirements<br>— Damage to third-party/public property and personnel |
| | Pressure and Volume Limits | Ineffective geological containment | — Lateral or vertical loss of stored gas inventory<br>— Safety and environmental hazard to company personnel and the public<br>— Inability to meet design performance requirements |
| | | Exceeding maximum/minimum pressure, or volume limits, faulty operating practices | — Loss of stored gas inventory<br>— Safety and environmental hazard to company personnel and the public<br>— Cavern geomechanical instability or failure<br>— Excessive creep closure or subsidence<br>— Excessive stress or failure of casing strings |

**Table 1—Potential Threats, Hazards, and Consequences (Continued)**

| Category of Review | Threat or Hazard | Threat/Hazard Description | Potential Consequences |
|---|---|---|---|
| Cavern | Geologic uncertainty | Uncertainty of extent of salt or close proximity to salt boundary | — Gas migration beyond salt cavern boundary<br>— Damage to third-party/public property and personnel |
| | | Uncertainty of salt boundaries and zones of preferential dissolution | — Vertical gas migration into shallower zones including water sources<br>— Loss of stored gas inventory<br>— Gas migration beyond salt cavern boundary |
| | | Subsidence | — Loss of cavern utility<br>— Damage to casing, surface piping, equipment and third party/public property |
| | | Failure of Cavern Roof or Neck | — Loss of storage cavern utility<br>— Damage to third-party/public property<br>— Hazard to personnel and public safety |
| | Design | Inadequate cavern spacing, geometry | — Cavern geomechanical instability or failure<br>— Loss of cavern utility<br>— Excessive creep closure or subsidence<br>— Excessive stress or failure of casing strings |
| | Stored fluid compatibility issues | Failure of Casing or hanging string due to lack fluid capability | — Wellbore damage caused by drilling and completion fluid, water/chemical flood, $H_2S$ generating bacteria, stored gas quality, etc.<br>— of storage cavern utility<br>— Internal corrosion that could result in a degradation to) well casing or facility piping |
| Surface | Third-party damage (surface encroachment) | Surface encroachments restricting operations or facility integrity | — Buildings/roadways/structures construction, cathodic protection current from pipelines, power line current and overhead wires, expansion of park land; mining, flood control dams, etc. that could result in:<br>— Inability to access, operate or maintain facilities<br>— Facility abandonment<br>— Reduced ability to site additional wells and facilities due to setback restrictions |
| | Intentional/ unintentional damage | Damage to surface equipment by accidental impact by moving objects (e.g. equipment, trucks, etc.) vandalism terrorism, etc. | — Loss of ancillary facilities<br>— Loss of wellhead integrity<br>— Impact to service reliability<br>— Impact to neighboring public, storage gas loss |
| Surface | Outside force—natural causes | Weather related and ground movement | — Hazardous weather conditions, earth movements, groundwater table changes, subsidence, etc. that could result in:<br>— Damage to facilities/impact to service reliability |
| | Flammables on wellsite | A source of fuel for combustion that may either damage a well or be an additional fuel source for an ongoing well incident | — Safety and environmental hazard to personnel and public<br>— Damage to company facilities<br>— Risk of a minor integrity incident escalating into a major event |

## 8.5 Preventive and Mitigative Measures

### 8.5.1 General

Preventive and Mitigative (P&M) measures are actions conducted by the operator to monitor and reduce the risks to the storage facilities by reducing the likelihood (preventive) or reducing the consequence (mitigative) of events related to the threats identified in 8.4. The P&M measures can include programs, methods, tools, or routine condition monitoring activities to monitor and manage risk. Examples of P&M measures for storage activities are listed in Table 2.

### 8.5.2 Development and Use of Preventive and Mitigative Measures

The operator shall develop P&M measures to manage risks.

The operator should review the P&M measures listed in Table 2 to determine those measures that manage risks based on site-specific conditions. Not all risks need a P&M measure if the level of risk is fully acceptable or if it is not necessary to reduce risk by further efforts.

### 8.5.3 Training

The operator should train their personnel on the procedures related to the P&M measures (see 13.11). The operator can apply these P&M measures to individual wells, individual caverns, or groups of wells, caverns, or any other component of the cavern system.

## Table 2—Preventive and Mitigative Programs

| Category of Review | Threat or Hazard | Preventive/Mitigative (P&M) Measures or Monitoring Programs | Reference Location(s) of Program in API 1170 |
|---|---|---|---|
| Wells | Well integrity (corrosion, material defects, erosion, equipment failure, annular flow) | Casing condition and inspection program | 7.4.3, 9.6.5, 9.7, 9.8.3, 9.8.7, 11.3, B2 |
| | | Monitoring pressure, rate, and inventory | 9.6, 9.9, 10.2.3, 10.2.3, 10.3.1, 10.3.5,11.2, B.1.4, B.1.5, B.4.3 |
| | | Cement analysis and evaluation | 7.4.3, 7.6, 9.6.5, 11.3, B.2.8 |
| | | Internal corrosion monitoring | 7.4.3, 9.6.5, 11.3, B.2.5 |
| | | Plugged and abandoned well review and surveillance | 5.3; 6.7; 9.3 |
| | | Monitor annular pressures, rates, or temperatures | 11.3, 10.3.5.2, B.4.3 |
| | | Surface shut-off valves | 9.4.1, 9.5.2, 9.8.5, 10.2.2, 10.4.2, 10.4.4 |
| | | Monitor cathodic protection as applicable. | 9.6.5 |
| | | Operate, maintain, and inspect valves and other components | 10.4.2, 10.4.4, 10.5.2.4, 11.3, B.4 |
| | Design | Collect and evaluate plugged and abandoned well records; and rework or plug | 5.2.2, 5.2.5, 5.4.3, 5.4.4, 5.4.7, 9.10.2.5 |
| | | Develop design standard for new wells and consider factors that may affect each well's design | 6, 9.4, 9.5 |
| | | Evaluate current completion of existing wells for functional integrity and determine if remediation or monitoring is required | 9.6.5, 9.7, 9.8, 9.10, 10.4, 11 |
| | | Establishment and implementation of procedures | 6.3.5, 6.3.6, 6.4.5, 13 |
| | Operations and maintenance activities | Establishment and implementation of procedures | 9.6.5, 9.9.4.2, 10.5.2.3, 11, 12.2, 12.3.2, 12.4, 13 |
| | | Training of personnel and contractors | 12.4.2, 12.4.3, 13.8, 13.11, 13.12.2 |
| | | Implement site specific training and safety plan programs for company and contractor personnel | 12.4 (for emergency response training), 13.2, 13.3, 13.4.2, 13.5, 13.11, 13.12.2 |
| | | Evaluate the risk of removing the hanging string | 9.4.2, 9.7, 9.8 |
| | Well Intervention | Develop detailed drilling and well servicing procedures | 10.5.2, 13.4, 13.5 |
| | | Install protection equipment (e.g. fences, alarms, etc.) for site security and safety | 9.5, 10.3, 12 |

**Table 2—Preventive and Mitigative Programs (Continued)**

| Category of Review | Threat or Hazard | Preventive/Mitigative (P&M) Measures or Monitoring Programs | Reference Location(s) of Program in API 1170 |
|---|---|---|---|
| Wells | Third-party damage (intentional/unintentional) | Include storage facilities into the corporate security plans | 12.2 |
| | | Develop storage well control plan | 12.4.3 |
| | | Monitor third-party drilling permits and well operations | 8.2.1, 8.2.2 |
| | | Develop site-specific designs and plans to protect wellheads and wellsite facilities | 10.3.6, 10.4.2, 12.2, 12.3 |
| | Outside force—natural causes | Develop site specific designs and plans to protect wellheads and wellsite facilities | 10.3.5, 12.3, 12.4.2 |
| | | Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites | 10.5; 10.6 |
| | | Collect and evaluate plugged and abandoned well records and rework or plug | 14 |
| Cavern | Pressure and Volume Limits during Gas Operations | Verify compliance with bilateral agreements or statutory requirements for production wells or caverns to incorporate additional design features to isolate the storage horizon during drilling, completion, stimulation, and production. | 5.4, 7.4, 9.10 |
| | | Attempt to establish agreements with third-party production and caverns operations to have access and observation during the drilling, completion, operation, maintenance, and production phases | 5.2, 5.3, 8.6.1 |
| | | Monitor drilling and mining permits and activity | 11.2, B.1.4, B.1.5 |
| | | Agreements with third parties to establish sharing of salt testing, geo-mechanical study of cavern(s), etc., in proximity and develop a safety factor | 5.3, 5.4, 9.10 |
| | | Promote the protection of storage from third-party oil and gas development thru public awareness and damage prevention | 11.2, B.1.4, B.1.5 |
| | | Surface and subsurface setback requirements from storage caverns and cavern sites for both vertical and lateral buffer zone | 5.2, 5.4, 5.5, 7.2, 9.2.5, 9.10.2 |
| | | Gas sampling analysis of storage wells and production wells and collection of production data to review for hydraulic communication with storage operations | 5.2.2, 5.3, 5.4 |

**Table 2—Preventive and Mitigative Programs (Continued)**

| Category of Review | Threat or Hazard | Preventive/Mitigative (P&M) Measures or Monitoring Programs | Reference Location(s) of Program in API 1170 |
|---|---|---|---|
| Cavern | Geologic uncertainty | Collect and review existing regional geological studies and data | 9.5, 10.1, 10.2.3, 10.35, B.4.3 |
| | | Collect geological, geophysical, and salt data on existing wells in/adjacent to the storage cavern | 5.2, 5.3 9.4, 10.2.3, 11.2 |
| | | Acquire geological data from previously drilled penetrations in or around the salt from oil and gas wells, disposal wells, storage wells, etc. | 9.6.3.5, 9.6.5 |
| | | Acquire new data, which can include electric logs, new wells, core, seismic, well testing, and tracer gas studies | 6.4.3, 6.5, 11.3, Annex B |
| | | Establish area of review and buffer zone, and update as necessary | B.1.3, B.1.4 |
| | | Conduct tests for inventory verification | 5.2.3, 9.6.3.5, 9.6.4 |
| | | Establish observation wells based on evaluation of need | 5.4, 9.4, 9.6.4, 9.6.6.1, 9.6.6.2 |
| | | Review records of plugged and abandoned wells; | 10.4.2 |
| | Deviations in Cavern Leaching Plan | Monitor composition and volume of return brine | 6.4.3, 9.6 |
| | Design | Conduct geomechanical studies. Design comprehensive cavern leaching program | 13.9 |
| | Pressure and volume limits | Collect and review surrounding geological studies and conduct geomechanically studies | 13.2.1, 13.9 |
| | | Monitor cavern pressure behavior for anomalous trends | 8.2, 10.4.2, 12.1, 12.2 |
| | | Monitor daily injection/withdrawal volumes, and inventory | 9.5.3, 10.3.3, 12.2, 12.3 |
| | Review fluid compatibility issues | Review and determine compatibility of the fluid to be stored in salt and under pressure | 12, 13.2.1 |
| | | Conduct internal corrosion studies and evaluate mitigation programs as needed | 12.4.2, 12.4.3 |
| | | Monitor composition and quality of gas | 9.4; 9.5 |
| | | Monitor water quality during re-watering and solution mining operations to prevent establishment of harmful microbiology in the cavern | 13.2.1, 13.9 |
| Surface | Third-party damage (surface encroachment) | Work with landowners, local officials, and others on the surface operating requirements around storage wells | 13.9 |
| | | Use of existing public awareness activities required for pipelines | 13.9 |
| | | Monitor activity of the surface and subsurface around wells and enforce setback rights when encroachments threaten the well | 5.3.2.2, 5.3.2.5.2, 9.2; 9.3; 10.3 |

**Table 2—Preventive and Mitigative Programs (Continued)**

| Category of Review | Threat or Hazard | Preventive/Mitigative (P&M) Measures or Monitoring Programs | Reference Location(s) of Program in API 1170 |
|---|---|---|---|
| Surface | Third-party damage (intentional/unintentional damage) | Install protection equipment (e.g. fences, alarms, etc.) for site security and safety | 13.8, 13.9 |
| | | Include storage facilities into the corporate security plans | 9.3, 9.4 5.2.5, 8.2, 8.3, 8.4, 8.6.3 |
| | | Develop storage well control plan | 8.4, 10.3.5.2, 11, Annex B.1.4 |
| | | Liaison with local, state, and federal law enforcement agencies | 5.2, 5.3, 5.4 |
| | | 811 Call-Before-You-Dig programs (damage prevention program) | 5.2, 5.3 |
| | Outside force—natural causes | Perform routine patrols and surveillance, and event-specific surveillance activities | 11.2, 12.2 |
| | | Develop design specifications (e.g. barriers to deflect flood debris) for areas prone to flooding, earth movements, river/stream bed movement, and other natural causes | 8.4, 12.2.6, 13.8 |
| | | Develop site-specific plans for known problems such as areas prone to flooding, earth movements, river/stream bed movement, and other natural causes | 8.4, 12.2.6, 13.8 |
| | | Monitor areas prone to flooding, earth movements, river/stream bed movement, and other natural causes for impacts on nearby well sites | 12.3 |
| | | Collect and evaluate plugged and abandoned well records and rework or plug | 14 |
| | | Remote control capabilities | 9.5.2, 10.2.2, 10.3, 10.4.4 |
| | Flammables on well site | Review need for flammables on site | 10.3.6, 12.2.7, 13.8 |
| | | Develop site-specific plan for ignition sources and flammables during well work and operations | 10.3.6, 10.5, 12.2.7, 13.4, 13.5, 13.8 |

## 8.6 Periodic Review and Reassessment

### 8.6.1 General

The operator shall assess the performance of the risk management program against goals and objectives as defined by operator.

The operator shall review the results of the risk assessment process to determine whether the risk assessment, resulting prioritization, or ranking represents its facilities and adequately characterizes the risks.

The operator shall review the results of P&M measures to determine the success of managing risk based on site-specific conditions.

### 8.6.2 Frequency

The operator shall define the interval of review and identify any new threats or hazards.

The interval should be of sufficient length that the quantity of new data and information that is brought into the analysis is meaningful and that any developing trends have sufficient data to be identifiable.

The operator shall define a review frequency for P&M measures, not to exceed three years.

#### 8.6.3 New Threats and Hazards

If new threats or hazards are identified, or the impact of existing threats or hazards changes markedly, the operator shall assess the risk associated with new conditions and evaluate and prioritize risk management options in accordance with the risk assessment.

#### 8.6.4 Evaluation Team

The operator should use a multi-disciplinary team for the review of the risk management program and performance of the risk assessment process and P&M measures. Members of the team should be trained and familiar with the risk management program and its operation.

#### 8.6.5 Performance Measures

The operator shall use performance measures to assess the risk management program.

Performance metrics tailored to the specific needs of the facility and operator should analyze such factors as integrity performance, the number and types of issues that are occurring, threat and hazard impact, P&M measures and monitoring program selection and success, established threshold exceedances, as well as other conditions, which may be used to determine if elements of the risk management program need update or revision based on risk trends. Examples of leading and lagging performance measures may include:

- Leading:
  - Established P&M measures are up to date;
  - Well and risk documentation is maintained and current;
  - P&M measures completed to operator defined plan frequency.
- Lagging:
  - Number and trend of P&M measures changes;
  - Number and trend of threshold or condition exceedances;
  - Number and trend of escalations needed based on P&M measures inspection results.

