FIELD STUDY TO DETERMINE THE FEASIBILITY OF DEVELOPING SALT CAVERNS FOR HYDROCARBON STORAGE IN WESTERN NORTH DAKOTA

Final Report

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DEFINITIONS

Aspect ratio – The ratio of a cavern's vertical height to its horizontal diameter dimension. Aspect ratio strongly influences cavern properties such as stability. Cavern aspect ratios used in the present study range from 1:1 to 1:5.

Aspen Plus – A computer program used to mathematically model, simulate, and optimize chemical processes. It supports chemical process monitoring, design, optimization, and business planning.

Associated gas – Natural gas coproduced during crude oil production.

BPS – Bakken petroleum system; geologic structures comprising organic-rich source rocks, reservoirs, and seals and in the Williston Basin includes the Bakken and Three Forks Formations.

Base gas – The volume of gas that must remain in an underground gas storage facility to maintain adequate pressure and delivery rates. Also referred to as cushion gas.

Battery limit – The perimeter of a specific manufacturing process area. This area will include process equipment and may include in-process tankage.

bbl – barrel; 1 barrel of crude oil is equal to 42 gallons.

Bedded salt – Geologic layers of salt (e.g., halite) that extend laterally, sometimes across large geographic areas, and bound by specific geologic formations. Salt beds are, in general, vertically thinner than salt domes. Bedded salt can be mobilized in response to burial of sediments but to a lesser degree compared to domal salt.

Blanket pad (or blanket material) – A noncorrosive fluid or gas (commonly, crude oil, diesel, or mineral oil) placed within a cavern that floats on the water/brine in the cavern and will not dissolve the salt or mineral impurities in the formation. The blanket protects the cemented casing from internal corrosion and prevents unwanted leaching of the cavern roof or around the cemented casing. The blanket material is placed against the cavern roof, within the cavern neck, and between the cavern's outermost hanging string and innermost cemented casing.

Brine-compensated drive system – Utilizes a system that displaces the brine in the cavern with the product fluids pumped into the cavern. The variation in buoyancy allows the fluids to stay separated. The displaced brine is stored at the surface in storage tanks or holding ponds until the demand occurs to withdraw the product.

Brine pond – Earthen ponds with a built-up berm/dike around the pond, lined with clay and typically utilize two impenetrable moisture barrier membranes over the clay to hold the fluid and offer additional containment protection. Groundwater is pumped from beneath the pond to prevent any contamination and is carefully monitored for any indication of brine leakage.

Bscf – Billion standard cubic feet.

Class III injection well – Used to inject fluids into the deep subsurface to dissolve and extract minerals, such as salt or potash. Production wells that bring the solution to the surface are not regulated under the Class III underground injection control program.

Constitutive property – Describes the deformation of a rock in response to an applied stress (or vice versa).

Dilation strength – Laboratory test that characterizes the strength of salt by applying stress and determining the point at which dilatational microfracturing (e.g., creation of voids) occurs, which is an estimate of the strength of the salt. Used for calibration in mechanical earth models.

Domal salt (salt domes) – Geologic structural dome formed when a bed of salt found at depth is mobilized in response to rapid deposition of sediments and intrudes vertically into and across overlying and adjacent formations.

Economies of scale – Cost decreases experienced when production becomes efficient, typically when manufacturing volumes increase and costs are spread over a larger amount of goods.

Effective porosity – Represents the porosity of a rock or sediment available to contribute to fluid flow through the rock or sediment.

Equivalent creep strain rate – Effective strain rate and direction resulting from calculation of strain rates in the vertical and horizontal directions (i, j, and k directional tensors). Abbreviated as "EQCreepStrain" in the near-wellbore geomechanics 3D MEM model results. See Appendix E for additional information.

Evaporite – A water-soluble sedimentary mineral deposit that results from concentration and crystallization by evaporation from an aqueous solution.

Finite-element method – Applied on a 3D modeling simulation mesh network by assigning each element of the mesh network a discrete value, e.g., porosity, permeability, salt creep value, etc.), which is then modeled using algebraic equations for selected time periods and based on boundary condition limitations to provide a solution. The approach uses "structured" meshes, e.g., the geometry of each mesh element is similar.

Finite-volume method – Applied on a 3D modeling simulation mesh network by assigning each element of the mesh network a discrete value, e.g., porosity, permeability, salt creep value, etc.), which is then modeled using algebraic equations for selected time periods and based on boundary condition limitations to provide a solution. Similar in some respects to the finite-element method, this approach has the capacity to use "unstructured" meshes; e.g., the geometry of each mesh element is not required to be similar. Unstructured meshes are powerful when modeling salt, given the mobile nature of salt when subjected to stress in the subsurface.

Fracture – A mechanical break in a geologic formation, such as a joint (no displacement) or a fault (displacement exists), that divides the rock into two or more pieces. Fractures are characterized as conductive (open to drilling mud invasion) or resistive (closed because of mineralization).

Friction angle – A measurement to determine the shear strength of a rock material; used in calibration of the mechanical earth model.

Gas bubble – See working gas.

Gas-compensated drive system – Utilizes a system that compresses the incoming storage gas to fill the cavern, increasing the pressure in the cavern as it fills with product.

Gas hydrates – Icelike crystalline structures that form when a low-density gas, like methane, ethane, or carbon dioxide, combines but does not chemically bond with water and freezes into a solid under low-temperature and moderate-pressure conditions.

Gas plant – A natural gas-processing facility located in the vicinity of production wells that separates raw natural gas into a natural gas stream suitable for pipeline transport to markets and a mixed natural gas liquid stream called “Y-Grade,” suitable for fractionation into its component hydrocarbons.

Geologic model (geomodel) – A 3D spatial representation of the structure (e.g., faults, surfaces, etc.) and reservoir characteristics (e.g., porosity, permeability, fluid saturation, etc.) of the modeled interval across a geographic area.

Geomechanics – Study of the mechanical behavior of geologic materials.

GOR – Gas-to-oil ratio; the amount of natural gas produced per stock tank barrel of oil.

H:D – Abbreviation to describe the vertical height (H) to horizontal diameter (D) aspect ratio of a cavern geometry.

HGL – Hydrocarbon gas liquid; hydrocarbons that occur as gases at atmospheric pressure and as liquids under higher pressures.

Hybrid cavern drive system – This system takes into consideration the fluids from the gas-compensated scenario using the brine-compensated simulation. This is hybrid because it utilizes the brine equipment from the brine model and the gas compressors and dehydration equipment from the gas-compensated model. Could be loosely considered a subdivision of the brine-compensated scenario.

Joule–Thomson effect – The change in fluid temperature as it flows from a region of higher to lower pressure.

Leaching – The removal of soluble material from a substance through the percolation of water. For this report, a leaching operation refers to the set of actions performed to dissolve salt from a salt deposit.

Mbbl – Thousand barrels.

MEM – Mechanical earth model; an interpretation based on data and measurements that represents the mechanical properties of rocks and fractures, as well as the stresses, pressures, and temperatures acting on the rocks at depth. MEMs can be prepared in 1D (e.g., along a wellbore) or in 3D (e.g., 3D volume around a target area and/or well).

MMbbl – Million barrels.

Mohr–Coulomb failure theory – A set of linear equations that describe how an isotropic material will exhibit shear failure in response to principal stresses, e.g., vertical overburden stress (Sv), maximum horizontal stress (SH_{max}), and minimum horizontal stress (Sh_{min}).

MPa – Megapascals; metric unit of pressure. One MPa = 145.038 psi.

Mpsi – Thousand pounds per square inch.

Mscf – Thousand standard cubic feet.

Natural gas – Hydrocarbon gas mixture containing primarily methane and to a lesser extent ethane, propane, butanes, and pentanes; can also contain impurities such as carbon dioxide, helium, nitrogen, and hydrogen sulfide.

NGL – Natural gas liquid; a group of hydrocarbons including ethane, propane, butanes, and pentanes plus, aka natural gasoline, a by-product of natural gas processing and refining.

Palygorskite – An acicular bristle-like crystalline form that does not swell or expand.

P_{min} – Minimum pressure on salt cavern walls resulting from seasonal cyclic loading. In this study, the minimum pressure is defined by the pressure gradient of the brine used in the modeled cavern operation at the depth of the cavern.

P_{max} – Maximum pressure on the salt cavern walls resulting from vertical stress or overburden at the cavern location. Results of the 1D mechanical earth model were used to determine the vertical stress value (psi) at the modeled cavern levels.

Poisson's ratio – An elastic constant that is a measure of the compressibility of material perpendicular to applied stress. Poisson's ratio is symbolized by σ. The static (vs. dynamic) value is required for mechanical earth model calibration and characterization of rock strength; e.g., lower Poisson's ratio values indicate the material is more resistant to deformation and is stronger.

SALGAS® – Leaching modeling software (Saberian, 1974) developed from SALT77® that is based on MIXING1 code, developed by Solution Mining Research Institute (SMRI) between 1970 and 1974.

Saline formation – A geologic layer consisting of porous rock (e.g., sandstone) that is filled with salty water (brine).

Salt cavern – Artificial cavities in underground salt formations, which are created under the controlled dissolution of rock salt by injection of water.

Salt creep – Slow deformation of a salt formation in response to forces and mechanisms that control underground salt flow.

Salt formation – A geologic layer where the rock consists primarily of salt (i.e., halite).

Shear stress – A deforming force, acting parallel to the surface of the sample, attempting to shear the sample. Shear stress can be represented by fractures in the rock with displacement and with borehole breakouts in the borehole wireline log when the shear stress is surpassed.

Strain – The permanent deformation evident in rocks and other solid bodies that have experienced a sufficiently high applied stress. Since strain is the ratio of two lengths of a material, the value is dimensionless.

Strain rate – The change in strain (deformation) of a material with respect to time.

Stress – The force applied to a body that can result in deformation, or strain, usually described in terms of magnitude per unit of area, or intensity. Stress is characterized vertically and horizontally.

Tensile stress/strength – A deforming force, acting perpendicular to the surface of the sample, attempting to elongate the sample. Tensile stress can be represented by cracks in the rock sample and in the borehole image wireline log when the tensile strength is surpassed. Used in calibration of the mechanical earth model.

Thenardite – A mineral that forms in evaporite environments related to lakes and playas; the chemical composition is Na_2SO_4.

Total porosity – The total void space that includes isolated pores and the space occupied by clay-bound water. It is the porosity measured by core analysis techniques that involve disaggregating the sample.

Unconfined compressive strength – The maximum axial compressive strength that a cylindrical core sample can bear under zero confining (around the core) stress; used in calibration of the mechanical earth model.

Variogram – A statistical structure which depicts how similar or dissimilar each pair of points are in a set of sampled data.

Variography – The process of examining spatial dependence using a variogram; a set of procedures for interpreting variograms.

Working gas (gas bubble) – A term used in natural gas storage systems that refers to the volume of gas added or withdrawn to meet demand. Working gas is the difference between the total volume of gas in storage and the base gas volume.

XRD – X-ray diffraction; an analytical technique used in materials science to determine the crystallographic structure of a material.

Y-Grade – An NGL (natural gas liquid) mixture that has been through field processing but has not been through NGL fractionation.

Young's modulus – An elastic constant that is the ratio of longitudinal stress to longitudinal strain and is symbolized by E. The static (vs. dynamic) value is required for mechanical earth model calibration and characterization of rock strength; e.g., higher Young's modulus values indicate a stronger, more brittle material vs. a material that is more ductile.

FIELD STUDY TO DETERMINE THE FEASIBILITY OF DEVELOPING SALT CAVERNS FOR HYDROCARBON STORAGE IN WESTERN NORTH DAKOTA

EXECUTIVE SUMMARY

The Energy & Environmental Research Center (EERC) was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP), NDIC No. G-054-104, to conduct a study on the feasibility of developing salt caverns in geologic formations in North Dakota for underground storage of energy resources, including hydrogen, natural gas (methane), and natural gas liquid (primarily ethane and propane), as directed by Section 14 of North Dakota Senate Bill 2014. The goal of the study was to provide stakeholders with information needed to assess the techno-economic viability of storing hydrocarbons and hydrogen in engineered salt caverns in North Dakota.

At the onset of the project, the EERC identified and selected a team of industry experts with direct knowledge and involvement in the development and operation of engineered salt caverns used for product storage. The advisory board was asked to provide guidance regarding project activities to ensure future commercial opportunities were well understood and technically achievable.

A major component of the project was to drill and core a dedicated well penetrating two of North Dakota's shallowest bedded salt formations: the Dunham and Pine Salt Members. Geologic site screening was conducted to determine a drilling location with a high likelihood of encountering significant thicknesses of both the Dunham and Pine Salt intervals. Determining factors leading to a successful stratigraphic test well were 1) salt formation depth, 2) salt thickness, and 3) proximity to local and regional infrastructure needed for future engineered caverns. Data used for the screening assessment were retrieved from publicly available sources stored in the North Dakota Department of Mineral Resources Oil and Gas Division database. Results identified multiple locations that met the outlined criteria for the drilling and coring needs of the study. Ultimately, the EERC worked in collaboration with the state to identify a previously abandoned well pad to serve as the location for the stratigraphic test well. This option minimized the amount of site preparation and road construction required at the location.

The well, HALITE 1 NDIC File #38890, was drilled, and two salt members were successfully cored: the Dunham Salt and the Pine Salt. The location of the well is in McKenzie County, North Dakota, near Williston. The Dunham was encountered at a depth of 6820 ft and the Pine at a depth of 7183 feet beneath the surface. Core from each of the two members and rock from the upper and lower confining members associated with each salt were collected. In all, 70 feet of salt was retrieved from the Dunham member along with 30 feet of overlying cap rock and 30 feet of underlying underburden. Likewise, 60 feet of Pine Salt was collected along with associated cap rock and underburden. The collected core, along with associated wireline logs, were analyzed, and the interpretations were used to estimate the viability of engineering and operating salt caverns for product storage in North Dakota.

Core analyses were conducted to determine the composition of material collected and assess the geomechanical properties of the salt intervals. Both properties are an important consideration in the successful development and operation of engineered salt caverns to be used for fluid storage. At the HALITE 1 site, the Dunham Salt was determined to be nearly 100% pure halite salt. This is a benefit to cavern development and operation as halite is soluble in fresh water and is known to be impermeable. The Pine Salt has soluble impurities that require additional consideration to determine their impact on development and operational scenarios. Results of mechanical testing show that both salt intervals at the HALITE 1 site have properties that are comparable to other North American bedded salts where commercial subsurface gas storage caverns have been developed and operated for decades.

Results of this study demonstrate that cavern development in North Dakota's bedded salts has potential. The work performed delivers information regarding the depth, thickness, salt quality, and mechanical properties at the HALITE 1 site that provides insight regarding other locations in the Williston Basin where salt thickness is comparable or even greater. Cavern modeling at HALITE 1 demonstrated that a cavern can be created that could store volumes between 25 and 100 Mbbl. If needed, multiple caverns could be created in a gallery arrangement to accommodate greater volumes of liquid or gas. Other locations in the Williston Basin may provide opportunities to develop larger-volume single caverns.

Future work should focus on pilot-scale demonstration activities to support development of an engineered-solution mined salt cavern to advance research knowledge gained from drilling, coring, and testing of the HALITE 1 well. The following next steps are recommended:

1. Select a location in the Dunham or Pine Salt of the Williston Basin that are of sufficient thickness and have low impurity content.

2. Drill, core, log, and test the salt member to confirm predicted characterization and site selection criteria (depth, thickness, and impurity content).

3. Test collected core and perform geomechanical modeling and simulation of the site, to design and develop a salt cavern for proof-of-concept demonstration of liquid- or gas-phase product storage in an engineered salt cavern in North Dakota.

The successful development of a salt cavern in North Dakota's bedded salts will provide commercial entities with the incentive needed for proceeding with commercial cavern development in the state, thereby supporting new markets, increasing the offtake storage capacity of gas and liquid production, and providing the fundamental research needed for future hub development opportunities in the state.

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1.0 INTRODUCTION

The Energy & Environmental Research Center (EERC) was awarded a contract by the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP), NDIC No. G-054-104, to conduct a study of the feasibility of developing salt caverns in geologic formations in North Dakota for underground storage of energy resources, including hydrogen, natural gas (methane), and natural gas liquid (NGL) (primarily ethane and propane), as directed by Section 14 of North Dakota Senate Bill 2014. This study follows a preliminary evaluation of the potential of salt cavern development completed by the EERC in December 2020 (Smith and others, 2020). The 2020 study identified three salt formations deemed worthy of further investigation for characterization activities to inform future cavern development studies. The goal of this follow-up study was to provide stakeholders with information needed to assess the techno-economic viability of storing hydrocarbons and hydrogen in engineered salt caverns in North Dakota.

2.0 KEY PROJECT FINDINGS

This study was conducted to investigate the potential for development of engineered salt caverns in bedded salt formations in North Dakota for the specific purpose of storing hydrocarbons or hydrogen. To accomplish this, a stratigraphic test well, HALITE 1, was drilled near Williston, North Dakota. Drilling activities included the collection of core sections taken from the Dunham and Pine Salt members at depths between 6800 and 7200 feet beneath the surface. At this depth, formation temperature presents certain challenges with respect to the salt creep properties, where a solid material slowly deforms over time as a function of temperature and pressure, that can impact the long-term operational stability of engineered caverns. However, examination of existing operations in bedded salts demonstrates that cavern storage is successful in similar geologic environments, such as the Lotsberg Formation near Fort Saskatchewan, Alberta. The average thickness of the salts targeted in this study across the Williston Basin are sufficient for fluid storage, whether in a single cavern or in multiple caverns collocated on a single site. This is encouraging for potential commercial salt cavern development and operation in the future.

Laboratory work conducted on samples taken from the HALITE 1 core intervals demonstrates that the Dunham Salt is composed of nearly 100% halite (NaCl). Halite is the most commonly targeted salt type for cavern development worldwide primarily because of the soluble nature of salt in water. Laboratory tests were also performed to determine the long-term mechanical stability of each salt member at the depths and temperatures at which they occur in the subsurface of western North Dakota. Salt creep is important to estimate the rate at which a cavern will reduce in size over an operational lifetime, usually as long as 30 years, or, in some cases, even longer.

Figure 2-1 shows results of creep tests performed on HALITE 1 samples compared to other locations with operational salt caverns. As shown, the Dunham and Pine Salt members have comparable creep behavior, indicating that caverns developed in North Dakota's bedded salts would likely behave similarly to those that have been commercially developed.

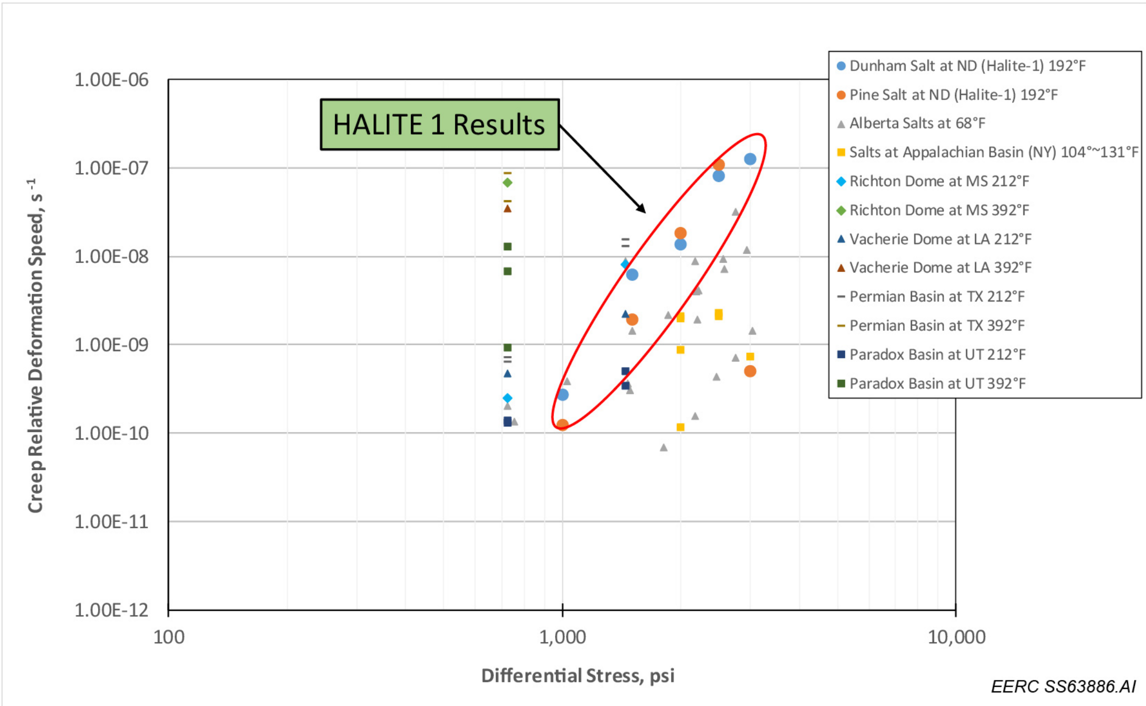


Figure 2-1. Results of laboratory creep testing. The Dunham Salt and Pine Salt of HALITE 1, the blue and orange dots, respectively, show similar creep properties to other regions, even if testing temperature is higher than Alberta and New York samples.

Geomechanical modeling of a cavern life cycle was conducted using data from the HALITE 1 site to understand the impact of cycling fluid in and out of a cavern over the operational life span. Specific fluids considered include hydrogen, ethane, propane, and Y-Grade NGL. Modeling conducted for Dunham and Pine Salts covered a range of height-to-diameter (i.e., vertical-to-horizontal) cavern geometry aspect ratios that ranged from 1:1 to 1:5. Salt creep displacement, cavern shrinkage, and cavern stability were investigated for each salt interval and aspect ratio geometry scenario. Modeling results show that, over a 30-year life span, caverns remained stable. Cavern geometries with ratios of 1:1 and 1:2 (height to diameter) were found to be more stable than the other modeled ratios. Cavern modeling demonstrated that a cavern can be created that could store volumes between 25 and 100 Mbbl within the Dunham and Pine Salts. These volumes are somewhat smaller than those of salt caverns used for hydrogen storage in Kiel, Germany, and less than 5% of the volume of U.S. Gulf Coast domal salt caverns used to store hydrogen. For NGL storage, multiple caverns may be necessary, especially to store individual NGL components after fractionation. Multiple caverns at a single location can be constructed to accommodate greater volumes of stored fluid. Petrochemical plants that fractionate NGL host multiple caverns to accommodate feedstock and each product, which could be pure components (e.g., ethane, propane, and butane) and/or commercial mixtures (e.g., EP, ethane–propane; or liquefied petroleum gas (LPG), propane–butanes). The lesser capacity of North Dakota salt caverns compared to other regions should not be of concern at this time. The value of storage is an economic question regarding the value of the products and the cost of North Dakota salt versus alternative storage, which are currently unknown. The existence of bedded salt of the quality and volume present in North Dakota is an advantage that more than 80% of the rest of the 48 contiguous states lack.

Cavern development in the Dunham and Pine Salts has potential. The work performed in this study provides information regarding the depth, thickness, salt quality, and mechanical properties at the HALITE 1 site. The results of the present study can be used to develop criteria for the development of individual or clustered salt cavern complexes, including minimum distances between caverns, maximum aspect ratios, salt cavern geometry, and economics. When the properties of the salts cored in this study are compared to commercially operational locations where bedded salts are used for storage, North Dakota's salts are similar. At the HALITE 1 site, the Dunham Salt has fewer impurities compared to the Pine Salt and could be considered for commercial development. A high percentage of the impurities in the Pine Salt are known to be soluble, but their mechanical properties may impact the long-term operational life span of a cavern. While modeling and simulations indicated that caverns developed in the Pine Salt are stable over the 30-year time frame, there is still enough uncertainty regarding the mechanical behavior and overall stability of caverns with high impurity content to warrant further investigation at other locations in the Williston Basin. For instance, the Dunham and Pine Salts reach thicknesses of up to 300 feet in the Williston Basin south and west of Dickinson.

Current North Dakota regulations for salt cavern storage projects reside largely in the recently created North Dakota Century Code (NDCC) Chapter 38-25 and the subsequent NDIC-promulgated regulations for the geologic storage of oil or gas within North Dakota Administrative Code (NDAC) Chapter 43-02-14 which took effect April 1, 2022. These chapters established the requirements for obtaining geologic storage facility permits for oil or gas storage in salt caverns as well as the requirements for obtaining the necessary permits to inject. Already well established in North Dakota were the regulatory requirements necessary for the development of a salt cavern through the solution mining process which are set forth in NDAC Chapters 43-02-02.1 and 43-02-02.4 which cover all aspects of salt solution mining, including requirements for the Class III injection well(s) saltwater-handling facilities and necessary containment measures.

NDCC Chapter 38-25 and NDAC 43-02-14 clarified several aspects pertaining to the requirements for salt cavern storage facilities, including clarifying the requirements for obtaining consent from the pore space owners and the salt mineral or salt lease owners within a proposed salt cavern project. It should be noted though that the current NDIC-promulgated regulations in NDAC 43-02-14 pertain only to the geologic storage of hydrogen and produced oil or gas with little to no processing involved and do not cover the storage of NGL or processed natural gas. NDIC's Oil and Gas Division has the established authority to regulate NGL and processed natural gas storage in solution-mined salt caverns that is nontransportation-related (NDCC 38-08-04), but currently no North Dakota regulations exist for permitting such facilities. Development of regulations that do pertain to the storage of NGL and processed natural gas is recommended to fill the gap that currently exists in the salt cavern storage regulations. Additional regulatory clarity would also be useful in regard to the ongoing brine handling and surface storage associated with salt cavern storage projects, including clarifications on what storage systems (i.e., brine storage ponds) will be considered acceptable.

The precedent for salt cavern development and commercial operation in North Dakota's bedded salts has been established by a previous operation, albeit for slightly different purposes. For nearly three decades, salt was mined from the Charles Formation by the Dakota Salt and Chemical Company at a location near Williston. While the cavern was developed and operated for mining salt for commercial use, the process was very similar to cavern development intended for fluid storage. This is noteworthy because the Charles Formation is deeper than the Dunham and Pine Salts, resulting in higher overall temperatures that are generally considered a concern because of accelerated rates of cavern closure over a cavern's operational life span. This operation supports the concept of cavern development in the shallower Dunham and Pine Salt members and warrants a new investigation of the Charles Formation salt intervals for fluid storage.

3.0 BACKGROUND

With the rapid development of the Bakken petroleum system (BPS), which includes both the Bakken and Three Forks oil reservoirs, the volume of oil and gas in the state of North Dakota has significantly increased from historic levels of production (Figure 3-1). Oil production expanded from just over 10,000 barrels per day (bbl/day) in January of 2007 to a peak of 1.46 million barrels per day (MMbbl/d) in October 2019, with an average of 1.0 MMbbl/d through 2021 and 2022 (North Dakota Industrial Commission, 2023). As oil production has increased, so has the volume of produced gas, also referred to as associated gas. Associated gas production increased from 11.3 Mscf/d in January 2007, peaking at over 3 Bscf/d in October 2019, and has maintained between 2.5 and 3 Bscf/d since mid-2020 (North Dakota Industrial Commission, 2023). As oil production continues in the BPS, the gas-to-oil ratio (GOR), or the volume of gas generated for every barrel of oil, continues to increase, which continues to generate concerns regarding North Dakota's ability to sufficiently collect, process, and export the associated gas generated in the state (Kringstad, 2023).

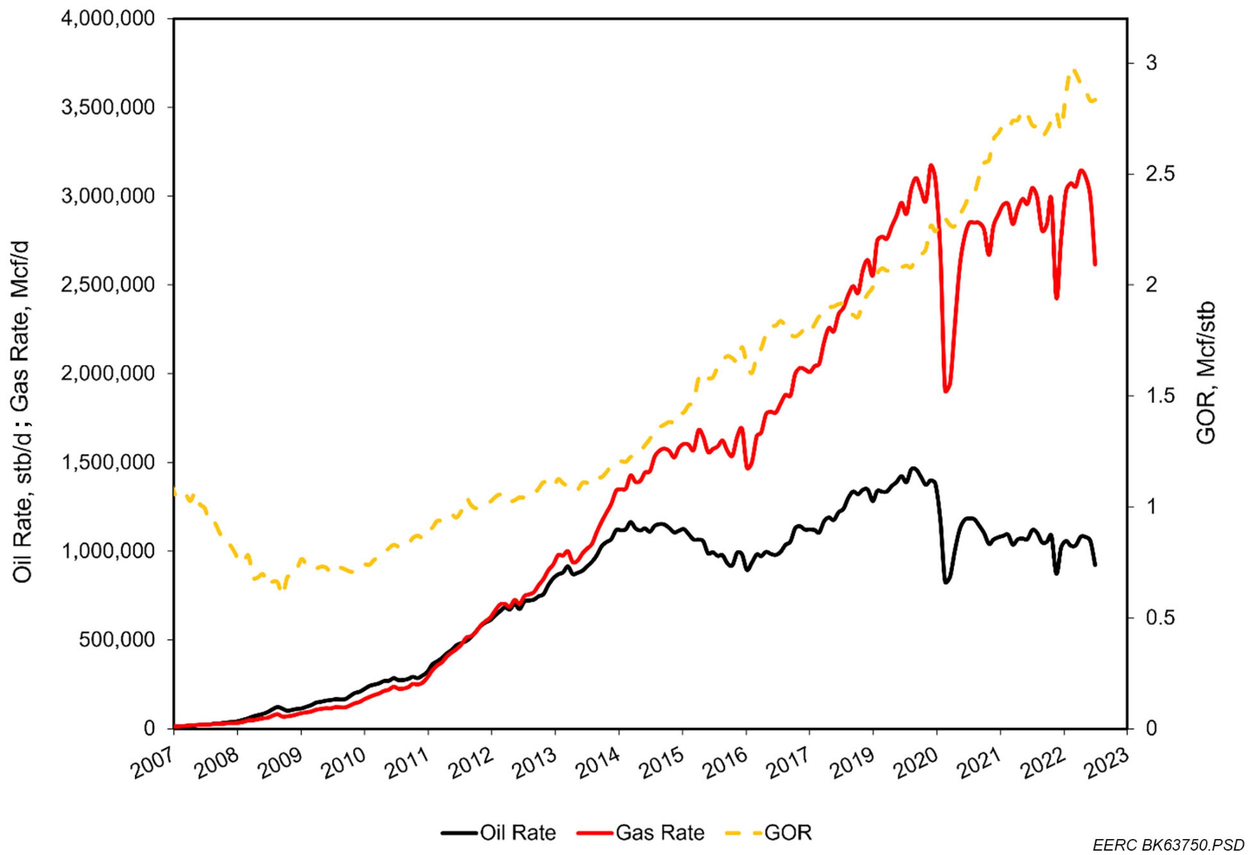


Figure 3-1. Illustration of increasing Bakken–Three Forks oil production (black), gas production (red), and GOR (yellow) from January 2007 to December 2022 (developed with data from the North Dakota Industrial Commission website [North Dakota Industrial Commission, 2023]).

Produced gas is transported to large gas-processing facilities where methane (i.e., natural gas) is separated from NGL, including ethane, propane, butane, pentane, hexane, and heptane. The proportion of methane to NGL for BPS produced gas varies across the basin, with a basin average methane concentration of 58%, whereas basin average ethane, propane, and butane concentrations are 20%, 11%, and 4.9%, respectively (Figure 3-2). Smaller concentrations of other hydrocarbons and nonhydrocarbon gases, such as pentane, hexane, nitrogen, carbon dioxide, and hydrogen sulfide, are also present (Kurz and others, 2020).

As associated gas production from the Bakken and Three Forks reservoirs continues to increase, so does the production of NGL. Figure 3-3 shows the increase in North Dakota NGL production, in barrels per day, from 2006 through 2022. The NGLs contained within produced gas are not only valuable fuels for heating, transportation, and drying but are also valuable feedstocks for the petrochemical industry where they are used to develop value-added products such as plastic, synthetic rubber, solvents, and resins, among other products (U.S. Energy Information Administration, 2023).

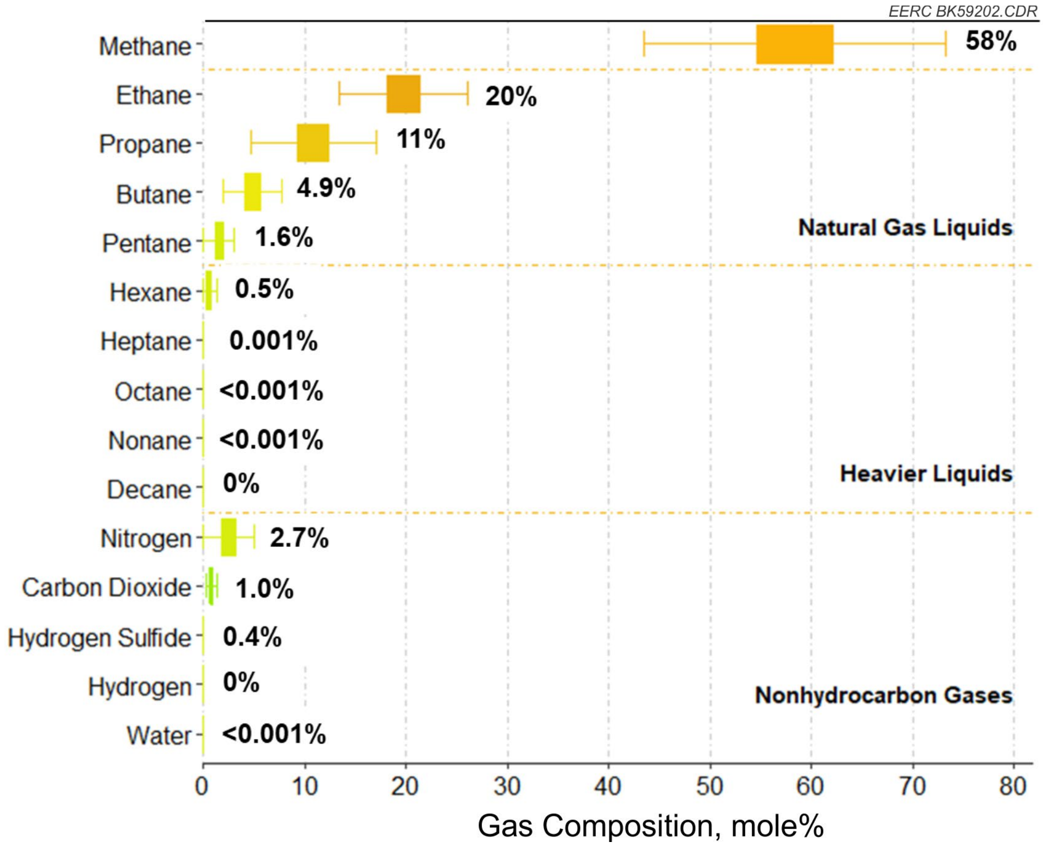


Figure 3-2. The average concentration and range in concentration (in mole percent) for individual gas components within Bakken produced gas. The values are based on basinwide gas composition data compiled by the EERC (Kurz and others, 2022).

