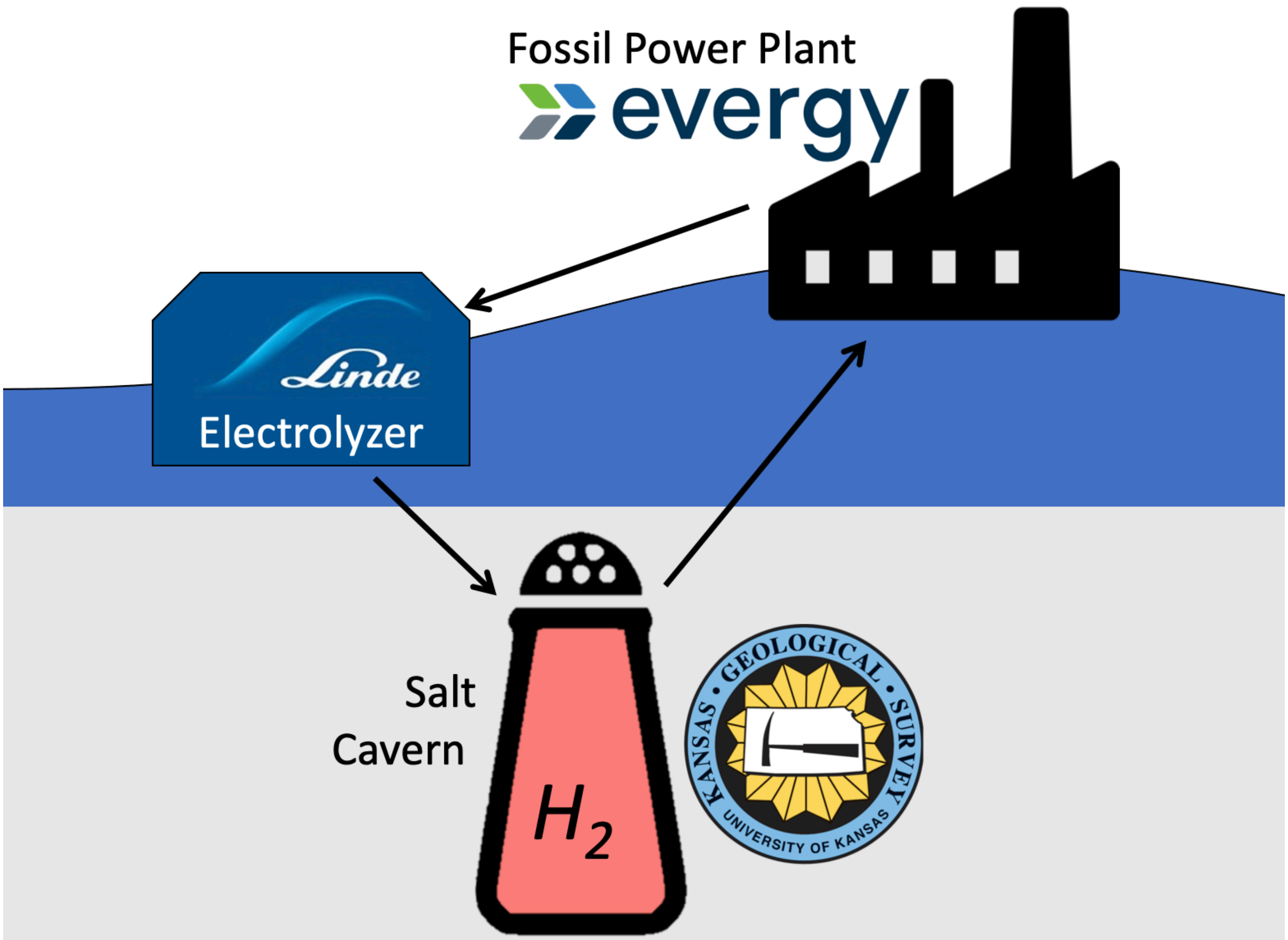
Final report

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

Franek Hasiuk, PI, Kansas Geological Survey



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Final Report

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

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Contents

Abstract

Hydrogen storage in subsurface caverns is known as perhaps largest and longest-term energy storage system. While few such systems are currently in service (e.g., Texas; Teesside, UK), they are envisioned as being a pillar of the current energy transition that will allow intermittent power production from renewable sources (e.g., wind, solar) to be balanced with demand at grid-scale. In addition, hydrogen energy storage can allow existing fossil power plants to run more economically either by minimizing startups/shutdowns or by allowing them to take advantage of arbitrage. Finally, stored hydrogen can feed a variety of non-power users such as pipeline gas, heating, transportation, and manufacturing.

The H-2-SALT paper study assessed the feasibility of a power-to-hydrogen system utilizing salt cavern storage of hydrogen in bedded salt in central Kansas, where over 750 such caverns have been constructed to date, of which approximately 350 are still in service. Legacy well and salt cavern data were collected to develop a regional geological database for two sites in Central Kansas and adjacent areas for use in more detailed geological and geomechanical site characterization efforts.

This study found commercial viability and competitiveness of large-scale, electrolytic H_2 production and storage ($1.78 per kg H_2) that can be used for both electrical power supply to the grid during high-priced electricity periods (including co-firing with NG and fuel cell power production) and sale of H_2 for various industries, such as petrochemicals or transportation. The commercial potential of the H-2-SALT system is also relatively high because each of its components operate commercially today.

It is recommended that a stratigraphic test well be drilled to collect log data and core samples that can reduce uncertainty surrounding geological and geomechanical properties of the salt beds that will be required for further cavern and energy storage system design studies.

Acknowledgement

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Disclaimer

Introduction

Today our global society is faced with a great challenge—uniting in collective action to address global warming. As with all similar challenges we have faced historically, there are roles to play for people, either acting as members of government, industry, academia, the media, families, or individuals. No single entity is to blame, and it will only be through concerted effort over a long period of time that global warming can be addressed. One such way humanity is addressing global warming is by the transition to more renewable sources of energy production, such as wind and solar. In the last 20 years, Kansas has seen its percentage of electricity produced by wind soar to 45% in 2021 (EIA, 2022). However, it is well known that renewable sources of energy like wind and solar produce power intermittently. For these technologies to attain greater penetration into the market, reliable large-scale energy storage systems need to be deployed commercially. Underground storage of hydrogen is the energy storage system with the ability to store the most amount of power over the longest durations—and it is the focus of this study.

The energy transition we are undergoing is one of many we have undergone as a species. From when we learned to use fire, to harnessing draft animals, to hunting whales, to exploiting underground oil and gas, and atomic power, in many ways our use of energy has defined major episodes in human history. It was not long ago that we worried about running out of whales from which we could produce whale oil, valued for its pure white light for illumination. The discovery of oil in Pennsylvania in the 1860s was heralded at the time as a discovery that could help save the whales (Figure 1).

Figure 1: Political cartoon appearing in Vanity Fair magazine on April 20, 1861, depicting whales celebrating the discovery of oil in Pennsylvania. Petroleum would replace whale oil as the major source of oil for home lighting.

Over the time since oil has been discovered in industrial quantities, the United States has seen several transitions in where we get our energy (Figure 2), from a predominantly wood-based society to coal's rise, to the current dominance of hydrocarbons. Nuclear and renewables will likely grow in relative abundance due to their low carbon emissions compared to hydrocarbons.

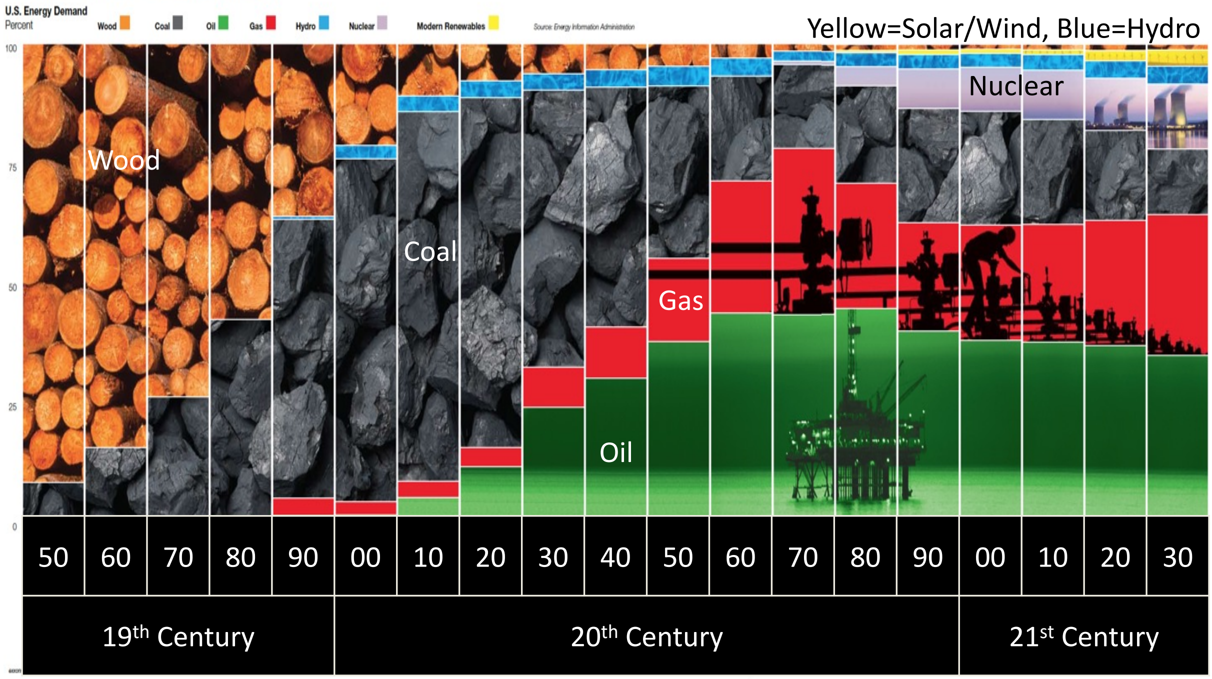


Figure 2: Change in relative abundances of sources of energy in the United States from 1850s to 2009 and projected to 2040. Energy sources depicted include wood, coal, gas, oil, nuclear, hydro, and wind/solar. Ethanol is included in wind/solar (after ExxonMobil Energy Outlook 2009).

In this way, many have talked about our current energy transition as one away from fossil fuels. However, more accurately it can be described as a transition away from the emission of greenhouse gasses like carbon dioxide and methane. This more holistic definition encompasses four major themes (Figure 3): carbon capture/use/storage (CCUS), energy storage, hydrogen, and critical minerals. ***CCUS*** captures CO_2 emissions at industrial sites (e.g., power plants, ethanol distilleries, refineries, cement plants) and injects those emissions underground deep below sources of drinking water in deep saltwater aquifers or oil and gas fields.

Carbon Capture & Storage	Energy Storage	Hydrogen Economy	Critical Minerals
• Gets CO_2 out of the atmosphere • Prolongs investments in current power plants	• Manages variable production of power from renewables ***and*** fossil generators • Network benefits	• Can be burned with natural gas • Transport fuel • Industrial uses	• Required for high tech manufacturing (e.g., solar panels, wind turbines, electronics, screens) • Complex to refine

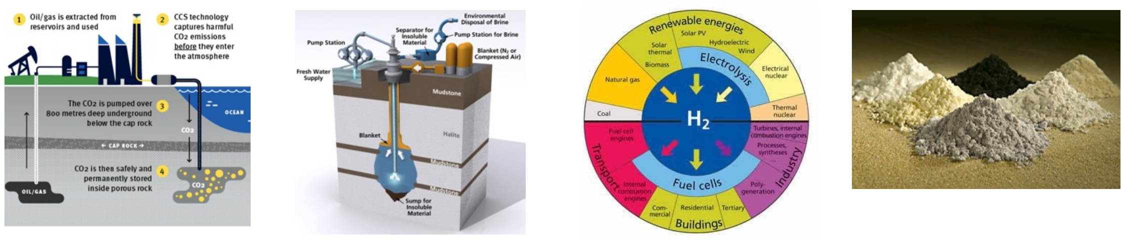


Figure 3: The current energy transition is composed of four major themes: carbon capture/use/storage, energy storage, hydrogen, and critical minerals.

Energy storage is the technology that allows large amounts of energy to be stored for long durations to allow greater penetration of variable power producers into the market. This is commonly thought of as wind and solar generators, but natural gas peaking plants can be considered variable power producers as well. Salt caverns, as studied in this project, are a premier place to store energy either as compressed air or hydrogen. The ***Hydrogen Economy*** refers to replacing hydrocarbons with hydrogen as the dominant energy storage medium in our economy and the network effects hydrogen provides beyond simply power storage in the fields of refining and manufacturing. ***Critical minerals*** are those rare minerals that are required to make advanced manufactured goods critical to our economy and/or national defense including electronics, catalysts, superalloys, and magnets. Solar panels and wind turbines also use copious amounts of critical minerals. The project detailed in this report involved studying the use of underground salt caverns to store hydrogen. That hydrogen would be produced via the electrolysis of water using surplus electricity form a natural gas combined-cycle turbine located at one of two facilities in Kansas. For salt cavern storage of hydrogen to work without pipelines, salt must exist in the vicinity of the proposed hydrogen producer. Because salt does not underlie the territory of the United States evenly (Figure 4), the H-2-SALT system is one that cannot be cited everywhere like, for example, a battery storage system. However, salt cavern storage of hydrogen is the energy storage system capable of storing the largest amount of energy over the longest durations.