### 8.7 Recordkeeping and Documentation

The operator shall develop a risk management records retention plan.

Risk management documentation can include data used during the risk assessment, P&M measures employed, and the periodic evaluation of performance metrics.

## 9 Cavern Solution Mining

### 9.1 General

A solution-mined salt cavern for natural gas storage use is developed in a naturally occurring bedded or domal salt formation. Solution mining requires drilling a well, circulating fresh or low salinity (raw) water down the well and withdrawing the resultant brine from the well. The salt in the formation dissolves, enlarging the wellbore to form a cavern.

This section covers the creation of a cavern following the drilling and completion of the well and wellbore through the debrining of the cavern with gas. This includes:

— design of the cavern and development phases;

— equipment and instrumentation;

— monitoring cavern development;

— performing workovers during solution mining (if needed);

— performing the workover to convert the mined cavern to gas storage service;

— removing the brine in the cavern with gas injections (debrining);

— other solution mining topics including:

  — conversions of existing caverns to natural gas storage service,

  — cavern rewatering,

  — cavern enlargement.

## 9.2 Cavern Solution Mining Design

### 9.2.1 General

As cavern geometries (shape, depth, size) influence cavern operations and integrity, geometries should be determined prior to the start of solution mining by running a cavern modeling program proven to be reliable for the type of salt (bedded or domal). See 9.2.5 for a description of cavern models.

### 9.2.2 Cavern Structural Components

#### 9.2.2.1 Casing Seat

The casing seat is the deepest position where the last cemented casing (production casing) is securely affixed by cement to the salt borehole. Often, the casing seat and the bottom of the casing are one and the same but can be different if cement bond is poor or if the salt is washed out behind the casing. The casing seat represents the deepest section of the borehole to be lined with steel casing. It is important that a good pressure seal is created by performing a sound, viable cement job on the production casing.

#### 9.2.2.2 Cavern Neck

The cavern neck is a section of the borehole beginning directly beneath the casing seat and ending at the cavern roof. The neck is left uncased and is virgin borehole or minimally washed borehole.

The neck should extend below the casing seat to the cavern roof, for a sufficient distance below the casing seat to prevent roof strains from affecting the integrity of the cemented casing(s). The length of the neck should be equivalent to at least one-half the diameter of the predicted, fully developed cavern and should be confirmed with geomechanical modeling.

Having a long neck with a small volume per foot of depth provides the ability to resolve smaller changes in the depth of the nitrogen/brine interface during mechanical integrity testing.

For thin bedded salt caverns, an analysis should be made to determine if a confining salt bed above the proposed roof can be used for the production casing seat to provide a neck. This salt bed should have the strength and impermeability to contain the gas should the existing roof fail. The casing seat should be located to just below the confining bed. If a neck is not possible, the maximum diameter should be limited based on geomechanical analysis of the salt and overlying formations.

#### 9.2.2.3 Chimney

The cavern chimney represents the initial development of the main portion of the cavern. It can be developed as a part of sump development or alone after sump development. The chimney should extend from cavern TD, or higher if the sump is developed first, to the proposed roof of the cavern. The chimney is developed using direct circulation. See 9.2.4 for descriptions of the flow circulation modes.

#### 9.2.2.4 Roof

The roof of the cavern is the section of the cavern beneath the neck and above the more vertical cavern walls. It is critical to develop a cavern roof that provides structural strength to support the weight of the overburden above the cavern. The shape of the roof helps determine the amount of load it can handle and the associated stress levels.

The shape and depth of the roof should be designed to enhance structural integrity of the cavern. The roof should be arched or conical (such as tapered or domed) in shape and be at a depth which provides a neck below the casing seat. An arched or conical shaped roof has an ability to carry higher loads as compared with a more flat, horizontal roof. Wide flat roofs should be avoided as well as roof depths at or near the casing seat.

The roof shall be developed with detailed planning, modeling, and execution. After the roof is developed, blanket material shall be placed and monitored to protect the roof from uncontrolled solution mining. See 5.5.2 for further information.

For thin bedded salt caverns, a dome-shaped roof may not be possible. In this case, the maximum diameter should be limited based on geomechanical analysis of the salt and overlying formations.

#### 9.2.2.5 Walls

The walls of the cavern are the vertical or near vertical oriented sides of the cavern beneath the roof and above the cavern floor.

#### 9.2.2.6 Floor

The cavern floor is the section of the cavern beneath the walls. In domal salt, the floor is covered by insolubles produced during the solution mining process. The floor of a bedded salt cavern is typically littered with rubble from collapsed, non-soluble beds within the salt structure.

#### 9.2.2.7 Sump

A sump is mined during the early phase of cavern development to allow for the settling of insolubles embedded in the salt structure and released during the solution mining process. The sump should be large enough to handle all the insolubles produced during the entire solution mining process. The sump can be incorporated into the chimney development to reduce the number of required workovers.

### 9.2.3 Blanket Material

Blanket material is a liquid or gas placed in the cavern above the water and brine. There are several options when choosing a blanket material for the solution mining of a cavern. The primary requirements are that it be immiscible with a specific gravity less than the water/brine in the cavern; the blanket material stays atop of the water/brine creating an interface. Typical blanket material choices include oils of various types, liquefied petroleum gas, and gases.

A mechanical integrity test may be conducted after drilling and before solution mining. The production casing cement shall be given sufficient time to reach full compressive strength before pressuring the annular space to the maximum allowable operating pressure (MAOP). If an integrity test is run, it should be a nitrogen brine interface test. Since the test is conducted when only a wellbore is present (no cavern), many more repair options are available if a problem is discovered. Some issues that may be identified include the casing seat not having integrity, a leak in the production casing, a hanging string leak, and wellhead issues.

The depth of the blanket material shall be carefully monitored so that the location and shape of the cavern roof meets the requirements of the cavern. At no time shall the cavern be solution-mined when the casing seat and neck are not protected by a blanket material.

The position of the blanket-water interface shall be periodically verified with a wireline log. The calculated volume of blanket material shall never be solely used to verify blanket protection.

NOTE If a gaseous blanket material is used, the blanket gas bubble expands and compresses and, as such, fluctuates in depth as the result of changing static and dynamic pressures within the cavern and well system. This fluctuation varies depending on the cavern and gas volume in question.

### 9.2.4 Flow Circulation Modes

#### 9.2.4.1 General

The two modes of circulating fluids through the cavern system are direct and reverse modes. Both modes require a single well to be equipped with concentric hanging strings. If two or more wells are used, single hanging strings can be set in the multiple wells for use in direct or reverse flow.

Since the sump and chimney of the cavern should be developed first, the combination of hanging string depths and mode of flow is used to obtain the desired cavern shape. Traditionally a cavern is initially developed through direct circulation followed by reverse circulation. Direct circulation should be used to prevent produced insolubles from plugging the longest hanging string and to create the proper size and shape of the lower portion of the cavern. As the mining progresses, the well should be switched to reverse mining so that the upper portion of the cavern and roof can be correctly shaped.

#### 9.2.4.2 Direct Circulation Mode

With direct circulation, raw water is pumped down the longest hanging string (lowest set string) and exits the bottom of the string into the cavern. The raw water then circulates through the cavern by flowing along the walls where it dissolves salt, gains saturation, and becomes brine. The brine is removed through the shortest hanging string and out the well.

As this mode of circulation places raw water toward the lower portions of the cavern, direct circulation tends to enlarge the lower portion of the cavern.

#### 9.2.4.3 Reverse Circulation Mode

When a cavern is in reverse circulation mode, raw water is injected down shortest hanging string. The raw water quickly rises toward the top of the cavern and the brine/blanket interface and continues its circulation path back down the walls of the cavern where it dissolves salt, gains saturation, and becomes brine. Completing its circulation in the cavern, the brine is removed through the longest hanging string and out the well.

The increased salt surface area below the water injection point allows for the water to obtain a higher saturation than with direct circulation and results in a higher saturation for any given flow rate. Reverse circulation tends to mostly enlarge the cavern above the water injection point upward to the blanket/brine interface.

Since the roof of the cavern is preferentially mined with this method, extra care shall be taken with roof control so that the salt neck below the casing seat is left intact.

### 9.2.5 Use of a Solution Mining Model

A solution mining model shall be used for the design and during the development of, at least, the first cavern of a gas storage facility. The model, modified after comparison to actual results obtained on the first cavern, may then be used for development of additional storage caverns.

The solution mining model shall be used to predict the geometries of cavern shape during the phases of cavern development. A model shall also be used to determine if and when cavern workovers may be required to shift the setting depths of the hanging strings, creating the desired cavern shape.

Salt properties, raw water injection and brine withdrawal flow rates, the number of days of direct and reverse circulation phases and hanging string and blanket placement and movements are some of the many input parameters required by a model to provide an accurate prediction of cavern and roof shape.

The final pre-mining model should be seen as a starting point in the development of the cavern to its desired geometries. The model should be updated at strategic points in the cavern development timeline. Updates to the model's parameters include actual salinities, flow rates, and cavern sizes as measured by sonar surveys.

The cavern chimney represents the initial development of the main portion of the cavern. It can be developed as a part of sump development or alone after sump development. The chimney should extend from cavern TD, or higher if the sump is developed first, to the proposed roof of the cavern. The chimney is developed using direct circulation. See 9.2.4 for descriptions of the flow circulation modes.

## 9.3 Cavern Development Phases

### 9.3.1 General

A cavern is developed in phases. Each phase includes a set number of days, flow rate, and solution mining circulation mode (direct or reverse) (see Figure 6).

There may be as many as three distinct phases required to develop a gas storage cavern. These phases are:

— sump only (direct circulation);

— sump and chimney (direct circulation mode); and

— upper cavern and roof (reverse circulation mode).

NOTE With proper modeling, it is possible to completely develop a storage cavern without a workover having been performed. The intermediate hanging string can be modeled in a single position for both direct and reverse circulation and the long hanging string can be adjusted by a casing cut. Sonar surveys can be run through casing to verify cavern shape.

Once solution mining of the cavern has started, comparisons should be made of actual mining results to those predicted by the model. Analysis of the actual versus predicted results could lead to adjustments to the mining plan. Adjustments could include resetting the blanket depth, cutting the hanging string to prevent plugging with insoluble, or a workover to adjust the setting depths of both hanging strings. These actions should be completed to bring the actual results back in line with the model.

### 9.3.2 Sump Only Development

Sump only development requires the long string to initially be set at or near total depth of the borehole. The shorter string would be set at a point above but fairly close to the depth of the long string. The blanket material can be set at any point between the short string and the final roof position. Direct circulation is used to mine the sump to a volume determined by the model. The sump volume should allow for all the estimated insolubles expected for the remaining development.

Sump only development is more apt to be used when mining in bedded salt with relatively thin beds or in multiple well domal salt caverns to connect the boreholes. During this initial phase of cavern development, the inner hanging string is susceptible to plugging since it is almost immediately in the insoluble pile. Operations should avoid outages during this period and should not backflow the cavern well as this would force insolubles up into the string and cause plugging. One design technique that can mitigate backflow is the placement of a check valve on the water piping near the well. After an unintended outage, such as a power failure, a portable high pressure positive displacement pump may be used to re-start the well if site pumps fail to do so. Once water flow has been established with the portable pump, the site pumps can be re-started. If flow cannot be re-established, the longest hanging string should be cut or a workover performed to re-set the plugged string.

NOTE A sump only phase may require a workover to re-position the hanging strings for further cavern development.

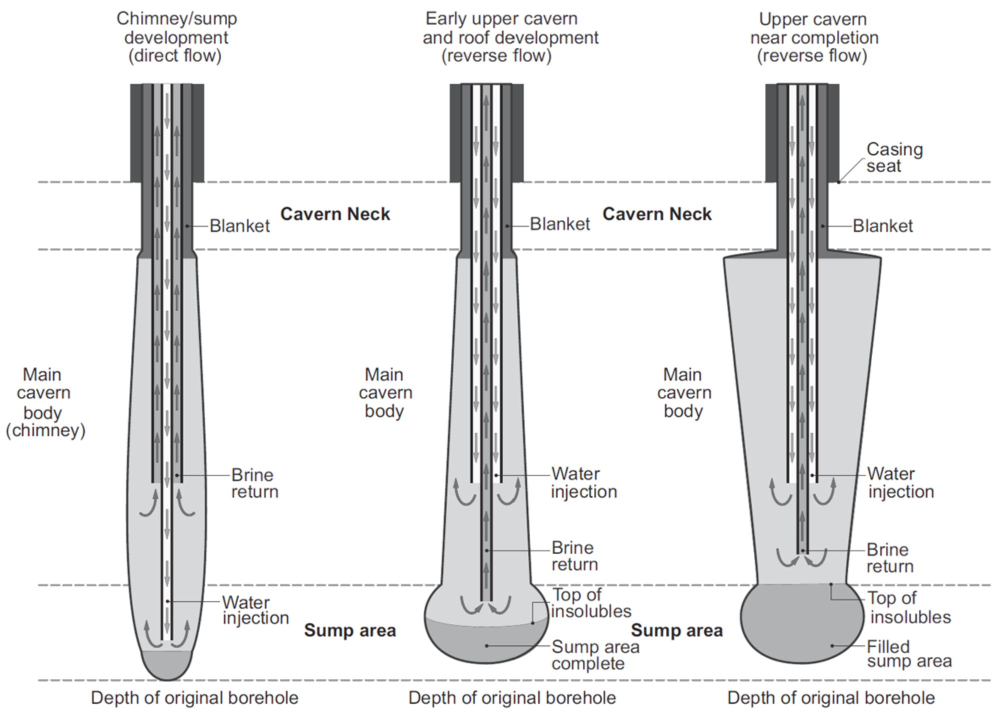


**Figure 6—Cavern Development Phases**

### 9.3.3 Sump and Chimney Development

A sump and chimney development phase should be used when developing caverns in relatively thick bedded salt strata or domal salt. This method requires the long string to initially be set at or near total depth of the borehole with the shorter string set in position for all future development. Blanket material should be set at or near the desired roof depth.

As in the sump only development, the inner hanging string is susceptible to plugging since it is almost immediately in the insoluble pile. Operations should avoid outages during this period and should not backflow the cavern well as this would force insolubles up into the string and cause plugging.

Sump and chimney development should continue until:

— the sump size is sufficient to handle the insolubles produced by future development, or

— the chimney reaches the desired volume and shape of the lower portion of the cavern.

NOTE The long hanging string may require multiple cuts to prevent plugging with insolubles and to re-position the long string for upper cavern development.

### 9.3.4 Upper Cavern Development and Roof Control

The location of the roof can and will change during the mining of a cavern. This upward growth shall be controlled by planned use of raw water injection points, flow rates and blanket material positioning.

Frequent interface logs as well as periodic sonar surveys shall be performed to confirm desired shape and volume.

The upper cavern and roof development should be performed in reverse flow mode. Reverse flow along with blanket adjustment are used to form the upper portion of the cavern and roof into the desired shape.