Some gas plants in North Dakota experience periodic constraints in their ability to export natural gas and NGL to market which can create price discounts for these products or prompt petroleum producers to consider reducing production to avoid flaring. The development of salt caverns for subsurface gas or NGL storage could provide relief and an ability to optimize delivery timing to take advantage of market conditions and avoid undesired production cutbacks. Availability of inexpensive large-volume gas storage would also be attractive to existing chemical and refining industries and to a nascent hydrogen-based energy economy. NGLs serve as raw materials for the production of multiple products of value to the United States, while the natural gas itself (methane) can serve as a raw material for producing high-value products, including ammonia and hydrogen. North Dakota's geology provides an opportunity to 1) assist the industry it hosts in optimizing existing operations and 2) attract new industry – both of which benefit from local availability of inexpensive, large-volume gas storage.

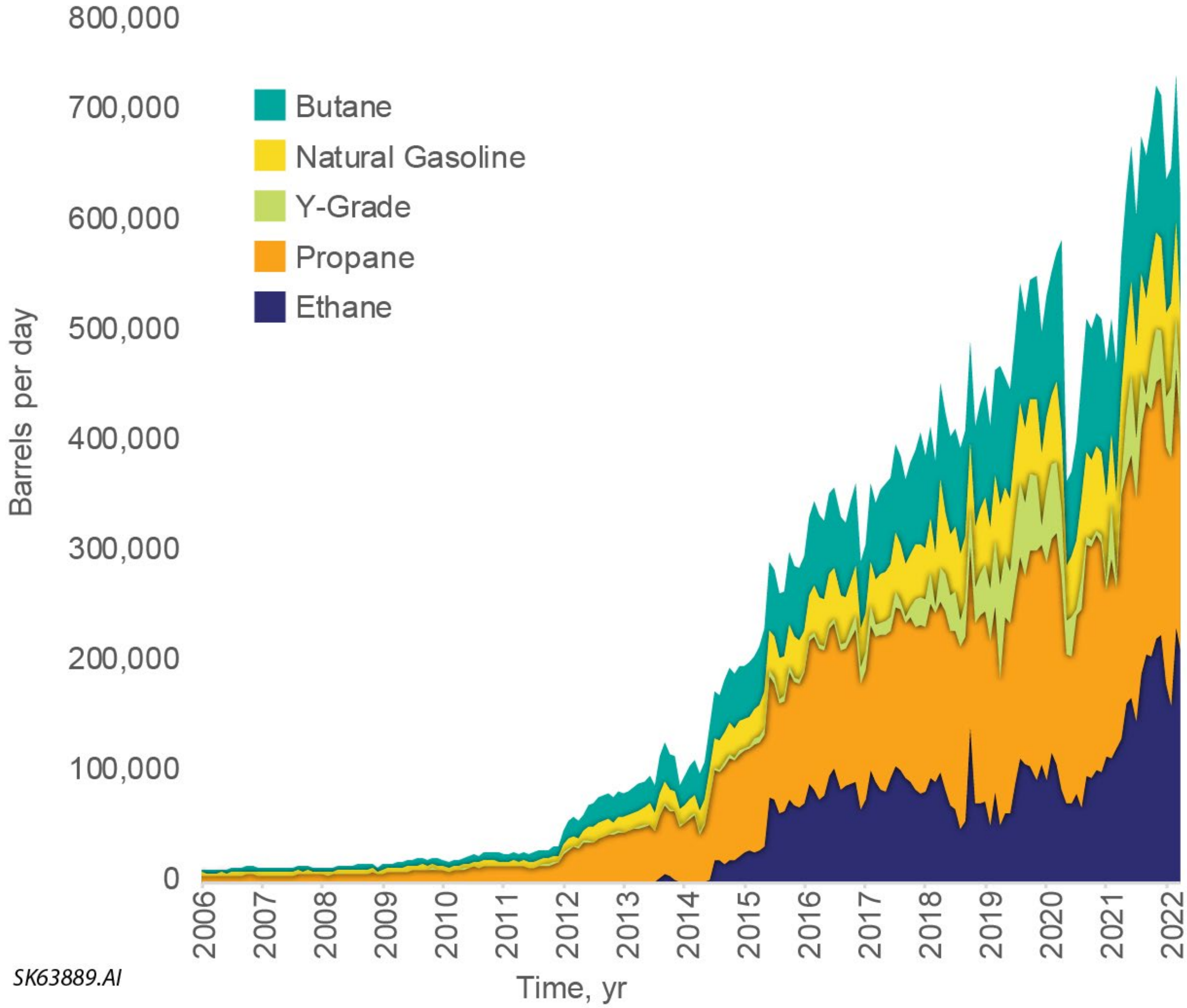


Figure 3-3. Production of NGL in North Dakota: 2006 through 2022. Note that "Natural Gasoline" primarily comprises heavier NGLs, such as butane and pentane.

Chemical plants and petroleum refineries that process petroleum gases and liquids perform most efficiently and economically when they operate steadily and continuously. Shutdowns can require days to recover, and upsets can produce lower quality, less valuable product. Both are costly. Effective storage serves as a buffer to protect plants from supply disruptions, to insulate units within a plant from problems experienced by neighboring units, and to protect plants from shutdown if transportation of product to customers is interrupted. Petroleum refineries process hydrocarbon liquids that can be stored economically in tanks because their density requires less space for a given weight. Petrochemical and hydrogen plants, on the other hand, process hydrogen and hydrocarbon gases, the storage of which is challenging because gases occupy much more volume per pound even when compressed. Thus plants such as these that have access to inexpensive, large volume storage possess a competitive advantage.

Hydrogen is emerging as a major participant in the evolving low-carbon economy. Variability of wind and sun in renewable energy generation requires energy storage to absorb energy when electricity generation exceeds demand and to provide energy when demand exceeds supply. Battery storage is very efficient and economic at supporting short- to medium-duration cycles of moderate size; however, hydrogen (which can be produced from electricity and water) experiences less leakage and can be less expensive in addressing longer-term (e.g., seasonal) cycles—but only if inexpensive, large-volume storage is available. Additionally, hydrogen and hydrogen-derived ammonia are easier to transport across vast land and marine distances than electricity. Finally, adding hydrogen to an electricity-centric energy system provides redundancy and a backup when the grid fails. The attractiveness of all of which again relies on inexpensive, large-volume hydrogen storage.

Geologic, or subsurface, storage has the potential to provide the large volumetric space required for industrial-scale gas processes but only if it is economical and compatible with the gases to be stored and in the manner customers will use them. Where these conditions are met, such as the salt domes of the U.S. Gulf Coast and the bedded salt formations of central Kansas, petrochemical facilities have flourished. Salt caverns can provide cleaner, more secure, and lower-cost storage for valuable gases than the alternatives: depleted reservoirs that can add contaminants to gases, freshwater or saline aquifers that can absorb and move gases away from their recovery zone, or costly rock caverns carved out of granite. Gases like hydrogen, ethane, propane, and Y-Grade NGL can benefit from such storage and can support industrial development if the subsurface geology demonstrates the necessary economic and physical characteristics for cyclic storage.

This study was accomplished by completing several tasks, including an assessment of the presence, depth, and composition of identified salt formations; assessment of the sealing potential of overlying and underlying geologic strata; geomechanical stability modeling and simulation; salt cavern leaching modeling; and site-specific engineering design recommendations for future cavern development pilot studies. Geomechanical, leaching, and engineering modeling focused on validating the suitability of the Spearfish Formation Pine salt member and the Piper Formation Dunham salt members based on the core samples collected from the HALITE 1 stratigraphic test well site, which was drilled as part of the project scope of work. Regional geologic studies were conducted to assess the depth, thickness, and geologic suitability of the Dunham and Pine bedded salt formations across western North Dakota for potential cavern development.

Salt formations capable of hosting caverns are not common. As exhibited in Figure 3-4, domal or bedded salt exists in only 25 of the 48 contiguous United States and underlies less than 20% of that land area. Furthermore, not all of that salt has the depth, extent, thickness, creep (e.g., how fast the salt moves in response to cavern conditions, e.g., pressures), and other characteristics that can support cavern construction and economic commercial operation. These characteristics vary not just from basin to basin but from site to site. Consequently, it is important to understand both 1) technical aspects (e.g., geology and geomechanical characteristics and cavern behavior) of salt in general by studying salt formations globally and 2) site-specific characteristics in order to understand the lifetime potential for salt cavern storage at a particular location.

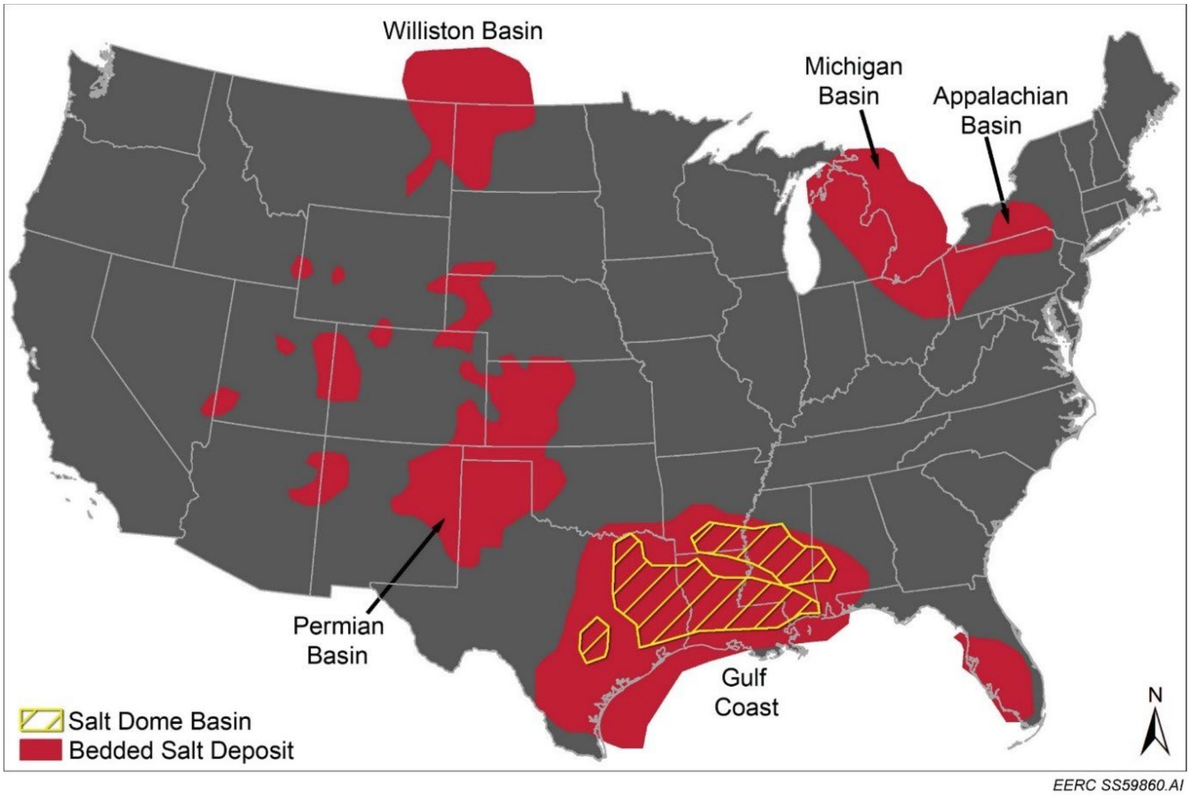


Figure 3-4. Salt deposits in the United States (modified from Argonne National Laboratory [1999]).

Figure 3-5 depicts the structures of domal and bedded salt and surrounding formations. As shown, domal salts are tall vertical structures extending through multiple formations while bedded salts are typically contained within one formation. In many cases, bedded salts have impurities, referred to as interbeds, that need evaluation to determine the operational impact prior to developing caverns. Most salt domes can be found in the U.S. Gulf Coast region while widespread distribution of bedded salts occurs in the Williston, Michigan, Appalachian, and Permian Basins (Figure 3-4).

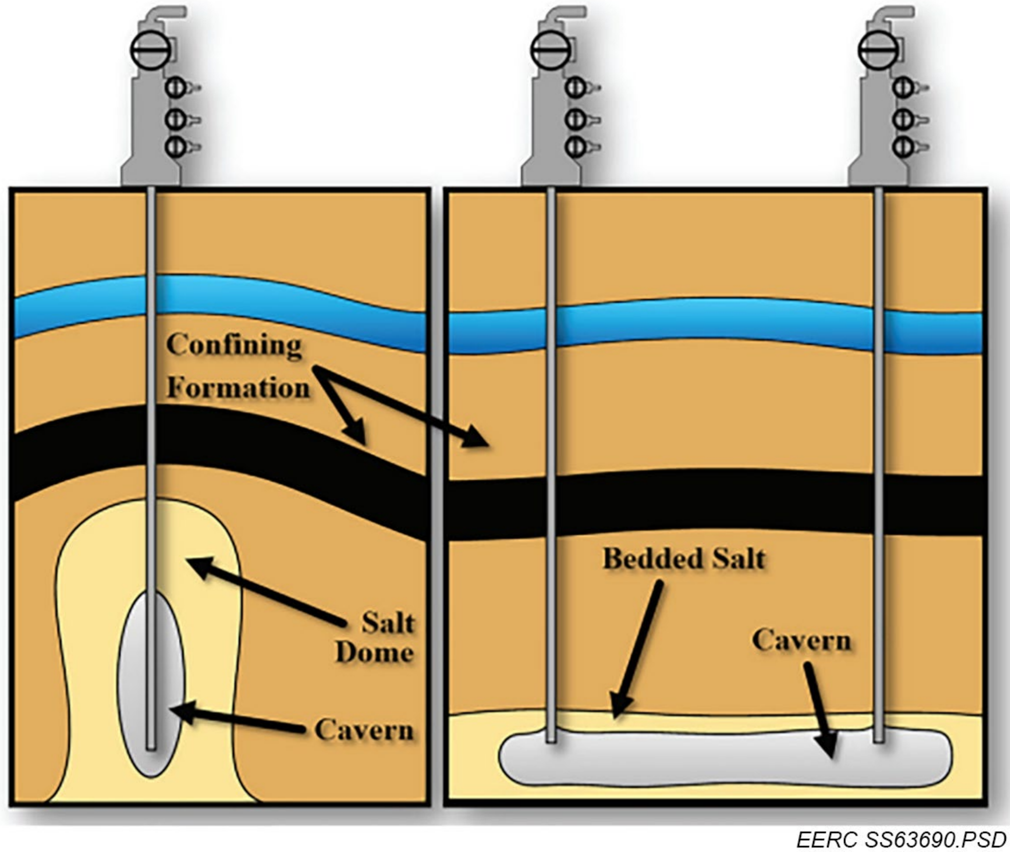


Figure 3-5. Example of the difference between salt domes and bedded salt formations (Arthur and others, 2017).

The North Dakota portion of the Williston Basin has bedded salt deposits in several stratigraphic horizons (Figure 3-6) (Nesheim and LeFever, 2009; Nordeng, 2009). Salt strata are divided into minor and major salts based on their thickness and extent throughout the basin. Minor salts are identified by their limited thickness and distribution. The minor salts in the state include, from top to bottom, beds in the Kibbey, Charles, Duperow, Souris River, Asher, and Interlake Formations. The maximum thickness of the salt horizons in these formations ranges from 7 to 44 feet. Major salt beds are recognized by their thickness and extensive distribution throughout the basin. Major salt beds include, from top to bottom, the Dunham, Pine, Opeche, Charles, and Prairie salts.

In consideration of salt purity and depth, the Dunham and Pine Salt members are pertinent to the current study. The Dunham Salt within the Piper Formation has a maximum thickness of approximately 205 feet and extends over most of western North Dakota, with a few isolated lenses outside of the main salt body. The Pine Salt is the thickest of the three Spearfish Formation salts and has the greatest areal extent. The Pine Salt reaches a maximum thickness of approximately 250 feet. Two salts were identified within the Opeche Formation. The upper salt, Opeche "A,"

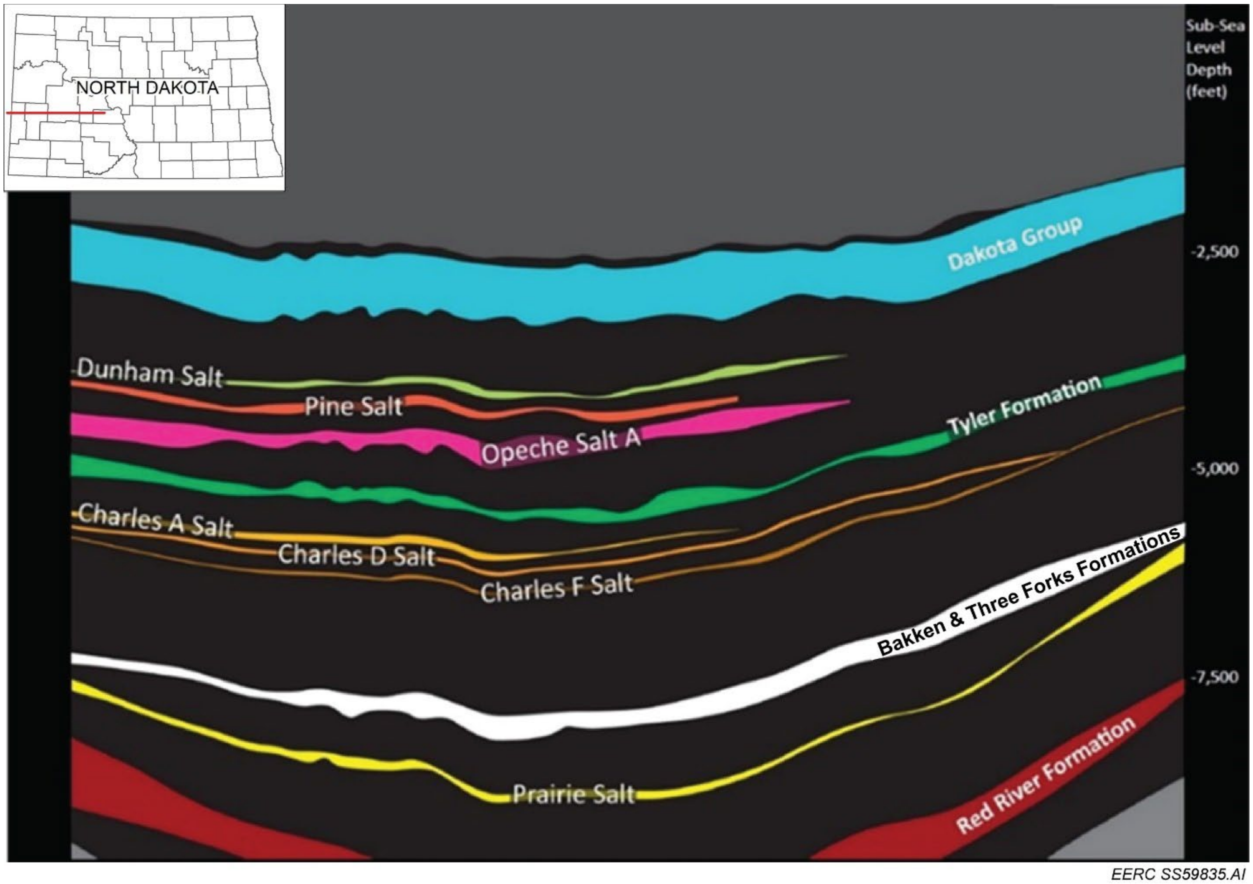


Figure 3-6. Stratigraphic cross section through western North Dakota (see red line in inset map) highlighting salt formations of interest. The Dakota Group, Tyler Formation, Bakken and Three Forks Formations, and Red River Formation do not include salt beds but are included as points of reference because of their relevance to the oil and gas industry as either produced water disposal zones or oil-producing zones. The scale at right shows elevation referenced to mean sea level (modified from Nesheim and LeFever, 2009).

has a slightly greater areal extent than the lower Opeche "B" salt. The maximum thicknesses of these salts are ~230 and ~55 feet for the Opeche "A" and "B," respectively. The Charles Formation comprises major salts, "A" through "F," as well as several minor salts. The Charles "A" salt has the greatest thickness, and the "F" salt (also known as "the Last Salt") has the greatest areal extent. The most significant and the thickest single salt in the Williston Basin occurs within the Prairie Formation (maximum thickness of ~640 feet). The depth (temperature and pressure) of any salt bed depends on its geographic location within the Williston Basin. Generally, the Dunham, Pine, and Opeche "A" salts are found at depths ranging from approximately 5000 to 7500 feet beneath the surface. The salts within the Charles and Prairie Formations are found at depths greater than 7500 feet in the North Dakota portion of the Williston Basin. In considering the thickness, average depth, and areal extent, the Dunham and Pine exhibit the most favorable characteristics for cavern development and storage within the region. Although the Charles and Prairie Formations include the thickest and most widespread salt beds in North Dakota, their depth, temperature, and pressure conditions warrant further investigation for cavern development and commercial use.

The 2020 study (Smith and others, 2020), using primarily unpublished data provided to the EERC by the North Dakota Geological Survey (NDGS), presented more detail on North Dakota salt formations.

3.1 Salt Cavern Purposes and Modes of Operation

Salt caverns are developed for two purposes: brine production and inert storage of bulk fluids. Under both scenarios, a cavern is developed in a salt formation by dissolving the formation with water, a process called leaching. In some geographic areas, there is high demand for the brine or salts precipitated from the brine that can drive the economics of cavern development.

With respect to storage of fluids, there are two general modes of salt cavern operations: gas-compensated and brine-compensated (Figure 3-7). Gas-compensated caverns are analogous to gas bottles that utilize the formation salts as the container and the pressure of the overburden to confine the fluid. The gas being stored is forced by a higher surface pressure through a string (tube) into the cavern. When there is demand for that stored gas, operators drop surface pressure below cavern pressure, and the gas exits the cavern through the string and a series of pressure control valves. Large injections and withdrawals can generate swings in cavern pressure; thus those such pressure variations are restricted in size to maintain geomechanical stability. Some amount of gas must stay within the cavern to maintain a degree of pressure and ensure cavern integrity. This is the basic mechanism of a gas-compensated cavern.

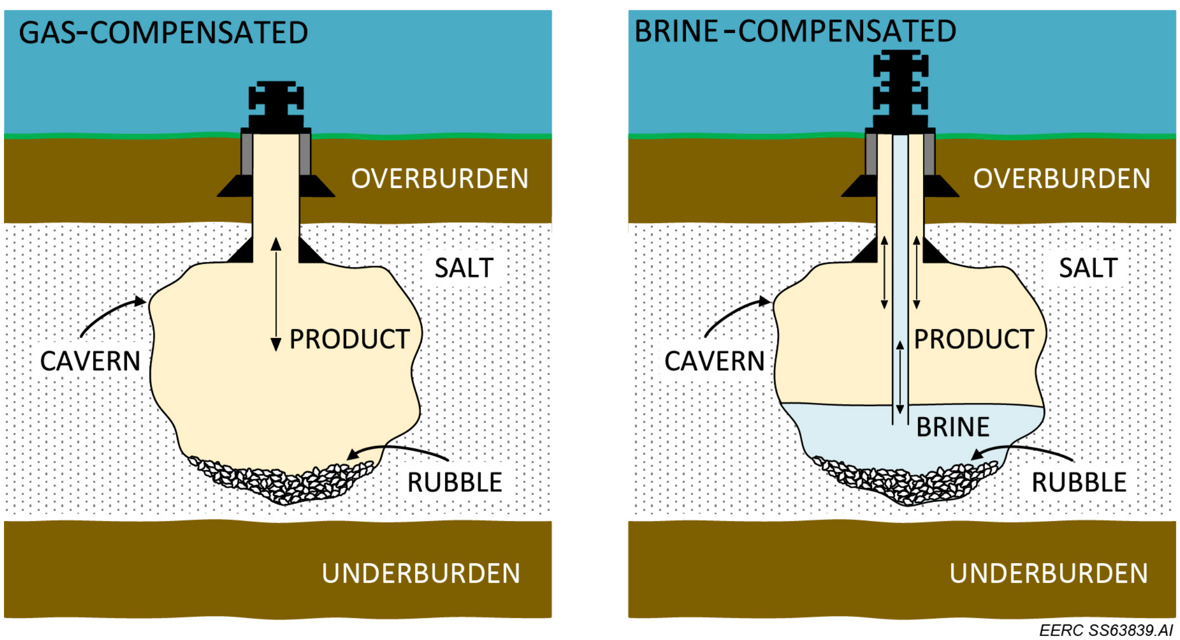


Figure 3-7. Comparison of gas-compensated vs. brine-compensated salt caverns.

Brine-compensated systems are commonly used with fluids that are liquids at the temperatures and pressures at which they are stored. In these systems, the injection well is designed with multiple concentric tubes (strings) that connect the surface with cavern interior. The inner string extends deep down into the cavern and serves as conduit for the denser brine to flow in and out of the cavern. The outer string terminates near the top of the cavern, with the annulus between strings serving as a conduit for the less dense product to flow in and out of the cavern. The difference in density keeps the brine separate from the product while the difference in surface pressures between brine and product fluids forces the higher-pressure fluid into the cavern while displacing and forcing the other fluid to exit. Balancing pressures enables the cavern to operate with less pressure swing than gas-compensated caverns experience. When the pressure of the product at the surface exceeds that of the brine, the product flows through the annulus into the cavern and displaces the brine which exits through the inner string. The brine is stored at surface until there is demand to withdraw the product. When product is demanded, brine pressure at the surface is raised above the surface product pressure which forces brine downhole to displace product. The forced displacement of one fluid with the other is the drive mechanism for this storage.

3.2 Cavern Life Cycle

A simplified cavern life cycle is shown in Figure 3-8, including creation of the cavern, operation, and eventual abandonment. The creation of a salt cavern consists of three phases: exploration, drilling, and leaching. The well is completed with a wellhead and tubing installed to be used as leaching strings. The process of leaching, also known as washing, is carried out by cycling injection water downhole through one tubing string. The water dissolves salt, creating a void. Brine is carried to the surface, driven by the pressure of the injecting pump. The brine can be sent to a holding tank or an engineered storage pond. Intermittent sonar surveys are conducted to determine the size and geometry of the cavern as it develops.

After cavern leaching is completed, a mechanical integrity test (MIT) is performed. A MIT requires a sonar survey and displacement of the brine with nitrogen (N_2). The wellhead is sealed with the pressurized N_2, and any pressure differences are monitored over time. When it is determined the cavern holds pressure against a leak rate threshold, it is ready to be placed into service, and the cavern is flooded with brine from the surface holding tanks or pond to displace the nitrogen.

The cavern is operationally ready to accept fluids for storage at this point. Operational parameters vary by the fluid being stored, the size of the cavern, and the type of drive mechanism. In general, a simple cycle involves filling the cavern with product, storing it for a period of time determined by plant or market needs, and releasing the product from the cavern. Specific equipment within the on-site surface facilities condition exiting gas to the proper process specifications for pipeline transport.

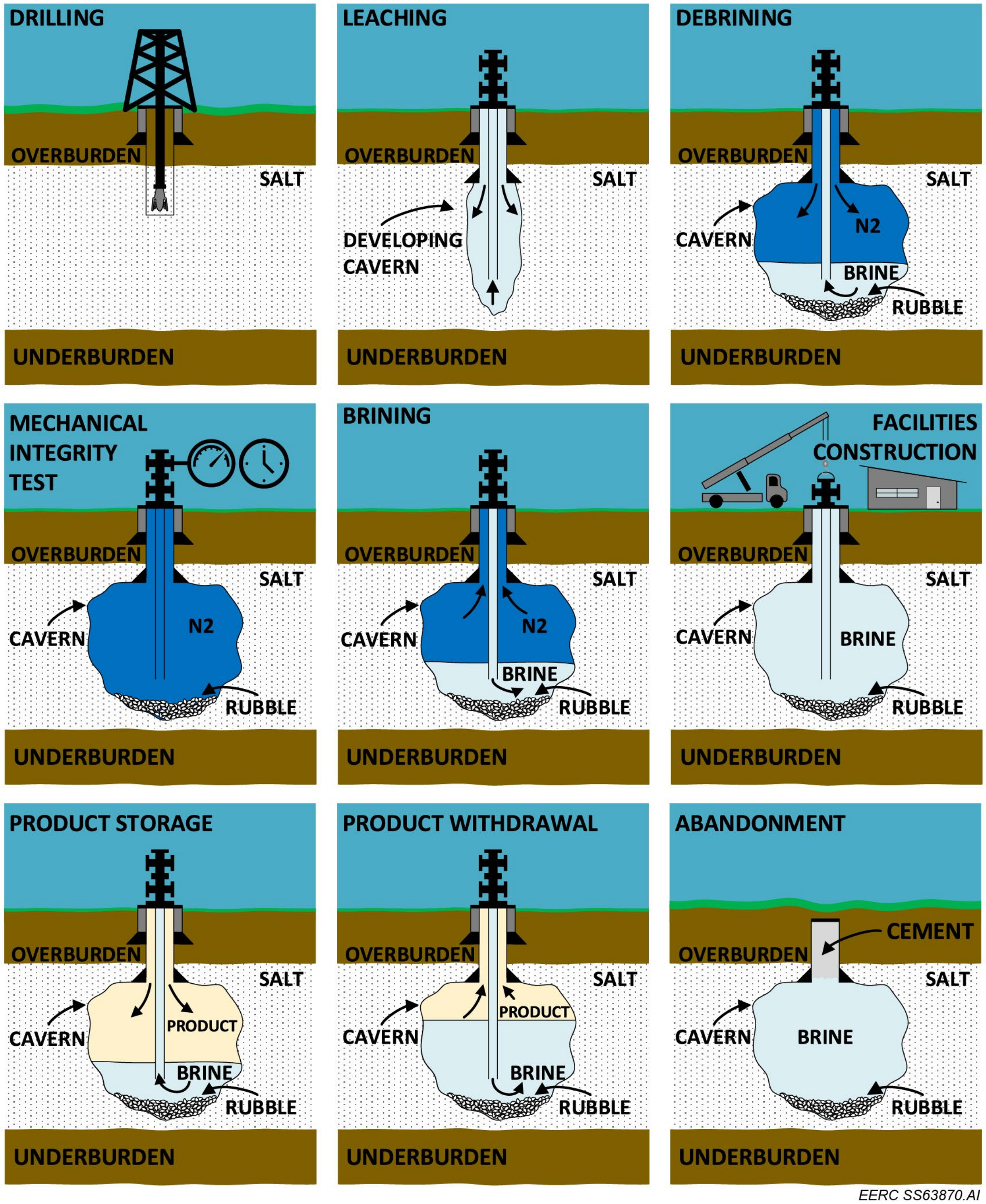


Figure 3-8. Life cycle of a generalized salt cavern used for product storage.

Maintenance of the surface equipment facilities can occur when the cavern is not in use. Since much of the equipment is used only during the injection or the withdrawal portion of the cycle, there is time to perform preventative maintenance or upgrades during the storage period or when the cavern is not being cycled. A typical site workover will consist of emptying the cavern product, inspection of the wellhead, inspection of tubing, and a sonar survey to quantify any changes to size or geometry caused by salt creep, followed by a MIT. Corrosion to the tubing or plugging by salts can not only compromise integrity but also increase power for pumping and operational costs. Flushing tubing with fresh water can prevent salt depositing. Managing brine inventory and monitoring brine quality and the integrity of the pond are constant activities.

Abandonment can occur when a cavern is no longer needed or no longer functional because of damage to the wellbore or mechanical instability of the internal salt structure. A common abandonment technique at the end of a cavern's life includes product removal and replacement with brine, monitoring the brine in the cavern while it reaches stability and equilibrium with the formation, removal of the tubing, sealing the cavern, and cementing the well. The wellhead will be removed, casing will be cut below surface, and a cap will be welded. The surface facilities can be demolished, scrapped, or sold as surplus, while the land can be reclaimed for alternative uses.

3.3 Critical Resources

The most critical resources for developing a cavern are a suitable subsurface salt formation and inexpensive access to water and brine disposal. Other components, while important for cavern development, become a series of economic trade-offs. The important characteristics of subsurface salt formations have been covered extensively in Sections 6.0 and 7.0 of this report. Typical water required to create a cavern is 10 bbl per 1 bbl of storage need. Economical accessibility to this water supply will drive the feasibility of developing the cavern at any location. Similarly, long transportation distances for water disposal can make a project cost-prohibitive. North Dakota has an advantage in that a robust water supply and disposal infrastructure have already been developed to support oil and gas extraction from the BPS. Additionally, cavern development must take into consideration the proximity to pipelines and/or customers, access to power, and appropriate land. Similar to current practices in developing the Bakken and Three Forks formations in western North Dakota, multiple wells or caverns can be accessed by a single equipment facility pad, reducing the footprint.