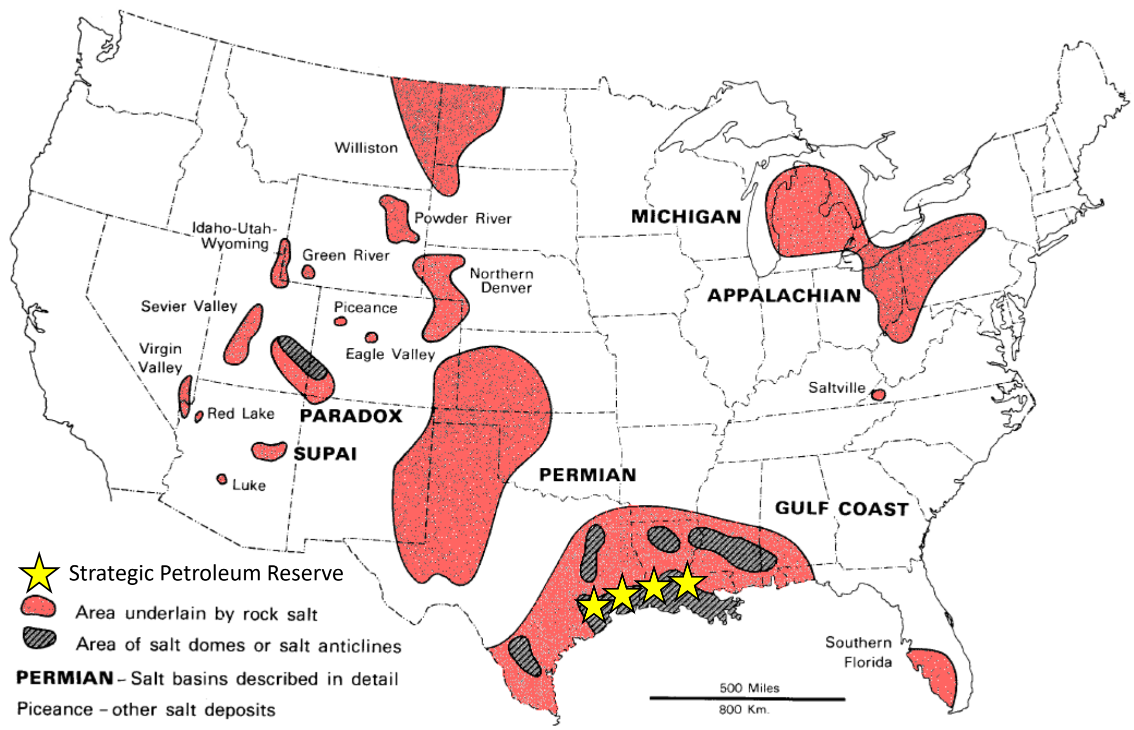


Figure 4: Map showing distribution of natural salt deposits in the lower conterminous United States. Red areas indicate presence of bedded salt and black cross-hatched areas indicate presence of domal salt.

Geologically, salt occurs in two major varieties: bedded salt and domal salt. Bedded salt is how all salt deposits start: as beds of salt laid down from the evaporation of seawater. However, if enough sediment is deposited on top of a bed of salt the resulting differences in density between less-dense salt and more-dense sandstone, shale and limestone rock types will cause the bedded salt to begin to flow upwards into domal structures. While the term "domal" is applied to this type of deposit, they exist in a wide variety of shapes and sizes due to the non-uniform way in which overlying sedimentary rocks are deposited.

The comparison, however, of bedded vs domal salt can be useful in understanding the major differences in the properties and morphologies of these types of salt. Bedded salt deposits tend to be thinner (less than 1000 feet); they occur at shallower depths; they are less pure in composition due to the inclusion of interlayers of shale; and they are not in motion. As a result, caverns in bedded salt tend to be smaller (~100 ft in diameter and ~100 ft tall). Domal salt, on the other hand, tends to be thicker (1000s to 10,000s of feet thick); occur at deeper depths; they are purer in composition; they tend to be in motion (inches per year).

Most basins have salt of only one age (Figure 5) so it is dominated by salt minerals of a certain family (e.g., KCl or $MgSO_4$) which will likely have more uniform properties. The Williston Basin of North Dakota has salt from numerous times in Earth history and thus the variable mineralogies of those various salt beds has likely led to salt beds with difference physical and chemical properties.

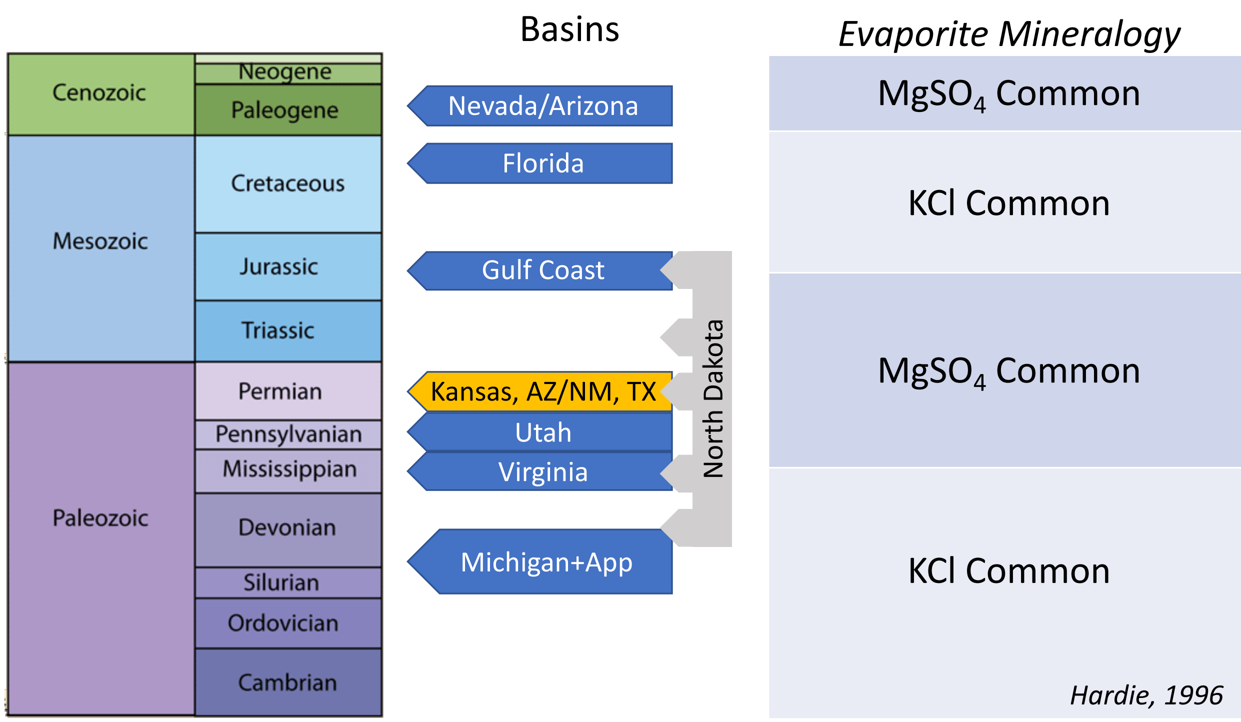


Figure 5: Diagram showing the ages and mineralogies of the major salt basins of the Unites States. "App" refers to the Appalachian Basin. Evaporite mineralogy after (Hardie, 1996).

Fossil-fueled electricity generating units overlie almost all salt deposits in the lower conterminous United States aside from some of the smaller deposits in the Intermontane West (Figure 6). Therefore, the H-2-SALT system can likely be applied to numerous sites nationally.

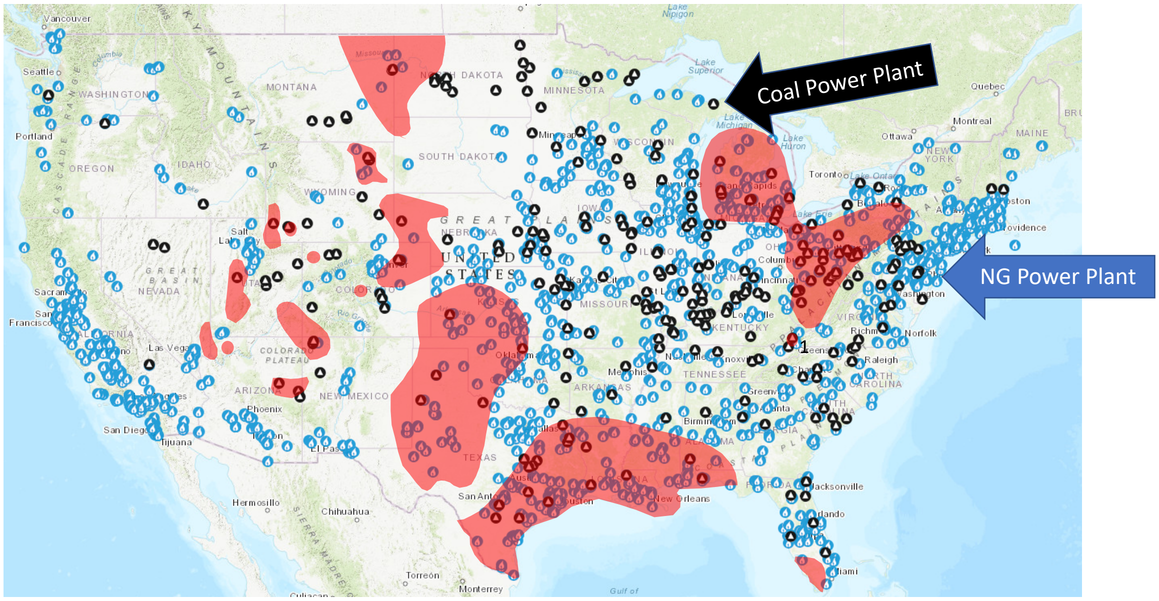


Figure 6: Map showing locations of coal (black) and natural gas (blue) fired electricity generating units.

Salt caverns or mines are already used for storage across the United States (Figure 7). Salt caverns in Texas, Louisiana, Mississippi, Alabama, Michigan, New York, and Virginia all store natural gas (methane). Liquid hydrocarbons are stores in salt caverns in Kansas, Utah, Texas, Louisiana, Michigan and New York. (Salt caverns in Texas and Louisiana host the US Strategic Petroleum Reserve.) While low level nuclear waste is stored in salt deposits at the Waste Isolation Pilot Plant in New Mexico.

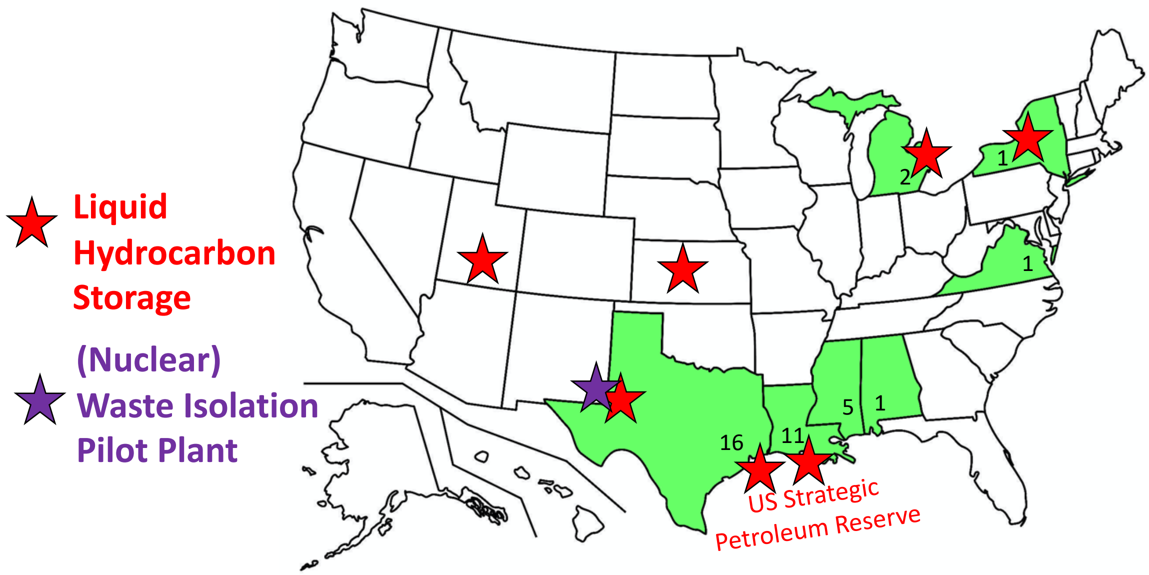


Figure 7: Map showing salt cavern storage facilities in the United States. Green states show their number of natural gas storage caverns. Red stars indicate states with salt cavern storage of liquid hydrocarbons. Purple star is the Waste Isolation Pilot Plant (WIPP) in West Texas that stores low-level nuclear waste.

Globally, salt caverns are used in numerous countries to store natural gas (Figure 8), the most analogous system to hydrogen storage. Germany stores 14.9 billion cubic meters in 32 caverns and the US stores 14.1 billion cubic meters in 37 caverns (cf. Figure 7). In this way, it can be seen that salt cavern storage of energetic gasses is commercially viable today.