## 9.4 Equipment

### 9.4.1 Emergency Shutdown (ESD) Equipment

During solution mining, ESD equipment shall be installed on caverns developed using a blanket of either a flammable gas or liquid that is gaseous at atmospheric conditions. ESD equipment shall also be used when rewatering or debrining a cavern. If ESD equipment is required, all flowline connections to a wellhead that could be opened during operations shall have ESD valve(s) installed at or very near the wellhead isolation valve (wing valve). This valve or valves shall be part of an ESD system that automatically shut in the cavern in the event of an emergency (see 6.4.11 and 10.2.2).

An instrument flange may be used between the wing valve and ESD valve. The wing valve can be opened slightly while the ESD valve remains closed to gather real-time pressure data when the cavern is not in use. The flange shall be rated for the same pressure as the valves.

### 9.4.2 Hanging Strings

#### 9.4.2.1 General

The injection of fresh water and removal of produced brine are accomplished through two hanging (non-cemented) strings of pipe. These strings are suspended concentrically from within the wellhead for single well caverns and the bottom of these strings is below the production casing. Multiple well caverns require a minimum of two hanging strings that are typically placed in separate wells.

Raw water and brine flow can either be in direct circulation mode (raw water down the long string and brine out the shorter string) or reverse circulation mode (raw water down the shorter string and brine out the long string). In multiple well caverns, one (or more) well(s) are used for raw water flow and one (or more) well(s) are used for brine flow. Typically, the annular space of each well contains the blanket material.

The setting depths of each string are based on the desired shape and geometry of the cavern.

Similar to rewatering and debrining operations, hanging string oscillation can occur during solution mining although the frequency of such an occurrence is less because of the dampening effect of the cavern fluid. Care should be taken to detect and correct any oscillation that occurs (see 9.9.4.2).

#### 9.4.2.2 Size

The sizes of the hanging strings shall be based on project or operational requirements including:

— the diameter of the production casing;

— the required solution mining rates;

— whether the cavern is used for storage during cavern enlargement periods;

— whether the hanging strings are replaced after mining and debrining, or are removed for gas storage service;

— how long the strings are anticipated to be in service;

— whether the hanging strings are compatible with a through pipe sonar survey;

— whether the hydraulics (both direct and reverse modes) are compatible with the pumping equipment.

Differences between the service and use of hanging strings and pipelines preclude the use of standard pipeline design models for size, wall thickness, and maximum velocity calculations. These differences include temporary versus permanent service life, vertical versus horizontal service, single point suspension versus fully supported, threaded versus welded connections, and size limitations due to wellbore diameter.

#### 9.4.2.3 Body Strength

The pressure requirements in both direct and reverse circulation modes shall be established once hanging string sizes are determined. Strings shall be checked for both collapse and burst resistance. By nature of being a hanging string, an axial load is present and therefore reduces the collapse resistance of the pipe.

API Technical Report 5C3 shall be used for hanging string evaluation and design.

#### 9.4.2.4 Connections

Once grade and wall thicknesses have been developed, string lengths for weight and required joint strength should be developed to choose a threaded connection type (e.g. 8-round, buttress, or modified buttress). Buttress, modified buttress, and premium threaded connections can withstand a much higher axial load than can v-shaped tapered threads (8-round). These connections provide a larger safety margin when using large heavy weighted hanging strings.

Buoyancy of hanging strings caused by the presence of brine may be used to calculate required joint strength and axial load but shall not be used for rewatering or debrining strings.

#### 9.4.2.5 Torque

Connections with premium threads (often proprietary) shall be made-up to manufacturer’s specifications.

Connections with API threads should be made-up according to API Recommended Practice 5C1 [8]. Make-up for round threads typically uses a torque as the primary specification and the position of the pin end in the coupling as a secondary indication of a proper connection. Buttress and premium threaded connections typically use a prescribed position as the primary specification and an estimated torque to aid in the make-up.

#### 9.4.2.6 Pipe Dope

Connections that have a metal-to-metal seal require a lubricant to prevent thread galling and promote installation. Other thread designs may have a natural helical leak path and require a lubricant/sealant. Threads should be cleaned and inspected prior to installation of any thread compound. API Technical Report 5C3 [9] provides recommendations for compounds pertaining to API threads. All thread compounds should be used per manufacturer’s recommendations.

#### 9.4.2.7 Setting Depth

Each phase of mining should be modeled with a solution mining model that is appropriate for the type of salt encountered (bedded or domal). Modeling is required to determine the hanging string setting depths along with the blanket setting depth during each phase of development.

#### 9.4.2.8 Quality of Sonar Surveys

Sonar vendors should be consulted during the hanging string design process for recommendations on tubing and hanging string combinations known to enhance sonar survey performance. It is advantageous to have the capability to sonar survey a cavern without first performing a lengthy workover to remove the hanging strings. Most modern sonar tools can “see through” steel tubing, however, tubing size, thickness, corrosion, and grade has an effect on the quality of sonar surveys. The result can be sporadic or even have the absence of return signals which leaves the sonar survey incomplete and requiring interpretation.

#### 9.4.2.9 Fluid Handling

Flow control equipment should be sized to handle the required project flow rates, and MAOP of the solution mining process. The proper piping and valves should be installed that allow the operator to regulate flow and direction of flow to the well. A manifold or wellhead design should be included that allows for change of flow in the cavern from direct circulation to reverse circulation. This set-up also allows for backwashing of the hanging strings in case of salt build up.

NOTE Salt build up and location is detected by reduced brine flow and increased brine pressure (build-up in piping beyond the wellhead) or reduced brine flow and no build-up in brine pressure (build-up downhole).

Injection rates shall be metered and recorded throughout the solution mining process. Temperature compensation should reflect all measurement relative to the base density (1.0 specific gravity) of water at 60 °F.

## 9.5 Instrumentation, Control, and Shut Down

### 9.5.1 General

During solution mining processes, the cavern system components shall have instrumentation control and shutdown devices to safely shut-in the cavern system in an emergency or when anomalous conditions are detected.

### 9.5.2 SCADA Systems

Detection devices should be connected to the control system that shut cavern ESD valves when necessary to isolate the cavern. Supervisory Control and Data Acquisition (SCADA) Systems are used to monitor and control the solution mining processes. These systems allow operators to monitor the real time status of the caverns and make control changes necessary to meet operations demands. They also alert operators to system upsets (alarms) or shutdowns that may require some action by the operator. The operator may be on site or at a remote facility.

### 9.5.3 Alarms

Audible or visual alarms should be incorporated into the control and shutdown systems. These can consist of devices such as strobes, horns, or SCADA alarms.

### 9.5.4 Overpressure Protection (OPP) System

If the plant pumps have the capacity to increase the pressure of the cavern over MAOP, then over pressure protection (OPP) systems shall be installed to prevent over pressurizing the cavern in the event that the brine production side becomes plugged, e.g. hanging string salted up, or the brine valve closed.

A pressure transmitter on the brine side of the wellhead should be installed on or near the wellhead to detect an abnormally high pressure. The pressure transmitter threshold pressure should be set below the MAOP of the cavern but above normal operating brine pressure during solution mining operations, which will cause the system to shut-in the cavern. The pressure transmitter should detect a complete or partial failure of the debrining string. However, it is not intended to detect small hanging string leaks or wellhead leaks below the threshold pressure

Gauges or transmitters shall be placed on the debrining string on the wellhead to monitor pressure change during static and fluid injection withdrawal and injection periods. Abnormal pressure conditions could indicate a leak of hydrocarbons into the fluid column.

#### 9.5.5 Excessive Flow Rate

A brine flow meter and transmitter should be installed to detect rapid increases in brine outflow rates. This equipment should detect a complete or partial failure of the leaching or debrining string and be tied into the alarm and shutdown systems.

NOTE The flow meter may not detect small hanging string leaks or wellhead leaks, if brine outflow is not being operated at a steady state condition.

### 9.6 Monitoring of the Cavern

#### 9.6.1 General

Monitoring of the cavern shall be conducted throughout cavern solution mining, debrining, and storage operations.

#### 9.6.2 Injection and Withdrawal Readings

The size and shape of cavern growth is directly proportional to the rate of fresh water injected into the cavern.

Flow rates and key well pressures should be checked periodically during the day for early determination of any abnormal operating condition. At minimum, flow totals along with pressure readings should be recorded, analyzed, and archived daily.

#### 9.6.3 Cavern Geometries

##### 9.6.3.1 General

As caverns are solution-mined, the shape changes and size increases. The change in shape and size shall be monitored to adjust (e.g. tubing depth, mining direction, blanket level) during the solution mining process. The resulting data should then be fed into the solution mining model to predict cavern growth. The actual data should be compared with the model prediction so adjustments can be made to the solution mining plan. This ongoing evaluation of well data and modeling data helps ensure that the final cavern meets the desired cavern geometries.

##### 9.6.3.2 Sonar Surveys

To assess the development of a cavern, a periodic sonar survey shall be run. Special attention should be paid to the sump, walls, and roof to determine any preferential solution mining or anomalies in the cavern. These data should be used to plan workovers, tubing or blanket adjustments, and flow direction. Sonar survey data should be used to check the accuracy of the mining model. Sonar vendors should be contacted for information on the accuracy of their sonar tools run in various media.

##### 9.6.3.3 Brine/Blanket Interface Logging

Wireline logs, along with other methods (e.g. pressure monitoring), shall be used throughout the solution mining process to monitor the depth of the blanket material. Special attention shall be paid to these data, as unplanned interface movement either up or down is indicative of cavern development problems.

##### 9.6.3.4 Other Surveys and Logs

Whenever a wireline log is run, an effort should be made to verify hanging string depths and verify the bottom of the cavern. The log should be tied back to the casing seat so that all logs, both past and future, can be directly compared.

#### 9.6.3.5 Raw Water Chemistry

Depending on the source of raw water used for injection, it should be tested for salinity, specific gravity, sand/silt, oxygen content, bacterial activity, and dissolved gases (such as oxygen, carbon dioxide, sulfur dioxide). Water sources include, but are not limited to:

— wells (both fresh and saline);

— canals;

— seawater;

— river water;

— recycled water.

### 9.6.4 Returned Brine Salinity and Chemistry

The operator shall measure the salinity of the water entering the cavern and the brine leaving the cavern. By measuring the salinity, the amount of salt removed versus water injected, can be used for calculation of volume and efficiency of the solution mining process.

Once the salinity of the brine that is produced has been recorded, the amount of salt that has been produced during a given mining interval can be directly calculated. This information can then be used to plan future mining operations on the cavern. The brine should be checked for minerals including the percentage NaCl, KCl, and $MgCl_2$. By calculating the amount and composition of salt that is being removed during a mining interval, the operator can evaluate the cavern development and problems during mining can be discovered and addressed. These problems include less soluble salt, which would cause the cavern to grow slower, and more soluble salt, which could cause growth of the cavern that is not planned. Even though the volume of the cavern should be continuously calculated from the saturation of the brine, periodic sonar surveys should be run to verify size and shape of the cavern.

### 9.6.5 Corrosion Monitoring

Solution mining procedures and facilities should include a corrosion monitoring program. When designing a corrosion control program, the following should be considered:

— wellbore casing program;

— influence of foreign direct-current sources;

— ground resistivity;

— quality of cement jobs;

— corrosive nature of the soil and formation fluids;

— potential oxygen sources;

— microbiology of the injection water;

— oxygen levels of the injection water.

While the cavern is being solution mined, the injection water and brine produced should be periodically monitored for sulfur reducing bacteria and acid producing bacteria along with dissolved oxygen.

The monitoring of casing and hanging strings for corrosion in a solution mining or storage cavern can be a difficult task. Corrosion monitoring is particularly difficult with single well caverns because the intermediate hanging string is not accessible.

### 9.6.6 Other Considerations

#### 9.6.6.1 Insoluble Materials

Insoluble impurities exist in most rock salt stocks. A common impurity is anhydrite ($CaSO_4$). The concentration and location of impurities varies from salt stock to salt stock and even within an individual salt stock. Dissolution of the salt during solution mining results in the insoluble material falling to the cavern floor and sump. The volume of insoluble material is typically negligible in comparison to the cavern volume but this volume should be determined to account for their impact on final cavern volume, since the bulk volume of these insolubles may be 30 % or greater than their original volume. Estimates of the total percentage of insolubles in the planned cavern volume should be determined from core samples and other reliable geological data.

#### 9.6.6.2 Preferential Mining

Cavern development can be significantly influenced by the presence of insoluble materials within the salt. Asymmetric cavern growth and internal collapse of unsupported salt could occur. Other salts, such as KCl or $MgCl_2$ may be within the salt formation, causing a differing dissolution rate that causes preferential mining. In bedded salt formations, these higher soluble salts can undercut upper strata and cause strain or even collapse. In domal salt, preferential mining tends to be at an acute angle to vertical due to the mechanism that forms the salt dome. Cavern development shall be monitored for preferential mining by thorough and periodic analysis of brine samples and periodic sonar surveys.

#### 9.6.6.3 Salt Falls

Salt falls, sometimes referred to as salt sloughing or spalling, occur primarily from flaws or heterogeneities in the salt structure, “skin” damage or improper solution mining techniques. These salt falls can result in the loss of hanging string(s), but rarely affect cavern integrity.

Structural flaws can cause salt falls during solution mining, debrining, rewatering or storage. Types of structural flaws include:

— differential movement within the salt mass (salt spines);

— areas with weak bonding of the salt crystals, sometimes referred to as “popcorn” salt;

— the incursion of higher solubility salts that cause preferential mining.

Skin damage occurs during solution mining, debrining, rewatering and storage operations, but is more apt to cause salt falls during the debrining and storage operations. Several feet of salt adjacent to the cavern walls and roof are affected by the stresses caused by temperature fluctuations and salt “flexing” caused by gas injection and withdrawal. Micro-fractures can develop allowing for weakening of the affected salt. Gas intrusion into the fractures can cause a differential pressure that causes the salt to fail.

Poor solution mining techniques that can lead to salt falls include the following situations.

— Failure to control the blanket material. Control of the blanket is crucial in developing a properly shaped roof and neck. A poorly shaped roof or neck can cause strains that can result in a salt fall. Blanket control shall be maintained at all times to protect the cavern roof and neck.

— Mining too long with tubing strings in the same position. Water injection in a single position in excess of the solution mining model can over enlarge a section of the cavern and reduce structural integrity. Any deviations from the solution mining plan should be remodeled for effectiveness.

— Blanket positioned too close to the injection point. If the blanket and injection point are too close, rapid over enlargement can occur at the blanket/brine interface due to the high volume of low salinity water concentrated in the interface area.

— Failure to maintain hanging string integrity. A hanging string leak in reverse flow can cause preferential solution mining resulting in a small height and large diameter volume without proper structural support. Hanging string integrity shall be maintained by careful monitoring of flow, pressures, and salinity of the brine. Any deviation from normal of the flow/pressure/salinity relationship should be immediately investigated.

— Use of too much water for backwashing a hanging string during debrining. Salt precipitation in a hanging string or wellhead requires backwashing with raw water. Backwashing during solution mining is essentially changing the flow mode from reverse to direct. However, during debrining, a backwash water volume in excess of the hanging string volume dilutes the brine in the cavern. The dilution effect increases as cavern brine volume decreases causing selective mining toward the bottom of the cavern. Water used for backwashing the brine string during debrining should not exceed the hanging string volume.

NOTE Salt precipitation can only occur at a position above a temperature drop in the brine stream. If the gas being injected is warmer than the cavern brine, any salting would have to occur above the gas injection point, not downhole.