3.4 Salt Cavern Facilities

Caverns used for storage in a gas-compensated and a brine-compensated scenario are identical, but the equipment and wellbore vary based on drive mechanism. The purpose of the cavern or its stored fluid may require additional equipment redundancy to safeguard uninterrupted operation.

A gas-compensated cavern will have a single entry into the cavern from the wellhead. The product delivery rate will determine the size of that production string. The product is metered for quantity and quality (composition, moisture, and impurities) as it comes into the facility battery limit. Dehydration or scrubbing out of impurities might be required to protect facility equipment or the cavern from unexpected contamination. The product will be moved into the cavern with a compressor, while a metering station at the plant boundary will verify quality and quantity of product leaving the facility. The facility will also include operational items, such as control equipment, flares for emergency use, backup power generation, pneumatic equipment, chemical storage, and assorted buildings.

Brine-compensated caverns have two concentric tubing entries: a center brine string and an outer product string as described above. The wellbore needs to be sized to account for the brine and production strings and the higher viscosity of brine and stored products relative to gases. Product enters the facility's battery limit and is metered for quality and quantity. The product is pumped into the cavern with a turbine pump. As product is pumped, it displaces brine in the cavern. The brine comes to surface and travels through a separator to remove trace amounts of dissolved gas from the brine. Brine holding tanks are not economical for large-scale storage applications and require secondary containment. Although ponds are more economical, their open nature can introduce operational and regulatory challenges. To withdraw product from the cavern, a separate set of pumps moves brine down into the cavern through the central string, displacing the product and pushing it to the surface. The pumps, ponds, and brine can be shared by multiple caverns, storing different products. Like the gas compensation drive scenario, when the product comes to the surface it must go through dehydration/separation equipment to remove any trace contamination from the cavern or brine. It leaves the facility at the plant battery limit after being metered for quality and quantity.

Cavern sizes vary greatly, but the upper limit is bounded by the salt formation itself, and the lower limit is bounded by the minimum size to reach an economy of scale. Grouping several caverns together from a single pad by directional drilling with shared facilities can help small caverns overcome the economies of scale, provided the same product is stored and they are proximally located. This can reduce the footprint and construction costs, further assisting the economics. The ability to share infrastructure might also provide other opportunities for development timeline, site expansion, operational flexibility, and optimization. The overall volume has implications for the type of fluids that are the most practical for storage in the cavern, engineering and design of the surface facilities, downhole equipment, and economics.

3.5 Operational Scenarios

The type of fluid planned for storage in a particular cavern will determine whether it would be best to store under a brine-compensated or gas-compensated drive mechanism. It is also important for designing the surface facilities as specific stored fluids can require special equipment and sizing for individual conditioning, treatment, or dehydration processes. Fluid type will vary the cyclicity and minimum and maximum storage pressure. This is not only important for facility design but also for geomechanical stability. Cyclicity describes the rate that a cavern is filled, the time it stays at a capacity, the rate product is removed, and the time before it is filled again.

Caverns can be retrofit for different fluid uses later in their life cycles, and it is likely some aspects of the facility may require significant changes that can impact the purity of the new product. Retrofits are possible, but implementation should only occur after significant investigation of the cavern is performed. This investigation should include a review of the mechanical aspects of the cavern for the new production cycles, modeling of the facility operation, and end use of the new project. This review process can be extensive, taking months to years to complete a thorough review.

4.0 SITE SCREENING, CHARACTERIZATION, AND SELECTION

As previously discussed, the North Dakota portion of the Williston Basin has bedded salt deposits in several geologic strata. Smith and others (2020) identified three salt deposits for potential cavern development: the Dunham Salt, the Pine Salt, and the Opeche Formation. Based on existing data, the Opeche Formation appears to contain high concentrations of insoluble salts that are typically not recommended for engineered salt cavern development; thus this formation was not evaluated further through this effort. Figure 4-1 shows the generalized stratigraphy of the Williston Basin and the relative position of each salt interval as well as the depth interval included in geologic modeling activities discussed in Section 7.0 of this report.

The goal for the screening task was to identify potential locations to drill a stratigraphic well and core the Dunham and Pine salt members. Screening criteria were defined to find locations of geologic, geomechanical, and engineering suitability of the salt formations for subsurface gas or liquid storage cavern development. Publicly available data including geophysical wireline logs, stratigraphic well correlations, and geographical data were used to characterize the salt intervals to determine salt thickness, salt depth, proximity to federal land, proximity to surface water, proximity to county roads, and topography (Table 4-1). Based on these input parameters, a series of maps were created and used to predict the chance of successfully encountering each of the salts during drilling. Chance of success (COS) mapping was performed in SLB's Petrel 2021.5 E&P software platform (SLB, 2022a).

Desirable and undesirable limits for each parameter and each salt interval were determined to identify areas considered to be more successful (e.g., 75 ft or more of Dunham Salt was considered desirable and less than 50 ft was considered undesirable). To predict the COS, parameters were normalized to within a common range of 0.0 to 1.0. COS low values were raised closer to 1.0 for parameters that were determined to be less detrimental to overall success. All parameters were multiplied together to determine the COS over the mapped area for each salt to find prospective areas for a stratigraphic well.

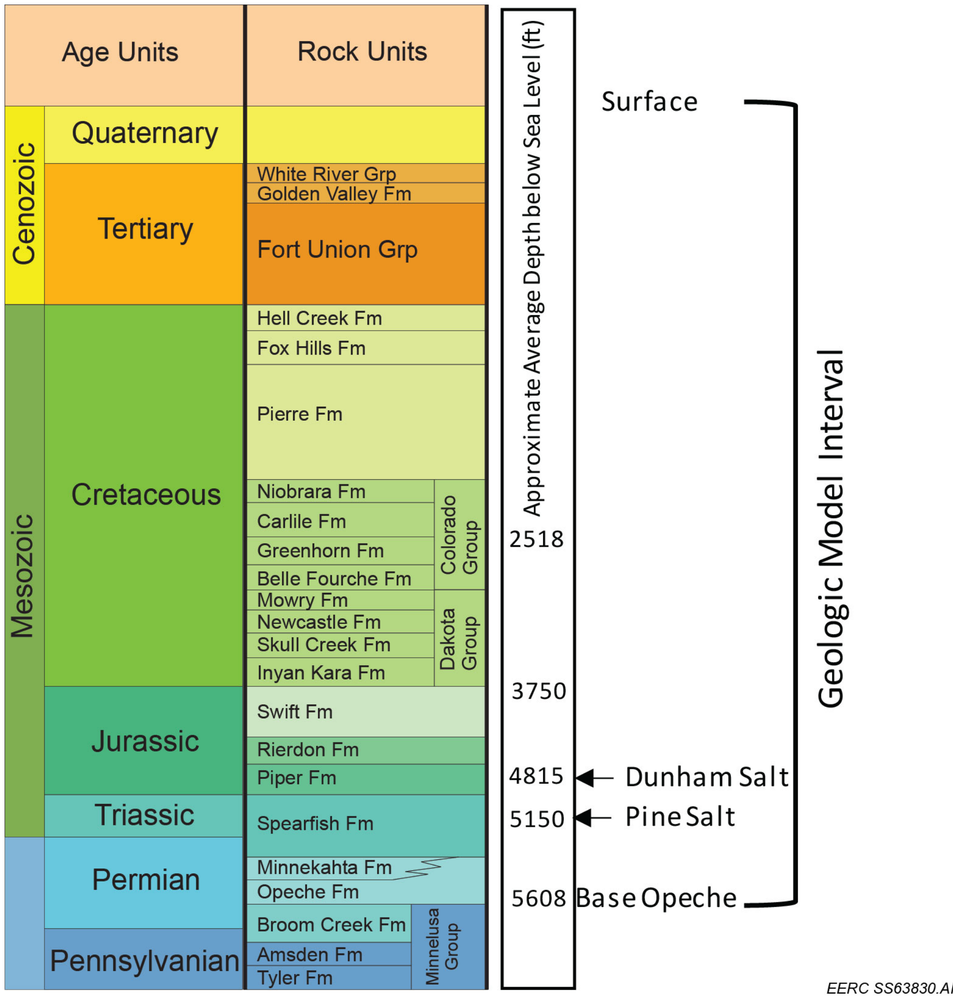


Figure 4-1. Stratigraphic column showing the salt intervals of interest and geologic model interval and approximate depth in feet below mean sea level.

Table 4-1. Screening Parameters and Criteria

	Parameter	Undesirable Limit	Desirable Limit	COS Low	COS High
Thicknes	Dunham	≤50 ft	≥75 ft	0.00	1.00
	Pine	≤25 ft	≥50 ft	0.50	1.00
	Charles	≤50 ft	≥75 ft	0.00	1.00
Depth	Dunham	≥9000 ft	≤8000 ft	0.75	1.00
	Pine	≥9000 ft	≤8000 ft	0.75	1.00
	Charles	≥9000 ft	≤8000 ft	0.75	1.00
Surface	Federal Land	Inside	Outside	0.00	1.00
	Surface Water	≤500 ft	≥1000 ft	0.00	1.00
	County Roads	≥1 mi	0 mi	0.00	1.00
	Surface Slope	≥10°	≤2°	0.00	1.00

After the COS study was complete, an opportunity to use previously abandoned well locations for the stratigraphic well was presented by the NDIC Department of Mineral Resources Oil and Gas Division. These well pads were assessed to determine if reusing an existing location would accommodate the drilling rig and on-site facilities. The COS study was used to evaluate each abandoned well location to determine if a particular location had sufficient salt thickness and depth to perform a successful coring operation. Ultimately, this decision reduced pad development cost, assisted with landowner outreach, and maintained the project timeline.

Two abandoned wells (NDIC Well File No. 15879 and 11926) were found to have sufficient COS for thickness of both the Dunham and Pine Salts. To determine final site selection for the existing well pads, the two abandoned locations were evaluated to confirm proximity to potential feedstock sources (e.g., ethane fractionation, separation of ethane from natural gas), pipeline infrastructure, and water resources—key considerations for future cavern development. Figure 4-2 shows the resulting COS map of thickness and depth for the Dunham, Pine, and Charles Salts. As shown, the darker-green colors on the map represent locations where there is a high chance of encountering salts meeting the previously mentioned criteria. The pad for Schmidt 44-30H (NDIC Well File No. 15879) was determined to best meet all criteria for drilling the HALITE 1 well.

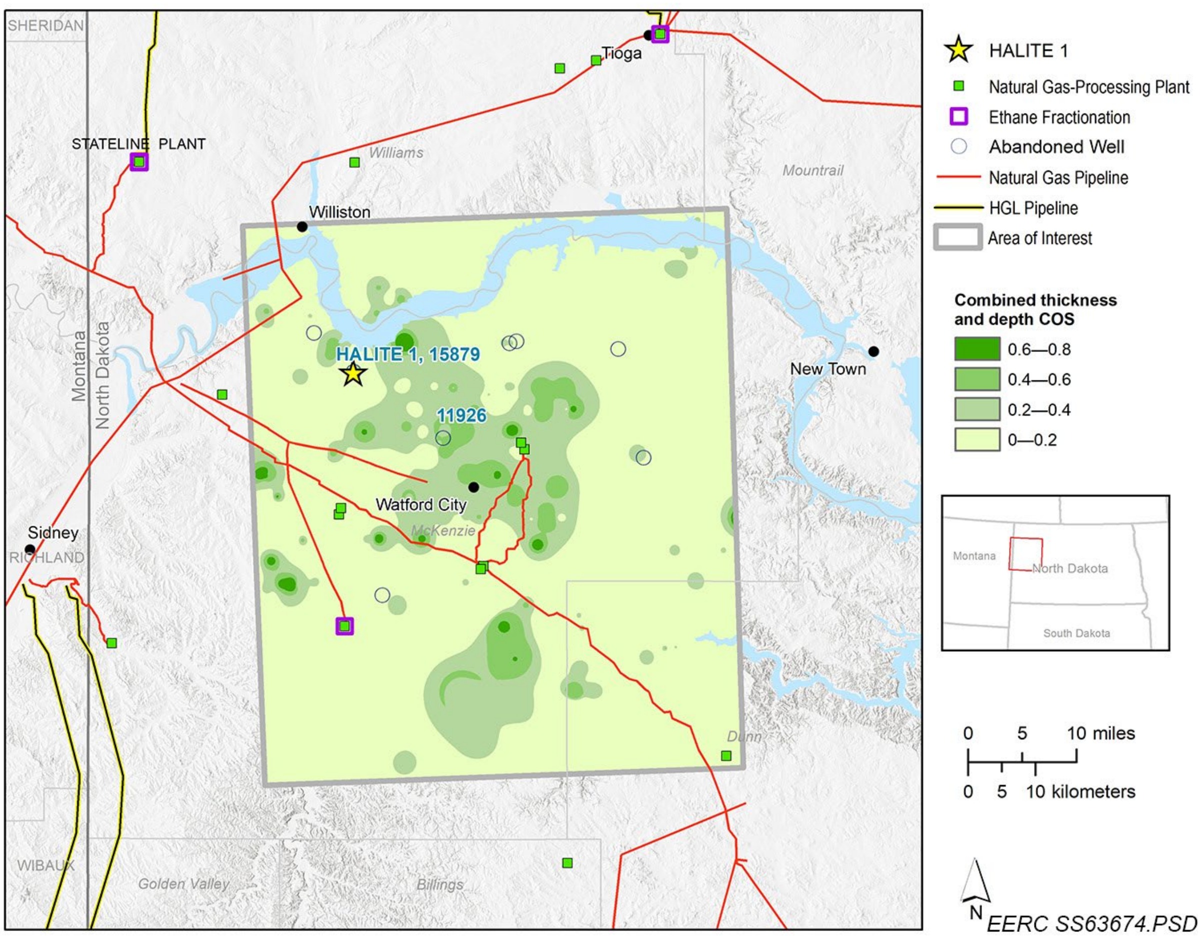


Figure 4-2. Resulting COS map of thickness and depth for the Dunham, Pine, and Charles Salts.

5.0 DRILLING AND CORE COLLECTION

Once the stratigraphic test well site was selected, a drilling program was developed. Figure 5-1 shows the well diagram for HALITE 1, the depth to core points, and the logging intervals. Formation evaluation activities included core collection and geophysical logging of the Dunham and Pine Salts and downhole testing of their corresponding cap rocks, namely, the Piper Formation for the Dunham Salt and the Spearfish Formation for the Pine Salt.

The Schmidt 44-30 well site is located in northwestern McKenzie County, North Dakota, approximately 15 miles south–southeast of Williston. Because this location exists within a highly productive area of the BPS and associated subsurface water disposal activities, careful attention was paid to the drilling program and core collection. This included drilling with heavier than normal mud weights and setting an intermediate casing string to ensure the well was in stable condition to collect the highest quality core possible.

The 17½-in. surface section was drilled with freshwater drilling fluid, averaging 8.6 lb per gallon (ppg) density. Total depth of the surface section was reached at 2208 ft. The casing shoe was set at 1935 ft, 72 ft into the Pierre Formation. Drilling of the intermediate section began on June 2, 2022. The intermediate section of the well was drilled with oil-based mud (OBM) averaging 12 ppg. Longer than average drilling times were experienced because of persistent fluid losses. Once the losses were controlled, drilling to the Mowry Formation was completed, and 9⅝-in. intermediate casing was set at a depth of 5054 ft. Setting of the intermediate casing was a protective measure.

The openhole portion of the well (8¾ in.) was drilled and cored to a total depth (TD) of 7469 ft. Four-inch whole core was collected from the Dunham and Pine Salts and their respective adjacent formations. Cored sections of the Dunham and Pine Salt Members included portions of nonsalt strata adjacent to each salt member. Some near-clear to clear halite was observed in the middle of the Dunham Salt (Figure 5-2).

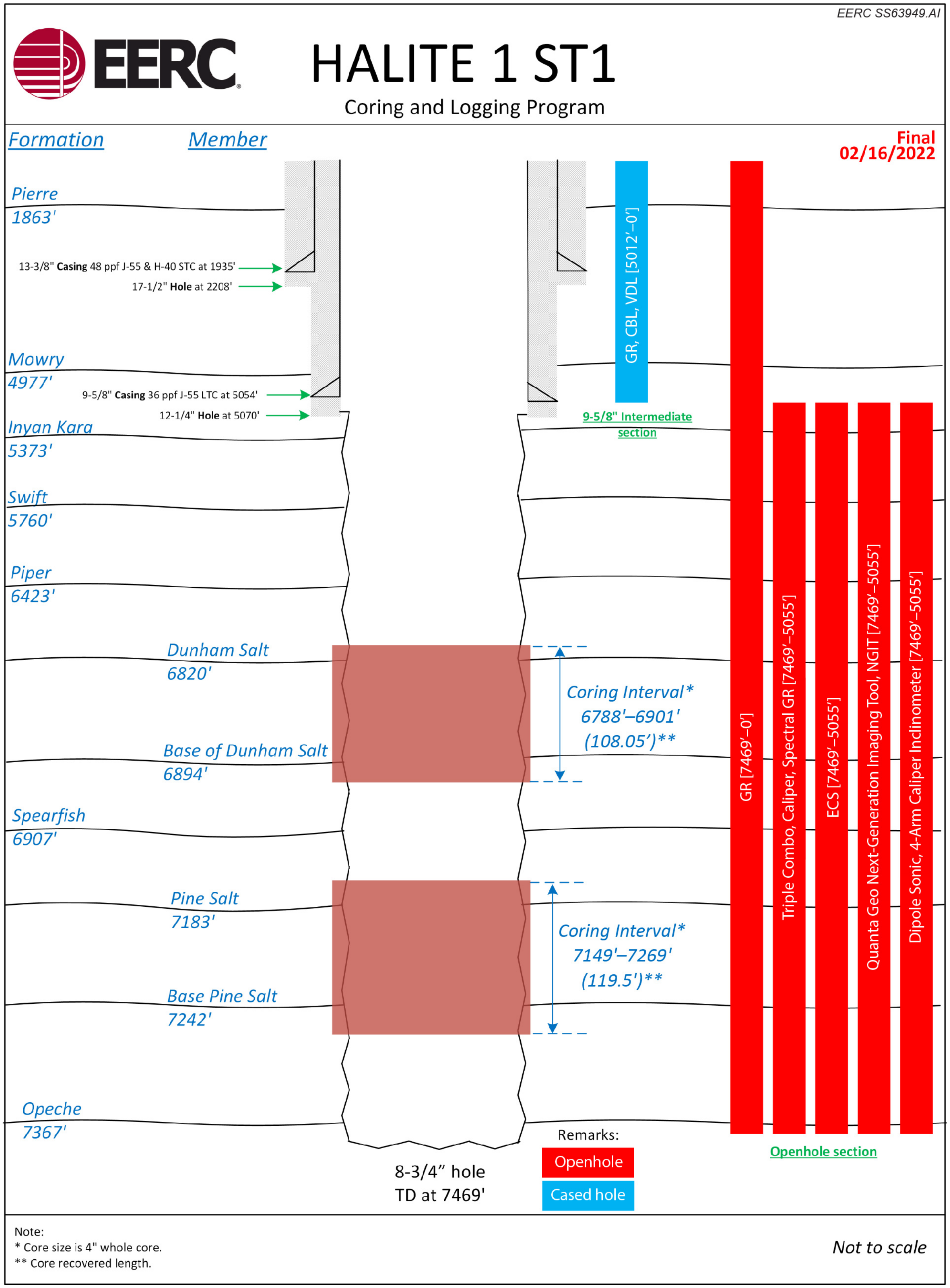


Figure 5-1. Coring and logging intervals in the HALITE 1 ST 1 (Sidetrack 1) well.

Figure 5-2. Dunham clear crystal salt. Grain size (measured in crosscut) averages 1 in., with minimum and maximum sizes of 0.25 and 2.5 in.

A total of 233.28 ft of core was cut, and 227.55 ft of core was recovered (97.54%). Total footage collected from the Dunham and Pine salts and their associated overlying and underlying formations were 108.05 and 119.50 ft, respectively. Core barrels for each run consisted of two 30-ft steel barrels with aluminum liners. Upon recovery, the core was cut into 3-ft increments on-site, placed into containers, and shipped to a commercial lab (RESPEC) for description and a series of geochemical, geomechanical, petrographic, and petrophysical analyses.

Openhole wireline logging was completed in two runs. Intermediate casing was set at 5054 ft, and openhole logs were run from TD of 7469 to 5055 ft. Cased-hole logs were acquired over the surface and intermediate sections at the conclusion of casing and cementing operations. A full suite of logs were collected for the site to support the geologic and geomechanical modeling activities.

Plugging and abandonment operations were completed using a total of four plugs set in the well. An NDIC representative was on-site to verify cementing, pressure-testing of casing, perforating, and the setting of cast-iron cement retainers and cast-iron bridge plugs. The as-drilled wellbore schematic is shown in Figure 5-3. The wellhead was cut off 4 ft below ground level, and the casing cap was welded. This marked the end of operations, and the rig was released. The site was reclaimed to its original condition to comply with all requirements of NDAC Section 43-02-03-34.1. Figure 5-4 shows the reclaimed wellsite. A detailed report of the HALITE 1 drilling operation is included in Appendix B.

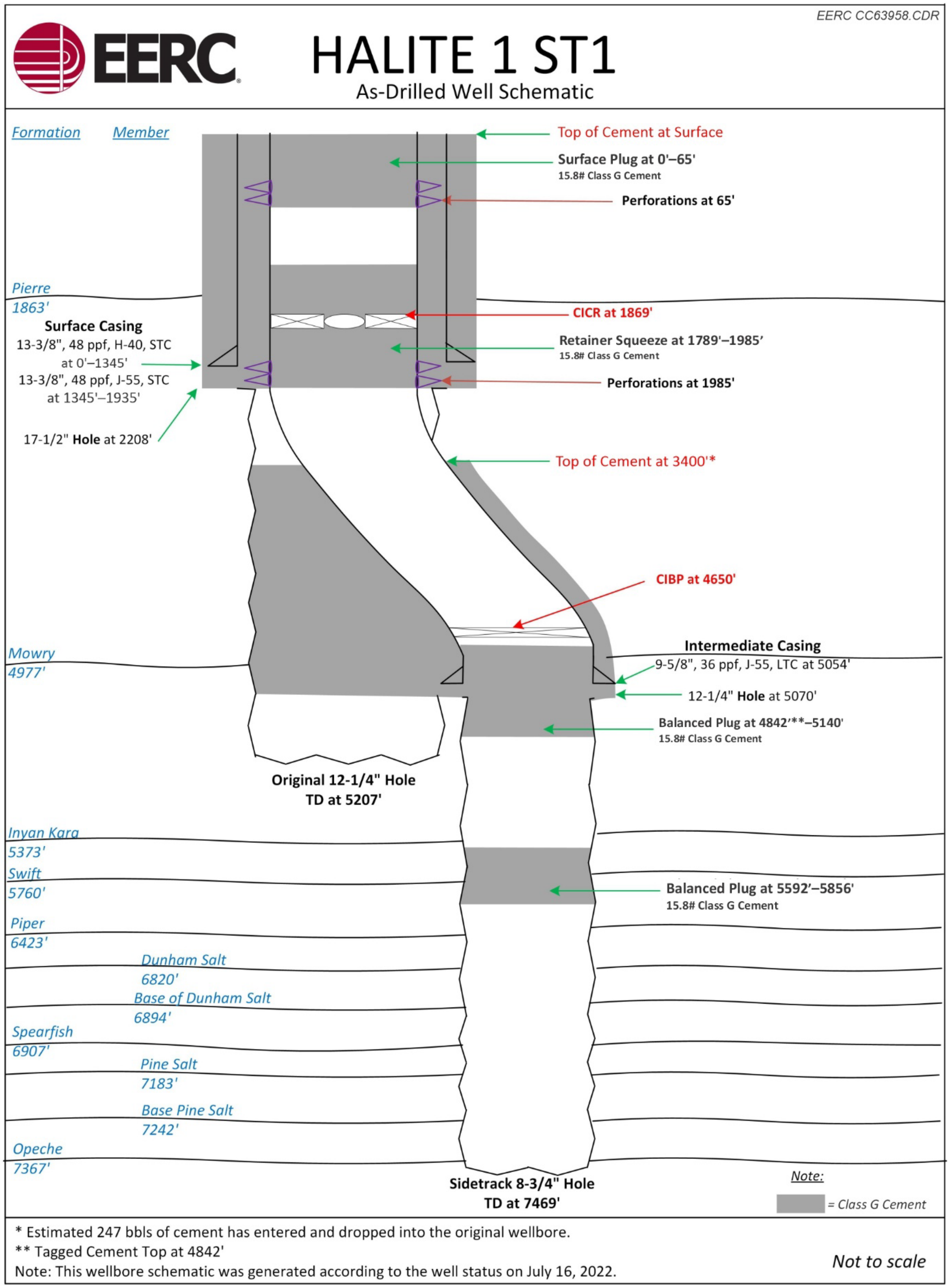


Figure 5-3. As-drilled wellbore schematic for HALITE 1 ST1.

EERC CC63961.CDR

Figure 5-4. Reclaimed HALITE 1 wellsite.

6.0 CORE TESTING AND INTERPRETATION

Core testing was performed to identify bulk characteristics of the formations of interest. For this study, samples were selected and tested to determine lithology, thickness, porosity, permeability, mineralogy, geomechanical competency of the overlying and underlying sealing formations, geomechanical properties of the salts, dissolution properties of the salts, and potential for the ability for caverns to close because of overlying stresses (salt creep). Because the structural stability of a solution-mined cavern partially depends on the strength and deformational characteristics of the host salt and nonsalt units, geomechanical testing is a large component of the core testing program. The EERC contracted RESPEC to process and perform most of the core testing. As noted previously, a total of 227.55 ft of core was recovered (out of the 233.28 ft that was cut), with 108.05 ft coming from the Dunham Salt interval and 119.50 ft from the Pine Salt interval. Each interval included core from the associated overlying and underlying nonsalt zones. The information obtained from core testing of the salt and nonsalt units is used to model cavern behavior under anticipated operating conditions. The following tests were performed to determine the bulk properties of the core. Sample numbers are shown in parentheses:

- Core description – to identify lithofacies of the core and to characterize the textural and sedimentary features, visible fractures, core colors, etc.

- Spectral gamma ray – to provide a correlation between the wireline log signature and core retrieved from the subsurface.

- X-ray diffraction (XRD) – to determine the mineralogical components of the core (54).

- Insoluble content analyses conducted on salt samples (25) – to distinguish between salt and nonsalt material.

- Porosity/permeability measurements on salt and nonsalt samples (19) – to understand the sealing potential of rocks overlying salt members.

- Brazilian tests on salt samples (11) and nonsalt samples (22) – to measure indirect tensile strength.

- Constant strain rate tests including a load/unload/reload cycle on salt samples (13) to ascertain their elastic properties and nonsalt specimens (44) performed to determine rock sample strength and elastic properties (Young's modulus and Poisson's ratio).

- Constant mean stress-dilation in triaxial compression (CMC) tests on salt samples (13) – to determine the initiation of microfracture dilation (e.g., creation of void space) as a function of mean stress and stress difference.

- Triaxial compression creep tests on salt samples (10) – to evaluate the time-dependent behavior of materials.

- Direct shear strength tests on intact interfaces (4) – to measure the shear strength of geologic interfaces.

6.1 Piper Formation – Poe Member (overburden)

The Piper Formation (Poe Member) lies directly above the Dunham Salt and is characterized as siltstone/mudstone with interbedded and intermixed anhydrite. Figure 6-1 shows a 3-foot section of the Piper Formation core and demonstrates the complex variability of the core. This overburden member is very low in vertical porosity and permeability, with values of 3.7% and 14 nD, respectively. Geomechanical tests indicate that the material has high strength and the potential to serve as a competent ceiling above an engineered salt cavern.

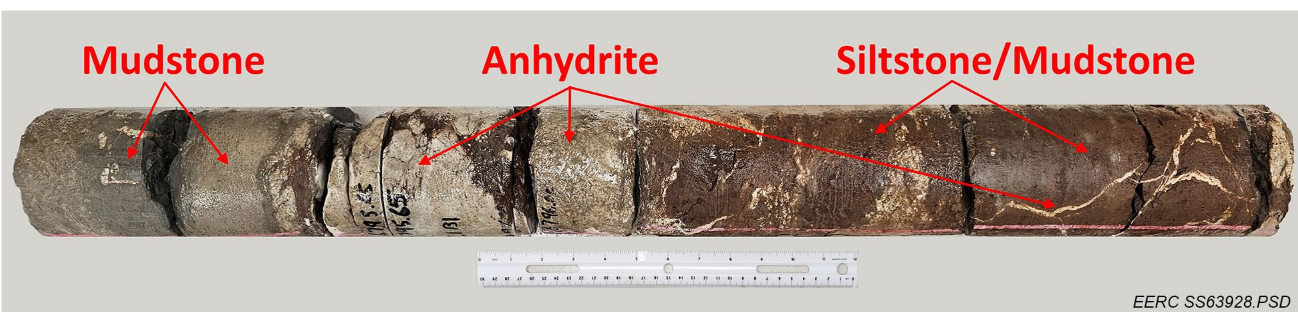


Figure 6-1. Siltstone and mudstone with intermixed anhydrite (Core Run 1, Box 1).

6.2 Dunham Salt Member

The Dunham Salt was observed to have a sharp contact (i.e., an abrupt change) from anhydrite to salt at 6821.20 ft. The Dunham Salt, as shown in Figure 6-2, is a bedded salt that often changes in crystal sizes and the percentages of impurity. The Dunham Salt is generally characterized as well-cemented halite that is near-clear to clear. The halite crystal grain size

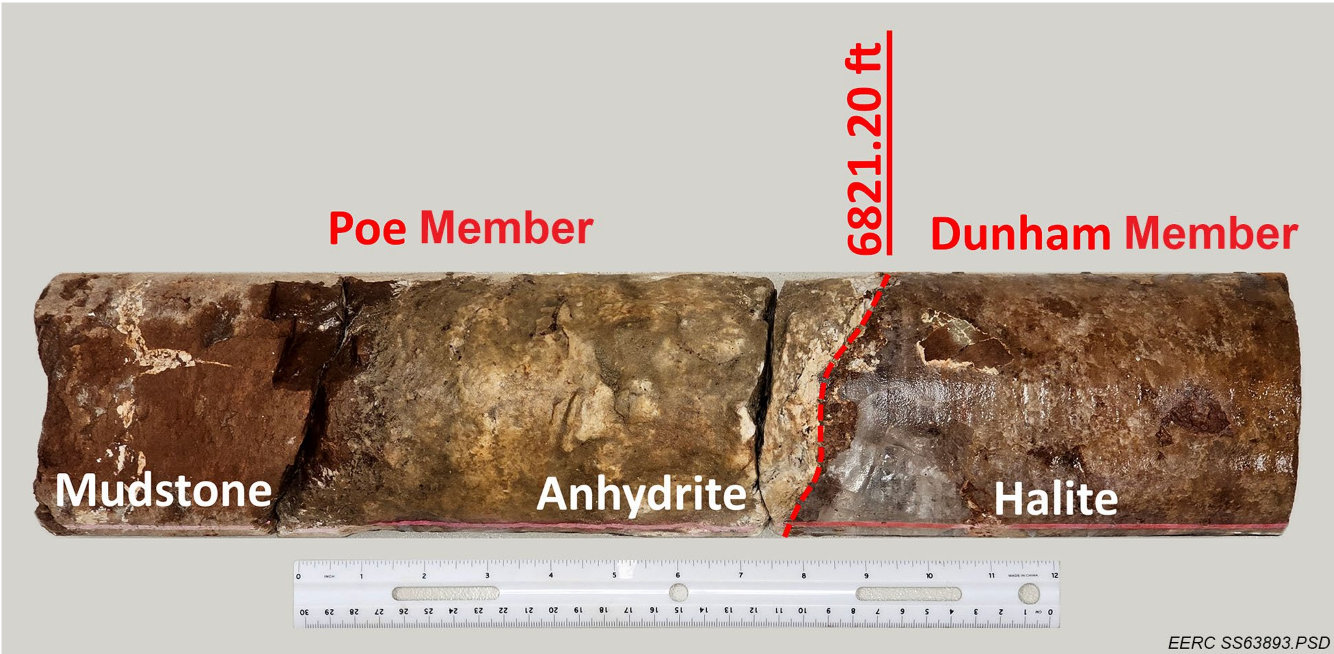


Figure 6-2. The Dunham Salt contact with the Poe Member's anhydrite at 6821.20 ft.

averages (measured in crosscut) 1 inch with minimum and maximum sizes of 0.25 and 2.5 inches, respectively. This parameter is an important consideration for cavern development as it has implications for long-term geomechanical cavern stability. The crystal sizes observed here are similar to other geographic areas where cavern operations have been successful, particularly the Lotsberg Salt Formation in Alberta where salt crystals are reported to range from 1.18 to 7.87 inches (or 3 to 20 cm) (Toboła and Kukiałka, 2020).

Red-brown clay intrusions are present between most of the halite crystals with other inclusions (dark spots) visible, as shown in Figure 6-3. The layers of near-clear salt are generally larger in crystal size than the salt with impurities. Based on XRD analyses, the Dunham Salt contained primarily halite with percentages ranging from 42.8% to 97.3%. A few of the samples contained considerable amounts of glauberite, anhydrite, gypsum, quartz, sylvite, and magnesite in varying quantities. The insoluble mineral content ranged from 0.00% to 25.53% for the Dunham Salt.