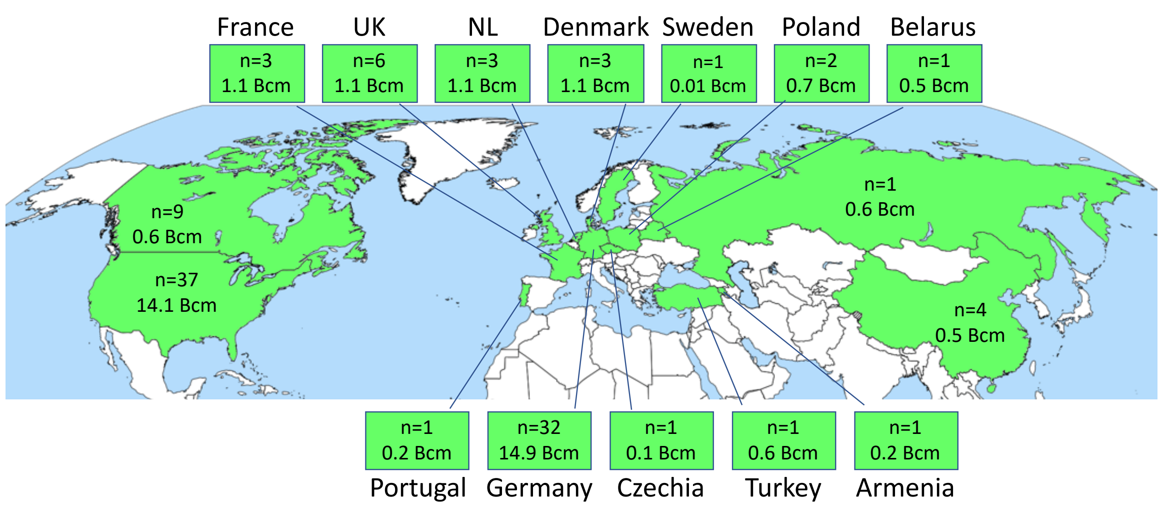


Figure 8: Map showing number of caverns and approximate storage volumes for countries around the world.

Salt cavern storage of gaseous and liquid hydrocarbons occurs in deposits of Paleozoic, Mesozoic and Tertiary (Cenozoic) age in Europe (Figure 9) in numerous countries. In the UK, hydrogen is stored in salt of a similar age (Permian) and type (bedded) to the deposits studied in this project. In this way, it can be argued that salt cavern storage of hydrogen in Permian bedded salt is commercial today.

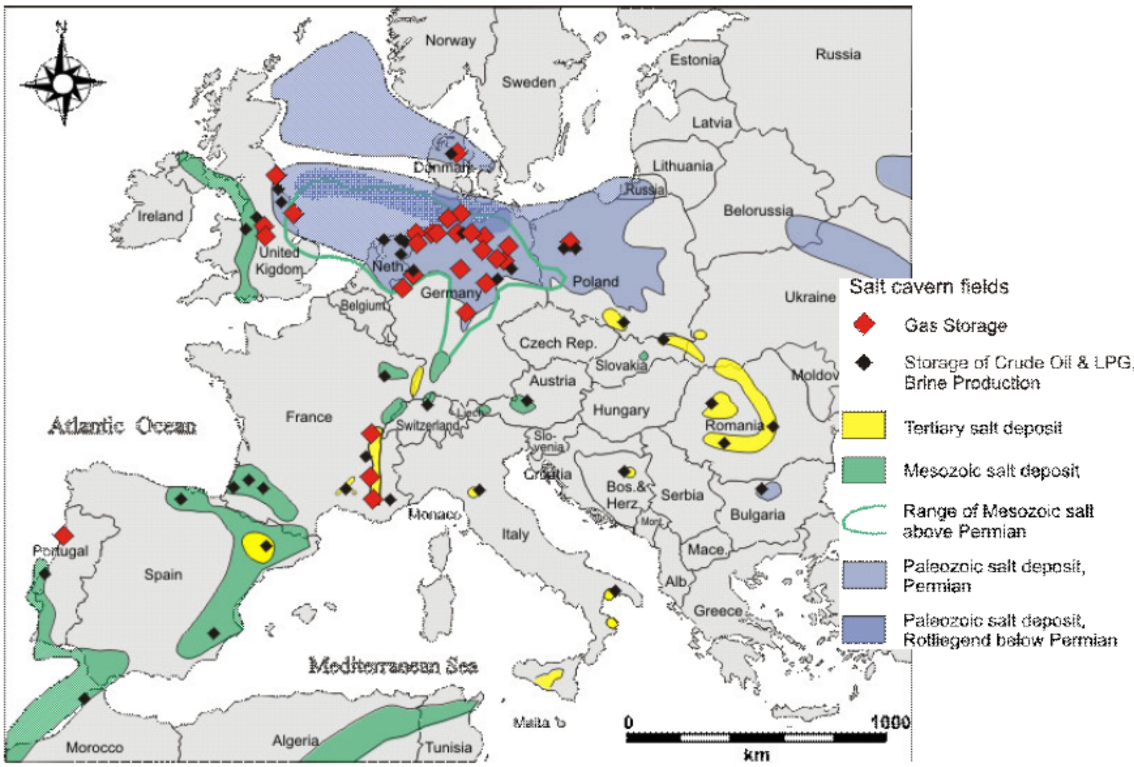


Figure 9: Map of salt deposits and salt cavern storage facilities in Europe (Crotogino et al., 2010).

The United States created the Strategic Petroleum Reserve in the 1970s by purchasing several salt cavern storage facilities along the Texas and Louisiana coast (Figure 10). This reserve consists of 60 caverns in total, each ~200 ft wide, ~2500 ft tall, and with a combined capacity of 714 million barrels of oil. The reserve is meant to buffer the US economy from supply disruptions caused by natural (e.g., hurricanes) and human-caused (e.g., war, OPEC) supply disruptions. It was most recently activated by in response to oil price spikes caused by supply disruptions due to the Russian invasion of Ukraine with the US selling 1 million barrels of crude oil per day for 180 days. ***This shows that the DOE is not only comfortable with salt cavern storage of energetic liquids but sees doing so is in the national interest in some cases.***

Figure 10: Map showing location of Strategic Petroleum Reserve Sites along the US Gulf Coast (Image: DOE: SPR).

Project partner Linde runs a hydrogen storage and distribution network in Texas and Louisiana. Storage Network in Texas and Louisiana (Figure 11). The system is anchored by a salt cavern storage facility with 40 million m^3 (1.4 Bcf) of working capacity (Figure 12). A 350-mile pipeline system runs from Texas City, TX, to Lake Charles, LA connecting 50 customers and pumps at a rate of 600 mscf/d. This system has been in operation for over 20 years.

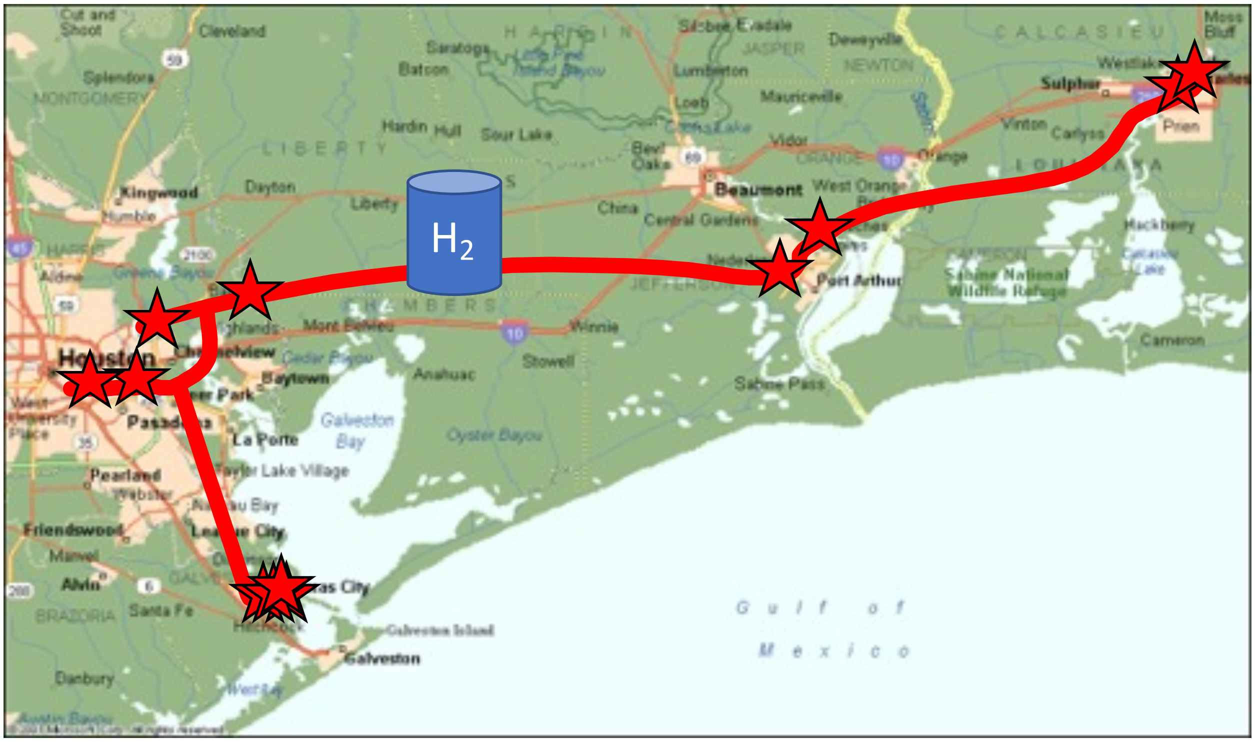


Figure 11: Map of Linde's US Gulf Coast hydrogen system including hydrogen storage cavern location. Industry customers are shown as red stars.

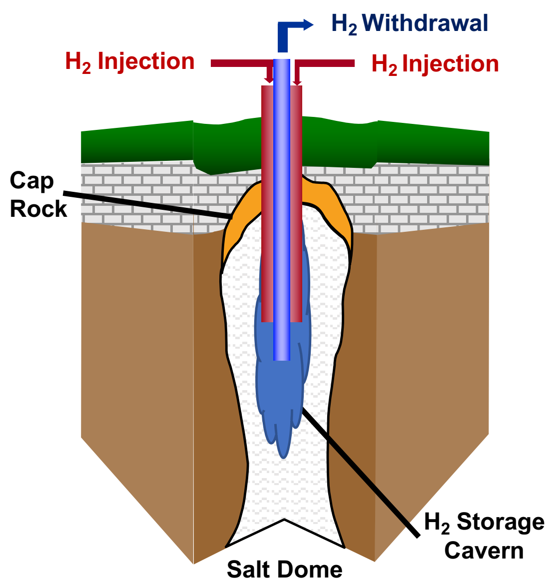


Figure 12: Schematic diagram of Linde's hydrogen storage salt cavern in Texas.

After the presence of salt deposits, a workforce talented in working with salt is required to ensure safe and successful salt cavern storage operations. Kansas hosts a diverse and vibrant salt industry (Figure 13) that—beyond cavern storage operations—includes open room mining, solution mining, secure item storage (e.g., documents, original movie reels, movie costumes), and tourism (e.g., train rides, foot races).

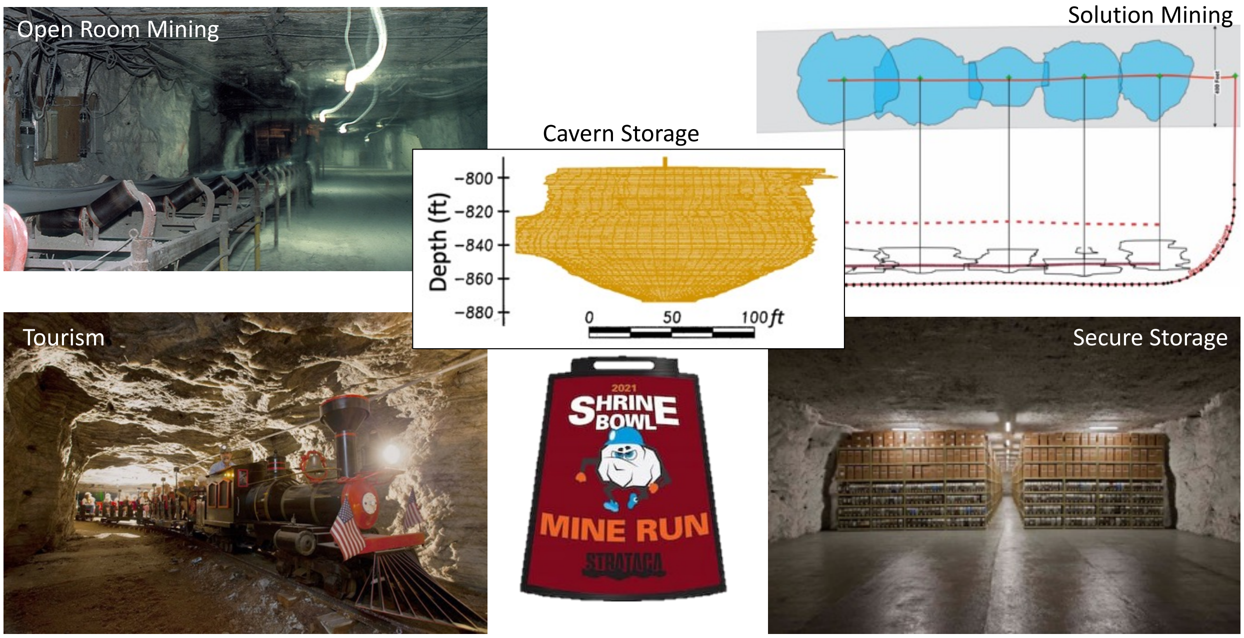


Figure 13: Kansas has a diverse salt industry including open room mining, solution mining, cavern storage, secure item storage, and tourism.