#### 9.6.6.4 Gassy Salt

Some salt masses have entrapped methane gas within the structure. This gas is freed during the solution mining process then collects in the production casing. If enough is produced, the blanket interface can be pushed downward affecting the roof location and development. If gas is encountered or the salt mass in question has a history of producing gas, a natural gas or inert gas pad should be used. A gas only blanket can be easier to control than a two-phase blanket. More frequent wireline log checks of the blanket depth should be initiated if gassy salt is encountered.

NOTE Gassy salt often is associated with a particular zone or location in the salt mass. Once solution mining is reduced or completed in that zone, gas production may wane or completely stop.

## 9.7 Workovers during Solution Mining

Periodic well workovers may be performed during mining operations for well inspection or maintenance. During workovers the hanging strings and production casing should be inspected when possible. Any time the hanging strings are removed from the cavern, the strings should be fully inspected by an inspection company, either onsite, or at a facility where an even more thorough inspection can be performed. Any joints that do not pass this inspection should be discarded and replaced with new joints.

There are several reasons for a workover during the mining process. These include, but are not limited to, re-setting the hanging strings to comply with the solution mining model; plugged or salted-up hanging string; leak in either hanging string; the loss of blanket integrity; and a partial or total loss of a hanging string.

When performing a workover, the following additional work should also be performed:

— a sonar survey if significant cavern enlargement has occurred since the last workover;

— inspection and maintenance of the components of the wellhead if a significant cavern enlargement has occurred since the last workover;

— a nitrogen/brine mechanical integrity test if the cause for the workover was a well or cavern integrity issue regardless of the timing of the last workover.

### 9.7.1 Trapped or Attic Gas

An irregular shaped cavern or roof, whether by structural flaw or by poor solution mining techniques, can trap gas. Precautions should be taken when performing a workover during solution mining, if a gas blanket is used, or following a rewatering process. As the cavern pressure is lowered for workover access, the trapped gas can expand and release to the surface. Well pressure control equipment shall be used at all times during a workover.

## 9.8 Workover to Configure for Gas Storage Service

### 9.8.1 General

Once the cavern is fully developed with respect to cavern volume, gas volume, and other design characteristics, a full workover should be performed. This workover shall include inspection of the production casing, installation of the gas storage wellhead (if not already installed) and a mechanical integrity test. The workover should also include pulling and discarding of the hanging strings, running a sonar survey in the open cavern, and installation of the debrining string.

### 9.8.2 Removal of the Solution Mining Hanging Strings

The hanging strings used for solution mining development should be removed and discarded. However, if one (or more) of the hanging strings are to be re-used, then a full body electromagnetic and ultrasonic inspection, along with a thread and coupling inspection shall be performed. Any joint or connection that fails the inspection shall be discarded. Strings that fail the full body inspection should be discarded or at minimum shall have the burst and collapse pressures derated based on wall thickness loss. Connections that do not pass inspection shall be replaced with new cut threads (pin end) and new coupling (box end).

### 9.8.3 Inspection of the Production Casing

An inspection of the production casing shall be performed during the workover to configure the cavern for gas service. Wireline logs should be run that measure wall thickness, ovality, and internal/external anomalies. Refer to Annex B.

NOTE The wall thickness measurement generally is not accurate for larger sized casing.

### 9.8.4 Performing a Full-Cavern Sonar Survey

A sonar survey shall be run to make a final verification of cavern geometries (shape, size, depths) and to ensure that there are no limitations of the shape that could make storage and debrining in the cavern infeasible. Shape limitations can include wings behind the production casing, growth too close to existing caverns, or ledges that do not allow the debrining string to go to the bottom of the cavern.

At this point in cavern development it is difficult to fix issues like upward growth of the cavern or areas that could be prone to roof falls. However, these areas should be noted so that, should an abnormal operating condition occur during debrining, the possible cause can be identified. Areas of non-uniformity should be sonar surveyed on a tighter pattern than the rest of the cavern to give the best estimate of the size and shape in these areas. The cavern roof and floor should be sonar surveyed using a fixed position(s) close to each and shot at angles using a sonar transducer that articulates from horizontal to vertical.

### 9.8.5 Installing the Gas Storage Service Wellhead

Wellhead and valves used during solution mining should be replaced during the workover to configure the cavern for gas service. Any components reused shall be removed, inspected, and tested prior to re-use for gas storage.

The wellhead configuration should be modified to include ESD valves for all wellhead valves connected to site flow piping. A snubbing valve and necessary wellhead components should be installed above the debrining hanging string to allow for a workover under pressure (snubbing) or to remove or replace the hanging string. Without a snubbing valve, cavern re-entry for rewatering or inspection would be difficult, if not impossible, should a problem occur with the debrining string.

### 9.8.6 Installing Debrining Strings

The debrining string should be new pipe with complete documentation including Mill Test Reports (MTR). However, if a used string is contemplated then it shall have an MTR and be full body electromagnetic and ultrasonic inspected and tested as is stated in 9.8.2. Strings of unknown quality (salvaged strings) shall not be used. Each connection of the debrining string shall be pressure tested to ensure integrity.

### 9.8.7 Conducting a Mechanical Integrity Test (MIT)

An MIT shall be performed on a cavern before it is put into gas service. This test is run to ensure that the well system has integrity. The test shall be a nitrogen/brine interface test. An MIT should also be performed after any significant enlargement of a cavern. An operator may perform an MIT prior to the start of cavern development, as stated in 9.2.3. See Section 11 for a holistic approach to cavern integrity monitoring.

## 9.9 Debrining the Cavern

### 9.9.1 General

Debrining is the process of removing brine from the cavern by injecting gas at sufficient pressure to lift the brine from the cavern to the brine disposal or other brine handling facilities.

In some circumstance an electric submersible pump can be installed in the tubing to lower the gas/brine interface deeper than what could be achieved using gas pressure alone. This provides for a larger volume and increased storage capacity.

### 9.9.2 Gas Injection

A newly developed cavern should be connected to an existing gas storage cavern prior to the initial gas fill. This can provide a large gas “bubble” (existing cavern) to cushion the new cavern should there be an upset. In most cases, steady state gas injection is not possible when debrining a new cavern; however, combined caverns can continue to be debrined at a steady rate whether too much or too little gas is available. Injection should continue to both caverns until a sufficient gas quantity is injected into the new cavern. At this point, flow can be separated for the duration of debrining.

If combining caverns is not possible, cavern surface piping should include a method to minimize water hammer during an upset condition. As a sufficient quantity of gas is reached, water hammer consequences are reduced. Also, until a sufficient quantity of gas is reached, gas or brine flow may have to be slowed or stopped to maintain required gas/brine pressures.

The debrined cavern volume can be determined by metering the brine removed from the cavern, less any water used for backwash. Gas volume can be estimated by using the Combined Gas Law. However, an actual integrated gas temperature is typically not available and can be assumed. Small differences in temperature can result in large errors to the gas volume calculation.

NOTE The Combined Gas Law is the amalgamation of Charles’, Boyle’s, and Lussac’s individual gas laws.

### 9.9.3 Wellhead Pressure

The maximum pressure shall be limited to MAOP of the cavern. If the casing shoe is shallow compared with the total debrining depth desired, MAOP may be reached prior to completion of debrining. If this occurs, other means, such as gas lift or downhole pumping or jetting equipment, can be used to maintain a safe pressure.

### 9.9.4 Brine Rates

#### 9.9.4.1 General

Fluctuating gas flow during debrining should be minimized where possible to maintain proper wellhead pressures. Steady state brine outflow can be accomplished during debrining by installation of a flow control valve on the brine return piping. A constant flow rate is desirable to maintain pump operation and production/disposal of brine, both of which raise the efficiency of the debrining process. A sufficient cavern gas volume (cushion) is required to inject gas at varying flow rates and maintain a constant brine flow. The greater the gas flow fluctuation, the greater the initial volume required to maintain constant brine flow.

Steady state brine outflow can also be accomplished in the early stages of gas injection if the new cavern can be combined with an existing storage cavern. This can provide a greater cushion for fluctuating flow rates.

#### 9.9.4.2 Oscillation of Hanging String

At times during debrining/rewatering a cavern, the hanging string can begin to oscillate and can reach a resonant frequency. Operational procedures or installation of wellhead accelerometer(s) should be used to detect and correct this oscillation. Typically, a change of flow rate, either up or down, corrects the problem. However, if the oscillation is allowed to reach resonance, correction may not be possible without completely stopping flow.

NOTE Uncontrolled oscillation can cause hanging string failure.

### 9.9.5 Regular Interface Checks

Interface proximity can be calculated based on metered quantity of brine removed (using the sonar survey volume tables). The interface should be verified periodically with an interface log. Calculations can then be corrected and adjusted to reflect the log results.

### 9.9.6 Monitoring Devices

When debrining a cavern by injecting gas, the debrining piping shall be monitored to prevent overpressure or gas escaping into the brine piping. There are several devices that may be used, including:

— weep holes in the hanging string;

— hydrocarbon detectors;

— flow measurement to detect a rapid, unexpected increase in flow;

— pressure transmitters.

## 9.10 Existing Cavern Conversions

### 9.10.1 General

Existing caverns, developed for a purpose other than gas storage, shall only be converted if they meet the same criteria as those purposely developed for natural gas storage. A thorough review shall be performed on all data including, but not limited to:

— cavern neck length;

— size;

— shape;

— solution mining history;

— salt characteristics;

— salt core analysis;

— MIT history;

— condition of the production casing;

— threaded or welded casing;

— number and depth of strings cemented into salt;

— proximity to other caverns;

— proximity to the edge of salt;

— proximity to adjoining property;

— subsidence monitoring data;

— use of the other caverns in the field.

### 9.10.2 Geomechanical Analysis

#### 9.10.2.1 General

A full geomechanical analysis of the cavern should be completed. The analysis should review the cavern's relationship to adjoining caverns and to the edge of salt, and the cavern shape as it affects maximum and minimum pressures under cycling conditions. Further analysis should include stress, strain, and dilation of the salt pillar between the cavern and other caverns in the field.

#### 9.10.2.2 Cavern Shape

The shape of the cavern shall be verified with an open-hole sonar survey. Attention should be paid to the shape of the top and bottom of the caverns, areas of upward solution mining and areas of lateral dissolution toward the edge of the dome or other caverns. It should be determined whether irregular shapes are caused by a poor solution mining program or is a characteristic of the salt structure. It should also be determined if an irregular shape effectively reduces pillar thickness between caverns or to edge of salt. Refer to 9.2.2.4.

#### 9.10.2.3 Flat Roof

A cavern with a large flat roof should be avoided; refer to 9.2.2.4. The diameter at which the roof diameter becomes too large shall be determined by geomechanical modeling of the specific cavern operating parameters. The modeling should be performed to determine the minimum allowable operating pressure that would prevent damage to the salt, spalling or even failure of the roof. If there is sufficient salt structure above the roof and sufficient salt neck, the roof should be re-shaped by additional solution mining. The distance from the casing seat to the roof should be adjusted to mitigate tensile stresses in cemented casings caused by salt creep or by failure of the roof. Tensile failure of the casing can result in a loss of structural integrity. Salt thickness and formation structure above the cavern roof should be evaluated for what would occur if the roof sags or fails.

Bedded salt caverns by their very nature tend to have flat roofs, especially in relatively thin beds. Strength of overlying beds, both salt and other types, should be determined, so as to model the developmental limits of the cavern diameter. Cavern roofs in thick beds can be developed in the same fashion as salt dome caverns.

#### 9.10.2.4 Salt Neck

The salt neck available in an existing cavern should extend for a sufficient distance below the casing seat to prevent roof strains from affecting the integrity of the cemented casings. The neck should be equivalent to at least one–half diameter of the cavern and should be confirmed with geomechanical modeling. It may be possible to develop a sufficient neck by relocating the casing seat to a higher level. Care should be taken that the remaining salt, above the new casing seat, is sufficient for the relocation.

For thin bedded salt caverns, a dome-shaped roof and neck may not be possible. In this case, analysis should be performed on the strength of the overlying beds versus diameter of the roof. Further analysis should be given to determine a confining salt bed above the existing roof. This salt bed should have the strength and impermeability to contain the gas should the existing roof fail. The casing seat should be relocated to just below the confining bed if analysis of the existing roof shows the possibility of failure. Caverns that do not meet these criteria shall not be used for gas storage.

#### 9.10.2.5 Adjacent Caverns and Edge of Salt

The proximity of a cavern being considered for conversion to adjacent caverns and the edge of salt should be evaluated. This evaluation should include a geomechanical study of the cavern operating conditions in relationship to each other, the behavior of the salt pillar between the caverns based on these operating conditions, and the salt at the edge of the salt mass, as the salt characteristics near the edge of salt may be different than from the rest of the dome. Sonar surveys should be reviewed carefully to see if there are any planes of weakness that could lead to cavern failure toward the edge of the salt. In addition, caverns that could be considered close to the edge of salt should have the casing seat location precisely determined. This includes running a gyro log on the wellbore and tying the sonar surveys exactly to this log. The borehole location should be shown on a salt contour map and the thickness of salt expressly evaluated for safety.

### 9.10.3 Cavern Rewatering

When rewatering a cavern, whether for maintenance purposes or to enlarge the cavern, the wellhead shall be equipped with safety devices (see 9.9.6) to prevent the escape of gas in the event of a hanging string failure.

## 9.11 Cavern Enlargement

Caverns can be placed in-service and later enlarged over time to their maximum size. This type of enlargement occurs primarily in the lower interval of the cavern. Also, this enlargement requires specific details on the number of future cycles planned to flood, circulate and debrine the cavern.

After a cavern has been placed into service, cavern enlargement may be used to regain volume lost to creep or to attain the maximum cavern volume. Cavern enlargement can be accomplished through a single hanging string by flooding the cavern with raw water and then debrining. Cavern enlargement can also be accomplished through two hanging strings by flooding the cavern with raw water, circulating raw water and brine and then debrining the cavern.

Prior to commencing cavern enlargement, the following items should be modeled: the resulting cavern shape; spacing to other caverns, property boundaries, and edge of salt; and review of geomechanical properties. The hanging string collapse and burst ratings shall be verified to accommodate the different fluid gradients of raw water and brine. Surface safety devices shall be employed for sudden changes in pressures, increased flow rates and detection of hydrocarbons (see 9.9.6). Wellhead components and safety devices shall be rated for the highest MAOP of the process.

During cavern enlargement, the gas-water interface shall be closely monitored. The volumes of raw water injected and brine displaced should be compared with a cavern volume table to predict the gas-brine interface level. Regular interface checks are recommended to verify the gas-water interface and the accumulation of insoluble material. If the gas-water interface alters the shape of the cavern roof or has caused solution mining near the casing shoe, a mechanical integrity test shall be performed prior to debrining.

Raw water injection is similar to the process of debrining a cavern, but in reverse. Gas withdrawals are required as the usable cavern gas volume decreases with the injection of raw water. Gas injections are required for debrining as the usable cavern gas volume increases.

NOTE Gas withdrawal during solution mining can reduce or even stop the brine flow.

After any significant cavern enlargement, the volume of the enlarged section shall be determined. Several methods can provide a volume determination of the enlarged cavern. Prior to debrining, a sonar survey can be conducted through casing in the brine filled interval of the cavern. During debrining, periodic interface checks can be performed and compared with cavern volume tables. Lastly, a material balance match of cavern inventory versus the amount of brine removed can be performed.