Important properties of salt formations for cavern development are porosity and permeability. Salt is typically considered to be nonporous and impermeable, making it ideal for gas or liquid storage operations. Tests conducted on the Dunham Salt interval confirmed this with results showing vertical porosity of 1.7% and permeability of 16 nD. Salt creep, or the cavern closure rate of the salt, for the Dunham was generally considered to be slow creeping. This is a positive indicator that cavern operations can be conducted for a sustained period of time.

Figure 6-3. Red-brown clay intrusions with small dark inclusions visible (6848.10 ft).

6.3 Piper Formation – Base Dunham Salt (underburden)

At 6893.35 ft in Core Run 2, the lower part of the Piper Formation (Base Dunham Salt) was contacted and is characterized as a siltstone/mudstone with anhydrite. Like the Piper Poe Member, the Base Dunham Salt Member is very tight with vertical porosity and permeability values of 0.7% and <5 nD, respectively. While the underlying formation is not as critical to the successful operation of a salt cavern, the Base Dunham Salt member was still tested to determine its mechanical properties. The samples tested were determined to have high strength and are very competent.

6.4 Spearfish Formation – Saude Member (overburden)

The Spearfish Formation is characterized as a mostly massive red siltstone with some anhydrite; however, the cored and observed Spearfish Formation in Core Run 3 and Core Run 4 showed a significant amount of intrusive salt mixed in and infilled into fractures, as illustrated in Figure 6-4. The well-cemented siltstone is red-orange, and the infilled halite is near-clear, subhedral to anhedral, semitransparent, and vitreous. Vertical porosity and permeability were determined to be very low with values of 0.6% and <5 nD, respectively. Like the Poe Member above the Dunham Salt, the Saude Member has excellent mechanical strength and will serve as a good ceiling for cavern stability.

Figure 6-4. Salt-filled fractures in siltstone (Core Run 3, Box 9).

6.5 Pine Salt

The Pine Salt has a gradational contact from siltstone to salt at 7184.70 ft, as shown in Figure 6-5. This bedded salt illustrates somewhat consistent crystal sizes with a significant percentage of impurities. The Pine Salt is generally characterized as well-indurated halite that is near-clear. The halite crystal grain size averages (measured in crosscut) 0.75 inch with minimum and maximum sizes of 0.50 and 1.5 inches, respectively. A zone of much smaller halite crystals is located from 7207.50 to 7240.60 ft, and crystal sizes average 0.125 inch with minimum and maximum sizes of 0.0625 and 0.50 inch, respectively. The entire Pine Salt contains many red-brown clay intrusions between the majority of the halite crystals with spotty dark inclusions, as shown in Figure 6-6.

Figure 6-5. Gradational contact into mostly halite (Core Run 3, Box 10 to 11).

Discerning the nonsalt units from halite in the Pine Salt was very difficult. Twenty-four sample locations were chosen to determine where to best select the CMC and creep test samples. The XRD results were variable across the zone tested. The zone that was characterized as the Pine Salt contained some high percentages of halite as well as thenardite and glauberite. Albite, anhydrite, calcite, dolomite, microcline, muscovite, orthoclase, quartz, sylvite, northupite, mullite, and palygorskite were also present in varying quantities. Insoluble content was also assessed in the remaining XRD material for two of the Pine Salt samples. These tests were performed to determine how readily thenardite would dissolve in the samples. One sample contained approximately 53% halite and 47% thenardite, and the other sample contained 24% halite and 76% thenardite. Both samples completely dissolved with no remaining insoluble material. Vertical porosity and permeability tests show values of 0.7% and 7 nD, respectively, which is very low. Creep tests performed on the Halite interval of the Pine Salt show a slow creep behavior, ideal for cavern development. Tests performed on the thenardite interval showed a fast creep behavior, which is less desirable. The impact of the fast-creep behavior on long-term cavern operations is uncertain.

6.6 Spearfish Formation – Belfield Member (underburden)

At 7241.60 ft in Core Run 4, the lower part of the Spearfish Formation was encountered. This part of the Spearfish Formation is characterized as mostly massive with minor salt-filled nodules and fractures for approximately 2 ft below the Pine Salt and then mostly massive with minor thin anhydrite laminations in zones to the end of coring at 7275.50 ft. Vertical porosity and permeability were 2.2% and <5 nD, respectively. As with each zone tested, the mechanical properties of the Belfield Member show high strength and competency.

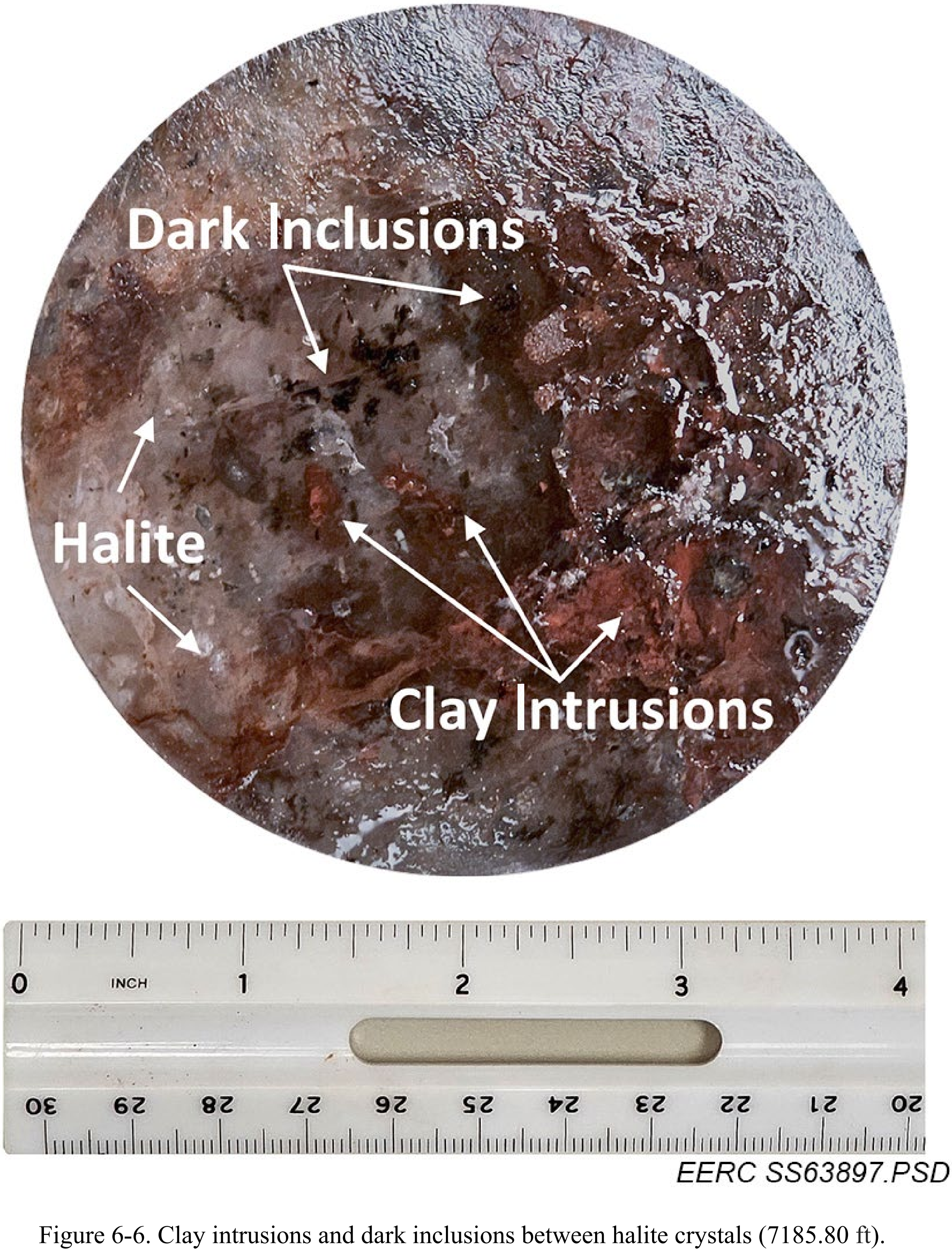


Figure 6-6. Clay intrusions and dark inclusions between halite crystals (7185.80 ft).

6.7 Summary of Geomechanical Tests

This section summarizes the tests completed on the salt and nonsalt intervals of the HALITE 1 whole core, including the Dunham and Pine Salts. Confined creep tests evaluated the time-dependent behavior of salt creep. The tests were performed at formation temperature and entailed applying a confining pressure to the exterior surface of the sample while increasing axial stresses. A typical creep test will result in a sample deforming and becoming shorter and increasing in diameter throughout the increase in axial load. The test is performed until no further change is observed or until sample failure.

Axial strains were calculated from the resulting change in height to diameter of the sample. Axial strain vs. time is plotted for each sample creep test to visualize the sample strain rate (Figures 6-7a and 6-7b). Strain rates are typically high immediately after the application of axial stress, but strain rate decreases with time as samples approach steady state values (Buchholz, 2023). Results of creep tests on the Dunham and Pine salt intervals are summarized in Appendix E and were integrated into the 3D mechanical earth model (MEM) simulations. In general, at low axial stress differences (i.e., axial vs. confining stress), the Dunham and Pine salts are described as hard salts or slow creeping, and at high axial stress differences, the salts are described as soft salts or fast creeping. In general, slow creeping salts are desired; however, the Dunham and Pine salts at HALITE 1 exhibit both fast and slow creep characteristics. Figure 2-1 shows results of creep tests performed on HALITE 1 samples compared to other regions where data was available. As shown, the Dunham and Pine Salt members have comparable creep behavior to salt formations in which caverns have been developed, indicating that cavern development and operation in North Dakota have potential.

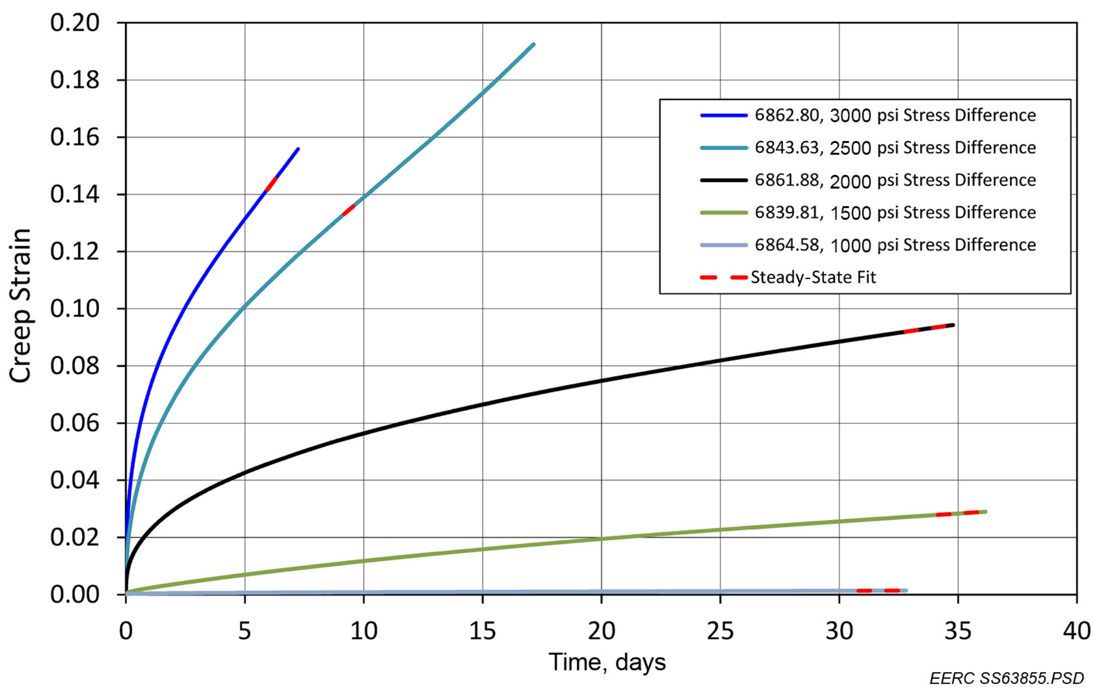


Figure 6-7a. Creep strain vs. time for the Dunham salt showing transient and steady-state strain behavior in response to axial stress (Buchholz, 2023). Sample composition is primarily halite.

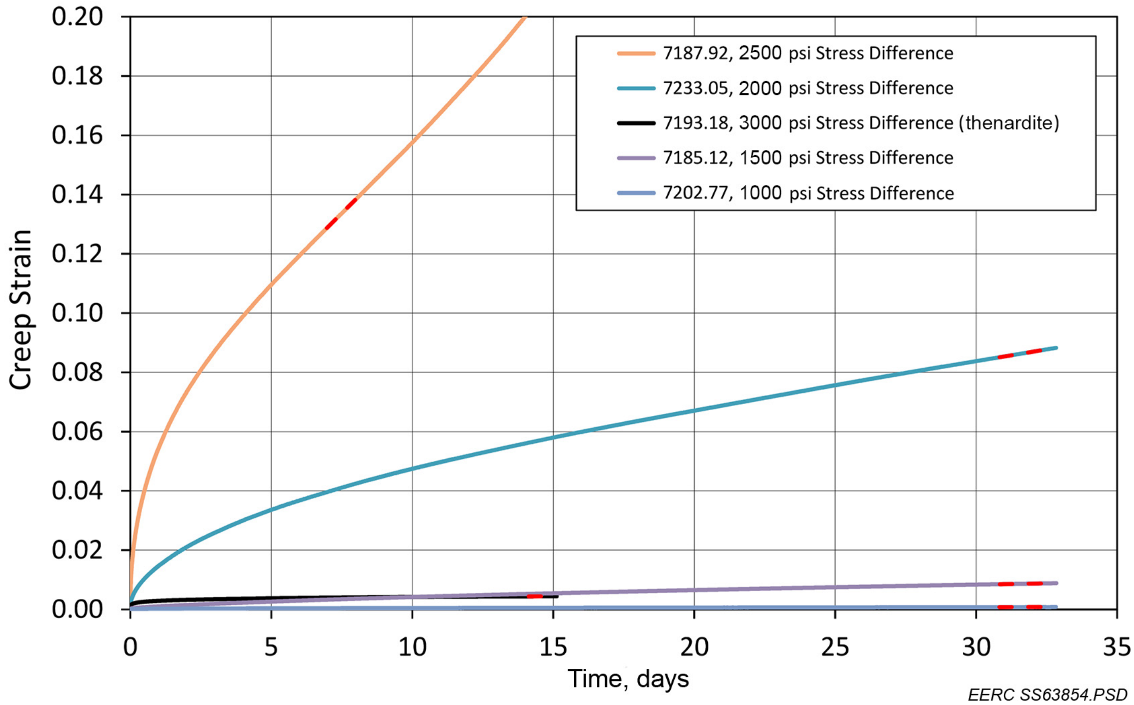


Figure 6-7b. Creep strain vs. time for the Pine salt showing transient and steady-state strain behavior in response to axial stress (Buchholz, 2023). Sample composition is primarily halite, but thenardite and glauberite are also present.

7.0 GEOLOGIC AND GEOMECHANICAL MODELING

Geologic and geomechanical modeling was completed and calibrated with the collected HALITE 1 geophysical well logs and core analysis and supplemented with data from nearby offset wells. The Dunham and Pine Salts were modeled in one dimension (1D) and three dimensions (3D) to determine optimum salt cavern geometries and recommended operational limits during the life of the salt cavern. A regional structural, stratigraphic, petrophysical, and mineralogical assessment was conducted and integrated with geologic modeling results to identify high-graded areas for future salt cavern exploration. The lack of site-specific calibration data excluded the Charles Salt from geologic and geomechanical modeling.

7.1 Geologic Model

The purpose of the geologic modeling efforts was to capture depth, thickness, and surrounding rock formations of the Dunham and Pine Salts for the HALITE 1 area to test the feasibility of salt cavern development and provide a framework for geomechanical testing. A local-scale 3D geologic model was constructed for the HALITE 1 area based on legacy well data and data gathered through drilling, logging, and core testing in the HALITE 1 well. The geomodel was developed using structure and property modeling best practices based on geophysical well log data within SLB's Petrel 2021.5 E&P software platform (SLB, 2022a).

An 8-mile by 8-mile area of interest (AOI), centered on the HALITE 1 well, was selected to ensure adequate structural control from surrounding wells (Figure 7-1). The zone of interest (ZOI) for the geologic model was from the base of the Opeche Formation (~5610 ft below sea level) to the ground surface. This ZOI allowed extractions from the geologic model that were 100 ft above and below Dunham and Pine Salts and supported overburden calculations for the geomechanical modeling (Figure 4-1).

Over the 64-square-mile area, the geologic model contains multiple individual layers, including the structural surfaces of each formation and salt member, rock types (facies) derived from petrophysical mineralogy, and porosity. These layers are supported by HALITE 1 core descriptions and testing and through statistical analysis from offset wells to capture the geologic complexity of the formations of interest and to predict the properties between known data points. Appendix D provides a detailed description of the process used to create each layer, statistical methods, and significant parameters determined through the analysis.

Figures 7-2 and 7-3 show the well log displays for the Dunham and Pine Salt intervals, respectively, at the HALITE 1 site. This log-based analysis allows for a direct comparison of properties that identify composition, thickness, and porosity for the salt and nonsalt intervals. As shown in the figures, the Dunham and Pine Salt are close to the same thickness, 69 and 57 ft respectively, at the HALITE 1 site. Likewise, they each exhibit very low porosity (less than 1%). Typically, the observed porosity coincides with impurity content. The two salt members differ in their total impurity content. Comparing the sixth track on each figure, the Dunham Salt is composed of a very high percentage of pure halite salt (NaCl), shown in red. This is beneficial to the development of caverns in that NaCl is highly soluble in water and is the dominant mineral where global caverns are developed and operated. The Pine Salt contains a significant amount of NaCl; however, the interval is much higher in impurities (all other colors), including dolomite, siltstones (clastics), and thenardite, or sodium sulfate (Na_2SO_4). Thenardite is known to be soluble in water, like halite; however, the mechanical properties of the mineral are not as well understood as to their impact on long-term cavern operations.

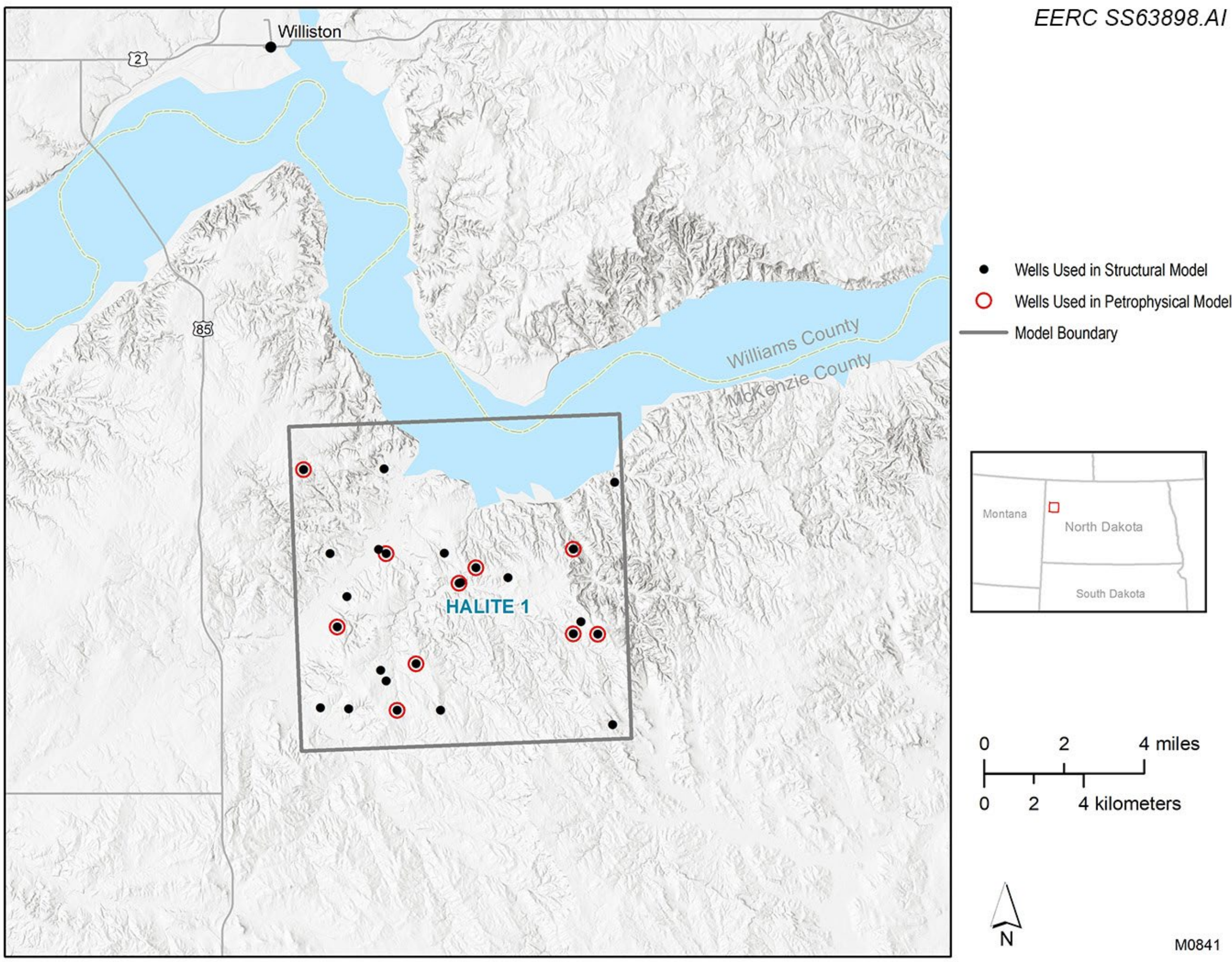


Figure 7-1. Model boundary with HALITE 1 and other wells used for the geologic model. Wells with solid black dots were used for structural modeling, and wells with open red circles were used for structural, facies, and petrophysical modeling.

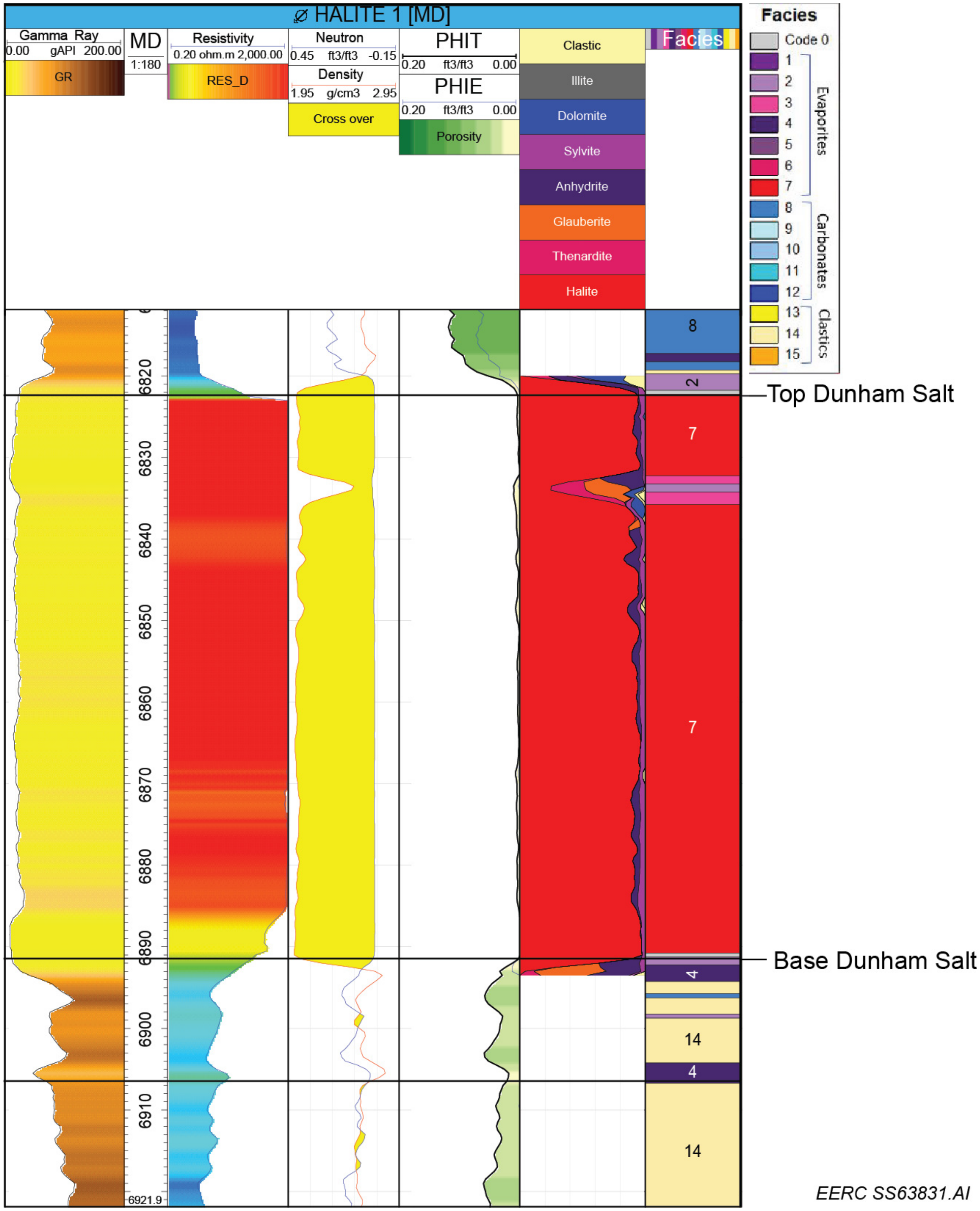


Figure 7-2. HALITE 1 well log display for the Dunham Salt with petrophysical mineral model and identified facies.

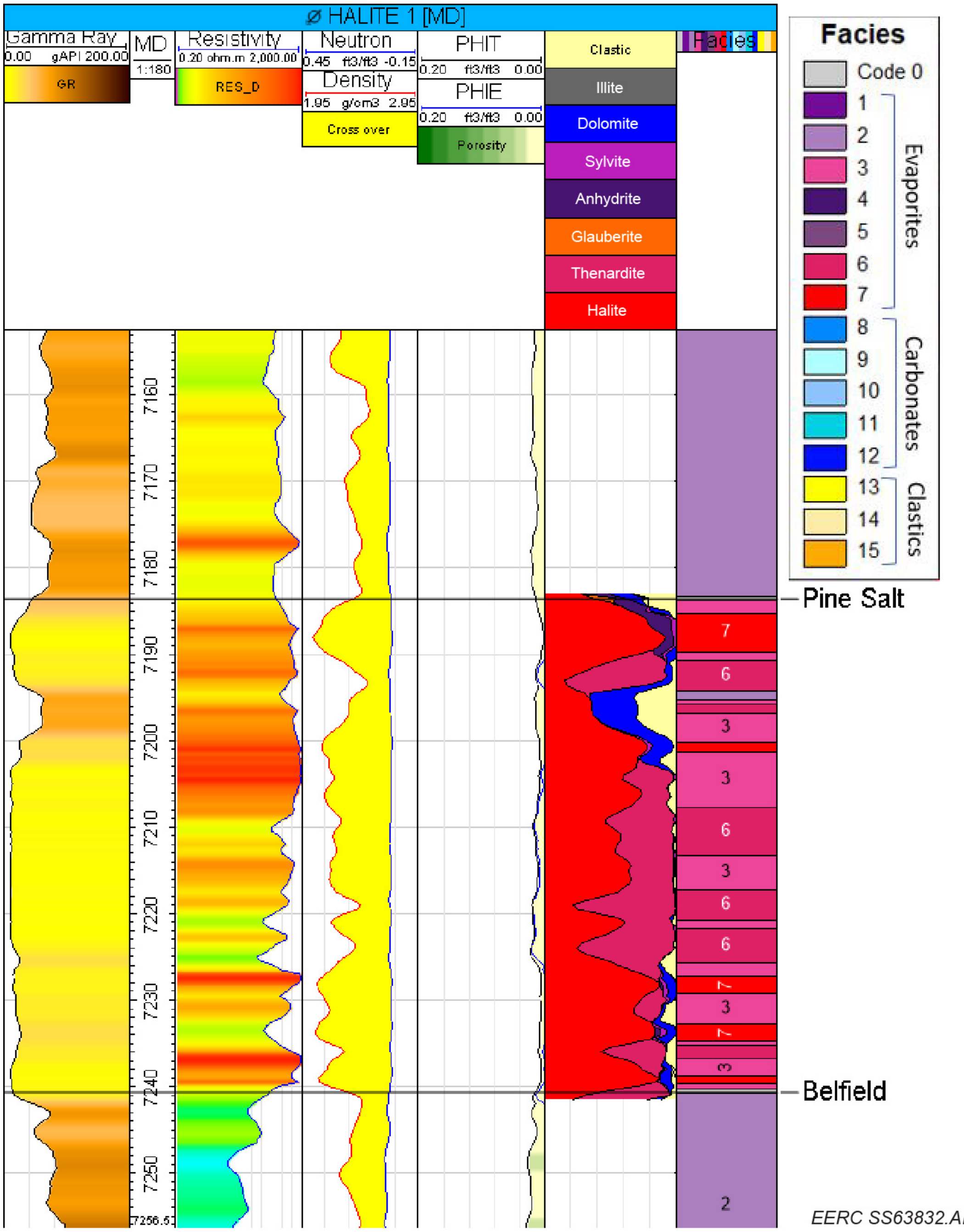


Figure 7-3. HALITE 1 well log display for the Pine Salt with petrophysical mineral model and identified facies.

The HALITE 1 petrophysics (e.g., mineralogy and porosity) and core analysis provided confidence for interpretations to be applied to the geophysical well logs for offset wells within the local-scale 3D geologic model. The data collected from HALITE 1 allowed for specific salt species to be distinguished from one another with the geophysical well log data. The ability to determine salt facies was important to the property distributions of the local-scale 3D geologic model, as well as the regional assessment (Section 7.3); however, additional core and log data from multiple locations across western North Dakota is needed to further improve the calibration of well log data to the bedded salt zones in other locations.

Facies were defined using an unsupervised artificial neural network classification method in Petrel and estimated from gamma ray, bulk density, neutron porosity, and photoelectric logs. The resulting classification was applied at the well log resolution and qualitatively calibrated to the petrophysical mineralogy interpretation of HALITE 1. The neural net identified seven evaporite facies, five carbonate facies, and three clastic facies. The evaporite facies distinguished halite, thenardite, anhydrite, and a mixed evaporite facies. The overall vertical trend of evaporite facies for each zone demonstrated good consistency laterally throughout the model area. Halite facies in the thicker parts of the Dunham Salt were found to be laterally continuous, but where the Dunham Salt was thin, likely because of dissolution, insoluble evaporite facies dominated (e.g., anhydrite, siltstone with halite, and silty shale). Halite facies comprised 89% of the Dunham Salt, with insoluble evaporite facies at 11% based on well log data. The Pine Salt interval contained stacked halite, mixed evaporite, and thenardite cycles that were laterally traceable throughout the model area. Pine Salt interval proportions of halite, thenardite, and mixed evaporite were 18%, 38.7%, and 42.8%, respectively, from the well log data. Insoluble evaporite facies (e.g., siltstone with halite) made up only 0.4% of the Pine Salt interval from the well logs (Figure 7-4).

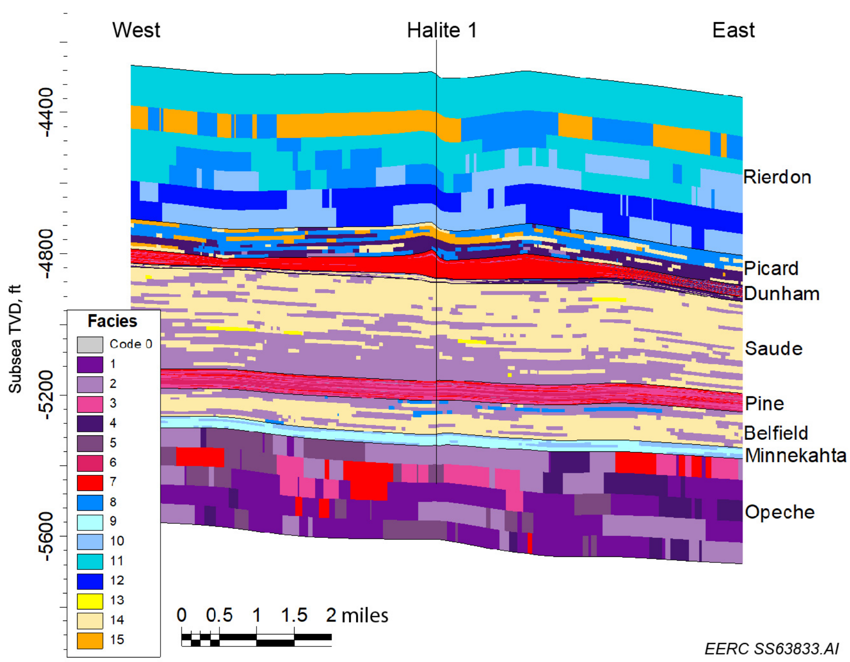


Figure 7-4. Distribution of predicted facies from west to east from the top of Rierdon to the base of the Opeche. Halite (Code 7), thenardite (Code 6), and mixed evaporite (Code 3) are the primary constituents of the Dunham and Pine Salts. Insoluble evaporite facies (Codes 1, 2, 4, and 5) are in shades of purple.

A porosity model was developed to support the geomechanical simulation and provide rock properties for the salt and surrounding intervals. Pure evaporites have very low total porosity (PHIT) and effective porosity (PHIE). Based on the petrophysical interpretation of the Dunham and Pine Salts, the PHIT and PHIE were assigned zero for the evaporite facies. For the carbonate and clastic facies, PHIT and PHIE were distributed stochastically using a Gaussian random function simulation algorithm for each facies (Figures 7-5 and 7-6). PHIE was much lower in the formations adjacent to the Dunham and Pine Salts, likely due to the presence of evaporite cements.