A typical cavern storage operation will look at the surface like a series of well heads equally spaced across a plot of land that would look not too unlike an oil or natural gas field. The only field for which detailed maps are publicly available is Yaggy Storage Field, northwest of Hutchinson, Kansas (Figure 14), which has been mothballed since 2003 when Kansas stopped permitting cavern storage of natural gas. The site was activated in 1993 and contains 74 caverns with a total of 3.2 BCF of nameplate storage capacity. Each cavern stores stored ~60 million cubic feet of natural gas. Caverns are ~80 ft tall, ~150 ft wide, and are spaced ~400 ft apart

Their depth of over 800 ft underground permits an operating pressure range of 550-685 psi (KGS Website, 2003).

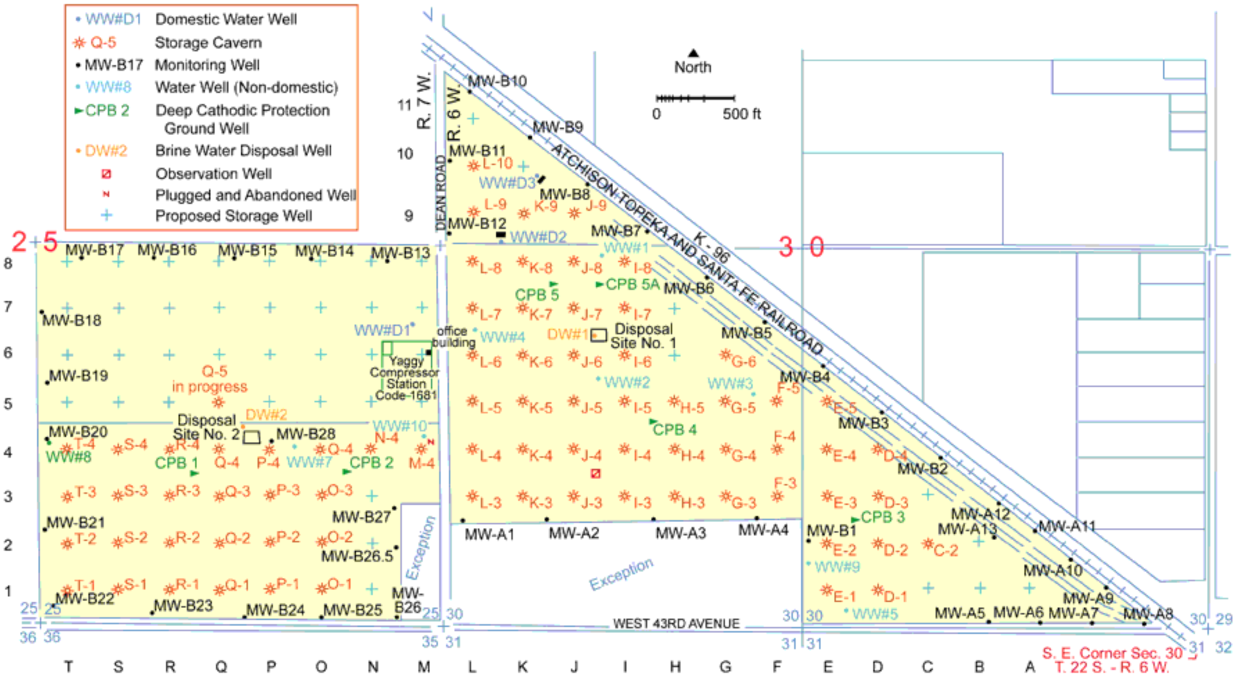


Figure 14: Engineering map of the Yaggy Storage Field, northwest of Hutchinson, Kansas. This map shows the spatial arrangement of wells in commercial salt cavern storage facility (KGS, 2001).

By state regulation in Kansas, hydrocarbon salt storage caverns are surveyed with a sonic tool every ten years to monitor cavern growth (Figure 15). Cavern growth occurs when brine used to displace stored hydrocarbons and maintain cavern integrity slowly dissolves some of the host salt. When the cavern reaches a regulated diameter (400 ft in Kansas) the cavern is decommissioned.

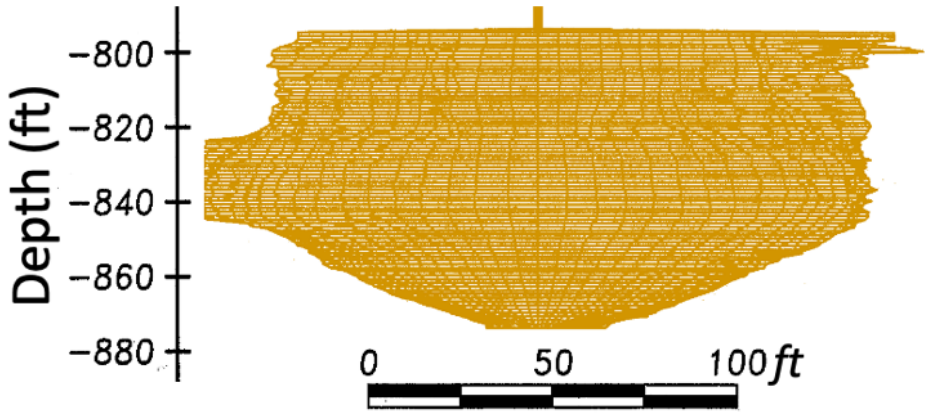


Figure 15: Sonic survey cross-section of a typical salt cavern at the Yaggy Field, northwest of Hutchinson, Kansas, showing depth range for cavern as well as horizontal scale (KGS, 2001).

The Hutchinson salt bed underlies much of central Kansas and Oklahoma (Figure 16) as well as numerous wind farms and fossil fueled electricity generating units, including the Hutchinson and Gordon Evans Energy Centers studied in this project. This location makes it ideal for deployment of hydrogen energy storage systems.

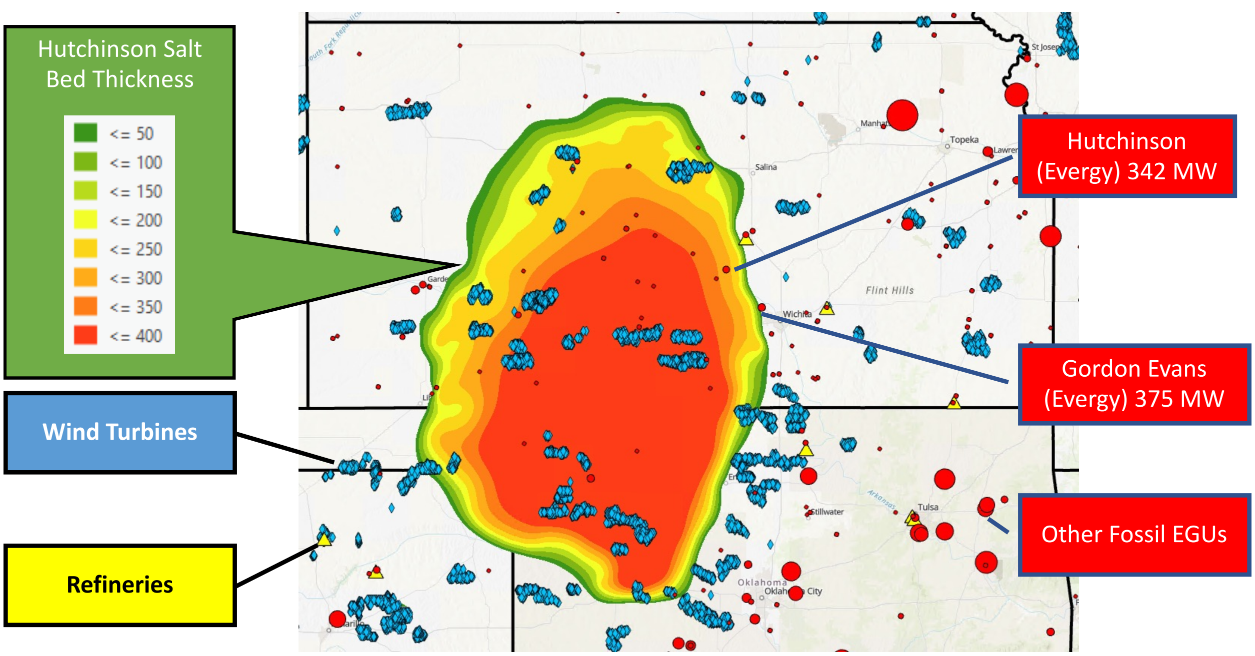


Figure 16:The Hutchinson Salt is over 400 ft thick in places in Kansas and Oklahoma. It is located under or near numerous wind farms, fossil fueled electricity generating units, and refineries.

The Hutchinson Salt is angled with it being shallower in the east and deeper in the west (Figure 17).

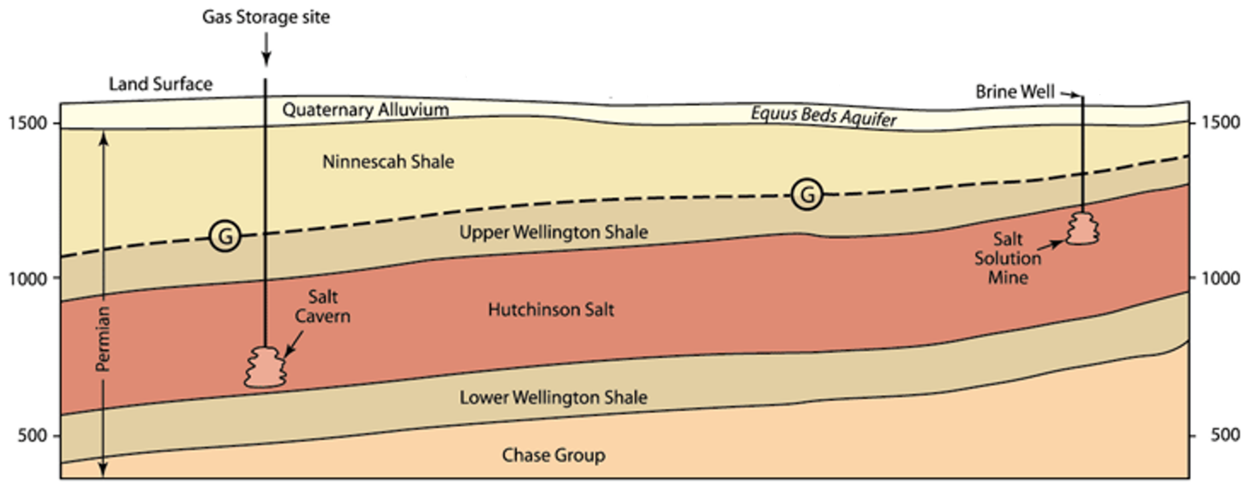


Figure 17: Schematic cross section of underground geology in the vicinity of Hutchinson, Kansas. Diagram shows approximate scale of current commercial salt caverns with respect to the thickness of the host salt bed (after KGS, 2001).

In addition to storing energy as hydrogen, energy can be stored as compressed air in Kansas salt (Figure 18). A previous study noted that the western half of the Hutchinson Salt was suitable for the "turbo" variety of compressed air energy storage (CAES). This is due to the deeper nature of the salt allowing the system to operate at higher pressures. A newer technology utilizing a dry screw compressor developed by the Japanese firm KOBELCO has been proposed to work at the lower pressures found in the eastern half of the Hutchinson Salt.