# 10 Gas Storage Operations

## 10.1 Minimum and Maximum Operating Limits

A maximum flow rate for each string can be established, based on the area of the tubing or annulus. In addition, the maximum flow rate may be established on other criteria based on measured vibration and erosion testing.

Maximum and minimum storage operating pressures at the casing seat shall be established by the operator. The operator shall then convert the maximum and minimum pressure at the casing seat to a maximum and minimum wellhead pressure.

The maximum gas temperature should be evaluated for effects on surface and wellbore tubulars. Gas temperatures are raised during the compression cycle and the use of gas coolers should be evaluated to limit injection temperature.

## 10.2 Equipment

### 10.2.1 Gas Storage Service Wellhead

A wellhead designed specifically for natural gas storage service shall be installed during the conversion workover and prior to debrining (see 6.4.4). The wellhead components that were exposed to raw water and brine flow during solution mining should not be re-used for gas storage service, particularly valves and other well control equipment. If wellhead components are to be re-used, refer to 9.8.5.

Gas storage service wellhead equipment is designed to allow for the injection of gas and removal of the remaining fluids in the mined cavern and is expected to have a sustained life in gas storage operations at maximum gas storage operating pressures.

### 10.2.2 ESD Equipment

Each outlet shall have an Emergency Shutdown (ESD) Valve (fail -close) installed adjacent to the manual valves (wing valves). These valves shall be part of an ESD system that automatically shut in the cavern in the event of an emergency or when monitored parameters exceed the maximum allowable values, see 10.3.4. Consideration should be made to determine appropriate closing times for automated shutdown valves to ensure the MAOP is not exceeded.

An instrument flange may be used between the wing valve and ESD valve to gather real-time pressure data when the cavern is not in use. The flange shall be rated for the same pressure as the valves (see 6.4.11 and 9.4.1).

### 10.2.3 Flow Measurement Equipment

Each cavern should be equipped to measure natural gas flow into and out of the cavern. Flow measurement is a valuable tool in facility inventory control and monitoring. These devices can be used to determine excess flow into/out of the cavern, and as a check of the custody transfer metering volumes.

## 10.3 Instrumentation, Control, and Shutdown Systems

### 10.3.1 General

The cavern system shall have control and shutdown devices installed and designed to safely shut-in the cavern system in an emergency or when monitored parameters, such as pressure or flow, exceed the maximum allowable values.

Monitoring equipment shall be used to detect an upset condition during the debrining process. There are multiple types of devices used for gas storage; any of these (see 10.3.4) can be used as a warning of an upset and all that are used shall be connected to the ESD system to automatically close-in the cavern.

### 10.3.2 SCADA Systems

Supervisory Control and Data Acquisition (SCADA) systems are used to monitor and control gas injection and withdrawal. These systems allow operators to monitor the real time status of the caverns and make control changes necessary to meet operations demands. They also alert operators to system upsets (alarms) or shutdowns that may require some action by the operator.

### 10.3.3 Alarms

Audible or visual alarms shall be incorporated into the control systems to notify the operator of abnormal conditions. Alarms can consist of devices such as strobes, horns, or SCADA alarms.

### 10.3.4 ESD System

Each cavern shall have an ESD system installed to isolate the cavern and wellhead from any attached piping in an emergency. This system should be integrated into the overall facility SCADA and Shutdown System. The ESD system should be activated automatically due to excessive pressure or flow; or when gas or fire is detected. The ESD system should allow for both local and remote activation.

### 10.3.5 Overpressure Protection (OPP) System

#### 10.3.5.1 General

An OPP system is designed to prevent overpressure of the cavern, wellhead, or wellhead piping. The system automatically shuts in the cavern or isolates piping to block the source of the overpressure. Even when gas is not flowing, heating of the gas in the cavern from the surrounding environment and creep closures of the cavern could cause the pressure in the cavern to exceed maximum allowable pressure. Pressure in the cavern should be monitored to ensure that the production casing shoe maximum pressure is not exceeded.

If the brine string extends into the brine, a pressure transmitter monitoring the brine string can detect an abnormally high pressure. The pressure transmitter threshold pressure should be set below the MAOP (both static and dynamic) but above normal operating brine pressure during debrining or normal cavern operations. The pressure transmitter should detect a complete or partial failure of the debrining string. However, it is not intended to detect small hanging string leaks or wellhead leaks below the threshold pressure. In addition, a OPP device should be installed between the wellhead and facilities (piping, valves, fittings, tanks, and other wellsite equipment) that is a lower MAOP than the wellhead pressure to protect those MAOP facilities. The pressure should be set to the MAOP of those facilities downstream of the OPP and the transmitter monitoring the pressure should be downstream but near the OPP device.

When shut in for long periods, pressure should be monitored to ensure that the casing shoe maximum pressure is not exceeded. Low gas pressure, high gas pressure, high brine pressure, and the convergence of gas and brine pressures can be used for alarming or shutdown.

#### 10.3.5.2 Pressure Monitoring Points

The annulus between the production casing and the next casing shall be monitored for pressure. Pressure increases could indicate a wellhead seal leak, a leak in the production casing or a micro-annulus leak through the cement from the cavern. Further investigation and testing would be necessary to determine cause of the pressure build up.

A tap between the wing valve and the ESD valve is recommended. Tapping the wellhead inside of the wing valve shall not be allowed, as it is a potential source of uncontrolled gas loss from the cavern if the valve on the tap is damaged.

The wellhead pressure should be monitored to ensure the pipe pressure does not exceed the wellhead MAOP and the cavern is not pressured beyond the casing shoe maximum pressure.

Cavern pressure can also be monitored where there is a logging valve on the wellhead, providing the hanging string is open to gas pressure. If the hanging string terminates in brine, the pressure should be monitored to indicate a tubing leak or break.

### 10.3.6 Fire and Gas Detection

The appropriateness of fire and gas detection systems should be evaluated for installation on operating wellheads. These systems are designed to detect fire, gas, or heat. Flame and gas detectors are recommended for enclosed wellheads but may not be effective for non-enclosed wellheads. Heat detection systems are typically used for outdoor wellheads.

Instrumentation for fire and gas detection includes thermal melt-outs, thermocouples, gas detectors, flame detectors, and others. The device or devices used depend on the location, layout of the wellhead, and engineering design requirements among other factors. For example, gas detectors may not be suitable in an outdoor environment. Where installed, fire detection devices shall be failsafe and shall be capable of activating the ESD system and initiating fire suppression (if installed).

Flame detectors can be used to safely shut-in a cavern if a flame is detected on or near the wellhead and associated piping. The type of flame detector used should be selected within the anticipated operating environment to maximize reliability while minimizing false alarms.

Thermal melt-out devices may also be used as part of the ESD system to shut-in a cavern wellhead. This device fails if heated above certain temperature and shuts-in the cavern. These types of devices are a good choice for outdoor facilities as they are not affected by factors such as wind, lightning, nearby welding, or intentional gas venting.

Gas detectors can also be used to safely shut-in a cavern if gas is detected at or near the wellhead and associated piping. Gas detectors are best suited to enclosed wellheads and may not be effective on outdoor wellheads.

## 10.4 Inspection and Testing

### 10.4.1 General

Wellhead gauges and transmitters should be tested and calibrated to ensure they are properly calibrated and function as intended. Any malfunctioning equipment shall be repaired or replaced. If the devices cannot be calibrated to within the manufacturer's specifications, they shall be replaced.

### 10.4.2 Wellhead Integrity Monitoring

See Section 11 for recommended practices regarding cavern and wellbore integrity monitoring programs.

The operator shall inspect the wellhead and well site for leaks and condition at least annually.

Visual inspections may include, but are not limited to:

— identifying mechanical or corrosion damage,

— gas leaks from wellhead assembly and surrounding wellsite,

— missing equipment (valve handles, control line piping, gates, or signage), and

— encroachment activities.

The operator shall annually conduct the following:

— Function test the operation of the master valve and pipeline isolation valve(s) by fully opening and closing the valves.

— Confirm the ability of the master valve and isolation valve(s) to isolate the well from the pipeline. The confirmation may be accomplished with noise or temperature surveys, pressure differential or other methods that do not require gas to be vented to the atmosphere.

All valves shall be maintained, repaired, or replaced in accordance with the operator's valve maintenance program.

#### 10.4.3 SCADA System Checks

All safety related components of the SCADA system should be tested on an annual, not to exceed 15 months frequency to ensure critical operational data are accurate, alarms are properly calibrated and functional, and safety related equipment is functioning properly.

#### 10.4.4 ESD System Testing

The ESD system shall be tested at least annually, to ensure they perform as intended in the event of an emergency. All components of the system should be functionally tested and the calibration checked (i.e. switches, valves, transmitters, electronic devices, and other end devices). Most ESD systems shut ESD valves located on or near the wellhead to isolate the cavern. Valves should be stroked fully open and fully closed.

NOTE Some operators conduct this testing on a quarterly or semi-annual basis.

### 10.5 Workovers

#### 10.5.1 General

Well workovers may be necessary during gas storage service. Reasons include:

— partial or total loss of rewatering or debrining string;

— well or cavern integrity issue;

— maintenance of wellhead components;

— downhole inspections; and

— recovery of volume lost due to creep closure.

### 10.5.2 Workover Methods

#### 10.5.2.1 General

The two most common methods used for a gas cavern well workover are:

— conducting a workover on a depressurized cavern; and

— conducting a workover on a pressurized cavern.

As the cavern will be out of service during the workover, consideration should be given to inspecting and testing the downhole tubulars, the wellhead, valves, and associated equipment to verify the functional integrity of the cavern system.

The operator shall repair or replace all gaskets, studs, and nuts removed during the workover.

#### 10.5.2.2 Workover on a De-pressurized Cavern

In this workover method, gas is evacuated from the cavern by brine or raw water displacement. The workover can then be performed in a similar manner as during solution mining. The use of raw water will result in cavern enlargement and additional solution mining of cavern roof. The effect of raw water on the setback distance, roof integrity, and casing shoe integrity should be taken into consideration prior to its use.

For a workover on a de-pressurized cavern, the well should be empty of natural gas and full of brine or raw water. If it is suspected that natural gas could be trapped in a washout above the last cemented string, additional care should be taken.

NOTE 1 Because trapped or attic gas may still be present in the cavern and could make its way to the surface, observation of the brine level in the wellbore during a workover on a depressurized cavern is important.

NOTE 2 Excessive brine flow can occur as brine pressure is lowered during the workover and attic gas expands.

#### 10.5.2.3 Workover on a Pressurized Cavern

In this workover method, gas is not evacuated from the cavern and all operations are conducted under pressure. Snubbing rigs, equipment, and procedures shall be designed for the maximum gas pressure anticipated during the workover. The gas pressure in the cavern should be reduced prior to conducting the workover.

#### 10.5.2.4 Workover Considerations

The operator shall keep records of the workover. The documentation may contain, but is not limited to, the following items:

— the beginning and final dates the cavern was filled with liquid and the gas displaced;

— the amount of liquid added;

— a log of all work performed on a well during the workover;

— results of tests and inspections;

— findings, recommendations, and immediate actions required, if any.

A properly rated blowout preventer or annular blowout preventer capable of closing in the well at full expected hydrocarbon pressure should be installed. If the wellbore is open to the cavern interval without well control equipment installed, additional safety considerations should be taken. The operator should install an isolation packer, plug or other isolation equipment prior to removing the wellhead.

# 11 Cavern Integrity Monitoring

## 11.1 General

Cavern integrity is a critical goal of the design and construction of the cavern system. Following the risk assessment, the operator should develop and maintain a program and procedures to address storage cavern and well integrity monitoring practices for each storage facility, multiple facilities, or system-wide. The operator's approach should address the need for reevaluation of risk-based conclusions and the monitoring task frequency.

Once in operation and throughout its life, the cavern system shall be monitored to ensure the continuance of integrity. This with be done by selecting monitoring tasks, evaluating the data from the tasks, then feeding the results of the monitoring back into the risk assessment. Table 1 provides a list of integrity monitoring methods.

## 11.2 Integrity Monitoring Program

The operator shall have a formal written Integrity Monitoring Program that contains at a minimum, the following components:

— identification of cavern system components to be monitored;

— monitoring methods specifying:

  — type of method, and

  — frequency of application of methods (inspections).

— cavern volume and inventory verification;

— analysis of data from inspections, reporting, and archiving of results;

— periodic review of the program for effectiveness;

— identification and assessment of risks to functional integrity (Risk Management—Section 8);

— the use of multiple monitoring methods (Risk Treatments);

— an approach that conducts integrity monitoring inspections, not just on a set planned frequency, but also when other well work or facility outage allows for accelerated monitoring inspections.

## 11.3 Integrity Monitoring Methods

When the opportunity arises during periods when the well/cavern is out of service and conditions are conducive, the operator can utilize monitoring methods in Table 3 or other methods, as appropriate.

These methods can be evaluated for applicability and inclusion in the Integrity Monitoring Program. Refer to Annex B for additional information.