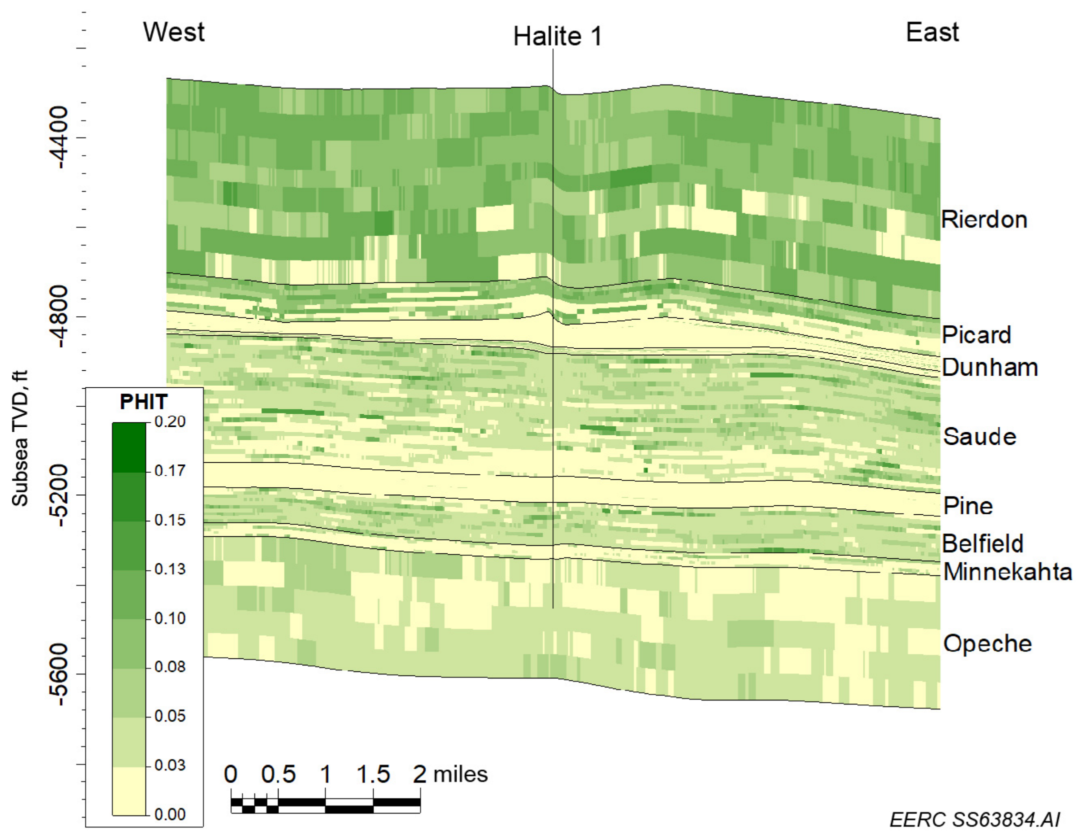


Figure 7-5. PHIT distribution from west to east from the top of the Rierdon to the base of the Opeche. Evaporite intervals have the lowest PHIT values.

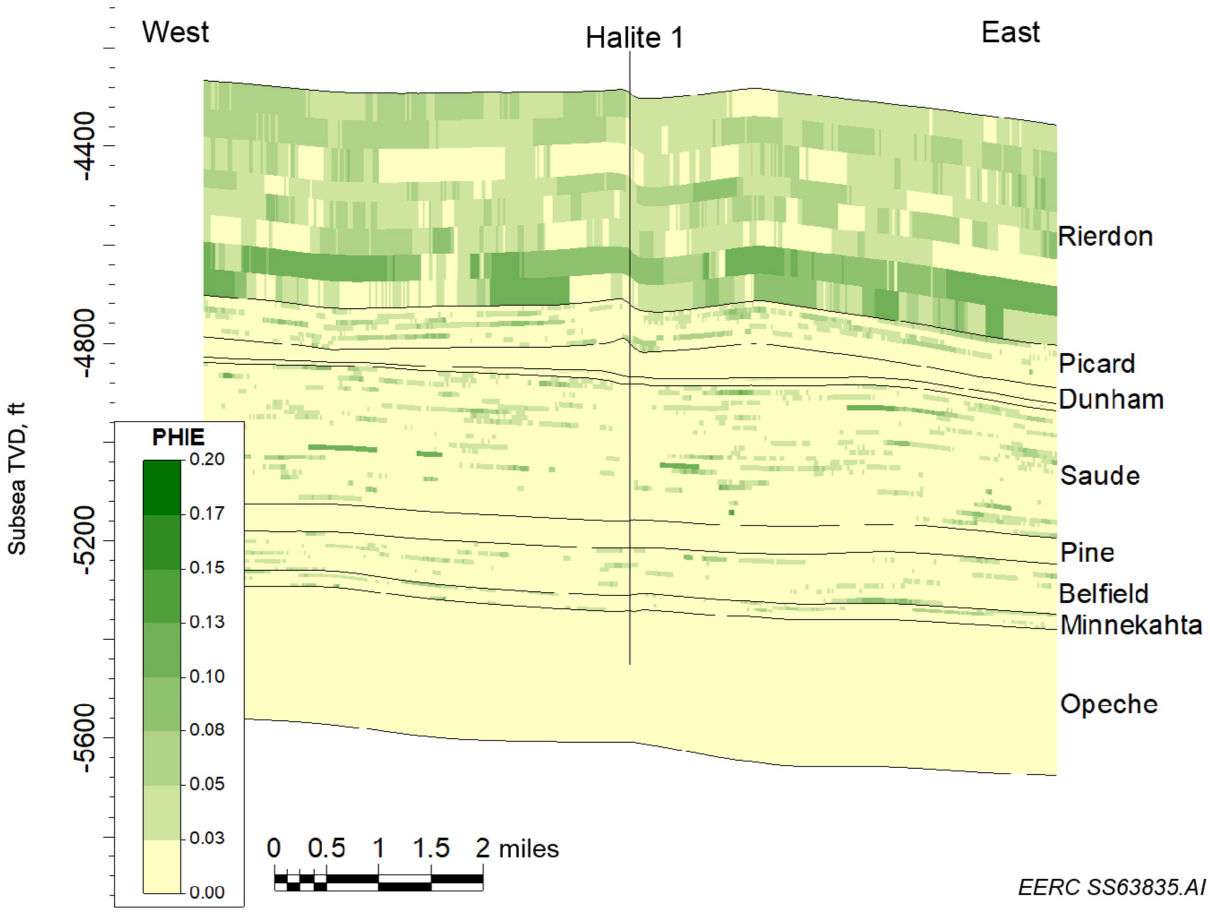


Figure 7-6. PHIE distribution from west to east from the top of the Rierdon to the base of the Opeche. Evaporite intervals have the lowest PHIE values.

Structural, stratigraphic, compositional, and porosity trends derived from the geomodel were made available for geomechanical simulations to aid in predicting stress, stability, and optimal operational conditions for salt caverns. Lessons learned from the HALITE 1 geologic model were also built into the regional assessment for salt cavern exploration (Section 7.3).

7.2 Geomechanical Modeling

Cavern stability is a major consideration for successful salt cavern design and operation. The geomechanical modeling workflow focused on characterizing ideal conditions and operational limits of salt cavern stability given boundary conditions, including pressure maintenance methods, operational pressure ranges, and cycle times (e.g., pressure cycle timing) for feedstocks being stored using a brine-compensated pressure system. Salt creep (e.g., deformation of salt) is a property of salt that helps understand how a cavern will deform at predictable rates over time in response to cavern operating practices. The deformation is dependent on formation temperature, confining pressure, salt grain size, impurities, and inclusion (e.g., free brine water or gas bubbles) (Barker and others, 1994).

The geomechanics workflow (Figure 7-7) followed two methods. The first method involved using SLB Petrel (SLB, 2022a) to convert the geomodel (Section 7.1) finite-element surfaces for import into FLAC3D (Itasca, 2023a, b) and development of an Itasca FLAC3D geomechanical model around HALITE 1 from surface to TD (Itasca, 2023c). The second method used SLB Techlog (SLB, 2022b) for HALITE 1 well borehole image log interpretation and then a 1D MEM (SLB, 2022c) and SLB Near Wellbore Geomechanics (NWG) 3D MEM (SLB, 2022d, e) were developed for the HALITE 1 well.

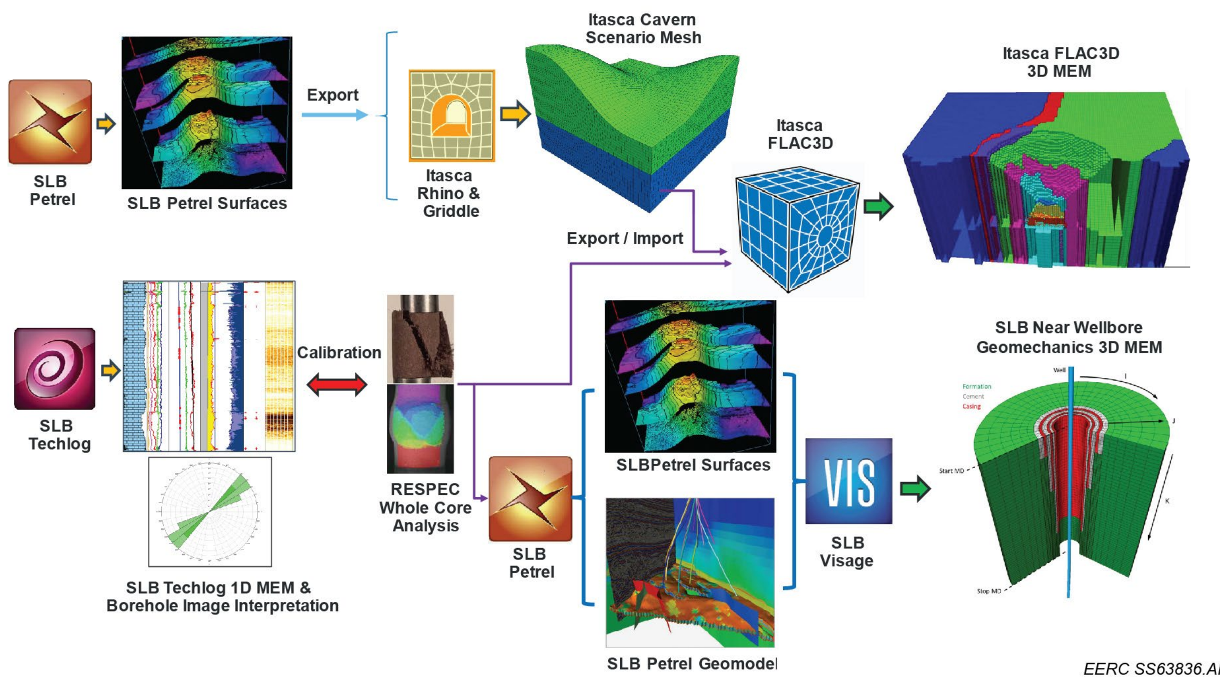


Figure 7-7. Integrated geomechanics workflow diagram.

1D and 3D models were developed for the Dunham and Pine Salts to estimate salt cavern stability and geometries. Models covered the same AOI (Figure 7-1) and ZOI (Figure 4-1) as the 3D HALITE 1 geologic model. The goal of the geomechanical study was to determine viability of salt cavern storage solutions for different feedstocks (e.g., hydrogen and hydrocarbons, including ethane, propane, Y-Grade NGL, and fractionated natural gas) based on the Dunham and Pine Salts material strength and stress regime within the AOI. Geomechanical modeling results informed operational conditions for stable salt cavern storage and were integrated with the engineering design (Section 8.0). Data used for the models were generated using the HALITE 1 set of geophysical well logs and whole core data available across the target Piper and Spearfish Formations, including under- and overburden of nonsalt sections for the Dunham and Pine Salt Members.

For this study, a cylindrical geometry was selected because this shape generally emulates a typical leached salt cavern geometry in a bedded salt formation (Cyran and Kowalski, 2021) and reduces computational run times for each modeled scenario. A range of cylindrical cavern geometry height-to-diameter aspect ratios from 1:1 to 1:5 was modeled for each zone. The objective of modeling a range of aspect ratios is to determine the limits of cavern stability, given the cavern size, rock mechanics, lithology, and cavern design input parameters for each model scenario. The modeled cavern height vs. the total thickness for each salt unit reflects cavern stability safety margins for salt cavern roof and base thicknesses after Li and others, 2021; Wang and others, 2023. Figure 7-8 shows an example of the vertical cylindrical cavern model design used in the 3D MEM methods. For each modeled ratio, the salt thickness above and below the cavern and the cavern height remained the same, only the cavern diameter was modified. A summary of key geomechanical modeling components is provided below, and a full description of the software, data, methods, and interpretations are provided in Appendix E.

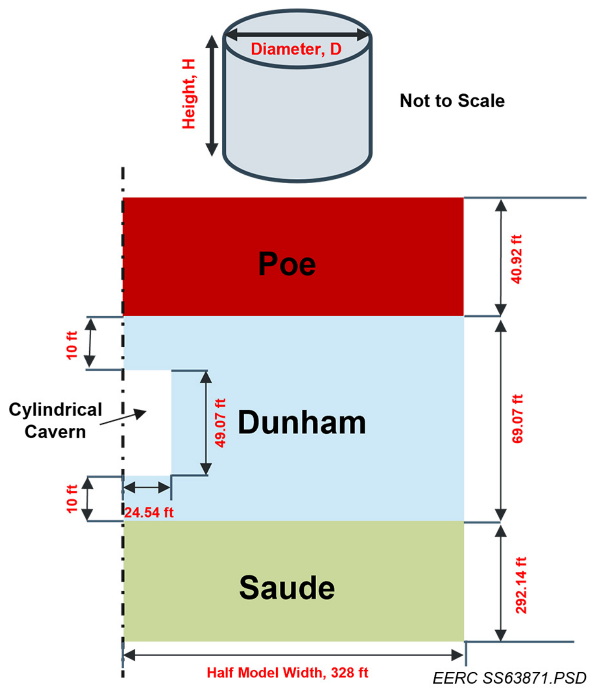


Figure 7-8. Schematic of Dunham Salt vertical cavern cylinder orientation (top) and a FLAC3D example salt model quarter cross section (bottom).

7.2.1 Modeling Cavern Geometry and Boundary Conditions

Modeling salt caverns to determine salt cavern stability and operational parameters in the Dunham and Pine Salts involved determination of loading conditions, boundary conditions, and the previously discussed range of salt cavern geometry aspect ratios. Durations of cavern storage ranged from 1 to 30 years. Boundary conditions, based on engineering design limits, include minimum (P_{min}) and maximum (P_{max}) operating pressures given a brine-compensated system. Basic natural gas and NGL loading conditions of constant pressure at P_{min} over 1 year, constant pressure at P_{max} over 1 year, and an annual seasonal pressure cycling scenario starting from a 100-day buildup from P_{min} to P_{max}, followed by an 82-day steady pressure, then by a 100-day pressure drawdown from P_{max} to P_{min}, and ending with an 82-day steady pressure, exhibited in

Figure 7-9 and Figure 7-10, reflect North Dakota's weather cycles, refinery cycles, and agricultural seasonal cycles. The hydrocarbon cycle differs from that of hydrogen, which is driven by refinery, electricity generation and, eventually, fuel cell vehicle requirements that exhibit different timing which, consequently, produces a different pressure profile over time, as reflected in Figure 7-11. The hydrogen cavern pressure profile has been modeled as comprised of three cycles of 60-day injection/increasing pressure, 40-day stable pressure, and 21-day drawdown/decreasing pressure within each year.

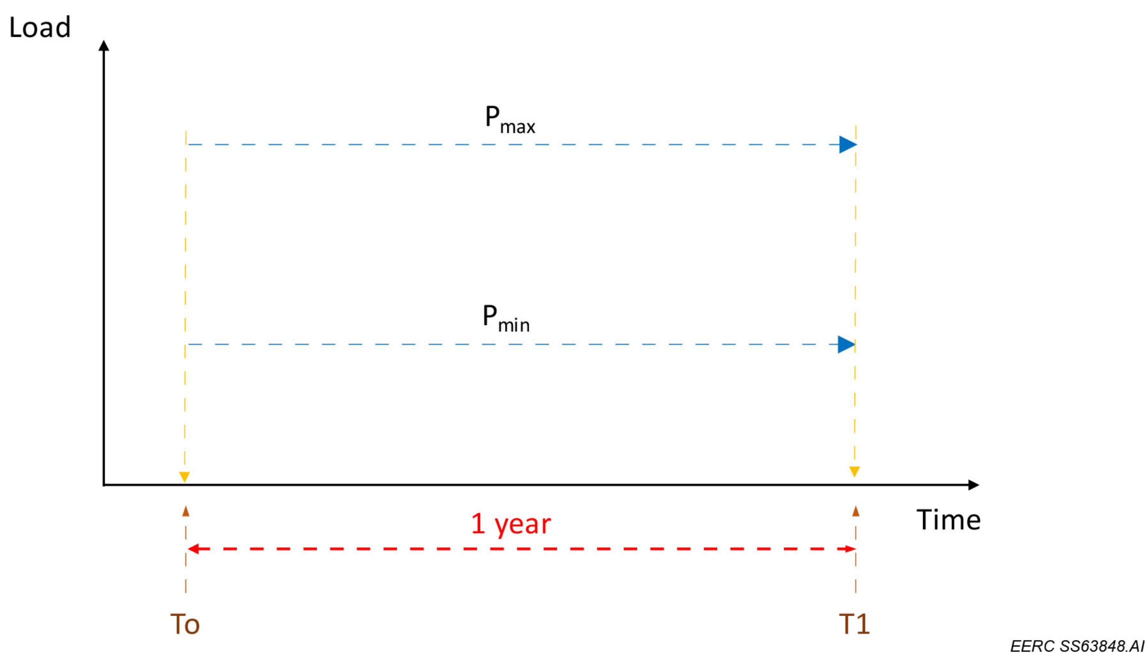


Figure 7-9. Brine-compensated salt cavern at 1-year constant loading conditions for natural gas and NGL storage at P_{min} and P_{max} pressures, where To = initial time and T1 = end of 1 year.

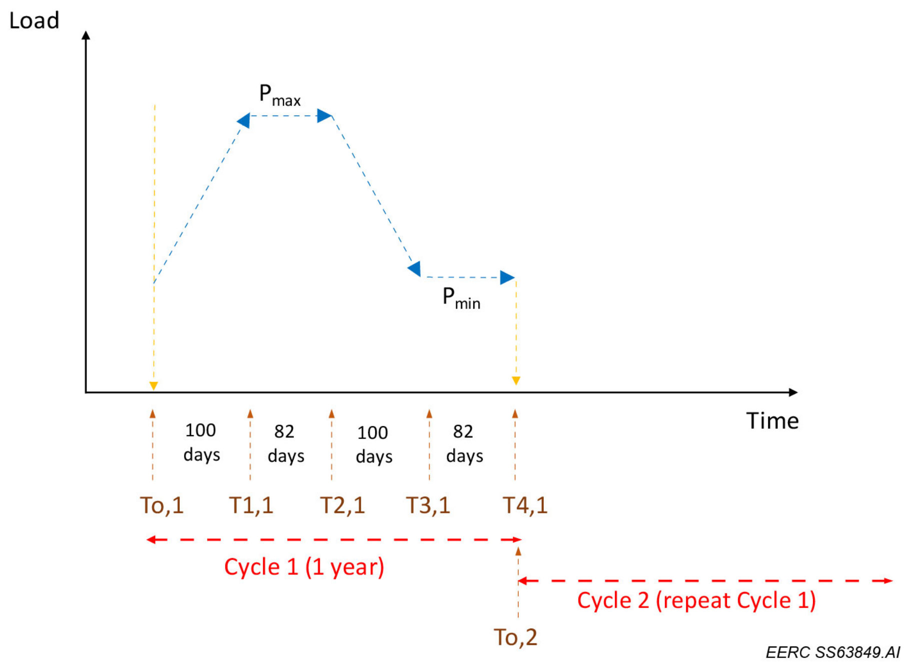


Figure 7-10. Brine-compensated salt cavern seasonal cyclic loading case boundary conditions for natural gas and NGL storage, where To = initial time; T1,1 = first time step, Year 1; and T2,1 = second time step, year 1, etc.

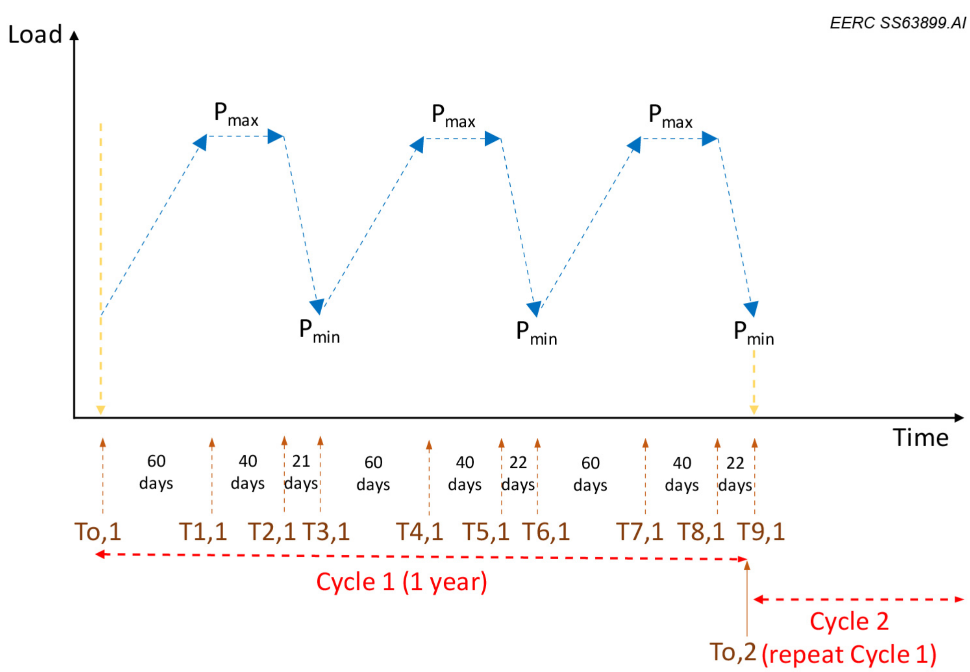


Figure 7-11. Brine-compensated salt cavern annual cyclic loading case boundary condition for a hydrogen salt cavern storage, where To = initial time; T1,1 = first time step, Year 1; and T2,1 = second time step, Year 1, etc.

The P_{min} pressure gradient for all 3D MEM models assumes a brine gradient of 0.52 psi/foot, while the P_{max} pressure gradients are dependent on the vertical overburden stress. The overburden stress gradient for the Dunham Salt Member is 0.984 psi/foot and for the Pine Salt Member is 0.988 psi/foot. See Table 7-1 for a summary of the 3D MEM modeling input parameters.

Table 7-1. Summary of 3D MEM Input Parameters

Zone	P_{min} Loading Condition, psi/foot	P_{max} Loading Condition, psi/foot	Number of Annual Cycles	Maximum Project Length, years	Height to Diameter Aspect Ratio Range
Dunham	0.52	0.984	One + three	30	1:1 to 1:5
Pine	0.52	0.988	One + three	30	1:1 to 1:5

7.2.2 Complementary Geomechanical Model Methods

Two complementary methods were used in the study. Each approach computes cavern stability and salt creep within the model to identify conditions to minimize creep over a 20- to 30-year project life. The modeling methods differ in that one computes cavern stability in the near wellbore environment and does not include deformation in the overlying and underlying rocks. The second method captures the geologic column above and below the salt zone of interest and models the potential for cavern deformation that will develop over time. By using two unique, but related, methods, results can be compared and integrated to improve confidence of conclusions and recommendations. Table 7-2 summarizes a comparison of the two methods regarding technical impact, addressing key technical questions related to cavern stability.

Table 7-2. Comparison of Technical Impact for the Two 3D MEM Methods Used

Cavern Stability Analysis Capabilities	SLB NWG 3D MEM	Itasca FLAC 3D MEM
Cavern Side Closure due to Salt Creep	X	X
Salt Creep Strain Rates and Direction	X	X
Tensile Fracturing of Cavern Walls (wall collapse)	X	X
Seasonal Cyclic Loading Impact on Salt Creep	X	X
P_{min} and P_{max} Pressure Range Impact on Salt Creep	X	X
Fundamental Salt Creep Property Capabilities	X	X
Advanced Salt Creep Property Capabilities		X
Cavern Roof Tensile Fracturing (roof collapse)		X
Identification of Bedding Planes Slip Between Salt Top/Base		X
Integration of Salt Over- and Underburden Geomechanics		X
Optimized Operating Conditions for Maximized Stability		X
Ability to Model Complex Cavern Geometries (vs. cylinder)		X

7.2.3 Results – SLB NWG Model

Results of all near wellbore loading scenarios indicate higher equivalent salt creep strain rates at the top of the cavern compared to the base. Additionally, equivalent creep strain rates were found to decrease in proportion to the distance from the center of the cavern. The highest salt creep equivalent strain rates in all modeled scenarios occur at the cavern roof and cavern wall, illustrated in Figure 7-12. The equivalent strain rates vs. time for the 20-year scenario with an aspect ratio of 1:1 provided a transient equivalent creep strain response early in the project and then a steady-state response after the first few years of operation (Figures 7-13a, b). Additionally, the Pine Salt demonstrates slightly more creep over the Dunham Salt system for all aspect ratio cases and is attributed to the differences in salt creep characteristics related to mineralogy as measured in the lab (Buchholz, 2023). Additional details regarding equivalent creep strain are in Appendix E.

Given that salt will deform in the subsurface at the formation temperatures and pressures that exist across the Williston Basin, creep strain is predicted to be cumulative over the project duration (i.e., once the creep progresses, it cannot be reversed). Effective engineering designs will require effective management of the inevitable creep progression within the salt cavern during the life of the project.

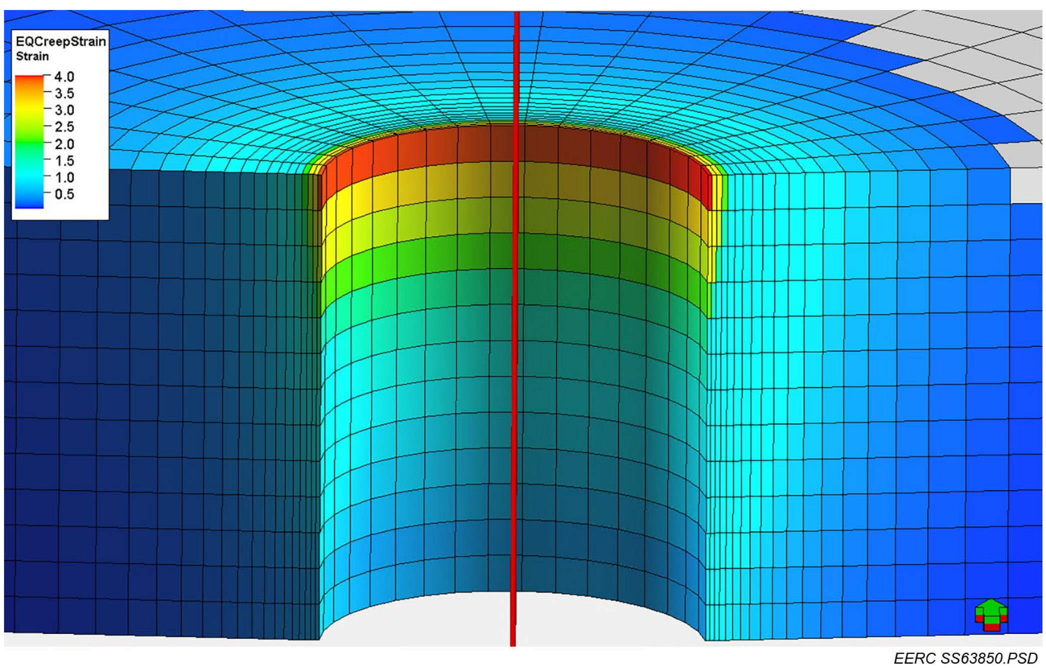


Figure 7-12. Dunham salt NWG model cross section showing vertical and horizontal trends of equivalent creep strain (EQCreepStrain).

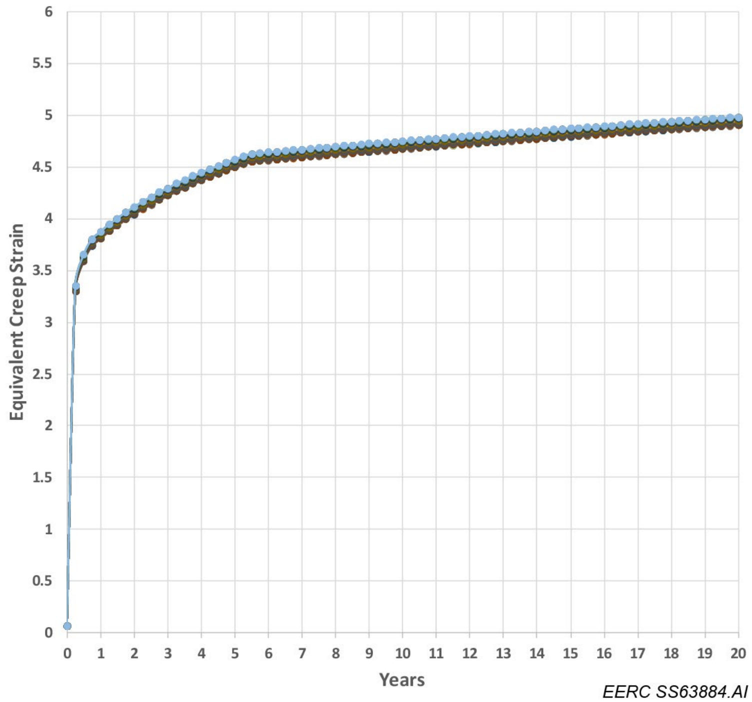


Figure 7-13a. Dunham Salt equivalent creep strain for 20 years with cyclic loading, showing transient creep strain early (Years 0 to 5) and steady-state later (after Year 5) in the project. Aspect ratio is 1:1.

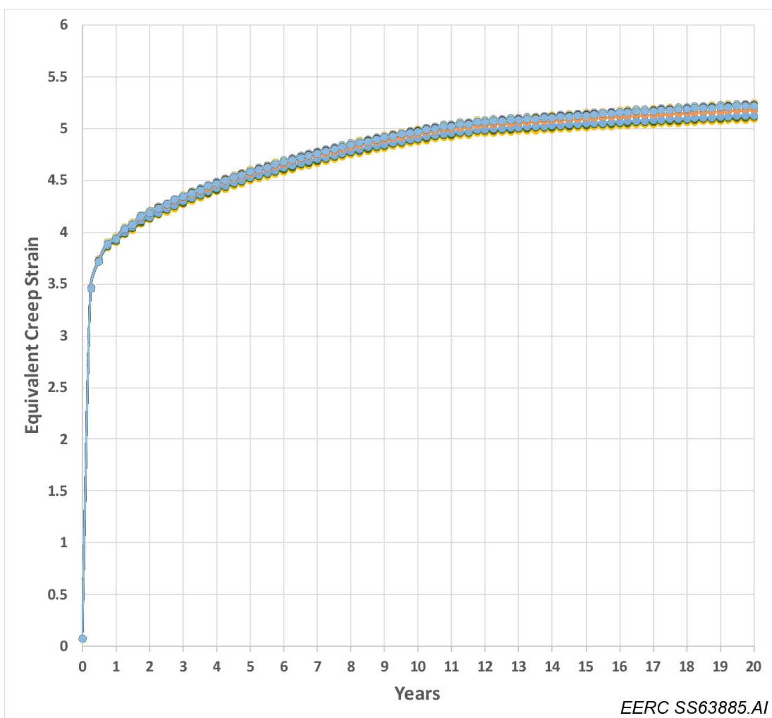


Figure 7-13b. Pine Salt equivalent creep strain for 20 years with cyclic loading, showing transient creep strain early (Years 0 to 5) and steady-state later (after Year 11) in the project. Aspect ratio is 1:1.

7.2.4 Results – FLAC3D MEM

Using FLAC3D's simulator engine, time-lapse 3D geomechanical simulations were conducted for project lengths of 1 year with constant minimum pressures (P_{min}) (Figure 7-9), 1 year with constant maximum pressures (P_{max}) (Figure 7-9), 30 years with a seasonal cyclic pressure loading schedule (Figure 7-10) for natural gas and NGL storage, and 30 years with a multicycle pressure loading schedule for hydrogen storage (Figure 7-11). Geomechanical properties that indicate the stability of a cavern over time were characterized for ten salt cavern simulation scenarios, including variations in thickness, height, and aspect ratios, and used for addressing problem statements related to cavern stability. Table 7-3 summarizes all modeled scenarios and estimated cavern volumes associated with each scenario. Note that the modeled salt cavern height ranged from 65% to 70% of the gross salt thickness; these design criteria were selected based on guidance from Li and others (2021) and Wang and others (2023).