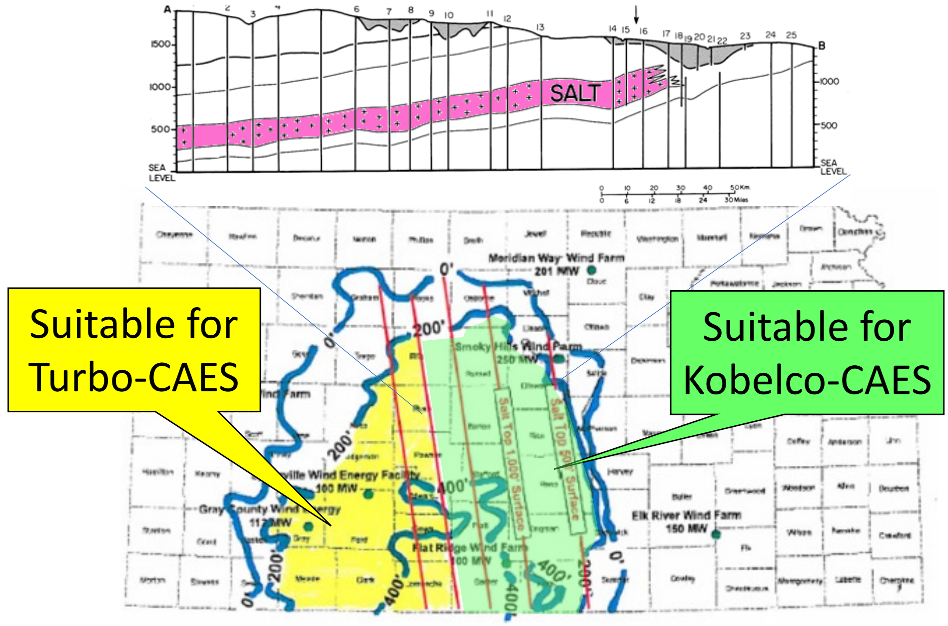
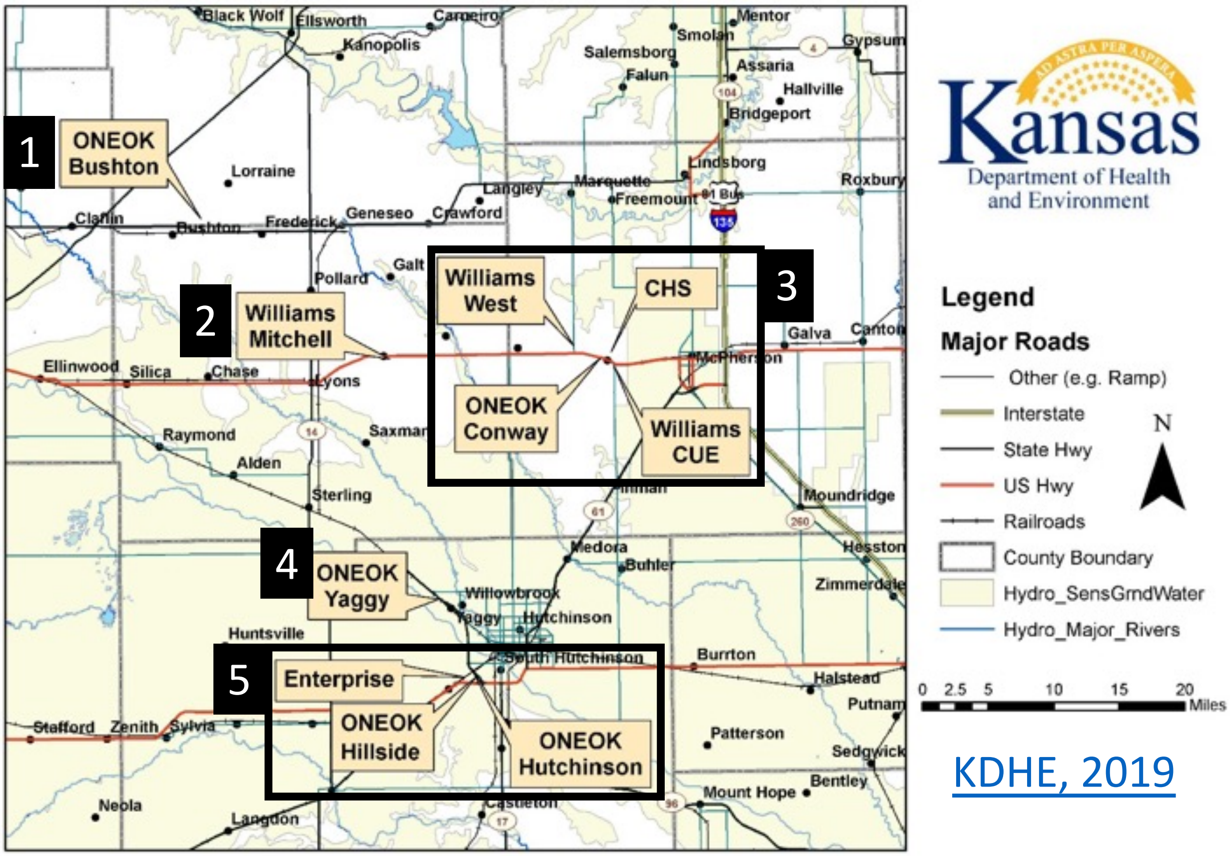


Figure 18: Compressed air energy storage (CAES) is also feasible in Kansas. Conventional, "turbo-CAES" is viable in the western half of the Hutchinson Salt. The proposed "Kobelco-CAES" system, which can operate at lower pressures, is possibly feasible in the eastern half of the Hutchinson Salt.

The Atomic Energy Commission sponsored research at the Kansas Geological Survey in the 1960s to understand if the Hutchinson Salt was suitable for nuclear waste storage (Figure 19).

Figure 19: Hand-sample and core boxes of Kansas salt collected as part of scoping studies for a possible nuclear waste repository near Lyons, Kansas, in the 1960s by the US Atomic Energy Commission.

Salt cavern storage facilities for liquid hydrocarbons (e.g., propane, butane) are located mostly in five areas in central Kansas (Figure 20): Mitchell, Conway, Bushton, Yaggy, and Hutchinson. Kansas as a whole hosts ~350 active caverns with 73 million barrels of capacity, ~225 monitoring wells, and ~750 total caverns (including decommissioned caverns).



KDHE, 2019

Figure 20: Map showing approximate location of five major areas hosting most of the active and mothballed salt caverns in Kansas.

The Gordon Evans and Hutchinson Energy Centers (Figure 21) are owned and operated by Evergy a large, regulated power company serving Kansas and Missouri residents.

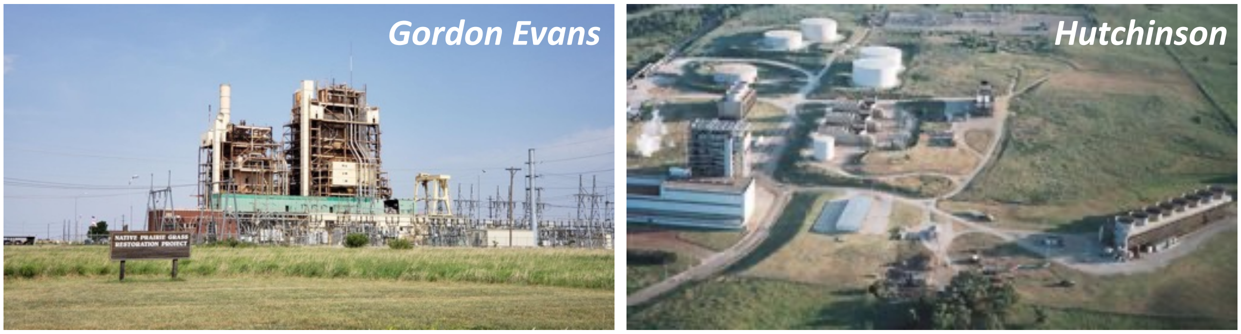


Figure 21. Photographs of the two sites studied in this project: Gordon Evans Energy Center (Colwich, KS) and Hutchinson Energy Center (Hutchinson, KS).

The H-2-SALT system that uses non-economic fossil power from a natural gas turbine to generate hydrogen by electrolysis and store it in an underground salt cavern (Figure 22). Stored hydrogen can then be converted back to electricity by co-firing with natural gas or supplying it to a fuel cell. Alternatively, stored hydrogen can be supplied for other uses such as transportation, pipeline gas, or industry.

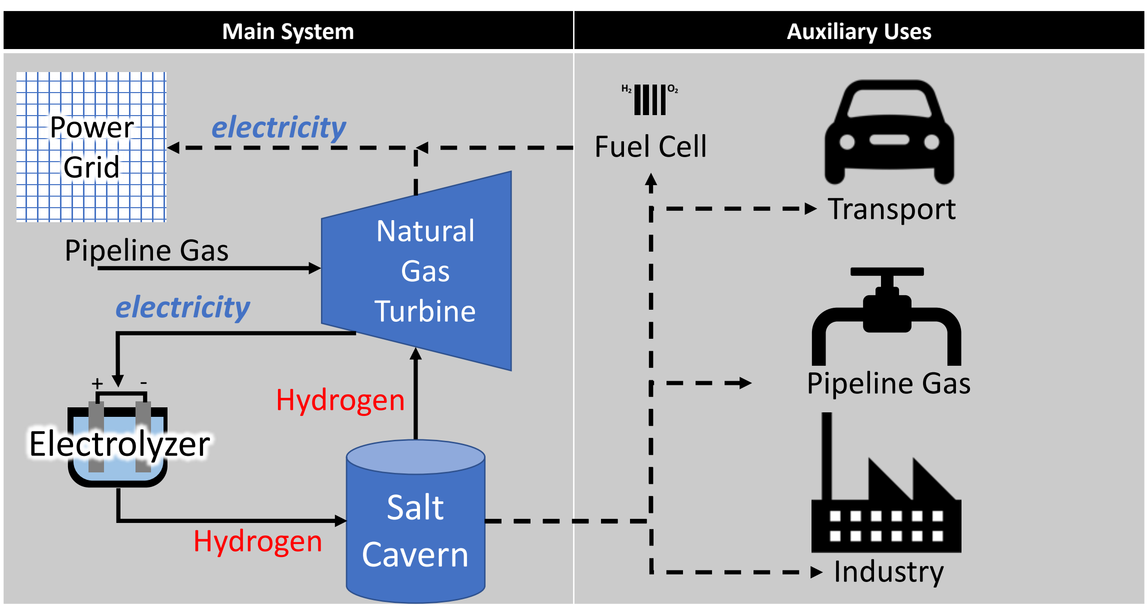


Figure 22: Schematic diagram of the H-2-SALT system including hydrogen production, storage, and use.

Results

Geological and Geomechanical Analysis (Summary of Appendix A)

The H-2-SALT study aimed to assess the feasibility of a power-to-hydrogen system utilizing salt cavern storage of hydrogen in Kansas. For such a system to be technically feasible, salt of sufficient thickness, depth and quality must be available underneath the two evaluated sites. Two specific sites were evaluated in this study included the Gordon Evans Energy Center (GEEC), located east of Colwich, Kansas, and the Hutchinson Energy Center NG-EGU (HEC), located northeast of Hutchinson, Kansas. Currently, over 350 active salt caverns exist in the salt layer that the two sites overlie so it follows that the two proposed sites would likely have sufficient salt resource to support additional storage caverns.

Key findings of this study included:

- Existing well and salt cavern data allowed for the development a regional storage database for the two sites and adjacent areas to support detailed site characterization efforts.
- The Hutchinson Salt Member is a bedded salt formation providing hydrogen storage potential in salt caverns in central to western Kansas.
- The top of the Hutchinson Salt under GEEC is at ~300 ft depth and at ~450 ft under HEC. The thickness of the salt under the GEEC site is ~200 ft, and under the HEC site it is ~300 ft.
- All available geological and geomechanical information were integrated for establishing suitable salt cavern parameters. Pressure, size limitation, and distribution of potential salt caverns for each site were determined to meet the criteria of cavern stability.
- No major stability issue exists in the study area. Uncertainty surrounding the risk of interbed slip in the Hutchinson Salt should be evaluated during storage operations.

- In Phase II, it is recommended to drill a stratigraphic test well to collect geological and geomechanical data from a core and well logs necessary for a cavern design. Future research should focus on obtaining core and log data to characterize salt formation and mechanical behavior for pre-FEED studies.

Conceptual Cavern Design (Summary of Appendix B)

The project team defined technical parameters for what would be a typical hydrogen storage cavern in Kansas based on parameters from current commercial storage caverns in Kansas. These parameters included: top of salt, roof thickness, cavern thickness, salt thickness, effective casing seat, base of salt, and mean cavern diameter. Details on cavern operation were evaluated and proposed for the final cavern design, including methods to pretreat the hydrogen before injection into the cavern and prevent contamination by impurities existing in layers outcropping in the cavern's walls. A large dataset provided by the Kansas salt cavern regulator assess cavern design parameters for the final H-2-SALT system cavern design based on analogous current, commercial systems.

Techno-Economic Analysis (Summary of Appendix C)

The techno-economic evaluation of a 727 MWe (net) natural gas combined cycle power plant (NGCC), integrated with a commercial-scale Linde proton exchange membrane (PEM) based electrolyzer and a hydrogen storage cavern designed to accommodate the scale of hydrogen production based upon experience. The process simulation and modeling was performed using UniSim Design R440 as well as actual electricity price data from January – December 2020 obtained from Evergy on the GEEC site, a 120+ MW_e (net) NGCC plant located in Colwich, Kansas. Technical and cost information for the Linde electrolyzer and hydrogen storage cavern have been determined using proprietary internal operating data, simulation models as well as commercial quotes and proposals. The Linde case presented is compared against the DOE-NETL Case B31A reference, a 727 MWe (net) NGCC plant without CO_2 capture.

The results of the techno-economic assessment show the energy demand for the electrolyzer, the incremental NG fuel requirement, and the net higher heating value efficiency of the NGCC power plant integrated with the electrolyzer system compared to the DOE-NETL reference case. A comparison of the capital and operating costs for each electrolyzer plant configuration corresponding to a 727 MWe (net) NGCC plant is also presented.

Overall, the net efficiency of the integrated 727 MWe supercritical pulverized coal (PC) power plant without CO_2 capture changes from 53.60% with the DOE/NETL Case B31A reference to 51.14% with the integrated NGCC, Linde electrolyzer, and cavern storage system. The Linde electrolyzer and cavern system results in an integrated cost of electricity (COE) of $45.77/MWh, compared to $43.33/MWh for the Case B31A reference, and a total cost of hydrogen production and storage of **$1.78/kg H_2** based on the modeling inputs used. The loss in efficiency and higher electricity costs are compensated by reduction in CO_2 emissions by addition of the hydrogen electrolyzer and cavern storage system.

Because it is relevant for the project goals to demonstrate the feasibility and environmental benefits of low-cost, large-scale, electrolyzer-based hydrogen production, storage and use, the final section of techno-economic analysis provides performance modeling and cost analysis of an integrated NGCC plant, electrolyzer, and cavern storage system at a much larger hydrogen production scale that significantly reduces the CO_2 footprint of the NGCC asset, while still providing reliable power to the grid.