**Table 3—Integrity Monitoring Methods**

| Method Name | Type of Test | General Comments |
|---|---|---|
| | | Cavern System Scope |
| Mechanical Integrity Test: Gas Filled | Containment Test | Wireline pressure and temperature gauges are lowered into cavern on two separate dates. Cavern gas volume is calculated from data acquired on each log run and difference in volume is assessed against pass/fail criteria.<br>Requires: gas-filled cavern of known cavern size at two different inventory levels, gas composition, and injection/withdrawal volume between each inventory level. |
| Inventory Verification Analysis | Containment Assessment | Known daily gas activity (volumes) are tabulated and tracked. Cavern pressure and temperature are collected at key points in time. Cavern gas volume is calculated and the difference in calculated and tabulated volumes is assessed against pass/fail criteria.<br>Thermodynamic simulations of gas operations can also be used to calculate gas volumes.<br>Requires: gas measurement by cavern, known cavern size, gas composition, cavern thermodynamic values. |
| Continuous Downhole Monitoring | Containment Assessment | Pressure and temperature gauges are lowered into the cavern on cables which can transmit gauge data to the surface. Cavern pressure and temperature are used to calculate cavern gas volume which can be tracked versus measured flow (while flowing) and static conditions (while shut in). Anomalies are assessed against pass/fail criteria.<br>Requires: gas composition analysis, known cavern size, wellbore configuration allowing for downhole gauge installation. |
| Hysteresis Curve Analysis | Containment Assessment | Operators plot the wellhead pressure versus gas inventory. The plot gives a relationship between pressure and inventory. Deviations from established trends may indicate an issue either with containment or unmetered gas.<br>Requires: daily wellhead pressure readings corrected to static cavern pressure and gas inventory. |
| | | Wellbore Scope |
| Mechanical Integrity Test: Nitrogen / Brine Interface | Casing Seat Containment Test | Nitrogen gas is injected into a brine-filled cavern to below the casing seat. Movement of the nitrogen-to-brine interface is monitored by wireline log. The ending amount of nitrogen is compared with the starting amount and assessed against pass/fail criteria.<br>Requires: fluid-filled cavern. |
| Caliper Log | Casing Assessment | Measures last cemented casing string geometries including internal diameter and ovality.<br>Requires: no hanging string be present. |
| Mag Flux Leakage Log | Casing Assessment | Measures last cemented casing string for corrosion characteristics including pits and defects.<br>Requires: no hanging string be present, casing size less than 24 in. |
| Ultrasonic Noise Log | Casing Assessment | Measures wellbore acoustics in last cemented casing string for leaks and other noise anomalies.<br>Requires: static wellbore conditions. |
| Temperature Log | Casing Assessment | Measures temperature in the wellbore. Temperature generally increases with depth due to natural geothermal heating. Deviations from expected trends can be an indication of a leak. |
| Cement Bond Log | Relative Measure of Quality of Cement Bond | Measures a relative degree of cement bond surrounding the last cemented casing by way of the attenuation of an acoustic signal.<br>Requires: no hanging string present, liquid filled wellbore. |
| Downhole Camera | Casing Assessment | Provides multiple single-frame or full-motion video of the condition of the inside of the wellbore.<br>Requires: clear liquid or gas. |
| | | Cavern Scope |

**Table 3—Integrity Monitoring Methods (Continued)**

| Method Name | Type of Test | General Comments |
|---|---|---|
| Sonar Survey | Cavern Shape Assessment | Uses sonar survey techniques (sonic wave generation and return time) to measure distances to cavern walls. Produces cavern shape and size measurements.<br>Requires: gas-filled cavern without a hanging string or liquid filled with (or without) a hanging string. |
| Cavern Total Depth Log | Cavern Floor Assessment | The bottom of the cavern is “tagged” by way of running a wireline tool with depth measurement into the cavern. Repeated runs over time can help assess floor movements, salt falls and wall slumps. When an interface tool is attached, the depth to any bottom brine level can be determined.<br>Requires: an open pathway for logging tool to the bottom of the cavern. |
| Subsidence Monitoring | Ground Subsidence Assessment | Using surface elevation survey techniques, including land based and aerial, any subsidence in the area above and near the cavern can be monitored.<br>Requires access to suitable surface locations. |
| Wellhead Scope | | |
| Ultrasonic Thickness Measurements | Remaining Strength Assessment | Using ultrasonic measurement tools, the wall thickness of key areas of wellhead valves and fittings can be monitored. Repeated measurements can help assess wall loss due to corrosion or erosion effects.<br>Requires marked locations for repeated measurements. |
| Cemented Annuli Pressure Monitoring | Casing and Casing Seat Assessment | Gas pressure may be present in the cemented annuli within the wellhead for several reasons. Monitoring the pressure on these annuli can help monitor for unexpected changes.<br>Requires access on the wellhead to the annuli for pressure gauges. |

# 12 Site Security and Safety Programs

## 12.1 General

This section provides guidance that will assist operating personnel in recognizing and responding to abnormal conditions so that life and property can be protected. The elements in this section are site specific and therefore will vary based upon such conditions as population proximity and density, natural forces, well(s) flow potential, vandalism, terrain, adjacent land use, and the environment that could be possibly impacted by the facility operation and emergencies related to the facility.

NOTE For reference, API Recommended Practice 1173 [33] provides relevant information to site security and safety processes and procedures.

## 12.2 Site Security Processes and Procedures

Site security and safety processes and procedures shall be developed to mitigate operational safety hazards and risks (as identified in risk identification process, see Section 8). Safety programs should include facility safety, staff safety, contractor safety, and public safety. These security and safety processes and programs should be coordinated with associated pipeline programs, as applicable.

### 12.2.1 Access Control

Access control is commensurate to the risk and consequences of the well(s). This can include automatic gate, keypads, call buttons, badge readers, and cameras. These devices allow the remote monitoring and control of access points throughout the facility.

The use of guard stations or controlled access points should be evaluated if any part of the facility has an unusual amount of personnel or equipment, such as during out of ordinary construction or maintenance operations. Personnel entering or leaving should be logged so that a record of those on-site is maintained for both security and safety reasons and in case an emergency arises.

Other considerations to control access are facility lighting, wellhead enclosures, and wellhead valve security.

Lease and well site roads should be maintained in a condition that permits personnel and equipment access.

### 12.2.2 Emergency Assembly Area

A designated assembly area shall be identified for employees, contractors, and visitors to proceed to in the event of an emergency during well work activities. The location of this emergency assembly area shall be identified to all employees, contractors, and visitors on site prior to the performance of any work. Sign in sheets or similar can be used to account for contractors and visitors in case an emergency arises.

The use of windsocks dependent upon terrain, prevailing weather and gas composition may be used to determine appropriate location.

### 12.2.3 Communications

Operators should have a means of communication or an alert system for operations personnel. This can include a phone system, radios, or cell phones.

### 12.2.4 Safe Work Practices

The operator shall maintain procedures that address safe work practices to ensure the safe conduct of operating, maintenance, and emergency response activities that impact underground gas facility safety.

### 12.2.5 Well Identification

Permanent weatherproof signage shall be installed at each well site or location specified by regulation for identification purposes. Signage should contain the following information, at a minimum:

— storage facility name, well name, or identification number;

— operator name; and

— operator’s 24-hour emergency contact number.

NOTE Signage requirements vary depending upon the jurisdiction.

The operator can add other information or signage to enhance facility or site security and safety such as additional information regarding the location or warnings for areas containing potentially hazardous, flammable, or noxious vapors.

### 12.2.6 Well Site Barriers

Well site barriers (e.g. jersey barriers, bollards, and fencing), as determined by risk assessment, should be installed around wellheads and other critical facilities to prevent accidental or intentional damage by vehicles and equipment. These barriers should be removable to provide space for maintenance or workover equipment.

### 12.2.7 Flammables

Sources of ignition and flammable-type equipment and materials should be located in a manner to provide for the ongoing safety at the wellhead or well site. The operator should evaluate the site-specific conditions of potential flow rates, pressures, and weather conditions when determining a safe distance from the wellhead for each source of ignition and flammable-type equipment and materials.

## 12.3 Site Inspections

### 12.3.1 General

Site inspections for review of safety and security assurance shall be performed to verify that requirements of Section 12 are met and maintained.

NOTE Site inspections for safety and security can coincide with site inspection to check the well area for mechanical integrity purposes as detailed in 11.3.

### 12.3.2 Procedures

The operator shall develop and implement site safety and security inspection procedures. Procedures should include:

— purpose of the inspection;

— identity of the trained person conducting the inspection;

— frequency of inspection;

— items to be inspected in the form of a list that can be checked off as completed and become part of the inspection record;

— risk identification of hazards and potential threats; and,

— documentation, reporting, and recordkeeping requirements.

## 12.4 Emergency Preparedness/Emergency Response

### 12.4.1 General

Operators shall develop emergency response plans (ERP) to provide for the safe operation, control, and management of the storage facility in the event there is an emergency condition. These should be coordinated with associated storage or pipeline facilities, as applicable. The safety of life, property and the environment should be the primary goal of these plans. Operators shall integrate underground gas storage emergency procedures with required regulatory procedures where possible and applicable. The plans shall include processes and procedures that address accidental releases, equipment failures, natural disasters, and third-party emergencies.

### 12.4.2 Emergency Response and Emergency Response Planning

The ERP shall contain, at a minimum, the following elements:

— determination and planning for potential types of emergencies;

— communication plan: internal and external protocols;

— identification of response resources and interfaces, including local emergency responders;

— recognition and use of Unified Command/Incident Command Structure or similar protocol with roles, responsibilities, and administrative details;

— incident management—safety, health, and environmental protection processes; and

— training, exercises, and drills to include frequency (external agencies and organizations can be included):

  — these exercises shall be evaluated against ERP goals and objectives and documented, including lessons learned.

The plan shall be reviewed at least annually, not to exceed 15 months.

NOTE 1 Potential types of emergencies may include spills, releases, natural disasters, security threats, fires, explosions, utility loss, pandemics, medical emergencies, or civil disturbances.

NOTE 2 Training, exercises and drills may include tabletop exercises, workshops, testing, specific functional drills or full-scale exercises

#### 12.4.3 Well Control Plan

The operator shall have a Well Control Plan (WCP) whether it is contained within the ERP or as a standalone document. The uncontrolled release of gas and management thereof from an underground gas storage well shall be addressed. The primary goal of a WCP is to protect life, property, and the environment.

WCP's are operator specific and proper risk assessments should indicate any needs for well specific issues to be addressed. WCP's should include, at a minimum, the following elements:

— well drilling, intervention, or workover planning considerations such as anticipated pressures, well control, access to current wellbore schematics, and other site or formation specific drilling or workover hazards;

— communications, event organizational structure, roles, and responsibilities;

— event site safety, security, and procedures;

— required materials and services;

— event response drills and exercises; and

— training that ensures adequate knowledge and demonstrates competency.

### 12.5 Cyber Security

To the extent that transmitted well data or remote flow control activities are security issues, the operator may employ cyber security measures to provide site security and safety.

NOTE API Standard 1164 [36], Pipeline Control Systems Cybersecurity can be referenced for further guidance.

## 13 Procedures and Training

### 13.1 General

This section addresses requirements for the development, implementation, and maintenance of programs, plans, and procedures intended to guide the operator safely and effectively in design, construction, operation, and maintenance of underground natural gas storage facilities. Associated requirements are set forth regarding training of operator and contractor personnel to comply with established programs and procedures. Documentation and record retention to demonstrate compliance with or deviations from the programs, plans, and procedures are also addressed. The programs, plans, and procedures required in this section specifically cover underground gas storage facilities; however, related pipeline and other regulated parts of the storage facility require the operator to have in place similar programs and procedures. Many publications and standards cover engineering requirements and recommended practices that impact the safe and reliable design, operation, and maintenance of underground natural gas storage caverns and related facilities.

## 13.2 Management of Procedures

### 13.2.1 Construction, Operation, and Maintenance Procedures

The operator shall develop and follow procedures for the operation, and maintenance of natural gas storage wells and caverns to establish and maintain functional integrity. When practicable, the operator's procedures should incorporate applicable industry recommended practices that promote personnel and process safety, resource conservation, environmental stewardship, mechanical integrity, and reliable performance.

Procedures shall be in place prior to the development of a new storage facility. The procedures should address the minimum requirements for construction including drilling and other well entry work, cavern integrity monitoring and management, O&M, emergency response, control room communications and responses, personnel safety, safety management systems, and site-specific procedures determined to be necessary by the operator.

Programs should integrate storage well and cavern elements so that procedures and programs work together to promote the functional integrity of the storage facility.

The operator should integrate natural gas storage procedures with regulatory-required procedures covering pipeline facilities where possible rather than creating storage-specific documents. Specific operations related to natural gas storage wells and caverns requiring procedures include, but are not limited to, drilling, well workover, and cavern integrity monitoring and management programs.

NOTE The operator likely already has in place procedures for operation and maintenance, emergency response, integrity management, control room communications, public awareness and damage prevention, qualification of personnel, management of change (MOC), and other procedures covering pipeline facilities.

Current procedures shall be available and readily accessible to operations, maintenance, and storage personnel. Procedures may be kept in paper or electronic format.

### 13.2.2 Review of Procedure Content

Procedures should be reviewed at a frequency determined by the operator. Procedures should be modified to account for changes in operating conditions, advancements in technology, regulatory changes, abnormal operating conditions, or as experience dictates. Procedure reviews should be documented, and deficiencies or other changes noted in the review records. Implementation of changes should be documented as per 13.10.

### 13.2.3 Review of Procedure Adequacy

The operator should review the work being done by storage personnel to determine the adequacy and effectiveness of the procedures used in normal operation and maintenance of storage facilities. Reviews should be conducted periodically at a frequency determined in accordance with risk assessment practices recommended in 8. The operator should identify and document deficiencies, nonconformance, or deviations from established procedures and correct deficiencies or modify procedures as appropriate.

### 13.2.4 Record Retention

The operator should retain records necessary to properly administer the procedures and establish retention requirements for specific records.

## 13.3 Operations and Maintenance

### 13.3.1 General

The operator shall develop and implement O&M procedures covering natural gas storage wells and caverns prior to the commissioning operations.

### 13.3.2 Scope of Procedures

Procedures should outline and define routine inspection, testing, and monitoring activities (see Section 10), P&M measures for risk reduction (see Section 8), recognition of abnormal operating conditions, and the associated schedules and recordkeeping requirements. The procedures should address indications or circumstances identified during routine activities that may require supplemental activities or additional maintenance.

The operator should adapt and enhance general procedures when additional integrity monitoring activities are required to address special site-specific hazards or threats.

The operator should establish general procedures for well isolation necessary to perform maintenance functions, including options of venting, flaring, blow down, or other isolation procedures, as well as an assessment of the characteristics and volume of fluids in the context of safety and environmental protection.

The operator should develop procedures to identify abnormal operating conditions, respond to those conditions, and document those events. The procedures should require a periodic review of documented abnormal operating conditions for the purpose of establishing trends or lessons learned and modifying existing procedures to prevent recurrence.

## 13.4 Well Work

### 13.4.1 General

The operator should establish a program to manage drilling, completion, servicing, and workover activities. This program should incorporate in a work plan the operator-established practices and procedures that are founded on industry recommended practices related to the drilling, completion, servicing, or workover operation to be performed. The work plan at a specific well should identify site-specific requirements, and the plan should account for hazards and conditions expected to be encountered in the well.

### 13.4.2 Scope of Procedures

The operator’s established procedures should define minimum safety requirements for surface equipment, pressure control equipment, downhole operations, MOC processes, and other requirements as specified the operator.

Drilling, completion, servicing, and workover plans should be reviewed with rig crews and other contractors as applicable prior to performing the work.

The operator’s well-specific work plan should identify the pressure rating of blowout preventers and ancillary pressure control equipment. The pressure rating should be greater than the maximum anticipated surface pressure, and the plan should include requirements for verification and documentation that blowout preventers are in good working condition and have been tested after installation.

NOTE API Standard 53 [7] and API Recommended Practice 54 [34] provide guidance related to blowout prevention equipment for drilling and well servicing operations.

The operator should require personnel whose duties include operation of well control equipment used in the drilling, completion, servicing, or workover operations to demonstrate knowledge, skill, and ability to operate the equipment (see 13.11).

The operator should require a person who is trained in well control, or knowledgeable, skilled, and capable through experience to perform well control duties, to be on site at the well during active drilling, completion, servicing, and workover operations.

## 13.5 Other Well Entry and Well Operation Procedures

### 13.5.1 General

The operator should establish a work plan when performing wireline, slickline, and logging operations, well testing, and other well operations requiring well entry. The plan should incorporate operator-established practices and procedures that are founded on industry recommended practices and applicable to the specific work to be performed. The work plan at a specific well should identify site-specific requirements and the plan should account for hazards and conditions expected to be encountered in the well.

### 13.5.2 Scope of Procedures

The operator should define operating conditions and activities where pressure control equipment is required.

The work plan should require that pressure control equipment be rated for the maximum anticipated surface pressure to be encountered during the operation.

The operator should verify that equipment used for pressure control is in good operating condition and suitable for the intended operation.

NOTE API Recommended Practice 54 [21] provides guidance related to pressure control equipment used in drilling and well servicing operations.

The operator should review the wellbore entry plan with the contractor prior to beginning the work.