Table 7-3. Modeled Cavern Aspect Ratios for Each Salt Unit and Associated Volume Estimates of a Cylinder in Cubic Feet and Barrels

Zone	HALITE 1 Gross Thickness, ft	Modeled Cavern Height, ft	Modeled Cavern Diameter, ft	Aspect Ratio (H:D)	Volume, ft^3	Volume, bbl
Dunham Salt Member	69.1	49	49	1:1	92,798	16,528
			98	1:2	371,192	66,112
			147	1:3	835,181	148,752
			196	1:4	1,484,766	264,447
			245	1:5	2,319,947	413,199
Pine Salt Member	57.1	37	37	1:1	40,106	7,143
			74	1:2	160,425	28,573
			111	1:3	360,956	64,289
			148	1:4	641,699	114,291
			186	1:5	1,002,655	178,580

7.2.5 FLAC3D Natural Gas, NGL, and Hydrogen Scenario Modeling Results – 1:2 Aspect Ratio

Figures 7-14 and 7-15 illustrate Dunham and Pine Salt caverns, respectively, with an aspect ratio of 1:2 modeled for 30 years with a seasonal cyclic (Figure 7-10) scenario. The diagrams show salt creep displacement magnitude (in meters). In general, once a cavern is developed, the roof and walls continue to move inward toward the center of the cavern. Notably, the cavern walls exhibit higher salt creep displacement compared to the roof or floor over time. This is shown in the zone displacement magnitude legend in the figures, where red signifies areas more significantly affected by creep displacement compared to those in blue. Maximum creep displacement in the Dunham model with a 1:2 aspect ratio (Figure 7-14) ranges from 12 centimeters after 1 year to 38 centimeters after 30 years. Within the Pine scenario (1:2 aspect ratio), maximum creep

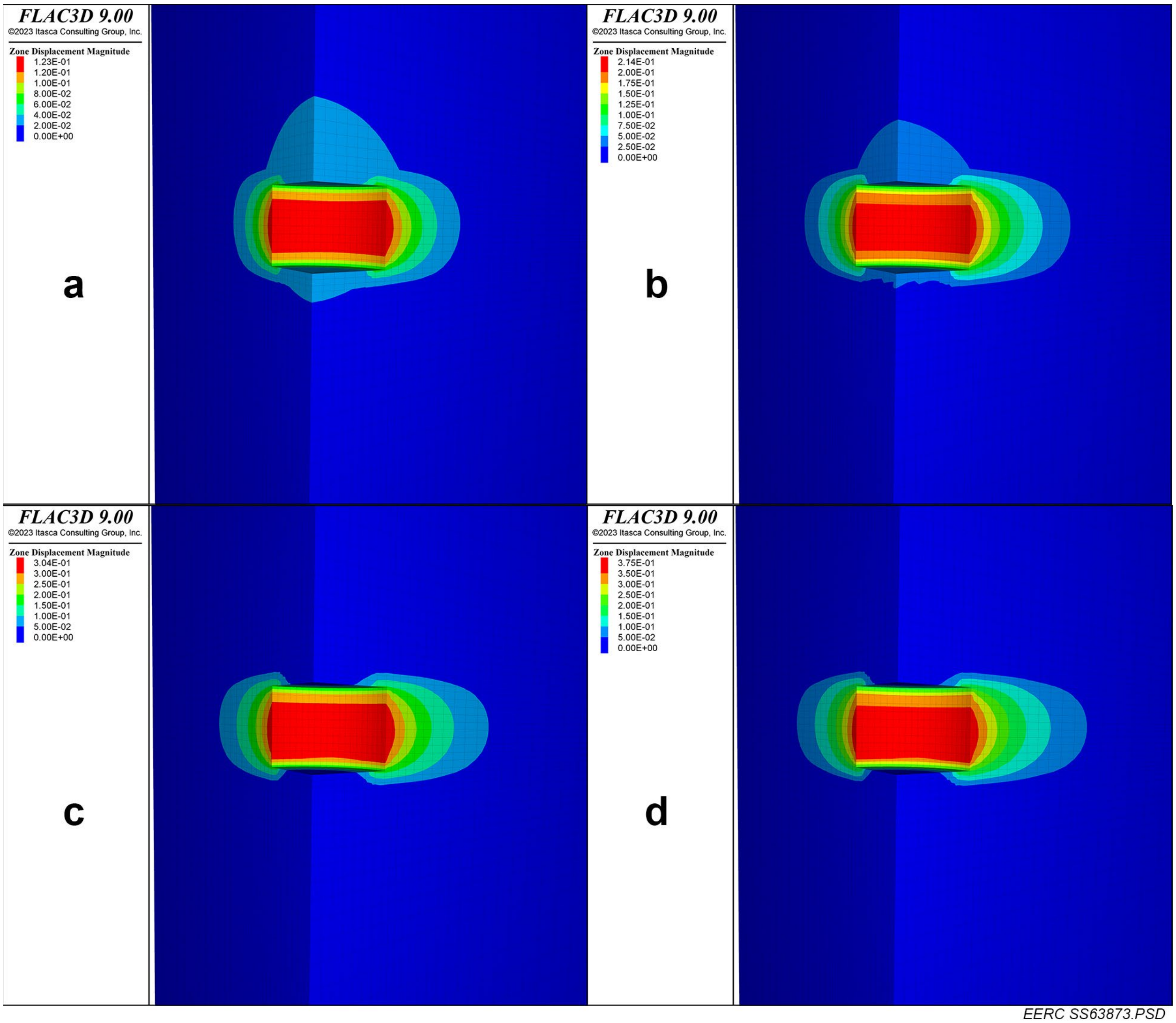
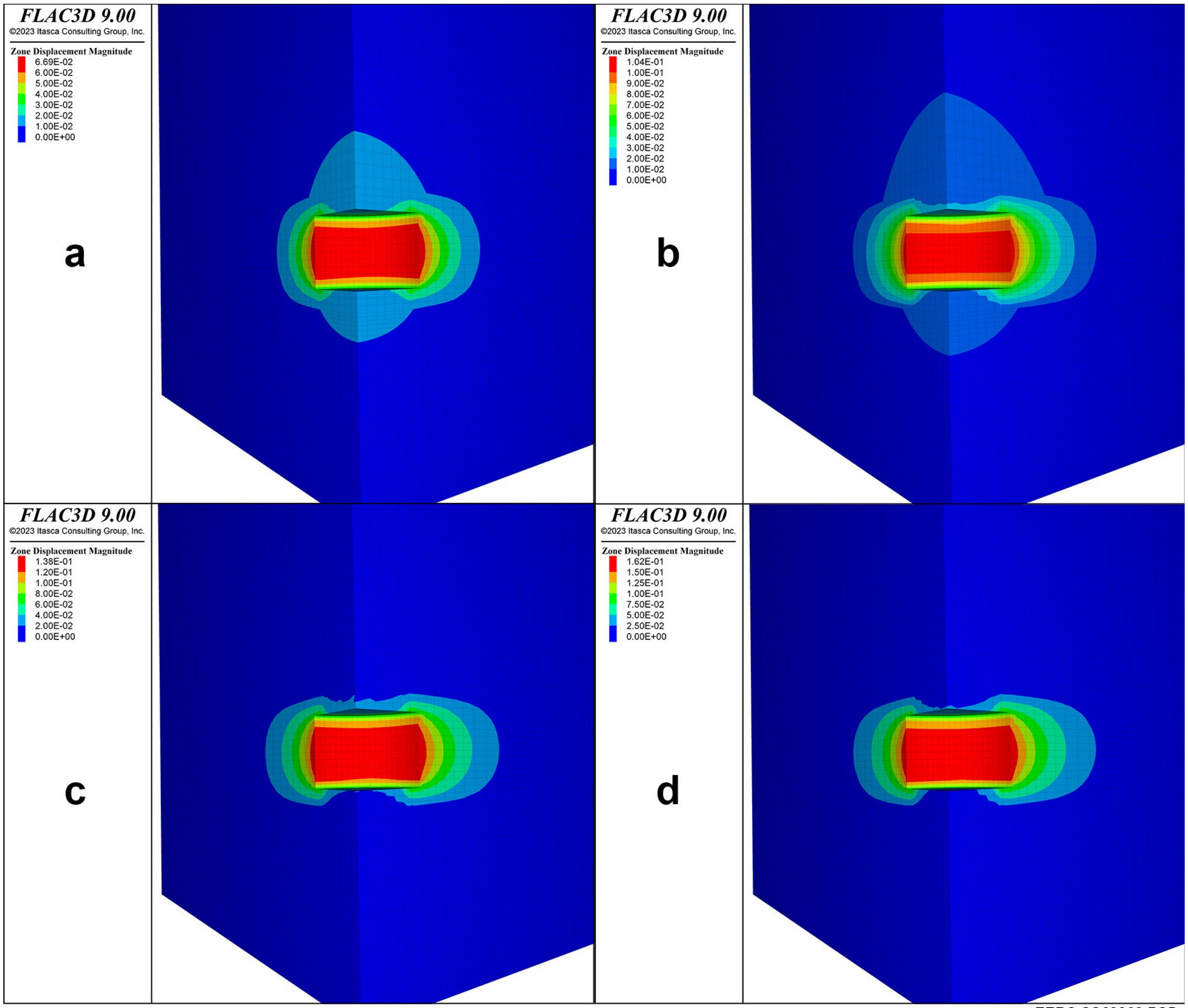


Figure 7-14. FLAC3D model of Dunham Salt shows salt creep displacement in meters and direction after a) 1-, b) 5-, c) 15-, and d) 30-year cavern life for storage of natural gas and NGL. Maximum creep displacement ranges from 12 centimeters after 1 year to 38 centimeters after 30 years. Cavern geometry uses a 1:2 aspect ratio.



EERC SS63863.PSD

Figure 7-15. FLAC3D model of Pine Salt showing salt creep displacement in meters and direction after a) 1-, b) 5-, c) 15-, and d) 30-year cavern life for storage of natural gas and NGL. Maximum creep displacement ranges from 7 centimeters after 1 year to 16 centimeters after 30 years. Cavern geometry uses a 1:2 aspect ratio.

displacement ranges from 7 centimeters after 1 year to 16 centimeters after 30 years (Figure 7-15). Figure 7-16 exhibits results of a similar analysis for hydrogen storage in the Dunham Salt. Maximum creep displacement in the Dunham hydrogen storage model with a 1:2 aspect ratio ranges from 8 centimeters after 1 year to 23 centimeters after 30 years. Within the Pine hydrogen storage scenario (1:2 aspect ratio), maximum creep displacement ranges from 5 centimeters after 1 year to 10 centimeters after 30 years (Figure 7-17).

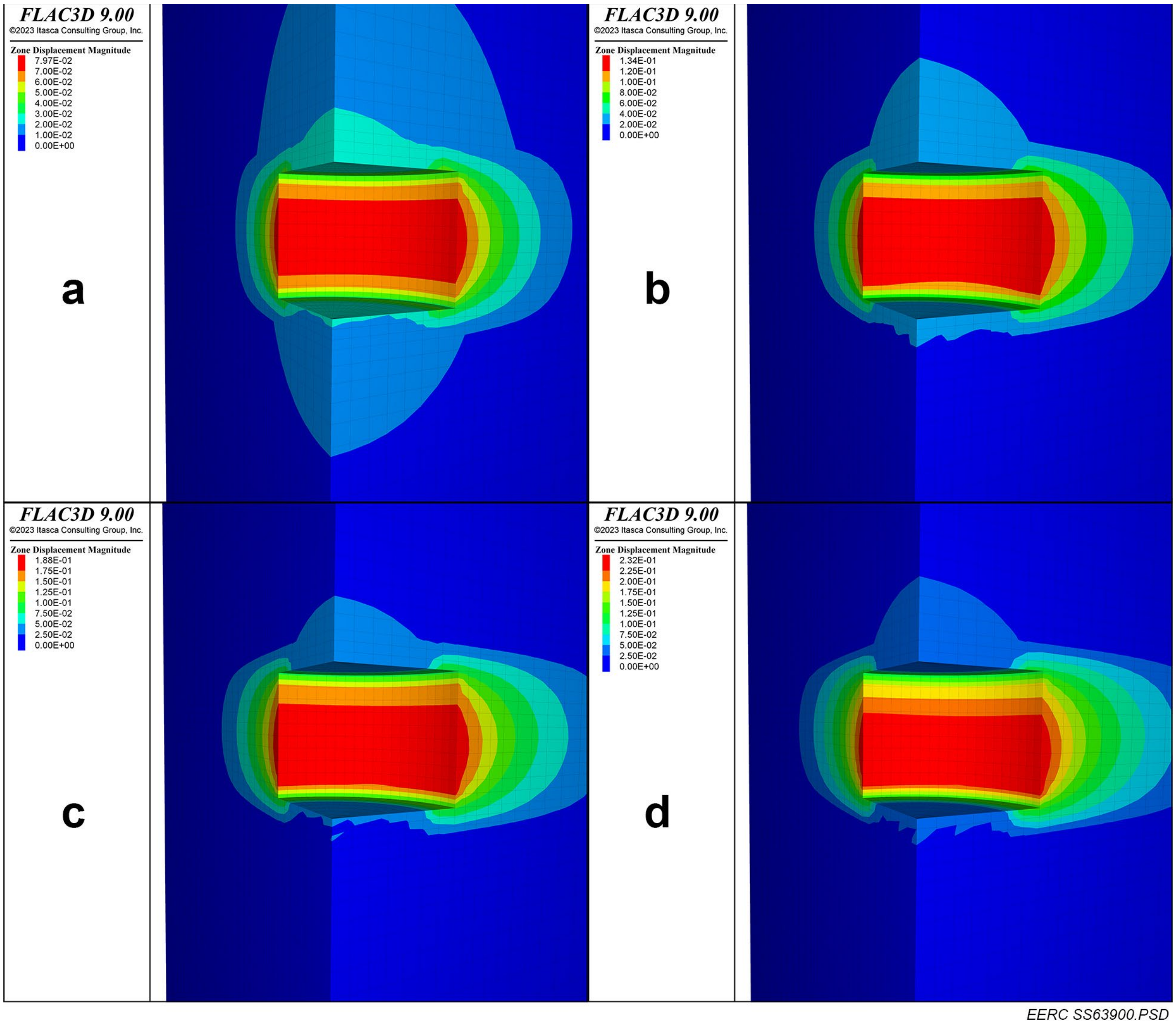


Figure 7-16. FLAC3D model of Dunham Salt showing salt creep displacement in meters and direction after a) 1-, b) 5-, c) 15-, and d) 30-year cavern life for hydrogen storage. Cavern geometry uses a 1:2 aspect ratio.

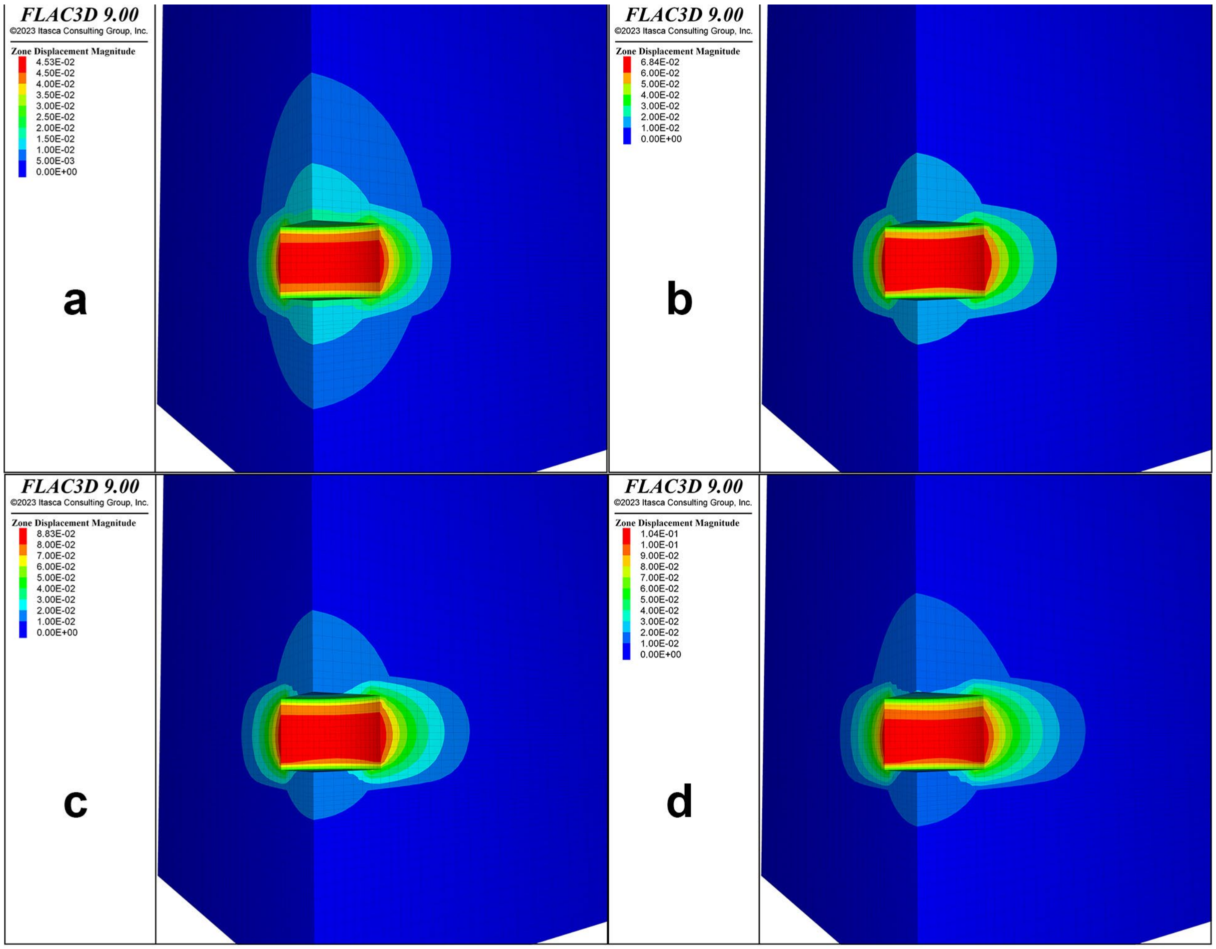


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Figure 7-17. FLAC3D model of Pine Salt showing salt creep displacement in meters and direction after a) 1-, b) 5-, c) 15-, and d) 30-year cavern life for hydrogen storage. Cavern geometry uses a 1:2 aspect ratio.

7.2.6 Operating Pressure and Volume Shrinkage Sensitivity Analysis – Natural Gas, NGL, and Hydrogen Storage

A range of operating pressure values from 15 to 30 megapascals (MPa) (2175 to 4350 psi) in 5-MPa (~725-psi) increments were modeled to better understand the impact of operating pressure on cavern stability, creep displacement, and volume shrinkage due to creep, assuming a 1:1 aspect ratio of the cavern geometry. The range of operating pressures used in the sensitivity analysis are greater and less than the modeled minimum operating pressure. Natural gas and NGL storage results are summarized Figure 7-18a for the Dunham Salt and Figure 7-18b for the Pine Salt, both assuming a 30-year cavern life. Observe the diminishing cavern shrinkage with increasing minimum operating pressure for both the Dunham and Pine intervals. The modeled minimum operating pressure, derived from a brine gradient of 0.52 psi/foot, equates to a pressure of 24.5 MPa (3553 psi) in the Dunham and 25.8 MPa (3742 psi) in the Pine, which support stable

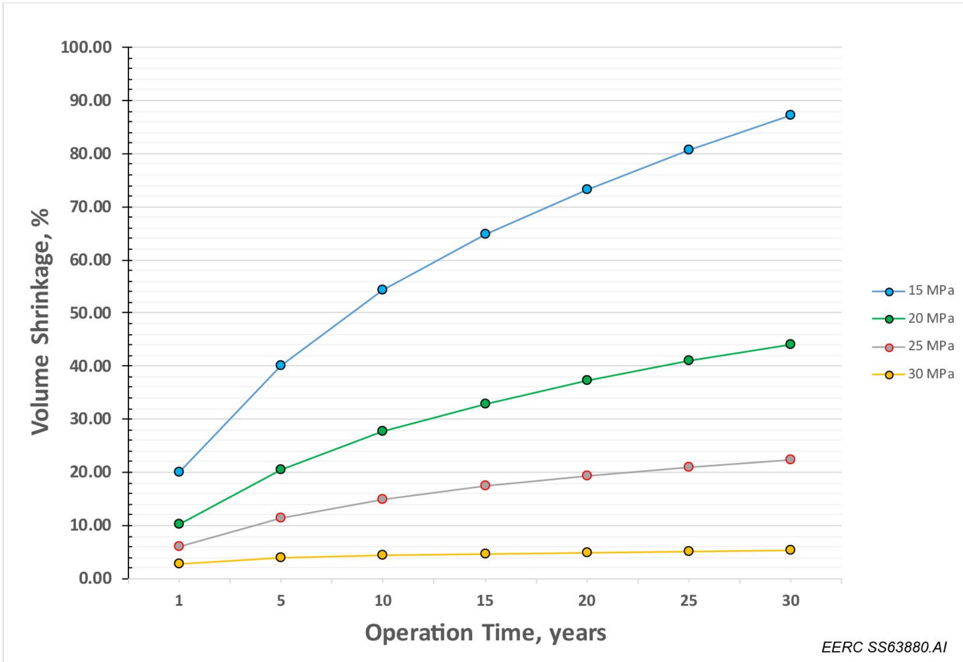

Figure 7-18a. Dunham Salt operating pressure vs. cavern volume shrinkage in percent vs. time assuming a 1:1 aspect ratio for natural gas and NGL storage. Note the volume shrinkage y-axis scale of 0% to 100%.

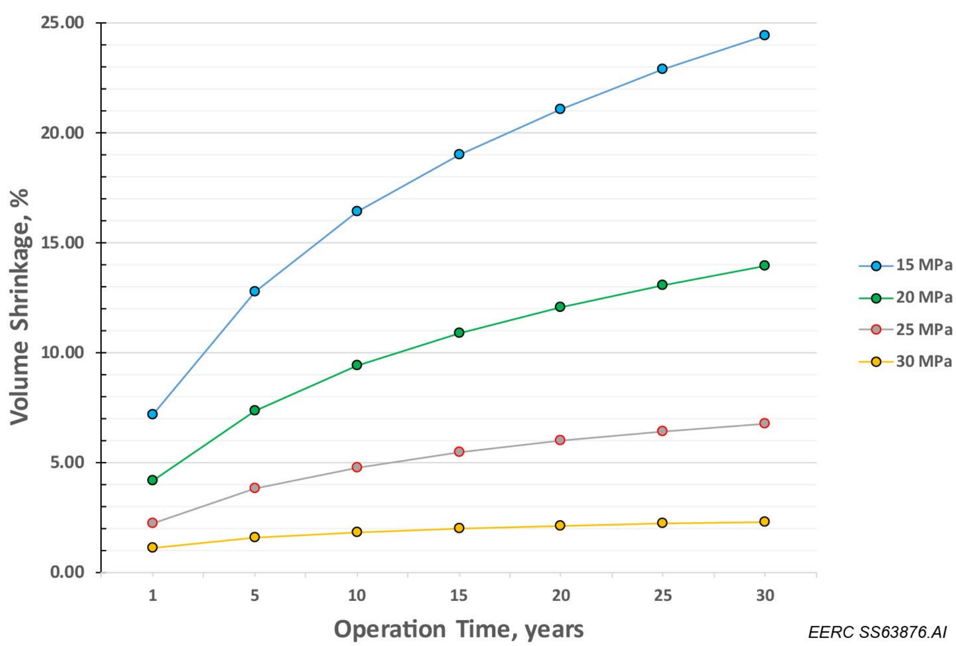

Figure 7-18b. Pine salt operating pressure vs. cavern volume shrinkage in percent vs. time assuming a 1:1 aspect ratio for natural gas and NGL storage. Note the volume shrinkage y-axis scale of 0% to 25%.

cavern operation by minimizing vertical and horizontal creep strain displacement throughout the life of the cavern. Volume shrinkage due to salt creep by aspect ratio scenario has been plotted in Figures 7-19a and 7-19b. Note that at the operating pressures of 24.5 and 25.8 MPa, respectively, the shrinkage in both the Dunham and Pine salt models is less than the threshold of 30% after 30 years based on studies of cavern stability of the Jintan salt storage complex in China (Li and others, 2021). The Jintan salt storage complex, comprising bedded salt, has been in operation since 2007 (Ma and Ding, 2022).

Simulations predict similar, but attenuated, behavior for hydrogen salt caverns as exhibited in Figures 7-20 and 7-21. Compare with Figures 7-18a and 7-19a, respectively.

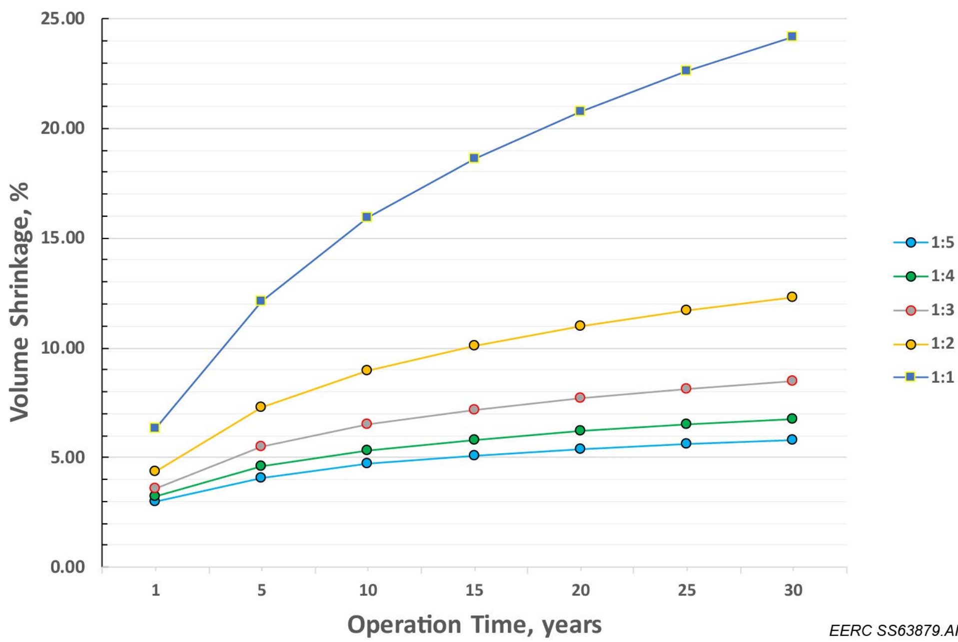

Figure 7-19a. Dunham Salt volume shrinkage by aspect ratio scenario and after 30 years for natural gas and NGL storage. Note the volume shrinkage y-axis scale of 0% to 25%.

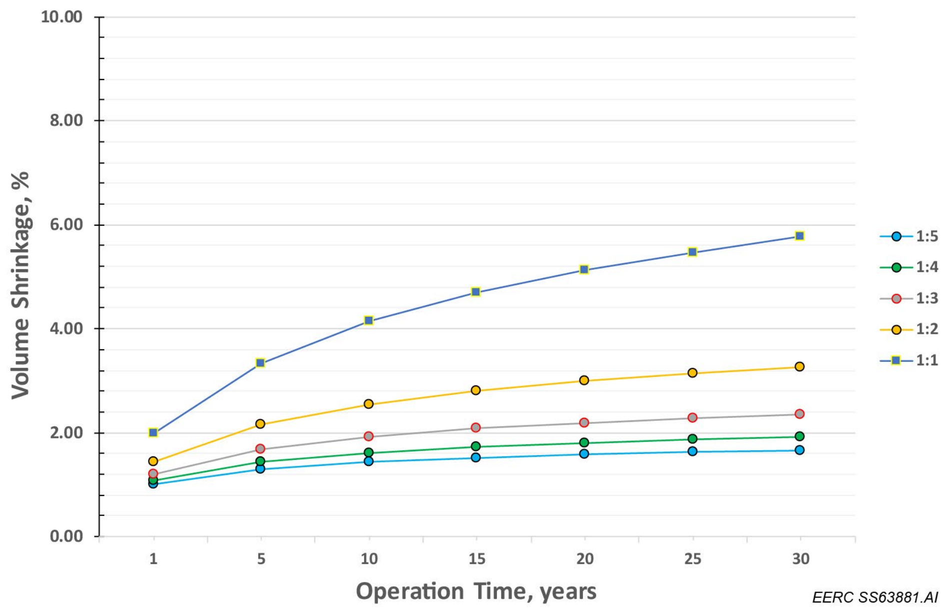

Figure 7-19b. Pine Salt volume shrinkage by aspect ratio scenario and after 30 years for natural gas and NGL storage. Note the volume shrinkage y-axis scale of 0% to 10%.

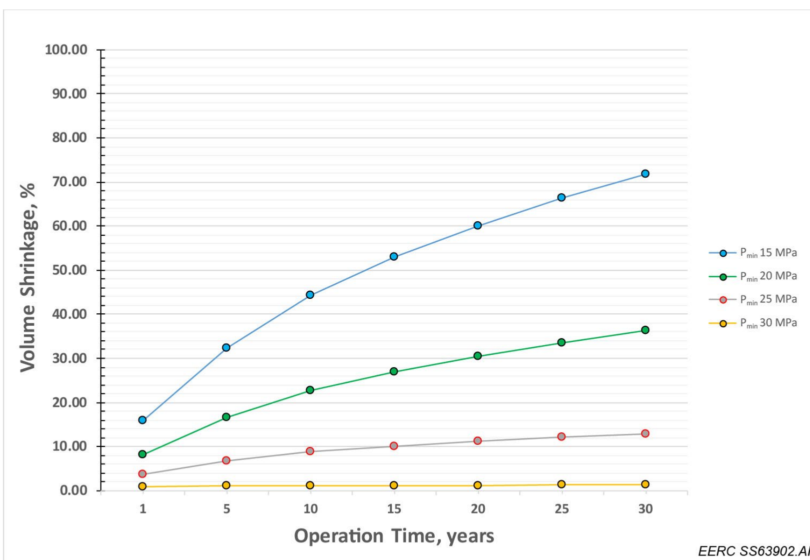

Figure 7-20. Dunham Salt operating pressure vs. cavern volume shrinkage in percent vs. time assuming a 1:1 aspect ratio for hydrogen storage. Note the volume shrinkage y-axis scale of 0%–100%.

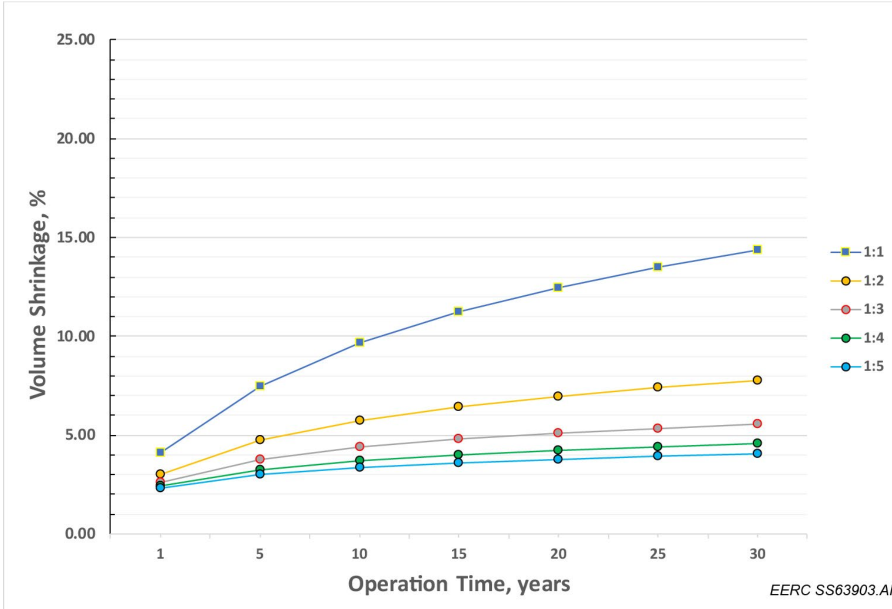

Figure 7-21. Dunham Salt volume shrinkage by aspect ratio scenario and after 30 years for hydrogen storage. Note the volume shrinkage y-axis scale of 0% to 25%.

Four main criteria were considered in the cavern stability analysis: salt cavern roof or floor dilation-related failure after 30 years, nonsalt over- and underburden failure mode after 30 years, salt creep displacement after 30 years, and shrinkage volume after 30 years. Based on scenarios modeled using the two 3D MEM approaches, results of the stability analysis criteria are summarized in Table 7-4, which considers stability of the over- and underburden nonsalt intervals and salt comprising the cavern. Of the conditions simulated, none showed salt cavern roof or floor dilation failure after 30 years, and none exhibited cavern diameter displacement that exceeded 5% after 30 years. The following parameters were applied to all scenarios:

- Minimum operating pressure (P_{min}), based on pressure gradient of brine
- Maximum operating pressure (P_{max}), based on overburden stress pressure gradient
- 30-year cycling scenario (Figure 7-10)
- Salt creep constitutive properties (see Appendix E)
- Mohr–Coulomb failure analysis and constitutive properties of nonsalt intervals (see Appendix E)
- Salt dilation strength

Based on studies of salt cavern stability of the Jintan storage complex in China, the maximum displacement should not exceed 5%–10% of the original maximum cavern diameter to avoid damage of the salt within the cavern, and volume shrinkage should not exceed 30% of the original volume (Li and others, 2021). Also, the occurrence of shear and/or tensile failure during cavern operations may be indicative of cavern failure and should be considered in cavern design to mitigate the risk of failure. Although not modeled and evaluated in the present study, the

Table 7-4. Summary of FLAC 3D MEM Cavern Stability Indicators for Natural Gas, NGL, and Hydrogen Storage

Zone	Cavern Aspect Ratio (H:D)	Nonsalt Over- and Underburden Failure Mode after 30 years	Cavern Volume Shrinkage after 30 years: Natural Gas and NGL	Cavern Volume Shrinkage after 30 years: Hydrogen
Dunham Salt Member	1:1	None	24.2	14.4
	1:2	Onset shear + tension	12.3	7.8
	1:3	Shear + tension	8.5	5.6
	1:4	Shear + tension	6.8	4.6
	1:5	Shear + tension	5.8	4.0
Pine Salt Member	1:1	None	5.7	3.6
	1:2	Onset shear	3.2	2.2
	1:3	Shear	2.4	1.6
	1:4	Shear + tension	1.9	1.4
	1:5	Shear + tension	1.7	1.2

presence of sharp edges of underground workings, e.g., the corners and sharp angles between salt cavern walls, are prone to stress concentration. Thus the determination of a sharp and smoothed edge on cavern stability is important (Cyran and Kowalski, 2021). Additionally, the consideration of salt cavern analogs is an important part of the salt cavern stability analysis. As shown, results of this investigation demonstrate that modeling Dunham and Pine Salts have displacement and volume shrinkage values within published limits. See additional information in Appendix E.