Technology Gap Assessment (Summary of Appendix D)

The Technology Gap Assessment provided the current state-of-the-art for energy storage, electrolytic production of hydrogen, and cavern storage of that hydrogen.

Hydrogen cavern storage is one of several energy storage technologies that include: electrochemical storage devices such as batteries (lead acid, lithium ion, nickel/metal hydride, sodium/sulfur), flow batteries (vanadium-redox, zinc/bromine), and capacitors; electromechanical storage devices (e.g., steel and composite rotor flywheels); electrical storage devices (e.g., superconducting magnetic energy storage); pumped hydroelectric energy storage, and compressed air energy storage. These technologies offer energy storage in a wide range of system power ratings and discharge times at required levels of power, though cavern storage of hydrogen is the system with the ability to store the largest amounts of power for the longest duration of times.

Linde's hydrogen storage cavern can be considered state-of-the-art because of the few such caverns that exist globally. It injects nearly pure pipeline gas into a salt cavern. When withdrawn, the hydrogen must be cleaned of impurities (e.g., water, CO_2, hydrocarbons) that exist in the cavern.

Key technical issues associated with the proposed technology include:

- Possibility that electrolyzer manufacturing cost will not reduce sufficiently to meet commercial metrics.
- Electrolyzer – compressor hydrogen production train may not be robust enough to withstand multiple stop-starts from cold without increased degradation/O&M costs.
- Existing NGCC turbines may be unsuitable for co-firing with hydrogen at the concentrations necessary to deliver energy storage objectives. Material changes, alternate system configurations, and increased safety measures need to be implemented to increase the % of co-firing of hydrogen in a natural gas turbine above 20 vol%.
- Managing cavern growth over time contributes to the potential for contaminants to leak into the cavern requiring more treatment of hydrogen post-withdrawal as well as possibly leading to leakage of hydrogen (as well as other impurities in the cavern like CO, CO_2, sulfur compounds) to surrounding groundwater and/or the surface environment.

Commercialization Plan (Summary of Appendix E)

The commercialization plan for the H-2-SALT system continues product development through 2025, followed by a first commercial test from 2025-2029, and then widespread commercial launch post-2030. In this way, H-2-SALT would go from this paper study to commercial deployment in ~8 years. At the completion of this project, the Commercial Readiness Level moves from 4 to 5.

Techno-economic Analysis (TEA) showed that the H-2-SALT system has a cost per kg H_2 of \$1.78. This is near the DOE "Hydrogen Shot" of \$1 per kg H_2. The H-2-SALT system provides the flexibility not only to store and consume hydrogen in natural gas turbines, but also sell hydrogen for use in a wide variety of commercial applications (e.g., chemicals/refining, manufacturing, transportation, pipeline gas).

Intellectual property for H-2-SALT's electrolyzers is owned by Linde. Competition in the electrolyzer field includes Cummins Inc., Siemens, and Plug Power. However, there is no competition organization that provides a system like H-2-SALT. Manufacturing and scalability of the electrolyzer will rely on optimizing current manufacturing systems, while for the cavern it will rely on suitable geology as well as drilling program execution. Additional research is needed in the field of aquifer storage of hydrogen.

Technology Maturation Plan (Summary of Appendix F)

The pre-project technology readiness level (TRL) of the H-2-SALT system was assessed in terms of the TRL of each of its key components that have been developed from the technology's conception. Overall, the H-2-SALT system was assessed to have a pre-project TRL of 4 per DOE TRL definitions.

The final TRL for each key component of the H-2-SALT system at the end of the project (after Phase II) allowed the overall TRL of the H-2-SALT system is expected to increase to 5 after Phase II of the project is completed and after relevant learnings and process improvements have been incorporated into an updated design for the larger scale process in an operational power plant environment.

Conclusions

This project provided technical evidence though geological, engineering, and economic studies that the H-2-SALT system could store greater than 10 MWh of energy in an energy storage system "within the fence" of an existing fossil-fueled energy generating unit.

The H-2-SALT operating principle is that during times that an EGU would normally shut down due to uneconomic conditions, the EGU would power an electrolyzer producing hydrogen for storage in a subsurface salt cavern. Commercial potential of the H-2-SALT system is relatively high because each of its components operates commercially today (e.g., cavern, electrolyzer, NG-EGU). The pre-project TRL is 5-6 because although each component technology is commercial, the combined system has not been commercialized.

The benefits of the system include:

1. ***H-2-SALT is large-scale energy storage.*** The performance target set by this FOA was 10 MWh of storage. Each H-2-SALT cavern would be capable of storing as much as 100,000 kg of hydrogen. At 33.3 kWh per kg H_2, that would yield up to 3330 MWh of energy storage per cavern. Therefore, a single H-2-SALT cavern can store over 300x the performance target set in the FOA. This is also likely larger than any other project supported by this FOA.
2. ***H-2-SALT can scale to store 2,000,000 kg of hydrogen*** at GEEC. The area "inside the fence" (G10) of the GEEC could support a cavern storage system with a capacity suitable for long-term, commercial-scale use (20 caverns with 100,000 kg of hydrogen each would yield ~2,000,000 kg of total storage), similar to Linde's high purity Gulf Coast cavern (~2,360,000 kg of hydrogen).
3. ***H-2-SALT makes cheap hydrogen.*** Total cost of hydrogen production and storage of \$1.78 per kg H_2, which is close to the DOE "Hydrogen Shot" of \$1 per kg H_2.
4. ***H-2-SALT increases fossil asset utilization*** by finding a use for low-cost power, when there is a lot of renewable power on the grid. This benefits customers in the form of lower utility rates and benefits operators who have made long-term investments in fossil power assets.
5. ***H-2-SALT reduces carbon dioxide emissions by up to 16.6%***, based on the Phase I Technoeconomic Analysis, compared to a traditional natural gas power plant when burning 20% hydrogen and 80% natural gas. Further CO_2 emission reduction can be obtained by increasing the hydrogen to natural gas ratio.

6. ***H-2-SALT is climate resilient.*** All three currently operating hydrogen cavern storage systems are located near sea-level (two on the US Gulf Coast, on adjacent to the North Sea in the UK). an area prone to violent storms/hurricanes, subsidence, and rising sea-levels. Located far from these climate hazards, Kansas is an ideal place to develop large-scale hydrogen energy storage that is hedged against climate risk.
7. ***H-2-SALT benefits national security.*** H-2-SALT is located near Wichita, a major site of defense aviation production and home of McConnell Air Force Base. Evergy's power network also serves Fort Riley, Fort Leavenworth, and Whitman Air Force Base. The Department of Energy's National Security Campus is in Kansas City.

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Appendix A: Geological and Geomechanical Analysis Report

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

30 November 2021

AWARD NUMBER: DE-FE0032015

FUNDING OPPORTUNITY ANNOUNCEMENT: DE-FOA-0002332

SUBMITTED BY

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National Energy Technology Laboratory

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Executive Summary

The H-2-SALT study aimed to assess the feasibility of a power-to-hydrogen system utilizing salt cavern storage of hydrogen in Kansas. For such a system to be technically feasible, salt of sufficient thickness, depth and quality must be available underneath the two evaluated sites. Two specific sites were evaluated in this study included the Gordon Evans Energy Center (GEEC), located east of Colwich, Kansas, and the Hutchinson Energy Center NG-EGU (HEC), located northeast of Hutchinson, Kansas. Currently, over 350 active salt caverns exist in the salt layer that the two sites overlie so it follows that the two proposed sites would likely have sufficient salt resource to support additional storage caverns.

Key findings of this study included:

- Existing well and salt cavern data allowed for development a regional storage database for the two sites and adjacent areas to support detailed site characterization efforts.

- The Hutchinson Salt Member is a bedded salt formation providing hydrogen storage potential in salt caverns in central to western Kansas.

- The top of the Hutchinson Salt under GEEC is at ~300 ft depth and at ~450 ft under HEC. Thickness of the salt under the GEEC site is ~200 ft, and under the HEC site it is ~300 ft.

- All available geological and geomechanical information were integrated for establishing suitable salt cavern parameters. Pressure, size limitation, and distribution of potential salt caverns for each site were determined to meet the criteria of cavern stability.

- No major stability issue exists in the study area. Uncertainty surrounding the risk of interbed slip in the Hutchinson Salt should be evaluated during storage operations.

- In Phase II, it is recommended to drill a stratigraphic test well to collect geological and geomechanical data from a core and well logs necessary for a cavern design. Future research should focus on obtaining core and log data to characterize salt formation and mechanical behavior for pre-FEED studies.

Introduction

Natural, bedded salt formations can be considered as host rocks for cavern storage of hydrogen produced by the conversion of excess energy to hydrogen via electrolysis. Kansas has a mature salt industry, including traditional mining, solution mining, and underground liquid hydrocarbon storage in salt cavern. Elsewhere in the US, natural gas is stored in salt caverns and one facility in the UK stores hydrogen in salt caverns. Thick salt deposits underlie south-central Kansas. A comprehensive understanding of the geology and geomechanics principles is vital to understanding site selection, sizing, and designing a hydrogen storage facility. The H-2-SALT study aimed to assess the feasibility of a power-to-hydrogen system utilizing salt cavern storage of hydrogen in Kansas. Sponsorship of this study was provided by the National Energy Technology Laboratory, US Department of Energy under award number DE-FE0032015, funding opportunity DE-FOA-0002332.

Salt caverns are used globally for storage of liquids and gasses because of the large storage volumes that can be attained (~100,000 barrels in bedded salt caverns, ~185 million barrels in salt domes). In addition, the impermeable nature of salt and strength characteristics support the mechanical integrity of the storage caverns such that both leakage from the cavern and contamination of the storage product by formation fluids are minimized. Underground salt beds do experience geomechanical stability issues that must be considered during the design of the salt caverns to avoid economic and environmental risks. Major cavern stability issues include cavern closure, roof collapse, interbed slip, and tensile fracturing. Based on experience of salt cavern storage projects, many of these issues and cavern design parameters designed to mitigate them have been reported in the literature (Duhan, 2018; Allen et al., 1982; Bruno and Dusseult, 2002; Zhang et al., 2016; Bruno, 2005).

The current research focused on obtaining salt distribution, stress and pressure information using a broad range of well and analog salt cavern data. This analysis provides insight on the potential storage resource and risk profile of the salt caverns in south-central Kansas and was used to help determine the storage site selection and pressure limitation, facilitating future development.

Data and Methods

Figure 23 presents a generalized diagram for the geomechanical study designed for Phase I (paper study) and Phase II (exploration drilling) of the H-2-SALT project. In Phase I, available data relevant to the salt formations were collected to map the distribution of salt in the subsurface of south-central Kansas. Well-scale data were gathered in the form of well header information (e.g., well name, API number, location, total depth) and formation tops from Kansas Geological Survey online database. A total of 9,035 wells contained top elevations for the Hutchinson Salt Member of the Wellington Formation and 2,064 wells contained base elevations for the Hutchinson Salt. Kansas Department of Health and Environment (KDHE) provided information of caverns in Kansas, of which 360 are for hydrocarbon storage, 127 are for salt mining, and another 265 are inactive or plugged. All well and cavern data were integrated into a database project using Petra Software (IHS Markit).

Two specific sites were evaluated in this study because of their proximity to salt of sufficient thickness to support salt cavern development. Gordon Evans Energy Center (GEEC), located near Colwich, KS, just west of Wichita, is Kansas's largest NG-EG. The Hutchinson Energy Center NG-EGU (HEC), located northeast of Hutchinson, Kansas. Based on existing maps, HEC sits over thicker salt and is further from the edge of salt than GEEC. However, data density around GEEC is sparser than that around HEC.

Depth structure maps showing the elevation of the top of the Hutchinson Salt were gridded from the tops data for using in calculating the injection pressure limit. Isopach maps showing the thickness distribution of the Hutchinson Salt were constructed to support the optimal storage cavern dimensions. Because the project lacked any salt samples from either site, mechanical properties of salt from analogous literature studies were used to assess the geomechanical envelope of the two study sites. Pressure and size limitation of salt caverns for each site were determined to meet generally accepted criteria of cavern stability.