The operator should confirm prior to wireline, slickline, and logging operations that the contractor is provided with:

— well configuration and completion details;

— characterization of the stored hydrocarbons and the presence of $H_2S$ or other hazardous or corrosive agents;

— anticipated wellbore and storage zone pressures and temperatures;

— anticipated presence of water, fluids, deposits, or scale and restrictions in the wellbore;

— safety requirements as outlined in 13.8; and

— reporting requirements.

## 13.6 Interaction with Control Room

### 13.6.1 General

Storage personnel shall be responsible for preparing and communicating guidelines for maintaining cavern and well functional integrity.

### 13.6.2 Scope of Procedures

The operator should establish procedures for interaction and communication with a control room, including authority for initiating flow, operating, and shutting in natural gas storage facilities as required to maintain cavern and well integrity during normal, abnormal, and emergency conditions.

### 13.7 Integrity and Risk Management

#### 13.7.1 General

The operator should establish procedures to manage and maintain integrity of storage wells and caverns in accordance with the requirements of other sections of this standard.

#### 13.7.2 Scope of Procedures

The operator should develop procedures related to integrity and risk management that define the frequency or interval of review, data, or information to be reviewed, and methods of data trending or normalization.

### 13.8 Safety and Environmental Programs

#### 13.8.1 General

The operator shall maintain programs that incorporate safeguards to the environment, site security, and safety and health prior to beginning storage design, construction, operations, and decommissioning that are founded upon industry recommended practices and nuances of their facilities and operations.

#### 13.8.2 Scope of Programs

The programs can include elements, such as:

— operational controls: safe work practices, system integrity, MOC, contractors, and incident investigation;

— safety assurance: audit, goals and objectives, evaluation of safety culture;

— management review and continuous improvement;

— competence, awareness, and training;

— documentation and record keeping; and

— other elements deemed necessary by the operator.

The operator should verify that procedures address the conduct of work in a manner that minimizes environmental and safety risks.

### 13.9 Public Awareness and Damage Prevention

For further information on public awareness programs, see API Recommended Practice 1162 [35].

### 13.10 Management of Change

#### 13.10.1 General

Revision of procedures and processes is an acceptable practice, but the operator shall require changes to be accomplished in a controlled manner. The program documentation, framework, and procedures shall be revised before the change can be implemented. Not all changes need be approved through a formal MOC process. Some changes are expected and may not be subject to a formal change control process. The operator should define the types of changes determined to be significant and requiring a MOC.

#### 13.10.2 Scope

The operator should develop and maintain a MOC process that addresses changes in equipment, processes, materials, or procedures. The MOC process should include procedures to identify impacts associated with changes and determine the effect of the change on the storage facility. The MOC process should address approval authority and responsibility for the change and document implementation of the change.

A MOC procedure should include a process for approval of deviations from the procedures when necessitated by abnormal/emergency conditions.

The operator should update procedures, communicate, and document changes to procedures in accordance with the operator's MOC process, and verify that personnel engaged in operating and maintaining the storage cavern and wells are aware of and trained in those changes.

## 13.11 Training

### 13.11.1 Training Requirements

The operator shall provide training for personnel responsible for operating, maintaining, and monitoring natural gas storage wells and caverns in accordance with their duties and responsibilities.

Training should address procedures specified in Section 13, safety procedures, recognition of abnormal operating conditions, and emergency conditions. Training programs may consist of various methodologies including but not limited to classroom, computer-based, and on-the-job training.

The operator should review training programs periodically, such as when changes occur in technology, processes, procedures, or facilities.

### 13.11.2 O&M Personnel

The operator should confirm by training and testing those persons assigned to operate and maintain natural gas storage wells and caverns possess the knowledge and skills necessary to carry out their duties and responsibilities including those required for start-up, operation, and shutdown of natural gas storage wells and caverns. Training may consist of but not limited to:

— site-specific procedures necessary for operation;

— recognition of abnormal operating conditions;

— reporting, documentation, and recordkeeping requirements.

Whenever changes are made to the operating procedures specified in 13.3, operating personnel shall be notified and trained as necessary in the changes and training documented before operating natural gas storage wells and caverns.

The operator should provide refresher training on a periodic basis for personnel on current operating procedures.

### 13.11.3 Supervisory Personnel

Specific job requirements may require the company person or persons (supervisors) directly responsible for the work being performed to be located on site while the work is being conducted. Personnel acting in supervisory roles should be trained to provide competent and effective supervision of the operations being carried out. Supervisor responsibilities should include, but not be limited to, the following:

— confirm that personnel on site can recognize abnormal operating conditions and applicable hazards and know their role in safety and emergency procedures;

— confirm that operating and contractor personnel conducting gas storage well operations possess or are working under the supervision of someone who possesses, the knowledge and skills to safely perform the work;

— confirm that operating and contractor personnel understand and adhere to reporting requirements in the operator's procedures.

#### 13.11.4 Contractor Personnel

The operator may use contractor personnel in the performance of constructing, operating, maintaining, and monitoring duties associated with storage wells and caverns. This subsection provides recommendations regarding training of contractor personnel.

The operator should include, but not be limited to, the following:

— provide and specify the scope of work to be performed by contractors;

— develop a method to verify contractor training, which may include a review of the contractor's safety training programs, worksite checks of individual contractor employee training, or operator observation of contractor work performance;

— confirm that contractor personnel conducting gas storage well work possess or are working under the supervision of someone who possesses, the knowledge and skills to safely perform the work;

— provide copies of the appropriate current procedures and review those procedures with contractors prior to any work being performed and ensure that persons performing work in the storage field are familiar with the procedures and recordkeeping requirements;

— provide training to contracted personnel that includes applicable site-specific safety procedures, rules pertaining to the facility, reporting requirements, and the applicable provisions of emergency action plans.

### 13.12 Records

#### 13.12.1 Documentation

The operator shall maintain records to document establishment of and compliance with procedures as required in Section 13. Records may be kept in an appropriate format (paper or electronic). The integrity of the records, especially electronic, should be verifiable. Records should include superseded procedures.

#### 13.12.2 Training Records

The operator shall maintain records that demonstrate compliance with this subsection. Company personnel training records should include:

— identification of the trained individual;

— identification of the training and methodology of training provided; and

— date(s) training was completed by the individual.

The operator should retain documentation of the contractor training review (see 13.11.4).

#### 13.12.3 Retention

The operator shall establish retention intervals for records that meet regulatory requirements; where no regulatory requirements exist, retention intervals should be determined by the operator but not less than five years.

# 14 Cavern Abandonment

## 14.1 Abandonment Objectives

The objectives of cavern abandonment are to stabilize the cavern and maintain its hydraulic integrity for the long-term.

## 14.2 Abandonment Design

As of this writing, there is no industry consensus for abandoning a salt storage cavern. Industry efforts for consensus include a Solution Mining Research Institute research project [10] that introduced a comprehensive abandonment theory. This research later prompted two studies to explore the cavern abandonment theory, one for relatively shallow caverns that was completed in 2009 [11] and one for deep caverns that has not yet been completed. Major questions remain concerning the length of time required for brine temperature equalization with the salt formation temperature prior to sealing and abandonment.

Most attempts at abandonment have followed the methods used to abandon exploration and production or disposal wells, e.g. the setting of a series of cement plugs across significant zones in the well, such as salt/caprock interface and potable water sands. One innovative abandonment design included perforating the production casing above salt and setting a tail pipe below the roof to prevent any hydrocarbon escape. As pressure in the cavern would build, brine moved up hole and released through the perforations into the zone above the salt.

Other operators prepare the caverns for continuous monitoring rather than attempting abandonment. Certain steps as listed below should be taken prior to abandonment or monitoring. These steps can provide the basis for analysis of future cavern integrity.

## 14.3 Removal of Stored Gas

The cavern shall be evacuated, to the extent practicable, of natural gas by the displacement of the gas with saturated brine, or with raw water if it can be shown the resultant cavern growth does not affect cavern stability or violate cavern spacing requirements.

## 14.4 Wellbore Integrity Test

A wellbore nitrogen/brine mechanical integrity test should be performed after removal of the stored gas.

## 14.5 Removal of Downhole Equipment

All downhole equipment and hanging strings should be removed from the cavern and wellbore.

## 14.6 Production Casing Inspection

A full inspection of the production casing should be made (see 9.8.3).

## 14.7 Sonar Survey

When possible, a sonar survey should be conducted to determine the final shape and areal extent of the cavern.

## 14.8 Long-Term Monitoring

A long-term monitoring program shall be developed if the cavern well is not plugged. Preparation for monitoring should follow the same steps as shown in 14.3, 14.4, 14.5, and 14.6 regardless of plugging or monitoring a cavern. Monitoring for a cavern not plugged should include the Integrity Monitoring Program outlined in 11.2. Monitoring data and analysis shall be maintained for life.

Monitoring of a plugged cavern should include periodic subsidence surveys as well as visual inspection of the area for unexplained changes in topography.

# Annex A
(informative)

# Open-hole Well Logs

## A.1 General

Subsurface geologic assessment primarily relies upon open-hole well log data. Well log data provide the means to evaluate the petrophysical properties of the subsurface strata and the basic data for creating subsurface geologic maps and cross-sections. While not a comprehensive list, below are short descriptions of some useful logs run in salt cavern wells.

## A.2 Gamma-Ray (GR)

GR logs measure the natural radioactivity of the formation. They are primarily used for well correlation and to identify the presence of shale or K-Mg salts, which can have detrimental impacts on the development of salt storage caverns. Without additional data, such as density or sonic logs, a GR log cannot distinguish halite from anhydrite or clean sand. A typical GR log also cannot distinguish shale from K-Mg salts. Borehole GR logs can be correlated with core gamma logs to improve core-log integration for salts having sufficient impurities to exhibit a gamma ray contrast. GR logs are useful for correlation between cased-hole and open-hole logs because they can be run in boreholes with and without casing. These logs are sensitive to borehole size changes.

## A.3 Spectral Gamma-Ray

A spectral gamma ray log segregates the GR signal into components (K, Ur, and Th), potentially allowing shales to be discriminated from K-Mg salts. These logs are sensitive to borehole size changes.

## A.4 Litho-density

Litho-density logs measure the photoelectric effect of the rock from which bulk density can be derived. These logs are useful for characterizing the impurity content of the salt as well as the lithology of the caprock (domal salt) and interbeds (bedded or deformed salt). The bulk density of halite derived from a density log is lower than the true bulk density of halite (i.e. halite density = 2.167 g/cc, log density for halite ~2.03g/cc). The tool is a contact tool so it is sensitive to hole size or borehole irregularity.

Density logs are typically run in oil and gas exploration and are usually presented as density porosity assuming either a sandstone or limestone matrix. For salt cavern wells it is more useful to request that the data be presented as bulk density so that the lithology and impurity content of the salt can be better evaluated.

## A.5 Compensated Neutron

Compensated neutron logs are porosity logs that measure the hydrogen ion concentration in the formation which is indicative of liquid-filled porosity in clean shale-free formations. They are sensitive to hole size, temperature, and salinity and require environmental correction. Interpretation charts are operator dependent and vary among logging companies. Neutron curves generally read low in gas-filled zones because of the gas effect. These logs can be used to identify gas zones in porous media when used in conjunction with a density porosity curve from a litho-density log. Neutron logs may give an indication of anomalous salt containing brine or gas.

## A.6 Borehole Compensated (BHC) Sonic

BHC sonic logs are a basic type of sonic log that measures interval transit time of compressional acoustic waves (DTC). DTC is the reciprocal of velocity and is dependent upon lithology (elastic properties and density) and porosity. Sonic logs are typically used to calculate matrix porosity in clastic and carbonate rocks. The DTC of clean halite is 67 µsec/ft. In salt cavern wells, sonic logs can give an indication of the relative amount and type of impurity content within the salt. Sonic data can also be useful for depth conversion and calibration of seismic data.

## A.7 Dipole or Array Sonic

Unlike BHC sonic, which records only compressional velocity, dipole, or array sonic are full waveform tools that measure the transit times of compressional, shear, and Stoneley waves. These log data can be used to determine the dynamic elastic moduli (e.g. Young's modulus and Poisson's ratio) of the rock along the borehole. Some tools can also measure the distance and orientation of acoustic reflectors a short distance away from the borehole.

## A.8 Check Shot Surveys

In general, check shot surveys provide more reliable velocity information for calibration and verification of seismic time/depth conversions than sonic logs can provide. Check shot surveys are similar to Vertical Seismic Profiles, but the two differ in receiver density, placement, and recorder spacing.

## A.9 Mud Log (Cuttings or Sample Log)

Although not a geophysical log, a mud log can provide useful lithologic information in relatively competent strata. To be valuable in salt the drilling fluid should be of sufficient salinity for the salt cuttings to survive. Formations are usually determined by first arrivals of identifiable cuttings and as such the results are influenced by mixing in the borehole, estimated bottoms-up time and cutting survivability. In addition to the lithology of the cuttings, mud logs can also include penetration rates, tight borehole, stuck pipe, lost circulation zones, and gas occurrence.

## A.10 Temperature Logs

Temperature logs can be run to measure the local geothermal gradient in newly drilled cavern wells before cavern development. Temperature data can be useful for the geomechanical assessment of the salt because salt creep and deformation is temperature dependent. It is important that the temperature of the fluid in the borehole be allowed to equilibrate to in-situ conditions prior to running a temperature log. Temperature logs can also be run during storage operations to provide a "snapshot" of cavern conditions to calculate gas inventory.

## A.11 Multi-arm Caliper

As part of the geologic site characterization, the caliper log is useful in that it can provide some qualitative information on the relative strength and dissolution characteristics of the rocks encountered. As many wireline logging tools are sensitive to borehole rugosity and bore-hole size, the caliper log can be used to quality control (QC) the wireline log data. The multi-arm caliper can also be used for cement volume calculations during the drilling operations.

## A.12 Resistivity

Resistivity logs measure the ability of a formation to transmit electrical current and are a function of water saturation. Salt typically has a high resistivity and extremely limited penetration of drilling fluid, and resistivity logs alone are not of much value in salt. Resistivity logs are of more use when run above the salt where they are useful for correlation, identifying caprock and carbonates, hydrocarbon versus water-bearing zones, permeable zones, and identifying the base of groundwater. The type of resistivity log used depends upon borehole conditions. Induction logs do not work in oil-based or salt-saturated drilling muds. Laterologs should be used in salt or salt-saturated drilling mud.

## A.13 Spontaneous Potential (SP)

SP logs measure the natural electric potential that arises due to differences in the ionic activities (relative salinity) of the drilling mud and the formation fluid. SP logs do not work in salt-saturated or oil-based mud. Therefore, other than indicating the presence of salt, SP logs are not useful for characterizing salt and are not typically run in salt. However, SP logs are useful for well correlation, identifying porous and permeable zones, and defining freshwater zones in the sediments above or adjacent to the salt.

## A.14 Borehole Imaging Logs

Borehole imaging logs can provide high resolution data to assist with the identification and characterization of the geology intersecting a borehole. Borehole image log tools can either be electrical or acoustic. Selection of the proper tool depends upon the borehole conditions, geology, and data requirements. Electrical tools measure resistivity from pads pressed against the borehole wall and the resolution is highly sensitive to borehole conditions. Electrical tools require conductive borehole fluids and are sensitive to mud filter cake development, shape, deviation, and rugosity. Resolution and borehole coverage are also influenced by logging speed and borehole size, with resolution tending to decrease as borehole size increases. Although standard electrical imaging tools can accommodate boreholes up to 21 in. diameter, they are ideally suited for boreholes from 6.0 in. to 12.25 in.