7.3 Regional Assessment

Learnings from the geologic and geomechanical modeling efforts guided a regional assessment to determine prospective locations of Dunham and Pine Salts for potential salt cavern development in western North Dakota. Based on publicly available geophysical well log data, an 11,650 sq mi AOI was established across McKenzie, Dunn, Billings, Golden Valley, Stark, Mountrail, and Williams Counties with partial coverage of McClean and Mercer Counties (Figure 7-22). The regional assessment consisted of three main tasks: 1) stratigraphic analysis to define regional structure and formation thickness; 2) machine learning cluster analysis of geophysical well logs to identify prospective facies; and 3) mapping to identify prospective areas within the regional AOI.

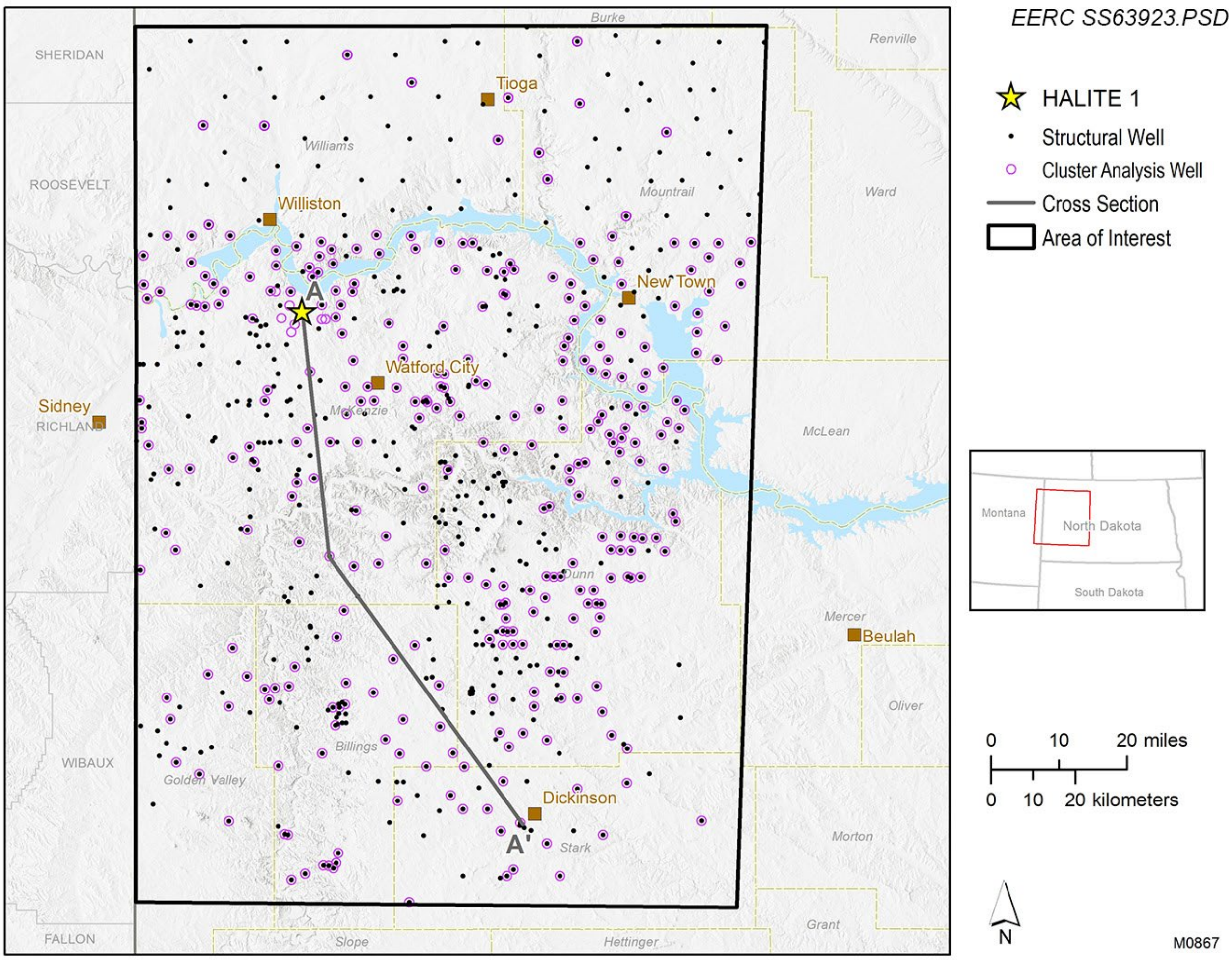

Figure 7-22. Regional assessment AOI. Stratigraphic and cluster analysis wells included as part of the assessment are indicated. A-A' cross section for Figure 7-23.

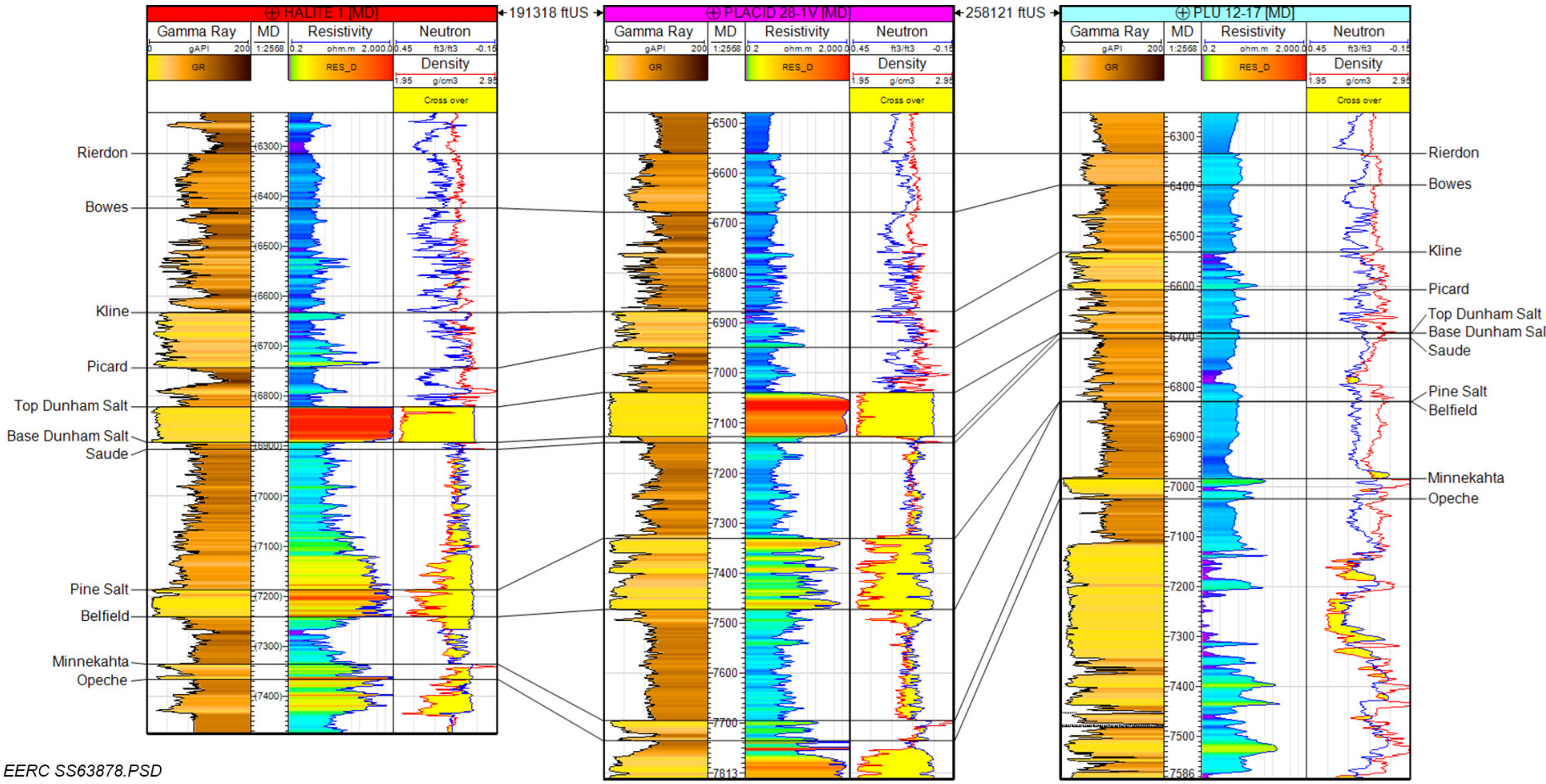

Figure 7-23. HALITE 1 well log display with well log correlations used for the regional study.

7.3.1 Stratigraphic Analysis

Stratigraphic frameworks established for the HALITE 1 geomodel (Section 7.1) were used for the regional study. Eleven well correlation markers, top of the Opeche Formation to the top of the Rierdon Formation, were used to build the regional stratigraphic framework (Figure 7-23) with well correlations adjacent and relevant to the Dunham and Pine Salts included in the stratigraphic framework. Well correlations were performed on a well log data suite (e.g., gamma ray, deep resistivity, bulk density, and neutron porosity) for the identification for rock type and depositional patterns. A total of 656 wells were used in the regional stratigraphic analysis. Key wells were chosen across the AOI that contained complete well log data suites across the ZOI. Neutron porosity and bulk density well log data were instrumental to identify halite. Well correlations went through a double quality control process, including both structural and thickness mapping steps to minimize errors within the data set.

Stratigraphic interpretation provided insight into the structure and thickness of the Dunham and Pine Salts. For the regional AOI, the Dunham Salt dips towards the northeast. Dunham depths range from -5390 to -3415 ft below sea level, in McKenzie and Mountrail Counties, respectively. The Dunham Salt is laterally discontinuous, with thicknesses ranging from 0 to 205 ft across the AOI. The Pine Salt structural trend is similar to the Dunham Salt, dipping toward the northeast. The elevation ranged from -5545 to -3530 ft below sea level, in McKenzie and Stark Counties, respectively. The Pine Salt is relatively continuous from north to south, with thickness ranging from 0 to 215 ft, with the thickest section in the southern part of the AOI. Additional details on the regional analysis are presented in Appendix F.

7.3.2 Cluster Analysis

For the regional AOI, 325 wells with complete geophysical well log suites across the regional stratigraphic ZOI were available for cluster analysis facies prediction. The well log suite selected for cluster analysis included gamma ray, density, neutron, photoelectric factor, and deep resistivity. A quality control process to depth match and clean the well logs was performed to prepare the well logs for cluster analysis. Logs were normalized and truncated to the ZOI.

The Python coding language (Python Software Foundation, 2023) was used for the cluster analysis. Eleven clusters were found to adequately cover the data set variance and were used in a Gaussian Mixture Model (GMM) clustering analysis. The facies prediction from GMM was evaluated against the petrophysical interpretations for the HALITE 1 well and compared to the neural net facies in the geomodel (Figure 7-24). Clusters were identified as shale, limestone with anhydrite, siltstone with halite, silty shale, dolomite, marl, halite, shaly siltstone, siltstone with halite, thenardite, and mixed evaporite. The Dunham Salt was made up mostly of halite (92%) with a minor component of limestone with anhydrite (7%). The Pine Salt was primarily halite (52%) with mixed evaporite (27%), thenardite (17%), siltstone with halite (3%), and limestone with anhydrite (1%) facies in decreasing abundance. Additional details on the cluster analysis are presented in Appendix F.

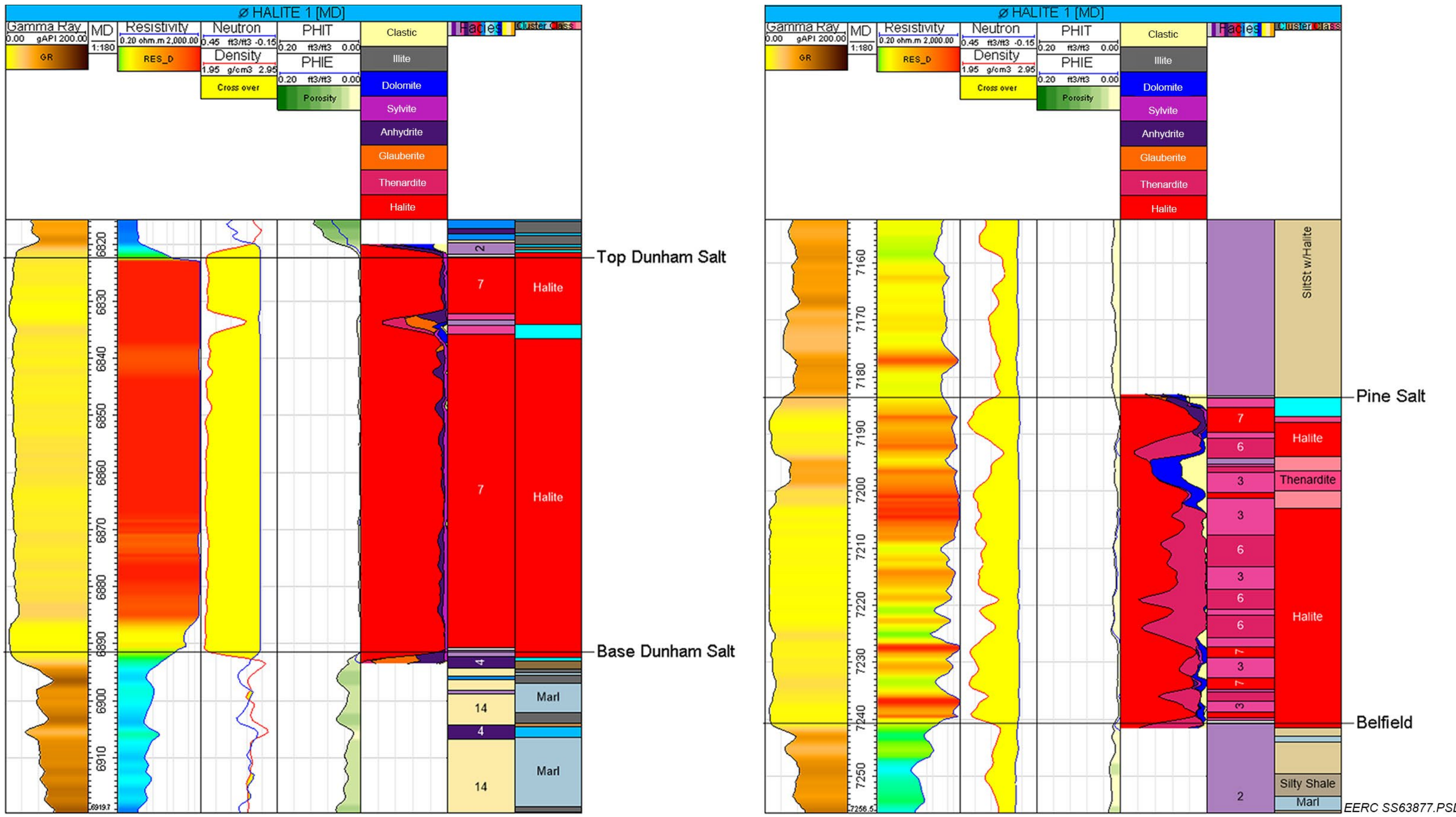

Figure 7-24. HALITE 1 well log display for the Dunham (left) and Pine (right) Salts with petrophysical mineral model, neural net facies, and cluster analysis facies. Overall cluster analysis facies (Track 8) have good match with neural net facies (Track 7). Cluster analysis facies present: halite (red), thenardite (hot pink), mixed evaporite (light pink), limestone with anhydrite (cyan), dolostone (blue), shale (gray), marl (gray blue), siltstone with halite (light tan), siltstone with anhydrite (tan), and shaly siltstone (dark tan).

7.3.3 Regional Prospectivity

The stratigraphic and cluster analyses were combined to determine prospective locations to further evaluate the Dunham and Pine Salts for salt cavern development in western North Dakota. Exploration prospectivity mapping was performed in SLB's Petrel 2021.5 E&P software platform (SLB, 2022a) to identify prospective locations and is similar to screening tasks discussed in Section 4; however, the locations identified through this effort were focused solely on geological parameters (i.e. – depth, thickness, salt purity) and do not include engineering and logistical parameters, such as proximity to gas-processing plants or pipelines, availability of water supplies, etc.

Using the geologic and geomechanical modeling results, favorable salt cavern conditions were linked to the temperature, pressure, overall salt thickness, and soluble salt percentage. From the stratigraphic analysis and cluster analysis, the proxy properties of true vertical depth (TVD), salt total thickness, and percentage of soluble salt were used to calculate prospectivity. TVD (i.e., depth below ground surface) provided the proxy for temperature and pressure as both properties increase with depth. Salt cavern size is linked to the available salt thickness (e.g., height), and overall thickness is a proxy for available cavern size. The soluble salt percentage was calculated over the thickness of the salt and is considered a proxy for less pinch points, sharp edges, or corners within the cavern because of insoluble material.

Prospectivity was determined for TVD, overall thickness, and soluble salt percentage of each salt interval to identify prospective areas for salt caverns. TVD for both salts is more prospective at less than 6000 ft below ground surface and lower prospectivity but possible at depths greater than 7500 ft. For Dunham and Pine Salts, an overall thickness of 100 ft or more was considered highly prospective and less than 50 ft was not considered as a potential prospect. The soluble salt percentage of 100% is highly prospective and less than 50% is not prospective. To control extrapolation of results within the AOI, distances greater than 40,000 ft from a control point were set as undefined. Selected value limits and prospectivity assignments are to provide an estimate of locations with a high probability for future salt cavern testing in North Dakota and should not be considered a limit of feasibility for the state.

The final prospectivity maps based on TVD, overall thickness, and soluble salt percentage provide many prospective areas for both Dunham and Pine Salts across the regional AOI (Figures 7-25 and 7-26). High prospective Dunham Salt areas (dark green) are isolated to 1- to 5-mi-diameter areas across central and northern parts of the regional AOI. The Pine Salt has large prospective areas across the southwestern quadrant of the regional AOI, with more isolated areas of high prospectivity in the north. For both Dunham and Pine, the salt thickness is the main driver for prospectivity. The control points of the map require that site-specific data for any prospective area are collected to determine true prospectivity for salt cavern development. Additional details on the regional prospectivity mapping are presented in Appendix F.

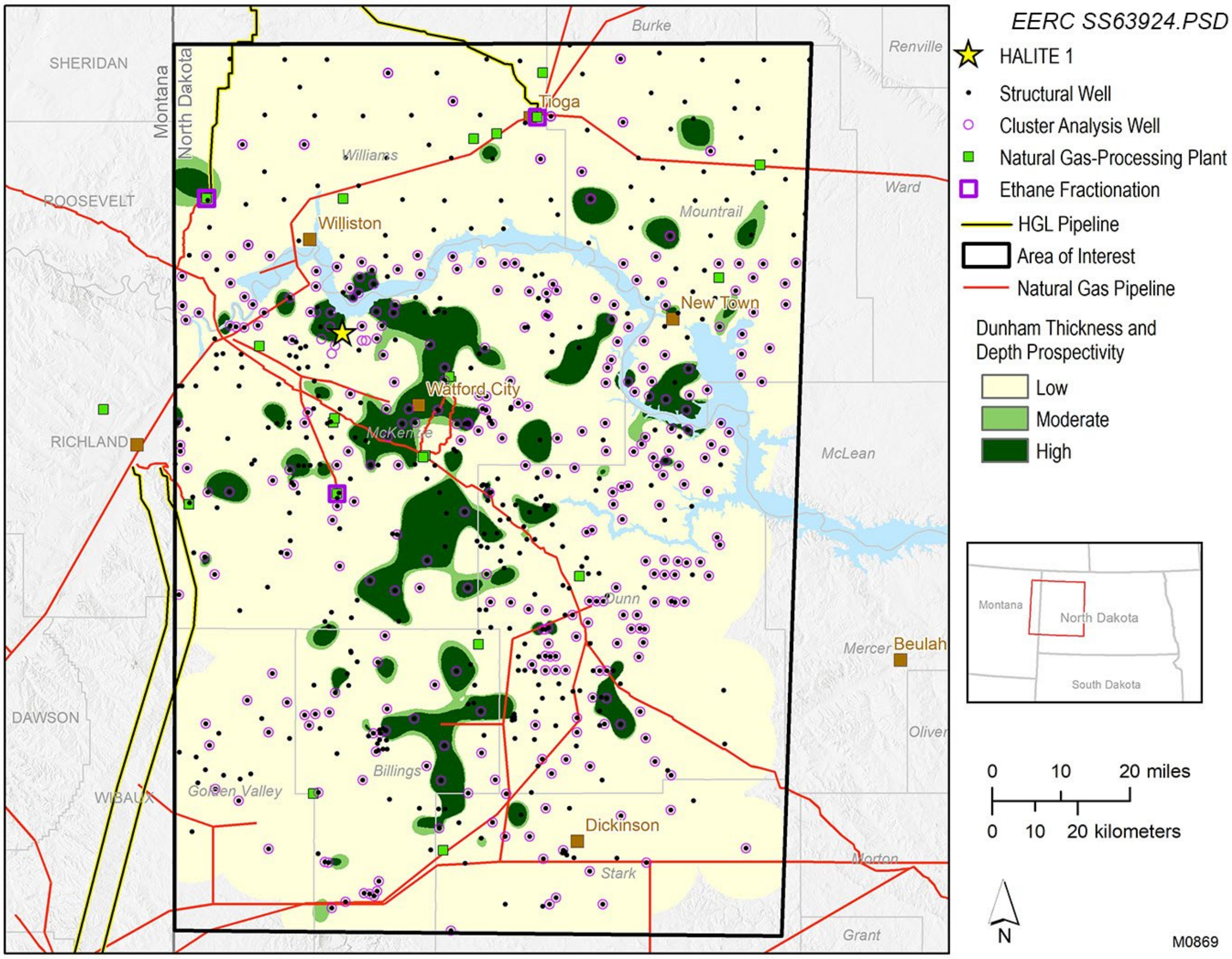

Figure 7-25. Prospectivity maps for the Dunham salts. High prospectivity areas (dark green) were identified to have a combination of depth, salt thickness, and higher percentages of soluble salts for additional exploration for possible salt cavern development.

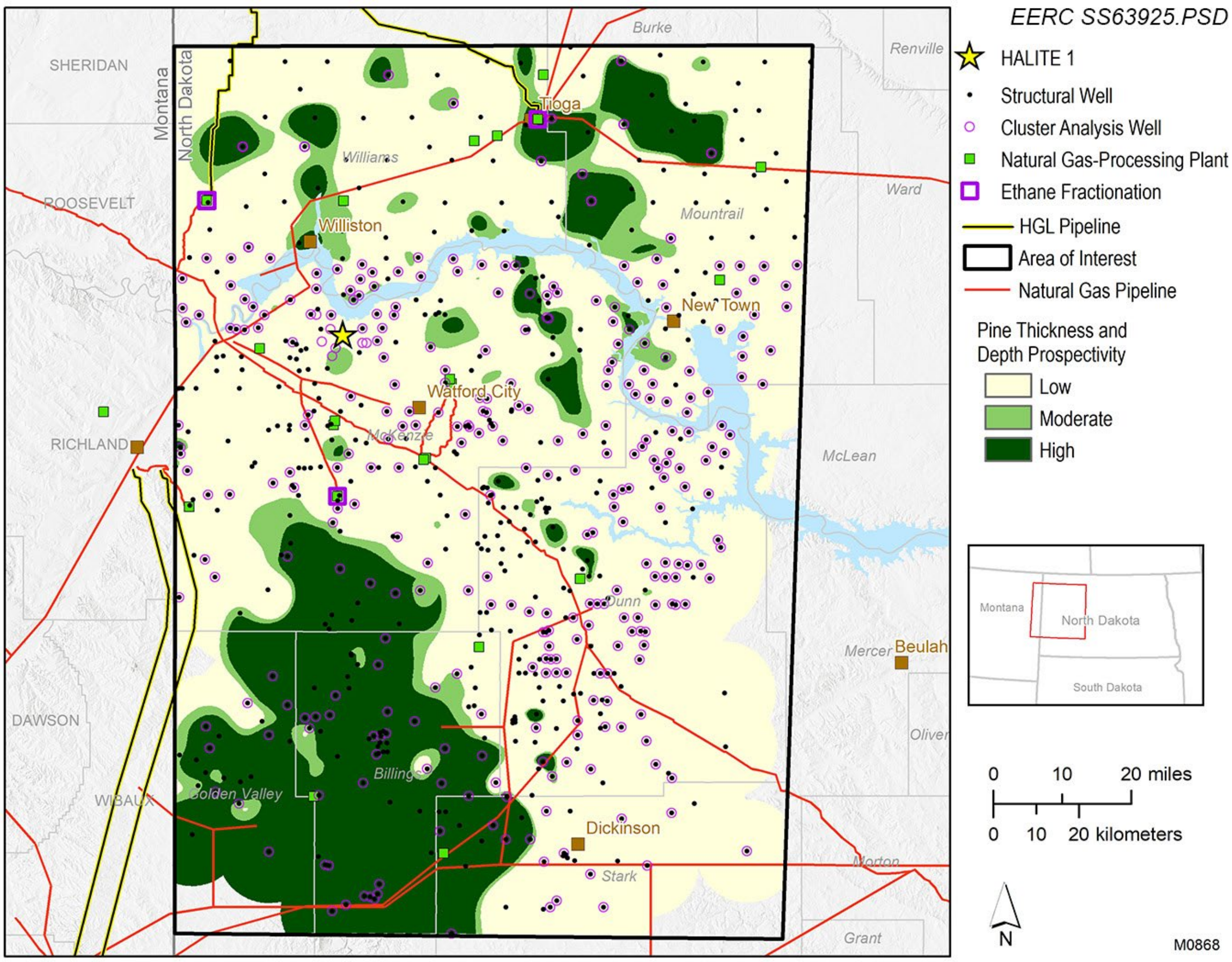

Figure 7-26. Prospectivity maps for the Pine salts. High prospectivity areas (dark green) were identified to have a combination of depth, salt thickness, and higher percentages of soluble salts for additional exploration for possible salt cavern development.

8.0 ENGINEERING ANALYSIS AND DESIGN

Engineering is a critical piece of any salt cavern development project. Just as location is important for development of a salt cavern, the intended fluid and way in which it will be stored is critical for the engineering. Questions such as scale, drive mechanism, cycling, and demand are critical for determining the equipment and loads used in the facility. This section provides the first glimpse of the economics required for salt cavern development and operation. The engineering analysis assessed the salt cavern industry worldwide (summarized in Section 3.0) to understand critical information and key pieces for design. The data from the engineering analysis was coupled with the geologic data to create a notional facility design. A preliminary analysis of the economics for cavern development and operation was performed to provide an initial benchmark to guide future study of salt caverns in the state.

This section describes the methodology for the design, leaching model, process model, fluids, and resulting economics that summarize findings of the design. Engineering design was built on the information developed from the engineering analysis as a basis for site-specific implementation in North Dakota. From a facility design perspective, similarities exist in the equipment and demand that allow the following three groupings of models: hydrogen, natural gas, and NGL. The engineering workflow includes a total of thirteen different models of operational modes and nine fluids and are fully detailed in Appendix G.

8.1 Methodology

The engineering design workflow included cavern leaching modeling, development of conceptual facility designs, development of base cases, operational process modeling, and integration with geomechanics. These activities enabled development of cost estimates for capital expenditures (CapEx) and operational expenditures (OpEx). An economic model was created to assess potential revenue associated with cavern operation.

Leaching operation simulations were performed to predict the cavern volume, shape, and required resources needed to develop the projected storage volume. To achieve this goal, salt cavern leaching software, SALGAS® (SALGAS, 1974), was utilized.

A conceptual design for a leaching skid, brine-compensated drive system, and gas-compensated system was developed by WSP, Energy Sector (WSP). Notional operational conditions were provided to WSP by the EERC, including injection/withdrawal rates, storage size and location, fluid type, and cyclicity. Details of the designs can be found in the WSP report in Appendix G.

The conceptual designs were used to develop a model for each of the process storage configurations: gas-compensated, brine-compensated, and hybrid, relevant to fluid storage in North Dakota. Iterations of these storage systems were completed in AspenHYSYS (Aspen Technology, 2023) to evaluate a range of operating parameters and fluids.

Aspen allows simulation of the multiple steps of the process, including interaction between the fluid, product, and surface support equipment, while performing calculations necessary for determining equipment size for conditioning the process fluid and moving it in and out of the cavern. Accurately sized equipment allows for a more precise calculation of energy inputs used for the operation of the salt cavern.

An economic model was developed to assess CapEx, OpEx, and revenue. CapEx was determined based on cavern development cost estimation and facility development with internal expertise. OpEx was based on maintenance, the appropriate cycle frequency, and the energy required to cycle the cavern. Revenue, where appropriate, was determined from historical data tracked by the Federal Reserve Bank of St. Louis's Federal Reserve Economic Data (FRED) Program.

8.2 Leaching

Two leaching models were developed for the two salt formations of interest in the Williston Basin based on the HALITE 1 well completion data, logs, mineralogy, and insoluble content profile.

For each formation, a cavern leaching operation model was developed. Sensitivity analysis was completed on brine flow rate, leaching time, and roof shape. The cavern was modeled maintaining a 15-ft and 5-ft interval of salt at the ceiling and floor, respectively, while the middle depth interval was leached using direct injection mode. The blanket pad fluid was assumed to be of uncompressible fluid and was used to control the roof shape.

Initial engineering analysis suggests it is possible to develop caverns between 25 and 100 Mbbl (140–560 Mcf) in the Dunham and Pine Salt Formations in less than 12 months utilizing moderate pumping capacities. Leaching of the cavern from the wellbore results in radial expansion over time, as shown in Figure 8-1. The optimal leaching time and cavern size will be guided by the height-to-diameter ratio determined by the geomechanics study. Insoluble content will remain in the bottom of the cavern, reducing its usable capacity.

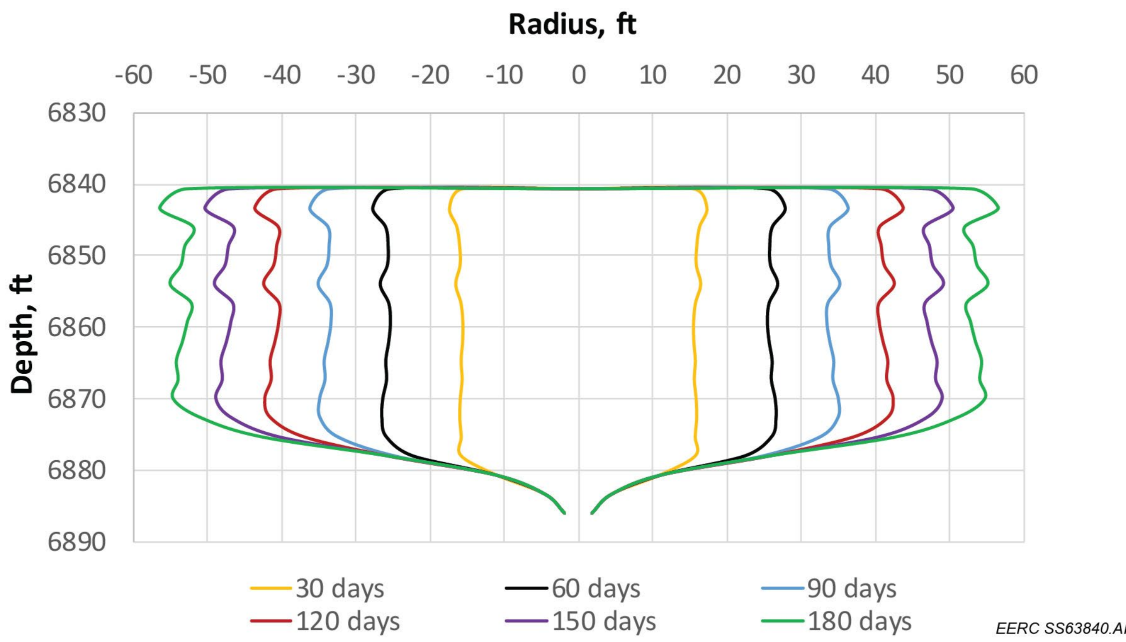

Figure 8-1. Cavern leaching model results for the Dunham Salt. As shown, cavern geometry and size expand radially from the center until a target volume is reached.

SALGAS provides 2D models and was developed specifically for domal salts. An additional software program was identified, PCL5, but the team determined that it would require more detail than was available through this project. Future work on the development of North Dakota salt caverns would benefit from using this software package, and its capabilities in bedded salts and generating 3D models, to further evaluate cavern leaching as additional data become available, such as higher well log resolution and history matching and calibration based off of caverns developed in North Dakota.

8.3 Models

Three storage systems were created in Aspen to provide a basis for gas-compensated, brine-compensated, and hybrid scenarios. Figure 8-2 shows process flow diagrams for each system. For each model, a facility consisting of four caverns, each 25 Mbbl in size, was created for a total volume of 100 Mbbl. The total amount of fluid stored depended on the fluid selected and the drive mechanism utilized.