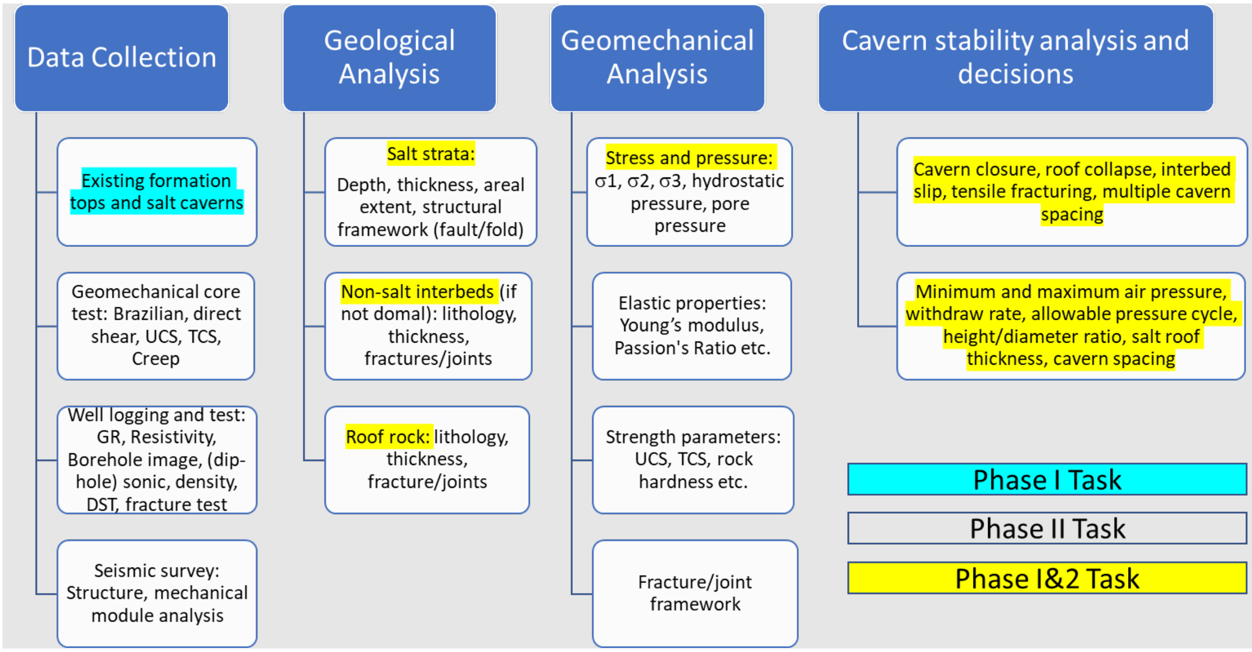

Figure 23. Workflow of geomechanical study designed for Phase I and Phase II of the H-2-SALT project.

Geological Analysis

Geological Background of the Hutchinson Salt

The Hutchinson Salt Member of the Wellington Formation is a major salt-bearing interval in Kansas and Oklahoma, United States, that hosts a robust salt-producing industry including open chamber mining, solution mining, document storage, and cavern storage of petroleum and other liquids and even tourism (Sawin and Buchanan, 2002). With respect to cavern storage of liquids, the Hutchinson Salt had hosted approximately 750 salt caverns of which approximately half are currently in operation (KDHE, 2021). The Hutchinson Salt and Wellington Formation are part of the Sumner Group, which is Leonardian in age (Sawin et al., 2008). This correlates with the Cisuralian series in the International Stratigraphic Chart and the Kungurian stage (Sawin et al., 2008). The only other hydrogen storage cavern system in bedded is also in bedded salts of Permian age (Teeside, UK), but its salts are slightly younger (Lopingian rather than Cisuralian, Waters et al., 2008).

Kansas salt deposits fall into the category of "bedded" salt deposits rather than "domal" salt deposits like those common on the US Gulf Coast. They are composed of interbedded halite, shale, and other evaporite minerals (e.g., gypsum/anhydrite) (Andeskie and Benison, 2020). While many thick evaporite deposits are associated with the evaporation of marine waters, recent research has concluded that the Hutchinson Salt was deposited from the evaporation of shallow groundwater in a continental setting far from sources of marine water based on *inter alia* the lack of marine fossils and minerals (Andeskie and Benison, 2020).

Site Geology

No subsurface geological information was available from either site investigated by the project so nearby wells were used as type analogs for what could be expected to be encountered under each site. The nearest well to GEEC with modern well logs is located approximately ½ mile away (High Plains Corporation-1, API 15-173-20203, Figure 24). This well shows ~205 ft (~62 m) of salt or salt interbedded with shale from 395 ft to 600 ft (~120 m to 183 m). The nearest well to HEC with modern well logs is located approximately 2½ miles away (Ekholm-1, API 15-155-00119, Figure 25). This well shows ~330 ft (~101 m) of salt or salt interbedded with shale from 460 ft to 790 ft (140 m to 241 m).

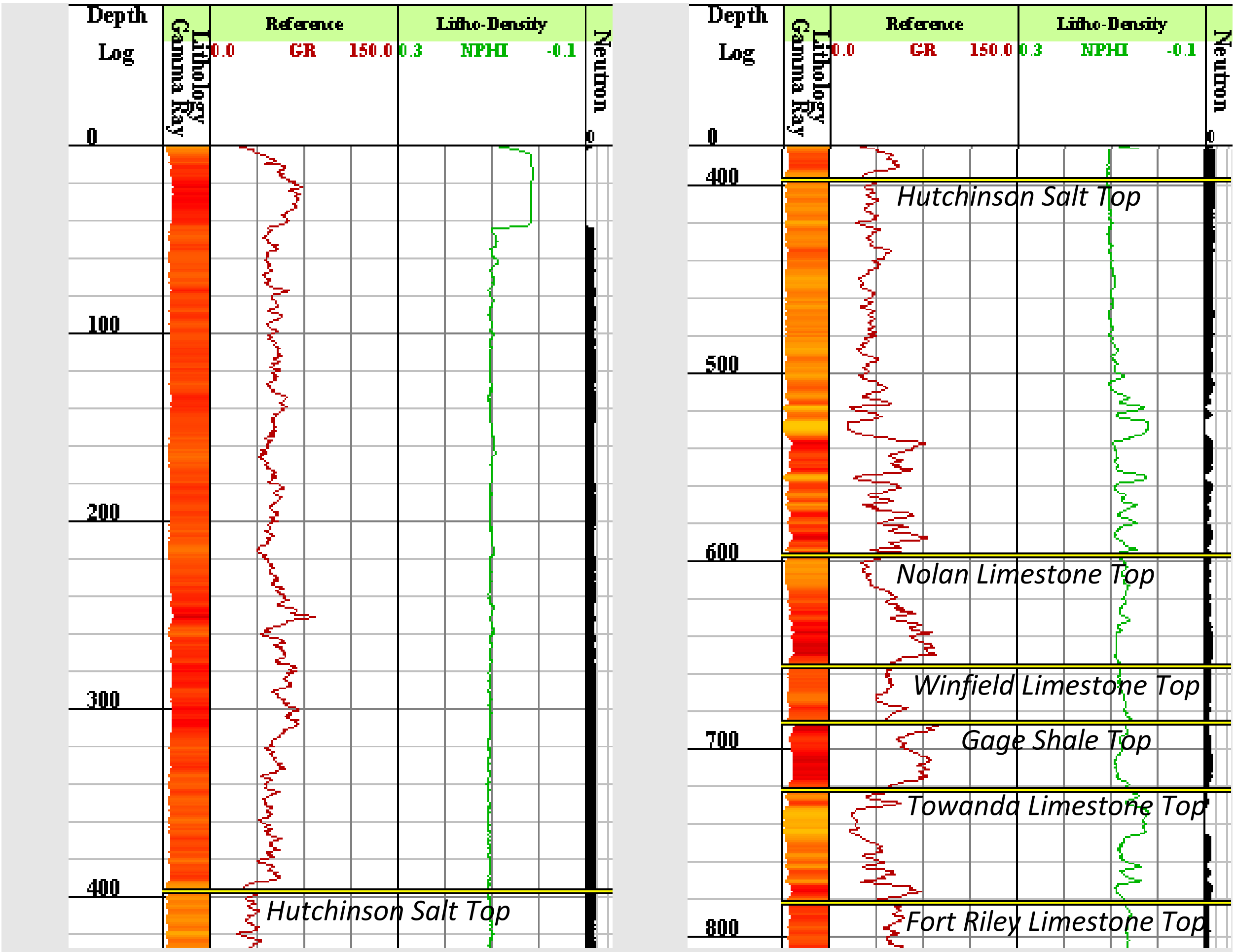

Figure 24. Type log for Hutchinson Salt in vicinity of GEEC (High Plains Corporation-1, API 15-173-20203).

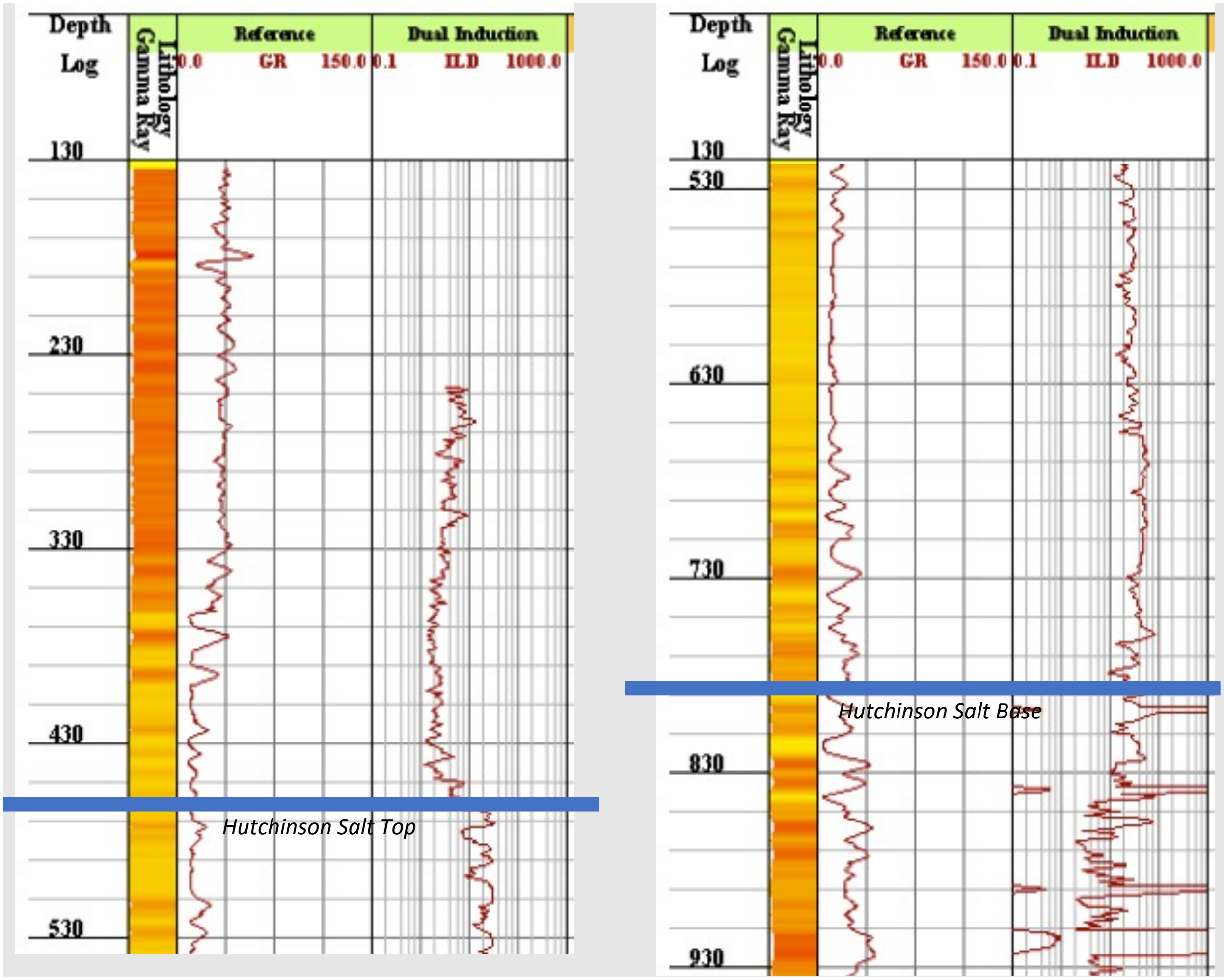

Figure 25. Type log for Hutchinson Salt in vicinity of HEC (Ekholm-1, API 15-155-00119) showing salt and salt interbedded with shale from ~460 ft to ~790 ft.

Based on tops in the Kansas Geological Survey Database, top and base of the Hutchinson Salt Member were mapped to identify the structural framework and reservoir distribution (Figure 26, Figure 28). The Hutchinson Salt exists in central to western Kansas dipping towards the west. The salt thickens to the south-central part of the state, where it reaches a maximum of 615 ft (Figure 28). Depth of the top of Hutchinson salt at GEEC is ~300 ft, and 450 ft at HEC. Thickness of the salt at the GEEC power plant is ~200 ft, and at HEC is ~300 ft. Well records showing the salt at both Gordon Evans and Hutchinson are bedded salt instead of dome salt.

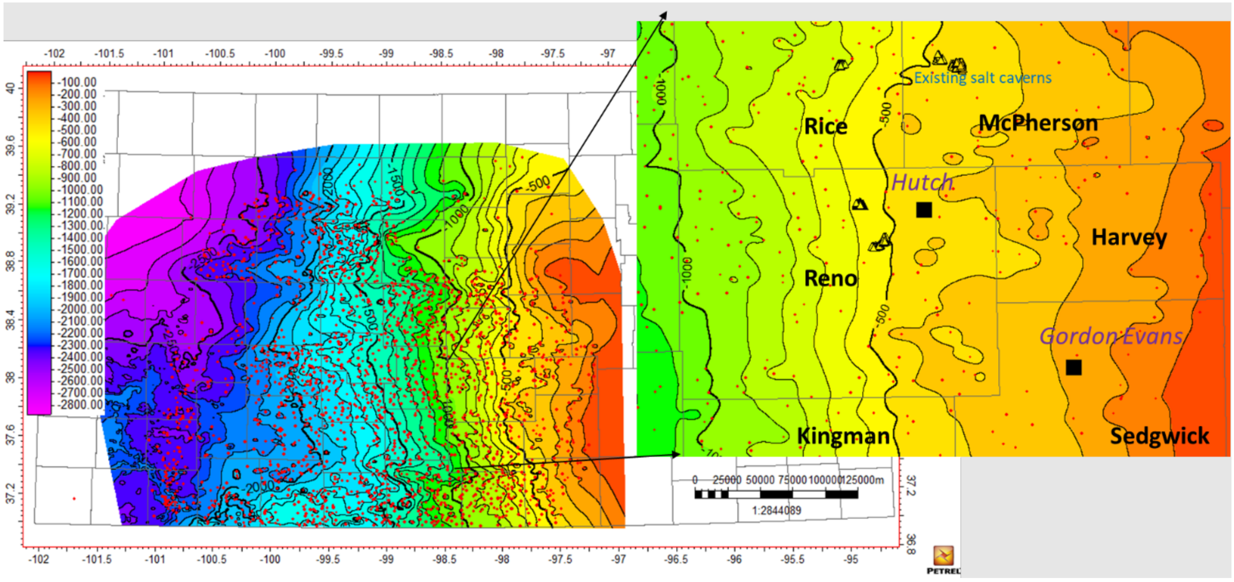

Figure 26. Depth structure map of the top of the Hutchinson Salt Member. Red dots represent well locations with top of the Hutchinson Salt Member record; Black squares represent two potential sites for salt cavern storage; Triangles represent existing salt caverns from KDHE; Color of the triangles represent the depth of the top Hutchinson Salt Member.