Acoustic imaging tools provide high resolution images of the borehole by emitting acoustical pulses and recording the travel time of returning pulses. The advantage of acoustic imaging tools is their applicability to different mud systems and full 360° borehole coverage. Mud additives and base fluid influence mud attenuation. Borehole acoustic tools operate best in boreholes with diameters from 4.5 in. to 13 in. In light borehole mud, the maximum bore hole diameter is about 13 inches. Data quality can be severely affected by borehole irregularities.

Borehole imaging logs can be used to identify and determine the orientation of linear features such as fractures, bedding, and faulting planes as well as information on lithofacies, bedding structures, porosity type, and unconformities. Borehole imaging logs may be used in salt to locate anomalous salt, shear zones, faults, and flow banding that may provide clues about preferential dissolution of salt prior to cavern solution mining and possible insoluble beds. Borehole imaging logs are limited to operating in light drilling fluids and are sensitive to borehole geometry. Borehole image logs work best when used in conjunction with other well log and core data.

If consecutive runs are made in an open borehole over a period of weeks or months, any observed variation can be attributed to geologic processes, such as swelling clays and salt creep. Such an interpretation requires the close integration of core data with a suitable suite of well logs.

# Annex B
(normative)

# Integrity Monitoring Methods

## B.1 Cavern System Scope

### B.1.1 General

The cavern system is comprised of the wellhead, the cased wellbore, the uncased wellbore, the cavern neck, and the cavern. Integrity Monitoring methods with this scope view the cavern system as a single containment unit in contrast to other methods that have a more focused scope, such as a sonar survey (cavern scope) or a caliper log (wellbore scope). Cavern system methods should provide an assessment of the ability of the System to contain gas under pressure, often up to the Maximum Allowed Operating Pressure (MAOP).

### B.1.2 Mechanical Integrity Test: Gas Filled Method

In contrast to testing a brine filled cavern with the Nitrogen/Brine Interface MIT, the Gas Filled MIT is a pressure test in which the cavern system is filled with gas throughout the System. The Gas Filled MIT is a test suitable for the long periods of time the cavern system is in normal gas service and refilling the cavern with water or brine is not advisable.

The test calculates the total gas volume in the cavern system at two points of time, often 72 hours apart. The difference in the starting and ending total gas volumes are assessed against a pass/fail criterion.

Requirements include knowing or estimating the cavern size and shape, cavern volume accurately sub-divided into depth intervals or slices (often 10 ft intervals), and an accurate gas composition analysis. The cavern will also need to be pressured at or near the MAOP and have an open pathway to the total depth to permit access for logging tools. It is advised to install blind flanges on the final outboard wellhead valves. Additionally, it is often beneficial to install a recording pressure gauge on a wellhead port which accesses surface shut-in pressure. The same pressure/temperature gauge should be used for both logging runs.

To determine the starting total gas volume, pressure/temperature gauges are run on wireline into the cavern and allowed to stabilize. The gauges are lowered in specific depth intervals to the planned total depth, with pressure and temperature recordings made at each interval. The gauges are then pulled out of the well and the data downloaded. After the predetermined length of time, these steps are repeated to collect pressure and temperature data for use in determining a second or ending total gas volume.

The gas volume in each depth interval can be calculated using natural gas law equations, the interval volume and the pressure and temperature recorded in the interval. The total gas volume is the sum of the calculated volume in each cavern interval. The change in total gas volume is the difference between the starting and ending calculated total gas volumes. Each operator applies their own pass/fail criteria to the results of the test. Often, a minimum detectable volume change is calculated based on the accuracy of the logging gauges and used as pass/fail criteria. If the change in total gas volume is less than the minimum detectable volume change, the cavern system passed the test and is fit for gas service.

The gas filled MIT method tests the entire cavern system including the cavern, casing seat, wellbore, and wellhead. The test does not require the cavern to be refilled with brine. The test can be repeated as needed to prove integrity. The larger the cavern volume, the lower is the accuracy of this method due to the lack of ability to measure temperature further away from the wellbore in the outer regions of the cavern.

### B.1.3 Continuously Reading Downhole Gauges

Using similar calculations of the total gas volume in a cavern system, the continuously reading downhole gauges method involves semi-permanently installing pressure/temperature gauges in the cavern close to the cavern's volumetric centroid. Pressure and temperature data delivered to the surface via special hardened conductor cable are used to calculate total gas volume.

Requirements include knowing or estimating the cavern size and shape, calculation of the cavern system's volumetric center, an accurate gas composition analysis, a suitable location to hang off or rigidly affix the gauges to prevent them falling off the cable, and the necessary equipment at the wellhead and on the surface to allow the conductor cable to communicate with facility SCADA processes.

The total gas volume can be calculated as frequently as every 5 minutes (or less) using the pressure and temperature recorded by the gauges, the natural gas law equations, and the cavern volume. Analysis of these data during shut-in periods is particularly useful as the calculated total gas volume should not be changing significantly.

Though this method collects pressure and temperature data from only one point in the cavern, the ability to collect these readings continuously through time allows a detailed analysis not possible with single-point-in-time methods. Operators have also been successful using fiber optic cable with distributed temperature measurement capabilities that can measure temperature throughout the length of the cable.

### B.1.4 Inventory Verification Analysis

Inventory verification analysis is the comparison of two methods of calculating the total gas volume stored in a cavern and looking for discrepancies. The two processes are:

— Gas Accounting Method—the calculation of total gas stored using the net of daily gas meter activity (injection, withdrawal, fuel, blow down, and other measured and estimated volumes);

— Physical Parameter Method—the calculation of total gas stored using physical parameters of the natural gas law equations.

For inventory verification, the cavern system should be evaluated as a single entity for the containment of gas stored within. The measurement of gas in the cavern using physical parameters (pressure, temperature, gas composition, size, and shape of the cavern) should be equal to, at any point in time, the gas accounting calculation using metered gas flow.

Significant variances between the gas accounting calculation and the physical parameter calculation should be investigated.

Types of metering include orifice, turbine, annubar, positive displacement, and ultrasonic meters. The operator should periodically test and verify that metered volumes are as accurate as necessary.

### B.1.5 Material Balance/Hysteresis Curves

There are a number of inventory verification models that may be used by the operator to both monitor integrity and determine inventory. The most widely used is either plotting pressure versus inventory or pressure divided by gas deviation factor versus inventory. Methods include:

— Wellhead pressure versus inventory. While this is the least accurate way of monitoring inventory, the accuracy can be improved if the operator corrects the pressure to cavern pressure by calculating the weight of the column and accounting for any frictional losses.

— Periodic pressure and temperature surveys combined with material balance. This allows for more enhanced monitoring that can be combined with more frequent wellhead pressure versus inventory monitoring to obtain better accuracy and tune the models.

— Thermal cavern simulation. Models are available as an additional tool to monitor inventory.

— Permanent pressure and temperature probes. Probes are placed downhole within the cavern. These probes are an emerging technology.

As gas is injected or withdrawn, the gas in the cavern heats or cools. Operators should evaluate the effects of temperature in gas operation. Evaluation of these effects should include:

— calculation of the casing seat pressure;

— working gas capacity.

When maximum or minimum pressures are established at the casing seat, a maximum wellhead pressure is calculated. If the assumed gas temperature changes within the wellbore that established the maximum wellhead pressure changes, then the operator will need to adjust the maximum pressure.

Working gas capacity can change significantly based on the average gas cavern temperature. As gas is withdrawn from a cavern, especially during rapid withdrawals, the gas cools and becomes denser. While this effect does not create a safety issue, the working gas capacity is reduced.

There are a number of thermal simulators that can aid the operator in determining temperature affects in operating a gas cavern.

## B.2 Wellbore Scope

### B.2.1 General

The scope of the wellbore is the hole of varying diameters bored into the subsurface by the drilling rig using multiple diameter drill bits. For the purposes of this RP, the wellbore has three sections:

— a long section comprising most of the depth from the surface to near the cavern roof which is cased with steel casing;

— the casing seat which is the point where the steel casing ends;

— a relatively shorter uncased section of open rock previously bored by the drilling process and immediately below the casing seat.

It is important to monitor these sections for the ability to contain gas under pressure.

### B.2.2 Mechanical Integrity Test: Nitrogen/Brine Interface Method

The Nitrogen/Brine Interface method MIT is a pressure test in which the cavern wellhead, wellbore and casing seat are tested for integrity and fitness of service. This MIT method is often conducted at the point of commissioning a cavern for gas service, which occurs at completion of solution mining operations and prior to debrining with gas. It is also suitable for an integrity test after cavern workover operations during which the cavern has been filled with water or brine and is being returned to gas service.

The cavern should be pre-pressured with water or brine injection through the inner hanging string to reach the target test gradient at the production casing shoe. If water or unsaturated brine is used, additional injections and stabilizations may be required due to the additional space created in the cavern.

In a Nitrogen/Brine Interface MIT, a brine-filled cavern is prepared for testing by injecting an initial volume of nitrogen into the annulus while producing brine from the inner hanging string. As this initial volume of nitrogen is injected, the wellhead and casing are checked for leaks. The initial injection of nitrogen is followed by further nitrogen injections into the annulus to bring the cavern to test pressure and to position the interface between the injected nitrogen and the brine below the casing seat and into the cavern neck.

Throughout the test, all wellhead pressures are monitored and the wellhead is checked for leaks. At the start and end of the test, the depth to the nitrogen/brine interface is determined using a suitable density measurement logging tool. The volume and mass of nitrogen can be calculated using:

— wellhead pressures converted to downhole conditions;

— nitrogen/brine interface depth measurements;

— an estimate of downhole temperatures based on brine temperatures in the hanging string; and

— the known volumes of the cased annulus and the cavern neck.

The test is evaluated by calculating the nitrogen volume at the beginning and end of the test period. The change in these volumes can be compared against a pass/fail criterion, determining integrity and fitness for gas service.

Pressure recorders should be installed on both the nitrogen and brine side wellhead outlets.

To avoid possible leak paths during the test, it is advisable to isolate the wellhead from all surface piping by installing blind or skillet flanges on the outboard wellhead valves. Wellhead pack-off flanges such as p-seals should be tested for leaks as well.

The wellhead pressure should be stable prior to starting the test or at least indicate a diminishing rate of decline. Nitrogen injection temperature should be regulated to that of the average wellbore temperature.

The profile and volume of the cavern neck below the casing seat should be determined by a previous sonar survey. Test resolution can be enhanced by positioning the nitrogen/brine interface in a known-volume section of the cavern neck.

### B.2.3 Cased Hole Logs

Downhole logs are run as part of monitoring the integrity of the cavern and wellbore. The following is a list of standard logs that operators run along with the purpose or how it can be used.

### B.2.4 Caliper Log

A caliper log is used as part of a casing inspection program. The tool is lowered into the well and centralized then arms, from 4 to more than 80, are extended from the tool. The arms measure the distance from the tool the internal diameter of the casing. These direct measurements allow the tool to locate holes, casing wear, and other interior defects. This method only allows the interior of the casing to be inspected.

### B.2.5 Magnetic Flux Leakage Log

Magnetic flux leakage log is a form of nondestructive testing that is used to detect corrosion or pitting in casing. A magnet of sufficient strength is used to induce a magnetic field around the steel casing. Areas of pitting or corrosion result in changes in that magnetic field that can be detected with the log. The method can be used to determine the location and magnitude of interior and exterior corrosion or pitting. Newer logs use directionally oriented rare earth magnets to also define the pit geometry so that casing integrity can be quantified. These logs are limited to smaller sizes and not typically available for the larger bore caverns.

### B.2.6 Noise Log

Gas leaking from a high pressure wellbore into the surrounding formation through a small hole or defect produces a high frequency noise signal. Under some wellbore conditions, a wireline conveyed noise logging tool can detect these signals. Recently, the ultrasonic leak detection tool has been used to find leaks that were undetectable by spinners, temperature logs, and traditional noise logs.

### B.2.7 Temperature Log

Pressure and temperature logs can be used for a number of different applications, such as MITs, inventory verification, determination of working versus base gas, heat transfer. In addition, temperature logs may have some application in determining wellbore leaks.

### B.2.8 Cement Integrity Log

As of the writing of this document, there are four main types of cement integrity logs: cement bond log (CBL), cement mapping log, ultrasonic cement mapping tools, and ultrasonic imaging logs (USI, RBT). Each log type should be evaluated for the specific job requirements.

### B.2.9 Downhole Camera

A downhole camera provides multiple single-frame or full-motion video of the inside of the wellbore to provide an indication of the condition of the wellbore. Two types of downhole cameras are most often used. Run on standard conductor wireline cable, the “hawkeye” or single frame camera can take one photo approximately once per second. For higher frame rate and picture quality, a full motion video camera can be run but requires fiber optic-based wireline cable. Both cameras have a lens mounted on the end of the tool carrier with a downward looking light source. Some cameras can tilt the lens 90° from downward to sideward looking. The camera can view approximately 4 ft down the wellbore, depending on conditions.

Wellbores filled with gas or clear fluid provide the clearest inspections. Experience has shown that cameras are most useful with inspections of the wellbore and casing.

## B.3 Cavern Scope

### B.3.1 General

The scope of the cavern is the void created by solution mining the surrounding salt formation.

Cavern scope integrity monitoring methods provide an assessment of the ability of the cavern to contain gas under pressure, often up to the MAOP.

### B.3.2 Sonar Survey

Sonar surveys are used to determine the shape of the cavern. A periodic program of running sonar surveys provides the best indication of cavern size and identifies issues that may occur within the cavern. Current sonar tools have the capability to determine cavern shape and capacity in a gas filled cavern without a hanging string. Some operators choose to cut off the tubing below the casing seat so that sonar surveys can be run in a gas filled cavern.

### B.3.3 Cavern Total Depth Log

Periodic gas/brine interface surveys should be run. These surveys may indicate anomalous behavior. Particular attention should be placed on the relationship between the gas/brine interface and the cavern TD. Any changes could indicate:

— the bottom of the cavern moving up; or

— salt falls.

### B.3.4 Subsidence Monitoring

Using surface elevation survey techniques, subsidence in the area above and near the cavern should be monitored and compared to amounts predicted by geomechanical analysis.

Subsidence is a natural process where an amount of subsidence is unavoidable. Natural subsidence is broad and wide-spread. However, greater than predicted subsidence in a localized area near a cavern can be an indication of cavern instability.

## B.4 Wellhead Scope

### B.4.1 General

The wellhead scope is comprised of the wellhead valves and fittings.

Wellhead scope integrity monitoring methods provide an assessment of the ability of the wellhead to contain gas under pressure, often up to the MAOP.

### B.4.2 Ultrasonic Thickness Measurements

Using ultrasonic measurement tools, the wall thickness of key areas of wellhead valves and fittings can be monitored. Repeated measurements can help assess wall loss due to corrosion or erosion effects. Specific locations should be marked so measurements can be repeated and monitored.

### B.4.3 Annulus Pressure Monitoring

Gas pressure may be present in the cemented annuli within the wellhead for a number of reasons. Monitoring the pressure on these annuli can help identify unexpected changes that require further investigation.

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