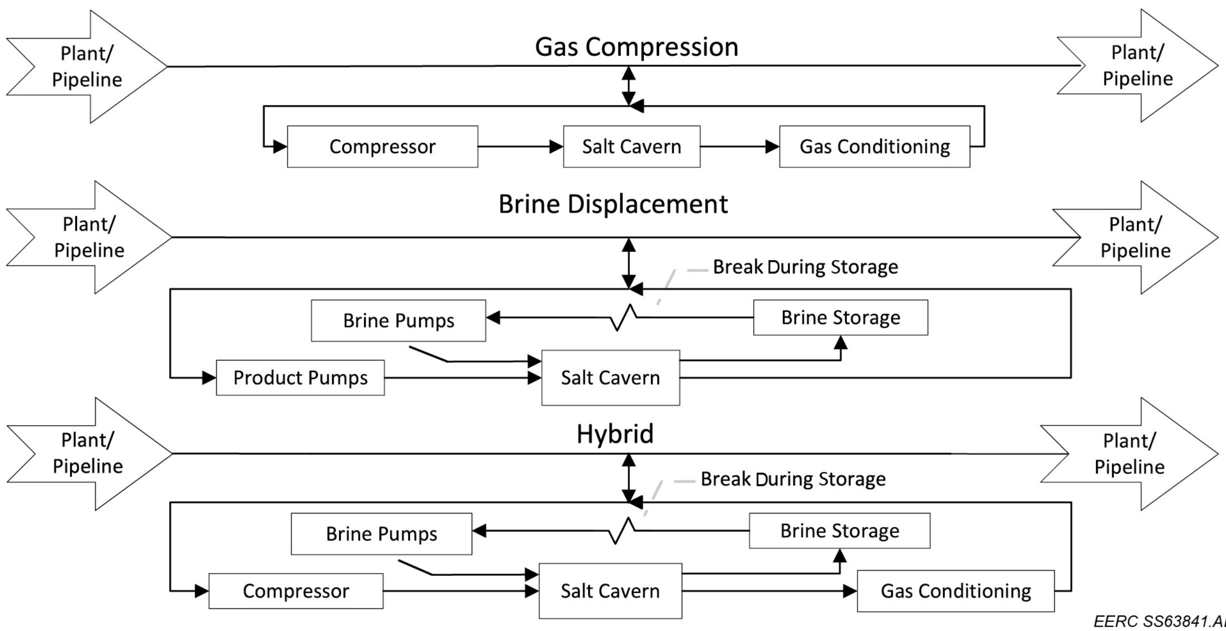

Figure 8-2. Process flow diagrams for gas-compensated (gas compression), brine-compensated (brine displacement), and hybrid.

The gas-compensated drive mechanism can be used for any fluids that would exist as a gas at the temperatures and pressures in which they will be stored. For this system, a compressor pressurizes the gas into the cavern, and a control valve was modeled to reproduce letdown of the product gas as it exits the cavern in production mode. Compression and expansion of gases can result in large temperature changes because of a phenomenon called the Joule–Thomson effect. Compression requires a separate cooling step to prevent excessive temperature rise of the gas and equipment. As gases leave the cavern in production mode, the pressure is reduced. This reduction causes cooling that can result in gas hydrate formation, a solid made of gas and water, plugging process equipment. Methanol is injected into the gas stream to help minimize hydrate formation and then separated downstream. The gas stream is later heated to meet pipeline transmission specifications. Conditioning equipment was included in the modeled simulation to remove methanol, lube oil, contaminants, and water at different points of the process.

The brine-compensated model is applicable for fluids that exist as a liquid at storage temperatures and pressures. For this configuration, a turbine pump transfers the fluid from the pipeline into the cavern, pushing the brine to the surface. A separator on the brine side ensures no product carries into the surface brine tank/pond. For production mode, brine pumps were modeled to inject into the cavern, displacing the stored fluid. Filter/dehydration systems were modeled to remove any water that may have contaminated the product from interaction with the brine.

The hybrid base case model was added to the engineering design to consider the unique challenges of North Dakota's salts when investigating gas storage. Typical gas storage works best in a gas-compensated mechanism scenario. This requires a cavern volume approximately double the quantity of the gas to be stored. In a large salt cavern complex, this can be acceptable because the cost of leaching a larger cavern is marginal relative to the other development costs. Since lithology in the state is limiting cavern size, the amount of gas that can be stored is reduced. Another challenge to a gas-compensated cavern design, discussed in Section 7.2, is the need to consider the internal pressure fluctuations. Brine allows the pressure in the cavern to be more consistent, which is better for cavern integrity and longevity. The hybrid model combines the brine-handling equipment from the brine-compensated model and pairs it with the gas compression and conditioning equipment from the gas-compensated model. The simulation scenarios for this case would be considered for product gases such as hydrogen and natural gas.

8.4 Cyclicity and Fluids

The operating cycles of gas storage caverns typically fall into three categories: long-term cycle based on seasonal demand with a 100-day buildup and 100-day drawdown and steady storage times between the buildup and drawdown; an intermediate cycle representative of chemical plant operation with a 60-day buildup and 21-day drawdown; and a short-term cycle based on a 7-day buildup with a 3-day drawdown repeated frequently during the year. This study considered long-term and intermediate cycles as those aligned best with current needs in North Dakota. Cycling is critical to calculating the rate a fluid is injected into or withdrawn from the cavern and is a key design parameter for sizing equipment.

Today, globally, there are only four active commercial-scale hydrogen storage facilities: all employ engineered salt caverns. Other methods of hydrogen storage exist, such as in saline aquifers, depleted gas fields, engineered rock caverns, and fabricated tanks, that possess distinct advantages over salt caverns, such as large, depleted gas fields that can exhibit capacities 100 times that of typical salt caverns. However, they also possess distinct disadvantages, such as expense, hydrogen loss due to subsurface migration and, in the case of depleted gas fields, contamination. Engineered salt caverns exhibit a competitive balance of scale, cost, security, safety, and contamination exposure that make them attractive. Hydrogen exhibits several properties that require special consideration in cavern design, including a negative Joule–Thomson effect, material interactions that require special attention to equipment design, and a low energy density that requires more cavern volume to store a similar amount of energy. Being a gas under storage conditions, hydrogen can be stored either under a gas-compensated drive or a hybrid drive. The gas-compensated base case and hybrid models were modified to utilize an intermediate cycle. After the simulations were completed with the described cycle, the equipment and energy outputs were entered into the economic model.

Natural gas is the most commonly stored fluid in salt caverns utilizing a gas-compensated drive mechanism, typically for seasonal heating demand fluctuations. Peak shaving scenarios also exist, associated with short-term immediate demand, such as a prolonged cold front or supply interruption. In addition to the gas-compensated scenario, a hybrid simulation scenario was also completed with long- and short-term cycle periods.

NGL is abundant in North Dakota as an associated gas in crude oil production. Methane is removed from the gas stream relatively easily, leaving behind natural gas liquid, or Y-Grade NGL, which is a mixture of ethane, propane, butanes, and pentanes. All hydrocarbons higher in carbon than pentane are aggregated with pentanes and denoted as “pentanes+.” Pentanes+, sometimes called “natural gasoline,” are differentiated from other components because of the value in motor fuel. The value of hydrocarbons present in NGL is typically increased when separated into pure products. Fractionation is the process used to produce pure streams of ethane, propane, and butanes and typically requires storage capacity for the NGL feed and the discrete products. A brine-compensated system is best utilized because ethane, propane, butane, and pentane+ are all stored and used in their liquid form. In general, demand follows a seasonal pattern, so a long-term cycle was modeled.

Based on market demands, the caverns can be repurposed or retrofit for storage of other fluids. However, after a detailed review of the new product fluids, a redesign of the surface facility equipment would most likely be necessary. The purity requirements for the new fluid that will be stored, consequences for cyclicity changes and pressure fluctuations on geomechanics, material compatibility if hydrogen is considered, the addition or replacement of equipment associated with drive type, and conditioning requirements of the new fluid will all be considered. Economics can drive the type and extent of change, but this type of change would not occur from one season to another, or even between a few years.

8.5 Economic Model

Information from modeling the leaching of a cavern and the type of facilities needed resulted in data critical for cost estimations. A model was developed to assess the economics of different storage scenarios. A summary of the different scenarios is shown in Figure 8-3.

Fluid	Natural Gas	Natural Gas	Ethane	Propane	Y-Grade	Hydrogen	Hydrogen
Drive Mechanism	Gas-Compensated	Hybrid	Brine-Compensated	Brine-Compensated	Brine-Compensated	Gas-Compensated	Hybrid
Cycle	Seasonal	Seasonal	Seasonal	Seasonal	Seasonal	Intermittent	Intermittent
Storage (tonnes)	2,422	3,520	5,882	8,117	6,091	259	371
Cavern Development	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000	$ 45,000
Facility Infrastructure	$ 9,388	$ 13,521	$ 5,446	$ 5,267	$ 5,417	$ 9,783	$ 14,233
CapEx	$ 54,388	$ 58,521	$ 50,446	$ 50,267	$ 50,417	$ 54,783	$ 59,233
Cost of Energy	$ 46.220	$ 48.620	$ 6.803	$ 5.013	$ 6.624	$ 80.638	$ 89.266
Maintenance	$ 177.702	$ 178.002	$ 75.873	$ 79.343	$ 79.537	$ 196.002	$ 211.258
Annual OpEx	$ 223.922	$ 226.622	$ 82.676	$ 84.356	$ 86.161	$ 276.640	$ 300.524
Average Differential (/tonne)	$ 0.123	$ 0.123	$ 0.153	$ 0.178	$ 0.107	–	–
Annual Revenue	$ 296.743	$ 431.270	$ 900.975	$ 1,447.058	$ 655.160	–	–
30 - year Cost (/tonne)	$ 0.822	$ 0.604	$ 0.299	$ 0.216	$ 0.289	$ 8.119	$ 6.132

In Thousand U.S. Dollars 2023 EERC SS63906.AI

Figure 8-3. Economic model summary.

The CapEx for developing a cavern, or group of caverns of similar size, is independent of the product that will be stored. The cost associated with facilities by drive mechanism is similar and reflects the costs for each process's equipment. Smaller cost variation occurs when individual fluid properties are considered, mostly associated with sizing of equipment or requirement for different separation and conditioning technologies.

OpEx consists predominantly of power consumption and maintenance. Operational labor was omitted as it would be best considered in a scenario with a field of caverns or operated as a portion of a larger plant. The power consumption value was based on the energy required to fill and empty the cavern multiplied by the anticipated number of annual cycles for the specific fluid. OpEx for the gases is considerably higher because the work involved in compression is greater, relative to the work required for the pumping of liquids. Figure 8-3 shows a total cost for 30 years of operation and initial CapEx.

As discussed in Section 3.0, some caverns generate revenue, but others are a requirement for profitable operation of an industrial or chemical plant that needs to store gases for use or distribution. Where revenue does occur, prices were included and developed from historical data from the FRED. The FRED data were extracted and normalized to 2022 dollars using the Consumer Price Index (CPI). Revenue for the complete injection and drawdown cycle was calculated by the amount stored in the cavern per cycle multiplied by the number of cycles annually. This revenue value was used to calculate a 30-year internal rate of return (IRR). The IRR shows a loss for the components stored.

The additional CapEx for a hybrid scenario for natural gas or hydrogen reduces costs of storage, relative to the compression scenarios. Storage of higher-value components or those with greater price fluctuations yields better returns. The cost for hydrogen storage is approximately 2 and 4 times higher than the average cost of hard rock mined caverns and salt caverns, respectively (Lord and others, 2014). Key to adoption of hydrogen energy infrastructure will be distributed storage. Like electrical generation, some sources may be higher in cost, but all contribute to a robust system. This summary of economics provides a benchmark for future studies. The results should not be discouraging at this early stage, but instead guide the research that follows. Targeting areas of the basin that would allow larger caverns would drive down the CapEx considerably and improve storage costs as well as IRR. Design optimization and integration of larger groups of caverns would also offer avenues for improvement of economic results of future studies. The IRR and cost for storage were limited to a 30-year exercise; however, as a matter of practice, caverns that are well taken care of can last for decades longer, which would also improve the economic outlook.

9.0 REGULATORY CONSIDERATIONS

Beyond the technical and economic components of developing a salt cavern storage project, a number of regulatory requirements and considerations must be addressed. A salt cavern storage project will require several phases of project permitting and regulatory requirements that will fall under multiple North Dakota state regulatory jurisdictions depending on the specific project phase or activity. Table 9-1 identifies the regulatory authority and applicable state regulations based on the different project activities that will be required to develop a salt cavern storage project. As of the writing of this report, the permitting process for developing a salt cavern storage project remains untested in North Dakota, and some aspects of the process could potentially require further regulatory clarification, rulemaking, or possible legislation. It should be noted that a large degree of clarification was achieved through the establishment of NDCC Chapter 38-25 and the subsequent NDIC-promulgated regulations through the creation of NDAC Chapter 43-02-14, Geological Storage of Oil or Gas, which took effect April 1, 2022. These new regulations set forth the requirements for permitting and operations associated with the geologic storage of hydrogen and produced oil or gas, with little to no processing involved, within oil and gas reservoirs, saline reservoirs and, pertinent to this report, salt caverns. It should be highlighted that these regulations do not pertain to the storage of NGL or processed natural gas. The Oil and Gas Division of NDIC has the established authority to regulate NGL and processed natural gas storage in solution-mined salt caverns that is non-transportation-related (NDCC 38-08-04), but currently no North Dakota regulations exist for permitting such facilities. Appendix H provides additional regulatory aspects of solution-mined salt caverns.

Table 9-1. Salt Cavern Storage Regulatory Jurisdictions and References NGL Storage Activity

Storage Activity	Regulatory Authority	Regulatory Framework
Salt Solution Mining (includes injection well)	NDIC Department of Mineral Resources (DMR) NDGS	NDAC Chapter 43-02-02.1 Underground Injection Control Program (Class III injection well) NDAC Chapter 43-02-02.4 Solution Mining
Salt Solution Production Well	NDIC DMR NDGS	NDAC Chapter 43-02-02.4 Solution Mining
Mined Salt – Surface Handling	NDIC DMR NDGS	NDAC Section 43-02-02.4-32 Saltwater-Handling Facilities NDAC Section 43-02-02-02.4-33 through NDAC 43-02-02-38 Secondary Containment (requirements for saltwater-handling facilities associated with solution mining)
Gas-Processing Facility	North Dakota Public Service Commission (PSC)	NDCC Chapter 49-22.1
NGL Pipeline Geologic Storage within Salt Caverns (includes injection well)	North Dakota PSC NDIC DMR – Oil and Gas Division	NDCC Chapter 49-22.1 NDCC Chapter 38-25 NDAC Chapter 43-02-14
NGL Extraction (NGL production)	NDIC DMR – Oil and Gas Division	NDAC Chapter 43-02-03 General Rules (oil and gas production)

9.1 Solution Mining for Salt Cavern Development

Regulations pertaining to geologic storage within salt caverns are relatively well defined in North Dakota. The NDGS regulates solution mining and is the underground injection control (UIC) primacy authority for Class III injection wells that are used for salt solution mining necessary for the creation of artificial salt caverns. The NDGS regulatory framework is set forth in NDAC Chapters 43-02-02.1 and 43-02-02.4, which cover all aspects of salt solution mining, including requirements for the Class III injection well(s) saltwater-handling facilities and necessary containment measures for the mining facility. These regulations set forth procedures for permitting and bonding of the injection wells and accompanying surface facilities, certifying the secondary containment measures of the saltwater-handling facility, establishing the area of review, confirming mechanical integrity, and ultimate closure and reclamation of the mine and surface along with the plugging and abandonment of all wells. North Dakota currently has no active Class III wells, but a robust regulatory framework exists that covers salt solution mining for the development of salt caverns that can then be utilized for geologic storage of oil or gas once additional regulatory requirements have been met, which will be discussed in the following section.

9.2 Requirements for Geologic Storage Within Salt Caverns

NDCC 38-25 statute and the subsequent NDIC-promulgated regulations in NDAC Chapter 43-02-14 set forth the requirements for geologic storage of oil or gas within oil and gas reservoirs, saline reservoirs, and salt caverns. Previous to NDCC 38-25, NDIC had issued a "Produced Gas Storage Facility Permit Application Guideline." The regulations set forth in NDAC 43-02-14, for the geologic storage of oil and gas, are very similar to the regulations for the geologic storage of carbon dioxide (CO_2) (NDAC 43-05-01) and contain many of the same permitting requirements. The main difference between the two being that oil or gas storage facilities do not require a financial assurance demonstration plan or a postinjection site care and closure plan as required for CO_2 storage facilities. No application for an oil or gas geologic storage facility has yet been submitted in North Dakota, but it should be noted that several CO_2 storage facilities have been successfully permitted in the state.

NDAC Chapter 43-02-14 covers the geologic storage of hydrogen and produced oil or gas with little to no processing involved. The guidance provided in that chapter is relevant only to hydrogen and minimally processed gas storage and would not apply to gas that has been processed at a gas-processing facility including NGL. Gas that has been processed at a gas-processing facility and stored for the purpose of further transport is regulated by the Federal Energy Regulatory Commission (FERC), which has jurisdiction over any underground storage project that is owned by an interstate pipeline and integrated into its system. Underground gas storage facilities that are used to store gas that is transportation-related would also fall under the jurisdiction of the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA). The Oil and Gas Division of NDIC has the established authority to regulate NGL and processed natural gas storage in solution-mined salt caverns that is non-transportation-related (NDCC 38-08-04), but currently no North Dakota regulations exist for permitting such facilities. Development of regulations specifically pertaining to the storage of NGL and processed natural gas (that is non-transportation-related) is recommended to fill the gap that exists in the current regulations.

9.3 Requirement for a Public Hearing

Within NDCC 38-25 and NDAC 43-02-14 is the requirement that a public hearing be held before the issuing of any storage permit. Notice of the hearing must be given to each salt mineral lessee, salt mineral owner of record, and pore space owner of record within the salt cavern outer boundaries and within 0.5 miles of the outer boundaries of the salt cavern. Amalgamation of the pore space within the salt cavern is required, which requires consent of at least 60% of the pore space owners. Nonconsenting owners may be required to have their pore space included in the geologic storage facility. A salt cavern storage project also requires unitization of the salt mineral and salt leases within the salt cavern. NDCC 38-25 specifies that 55% of the salt mineral and salt lease owners are required to consent to unitization and that nonconsenting owners may be required to have their minerals included in the geologic storage facility.

9.4 Area of Review Requirements

As part of the storage facility permit application, a storage facility operator is required to delineate an area of review (AOR) for the proposed storage facility. The AOR must be reevaluated on a schedule that is not to exceed every 5 years unless monitoring or operational conditions warrant a sooner reevaluation. To delineate the AOR and determine necessary buffers/setbacks for future drilling in proximity of the cavern and/or the creation of additional caverns, storage facility operators must utilize site-specific geology, cavern construction data acquired during dissolution mining, and geomechanical modeling. The storage facility operator is required to retain all modeling inputs and data used to support area of review delineations and reevaluations and deliver these records to the Commission upon project completion. The method for delineating the AOR, including the geomechanical model, model assumptions, and site characterization on which the model is based, are also required to be submitted as part of the permit application for a salt cavern storage facility. The AOR is a critical component of the storage facility permit application as the storage facility operator is required to evaluate all wells within the AOR to determine the need for corrective action and perform corrective action on any wells requiring it. Corrective action methods would be designed to prevent the movement of injectate or fluid into or between underground sources of drinking water or other unauthorized zones. The AOR is also a component of several other permit requirements such as the requirement for a map of all wells, producing wells, plugged wells, abandoned wells, drilling wells, dry holes, water wells, and other subsurface structures that are within the AOR and a map of all occupied dwellings within the delineated AOR. The AOR also informs the leak detection and monitoring plan and emergency and remedial response plan that are permit requirements for a storage facility.

9.5 Permit Requirements for Storage in a Salt Cavern

The permit requirements for storage in a salt cavern listed in NDAC 43-02-14 requires that surface, pore space, and salt mineral ownership be addressed and sets forth the requirements for doing so. It is also a requirement that permits be requested for all oil or gas injection wells, monitoring wells, and surface facilities associated with a proposed salt cavern storage project. Technical requirements for a permit to inject are spelled out within NDAC 43-02-14. The list of required information is provided in Appendix H. In addition, a research report summarizing the anticipated permitting process and the permit requirements for an underground gas storage facility permit, including storage in a salt cavern, is currently being developed by the EERC and is expected to be published in 2023 (Olsen and others, 2023).

Overall, the permitting requirements for a salt cavern storage facility can be grouped into five main categories: 1) pore space and salt mineral access, 2) geologic and geomechanical exhibits, 3) AOR exhibits, 4) supporting permit plans (testing and monitoring, emergency and remedial response, plugging), and 5) injection well and storage operations. The requirements for geologic storage of oil or gas in a salt cavern are similar to the requirements necessary to permit a CO_2 storage facility, and the learnings from the several approved CO_2 storage permits can readily be applied to the development of salt cavern storage facility permits (Olsen and others, 2023).

9.6 Leasing of the Subsurface – Salt Mineral and Pore Space Ownership Considerations

In North Dakota, salt formations are considered a mineral resource, and salt mineral ownership must be addressed as part of the salt solution mining regulatory process. Salt leases or mineral ownership will need to be obtained by the salt cavern operator prior to the solution mining process so that mineral owners agree to and are compensated for the mining of salt from their lands. As specified in NDCC Chapter 47-10-24 with regard to mineral leases, "no lease of mineral rights in this state shall be construed as passing any interest to any minerals except those minerals specifically included and set forth by name in the lease." In addition, NDCC 47-10-24 states that "the use of the words 'all other minerals' or similar words of an all-inclusive nature in any lease shall not be construed as leasing any minerals except those minerals specifically named in the lease and their compounds and byproducts." Therefore, unless prior salt mineral leases have specifically been granted or salt was specifically set forth by name in a prior lease, no previous mineral lease, such as for oil and gas, would allow for the mining of salt. Prior to the solution mining operation, leases specific to salt mining (or securement of mineral ownership) will need to be obtained by the salt cavern operator over the proposed salt cavern site. Consent will also be required from at least 55% of the salt mineral or salt lease owners agreeing to unitization of the salt minerals and salt leases within the salt cavern as a requirement to permit a geologic storage facility (NDAC 43-02-14-05). NDCC 38-25-07 also requires that a "good-faith" effort be made to obtain the consent of all persons who own the salt cavern's salt minerals and salt leases. It would be advisable to secure this required consent early in the project development, preferably at the same time as salt leases are negotiated.

Access to the pore space created during the solution mining process will also need to be obtained by a potential salt cavern storage operator. In North Dakota, the surface owner also owns the pore space underlying their surface estate as set forth in the Subsurface Pore Space Policy (NDCC 47-31). This policy also defines pore space as "a cavity or void, whether natural or artificially created, in a subsurface sedimentary stratum." The inclusion of the term "artificially created" in this definition is important as it directly applies to the pore space that is created and developed into a salt cavern during the solution mining process. In addition, a requirement for a geologic storage facility permit for storage in a salt cavern is that there must be amalgamation of the pore space within the salt cavern; this requires the consent of at least 60% of the pore space owners (NDAC 43-02-14-05). Similar, to the requirements for the salt minerals, NDCC 38-25-07 requires that a "good faith" effort be made to obtain the consent of all persons who own the salt cavern's pore space.

Prior to the creation of NDCC 38-25 and the resulting NDIC-promulgated regulations for the geologic storage of oil or gas in NDAC Chapter 43-02-14 Geological Storage of Oil or Gas, there was some uncertainty regarding pore space ownership of a solution mined salt cavern. However, these regulations taken together with NDCC 41-31, Subsurface Pore Space Policy, now make it reasonable clear that ownership of a salt cavern's pore space is separate from the ownership of the salt minerals and that agreements or leases must be reached with both the pore space owners and salt mineral or salt lease owners for subsurface access. There is also the requirement set forth in NDAC 43-02-14-05 that agreements of consent to amalgamation of the pore space within a salt cavern be obtained from at least 60% of the pore space owners, and agreements of consent to unitization of the salt minerals and salt leases within a salt cavern be obtained from at least 55% of the salt mineral or salt lease owners. It would be recommended that all agreements and leases be obtained in the early phases of a salt cavern storage project's development.

9.7 Brine Handling and Storage

The regulations regarding the ongoing brine handling and storage associated with a salt cavern storage project are not clearly specified within current North Dakota regulations, leaving some uncertainty as to the types of storage systems which will be considered acceptable. As specified in NDAC 43-02-14-08, the description and schematics for brine management at the surface are requirements for a salt cavern storage permit. Within NDAC 43-02-14-08, there is also a requirement for a description of measures in place to prevent unintended flowback as well as a requirement for a schematic or other drawing and tabulations "of the wellhead and surface facilities, including the size, location, construction, and purpose of all tanks, the height and location of all dikes and containment, including a calculated containment volume, all areas underlain by a synthetic liner, the location of all flow lines, and a tabulation of any pressurized flow line specifications." Notably absent from NDAC 43-02-14 is any mention of brine storage ponds; these large double-lined surface ponds are commonly a key component in the operation of a salt cavern storage project as they are required to store the large volume of brine, potentially millions of barrels, that is needed to displace the cavern volume and maintain appropriate pressures within the cavern. The use of earthen ponds or large open-top brine tanks has historically been prohibited by the Oil and Gas Division when utilized in oil and gas operations for drilling or hydraulic fracturing. Within NDAC 43-02-14-08, there is the mention of "tanks," but no specific requirements are given to their construction specifications or limits placed on their size. Given the mention of tanks and the absence of any mention of brine storage ponds within NDAC 43-02-14, it could be concluded that only storage tanks will be permitted to be used for brine storage. Clarification on what storage systems will be considered acceptable would be useful to potential salt cavern storage operators as the volume of stored brine will have significant implications on the size of caverns that be operated. There can also be significant economic differences between brine storage ponds and storage tanks, with the former being more economical when large quantities of brine are needed.

10.0 NDIC FINANCIAL INFORMATION

See Appendix I.

11.0 KEY RESULTS AND LESSONS LEARNED

Throughout the course of this study, which spanned activities that ranged from drilling and core collection to laboratory-based core analysis and detailed petrophysical and geomechanical modeling, the EERC team compiled a list of key technical lessons that can help guide and inform future efforts to evaluate and develop salt caverns in North Dakota's bedded salts. The lessons learned, as well as some of the key technical results and findings, are summarized below:

- Predrilling site characterization relies on publicly available data sets, particularly wireline logs. Data sets need careful examination and quality assurance/quality control (QA/QC) to ensure sufficient salt thickness, depth, and quality are encountered and successfully cored.

- Careful on-site monitoring of drilling operations and selection of drilling fluid properties are critical to the successful coring of salts to ensure the greatest chance of full core recovery.

- A full suite of wireline logs is required for characterization of locations for future salt cavern development. Through cluster analysis, a minimum suite of logs (gamma ray, density, neutron, photoelectric factor, and deep resistivity) is enough for basic salt identification. However, to provide accurate predictions of cavern quality and stability using 3D geomechanical simulation, borehole imagery, compressional and shear sonic, and spectroscopic logs along with core analysis are critical to lessen uncertainty of the properties.

- At this early stage of research into cavern development in North Dakota, core retrieved from salt zones under investigation should have full suites of petrographic, petrophysical, and geomechanical laboratory tests performed to provide adequate characterization and calibration data for any future project.

- Based on using HALITE 1 site conditions to optimize cavern size while minimizing the chance of salt or nonsalt failure, aspect ratios of 1:1 to as high as 1:2 can be considered for both the Dunham and Pine Salt for the storage of natural gas, NGL, or hydrogen. Thicker salt zones may allow for the development of caverns with higher aspect ratios (i.e., 1:3, 1:4, etc.); however, additional core collection, analysis, and testing are needed from locations with thicker salt deposits.

- At the formation temperatures and pressures anticipated for the Dunham and Pine Salts, reduction in cavern volume through creep strain (deformation) is expected to be cumulative over project duration. Once creep progresses, it cannot be reversed. Salt cavern operational engineering designs are necessary to effectively manage inevitable creep progression over the duration of a salt cavern project.

- Caverns are more stable at higher cavern operating pressures. For HALITE 1 site conditions, a base-case brine pressure using a brine gradient of 0.52 psi/ft supports stable cavern operations in the Dunham and Pine Salts for storage of natural gas, NGL, or hydrogen.

- Salt cavern stability indicators for storage of natural gas, NGL, or hydrogen at the HALITE 1 location suggest that:
  - Within the over- and underburden nonsalt intervals for the 1:2 aspect ratio scenarios, after 30 years, the Dunham exhibits the onset of shear and tensile failure, while the Pine exhibits the onset of shear failure.

- Creep displacement of less than 5% of the original cavern diameter for the Dunham and Pine Salts after 30 years suggests a minimal chance of salt cavern damage.
  - Volume shrinkage in the Pine is much less than the Dunham after 30 years, but both are less than 30%, which minimizes the chance of damage to the salt within the cavern.
  - After 30 years, the Dunham and Pine Salt cavern models do not exhibit dilation-related failure in the salt.

- Collection of additional core and geomechanical data are needed to reduce the uncertainty of the geomechanical modeling results of this effort. These data can be used to develop more detailed geomechanical models that better capture heterogeneity, reduce uncertainty, and provide additional insights into potential failures related to salt/nonsalt interfaces and nonsalt intervals.

12.0 CONCLUSIONS AND RECOMMENDATIONS FOR FUTURE WORK

North Dakota's abundant natural gas and NGL resources provide both opportunities for petrochemical development, as well as challenges with respect to gas processing and pipeline transmission capacity. On one hand, given the high NGL content of the associated gas produced from the Bakken, entities like the North Dakota Pipeline Authority are concerned about the state's long-term NGL takeaway capacity through existing pipelines (Kringstad, 2023). On the other hand, the state's abundant NGL resources can be used to develop value-added products like plastics, resins, and synthetic rubber. Natural gas is the primary feedstock required for hydrogen production, which is an emerging fuel of interest globally to help reduce greenhouse gas emissions from traditional fossil fuels. A key requirement to facilitate petrochemical development and provide the midstream service and pipeline industry with a solution to better manage swings in takeaway capacity is large-scale storage. NGL and natural gas storage in bedded salt formations has been an ongoing practice in North America for decades but has yet to be adopted in North Dakota. The ability to capitalize on North Dakota's bedded salt formations for cavern development and fluid storage would significantly increase the state's ability to manage natural gas and NGL supplies and provide opportunities to benefit from petrochemical development and hydrogen production.

To better understand the potential for development of engineered salt caverns to be used for storage in North Dakota, the EERC performed a study of two bedded salt formations using field-, laboratory-, and engineering-based techniques. To accomplish this study, a stratigraphic test well was drilled near Williston, North Dakota, HALITE 1 (NDIC #38890), targeting two bedded salt formations. The Dunham and Pine Salts were successfully cored and logged providing a first-of-its-kind data set invaluable for determining geologic, geomechanical, and engineering factors that are necessary for cavern development and operation in bedded salts.

Cavern modeling using data specific to the HALITE 1 well site indicated that a cavern can be created that could store volumes between 25 and 100 Mbbl and that the geomechanical integrity of the cavern would be sustained for at least 30 years of operation (assuming a brine-based operation with higher operating pressures). Based on the data from the HALITE 1 well and analysis of well log data from 325 locations, several geologically promising areas are located within the

Dunham and Pine Salts across western North Dakota with projected thickness and salt composition that may be suitable for cavern development. While cavern development and storage are currently unproven in these salt zones, the results of this study suggest that both the Dunham and Pine Salts have geologic and geomechanical properties amenable to cavern development and long-term operation.

The results of this study provide a strong basis for further evaluation and potential development of salt caverns in North Dakota's bedded salt formations. While this study thoroughly evaluated the HALITE 1 site and results of the work were encouraging regarding future development opportunities, it is important to note that this is only one data point in the basin regarding bedded salt quality and mechanical stability. Additional site-specific core collection, analysis, and testing are required to further assess the statewide cavern development potential and long-term geomechanical stability for various product storage scenarios across North Dakota.

North Dakota has existing regulations for the development of salt caverns through solution mining and for the storage of hydrogen and produced oil or gas with little to no processing. NDIC's Oil and Gas Division has the established authority to regulate NGL and processed natural gas storage in solution-mined salt caverns that is nontransportation-related (NDCC 38-08-04), but currently no North Dakota regulations exist for permitting such facilities. Development of regulations that pertain to the storage of NGL and processed natural gas is recommended to fill the gap that currently exists in the salt cavern storage regulations. Additional regulatory clarity would also be useful regarding ongoing brine handling and surface storage associated with salt cavern storage projects, including clarification on what storage systems (i.e., brine storage ponds) will be considered acceptable.

Because the likelihood of a widespread effort to collect and analyze additional data from North Dakota's bedded salt formations is low, the EERC recommends that a pilot study, targeting an area of the Williston Basin where the Pine and Dunham Salts are thicker, should be performed to further validate the potential for cavern development in the state. It is recommended that the study include a more detailed analysis of well log data and, if available, seismic data in the area of interest to target a specific location for development of a salt cavern. Once a location has been selected, core samples and detailed well log data should be collected from the site to inform the cavern development and engineering design. The core samples should undergo a series of laboratory tests, including mineralogical analysis, dissolution testing, and detailed geomechanical analysis. The laboratory testing results would be used in conjunction with the well log data to develop a detailed geologic and geomechanical model that would be used to assess various cavern development designs and product storage scenarios. Ideally, the project would be performed in conjunction with a commercial partner who has a vested interest in developing salt caverns for natural gas, NGL, or hydrogen storage. In addition, depending on the commercial partner's experience, inclusion of a third party with expertise in developing and operating salt caverns may be needed.

Successfully demonstrating the development of salt caverns in western North Dakota will assist new and emerging markets, support liquid and gas production with offtake storage capacity, and provide the fundamental research and demonstration needed for future petrochemical and hydrogen hub development opportunities in the state.

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