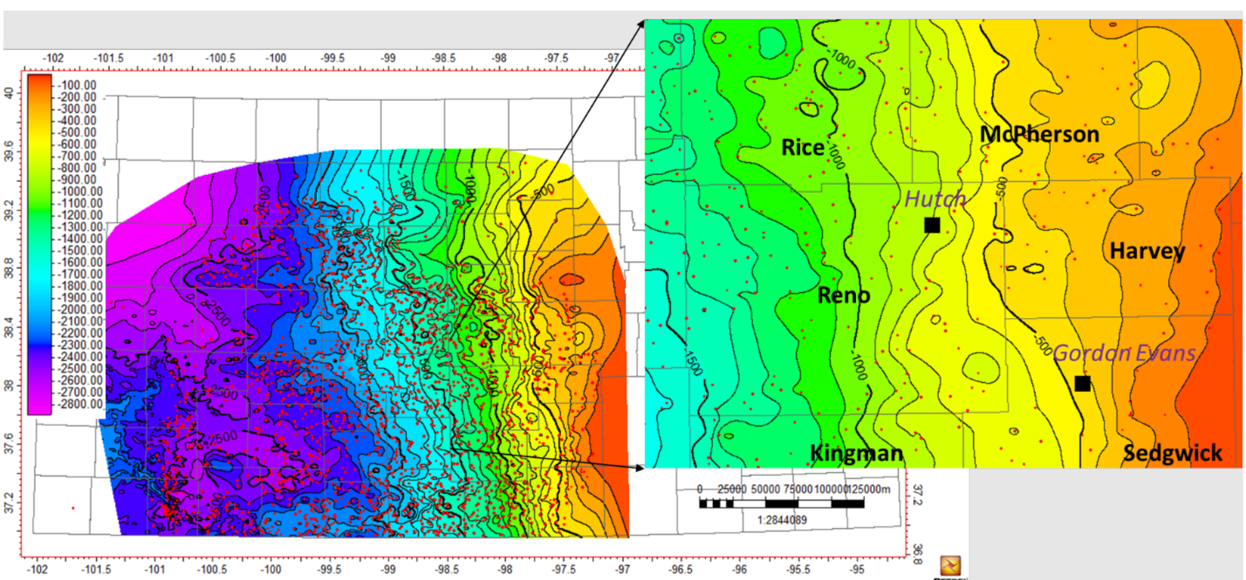

Figure 27. Depth structure map of the base of the Hutchinson Salt Member. Red dots represent well locations with top of the Hutchinson Salt Member record; Black squares represent two potential sites for salt cavern storage.

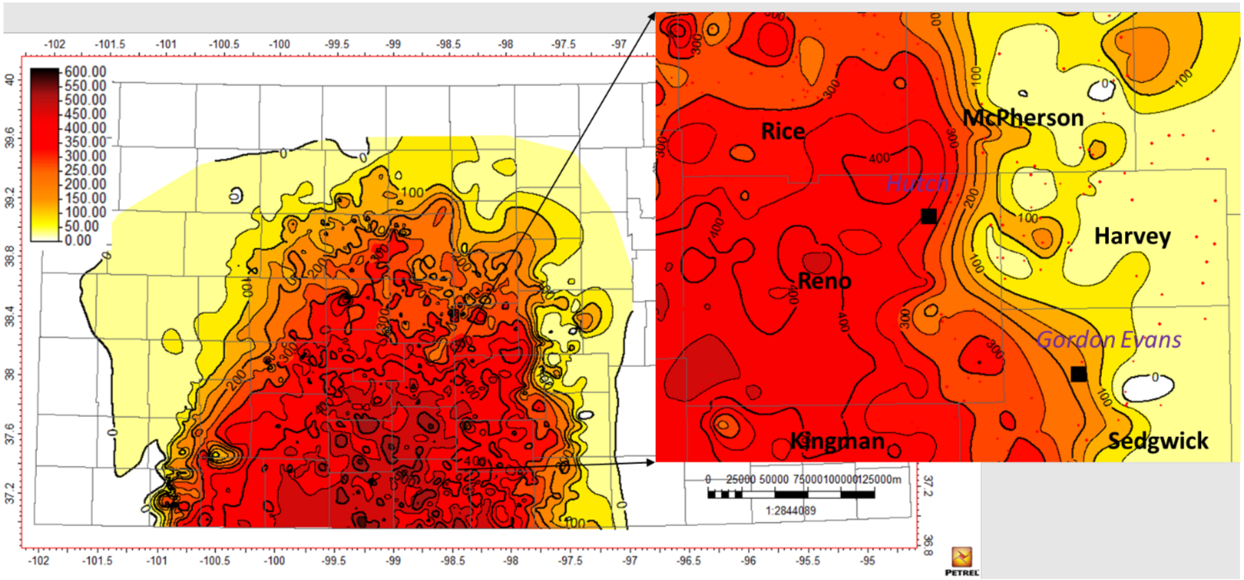

Figure 28. Isopach map of Hutchinson Salt Member showing the salt distribution. Red dots represent well locations with top of the Hutchinson Salt Member record; Black squares represent two potential sites for salt cavern storage.

Geomechanical Analysis

The literature provides several examples of cavern stability assessments for risks including cavern closure, roof collapse, interbed slip, and tensile fracturing (Duhan, 2018; Allen et al., 1982; Bruno and Dusseult, 2002; Zhang et al., 2016; Bruno, 2005; Lux. 2009). A few pressure and cavern design parameters based on experience of salt cavern storage projects. Most of these experiences have come from salt caverns used for compressed air energy storage (CAES).

Cavern closure is where the volume of the salt cavern was significantly reduced after a few years of operation. Two major creep parameters that affect cavern closure are pressure and temperature. Generally, the minimum cavern pressure should not be less than 25% of the lithostatic pressure (Duhan, 2018). It is recommended that cavity wall temperature should not exceed 80°C (Allen et al., 1982).

Roof collapse is possible due to one or combination of the following reasons: low height: diameter (H:D) ratio (Figure 29), low minimum cavern air pressure, inadequate roof shape, thin salt roof, and thin and incompetent non-salt roof. A minimum H:D ratio of 1:2, a salt roof with thickness of at least one-quarter of the cavern diameter, and, a non-salt, competent roof with thickness of one-third of the cavern diameter will provide sufficient stability (Zheng et al., 2016; Bruno and Dusseault, 2002).

Interbed slip can cause geomechanical issues in salt caverns in bedded salt deposits. The lithology, thickness, and frequency of interbeds will vary by basin. This is because salt and non-salt interbeds have different deformation mechanisms, such as salt creep and non-salt rocks do not creep over the engineering timescale. Domal salts can be more stable than bedded salt deposits, though many are still actively undergoing movement today. As the stress difference between salt and non-salt interbeds increases, slip can result. Commonly occurring interbeds within the Hutchinson Salt are anhydrite, shale, dolomite, and limestone.

Tensile fractures can occur in cavern walls and roofs when cavern pressures are too high. It is recommended maximum operating pressure should not exceed 75-80% of the fracture pressure of the non-salt roof rock and salt strata (Bruno, 1998; Duhan, 2018). Maximum allowable pressure is 0.8 lb/in^2/ft per Kansas Regulation 28-45-12(f).

Multiple caverns might be required in a large-scale hydrogen storage system due to limited salt strata thickness. It is important to ensure the distance between caverns is enough to avoid cavern stability issues. Spacing width of 2-4 times the cavern diameter should provide stability (Bruno, 2005; Zheng et al., 2016).

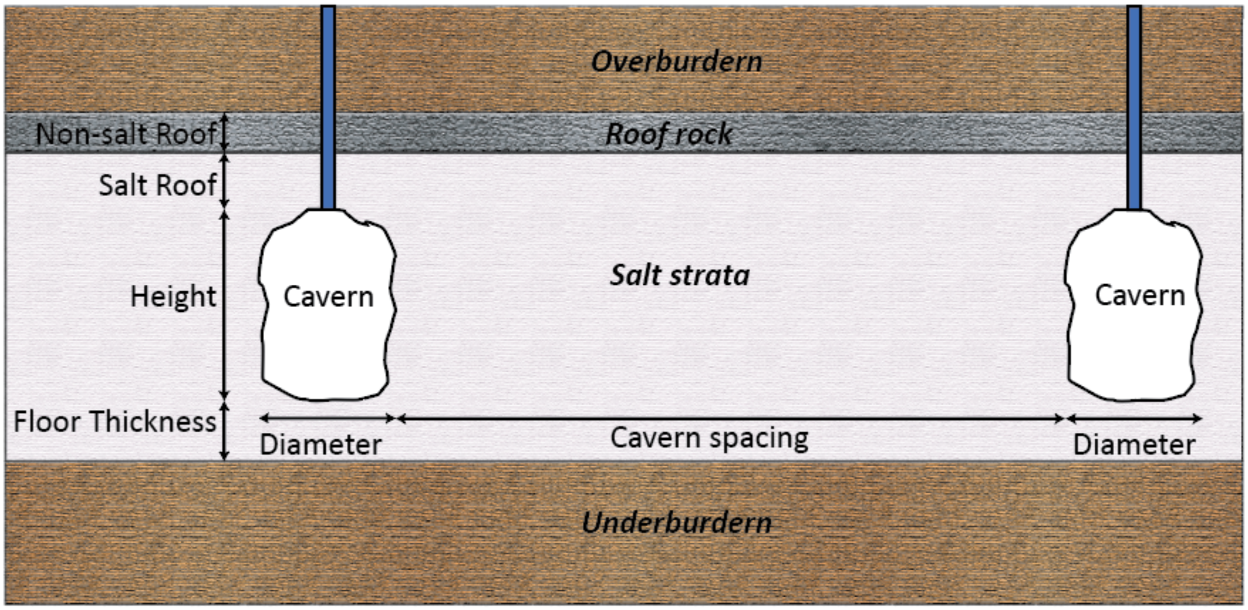

Figure 29. Design properties for salt caverns include not just parameters related to the caver itself, but also the spacing between caverns and parameters of the salt bed and surrounding strata.

Cavern design parameters for major cavern stability issues (Duhan, 2018). In this study, we performed an initial geomechanical analysis on the GEEC and HEC sites to acquire the pressure and cavern design parameters to model safe hydrogen storage. Minimum and maximum cavern pressure was computed using the calculation tool of Petra software. Minimum cavern pressure is computed as 25% of the lithostatic pressure. Lithostatic pressure gradian is 1.06 psi/ft at south-central Kansas (Schwab et al., 2017). Maximum operating pressure is computed as 80% of the fracture pressure (90% of the lithostatic pressure). Minimum (Figure 30) and maximum (Figure 31) pressure contour maps were generated. Minimum cavern pressure at GEEC fell in the range of 90-120 psi, and at HEC 150-180 psi. Maximum operation pressure at GEEC fell in the range of 300-400 psi, and at HEC 400-500 psi. Roof collapse, interbed slip and multiple caverns associated risk are controlled by the distribution of the salt. Salt depth at both sites was deeper than 300 ft, which provides sufficient no-salt roof to ensure cavern integrity.

To meet the minimum requirement of stability, the design parameter of a salt cavern should have:

- a minimum height: diameter ratio (H:D) of 1:2
- a salt roof with thickness of at least one-quarter the cavern diameter
- a spacing width of at least twice the cavern diameter.

Kansas Department of Health and the Environment regulations (K.A.R. 28-45a-4) further stipulate for natural gas storage caverns (the closest analog activity with an explicit regulatory framework):

- Minimum salt roof thickness of 100 feet must be maintained above the cavern
- Horizontal distance separating caverns shall be no less than 100 feet
- Maximum horizontal diameter of a cavern must not exceed 300 feet

Both sites continuous salt distribution. Therefore, the design parameters are mostly controlled by the thickness of the salt. An idealized salt cavern design for both sites of our study area was developed (Figure 32). The cavern parameters were designed to meet the minimum requirements of the stability. An estimation of individual cavern storage capacity and total numbers of caverns for each site were calculated with the same design of the cavern. At GEEC, the salt cavern is designed for height of 100 ft, decimeter of 200 ft, salt roof of 50 ft, and cavern spacing of 400 ft. The entire GEEC site could hold ~18 salt caverns with individual cavern storage capacity of 3mcf. At HEC, the salt cavern was designed with a height of 150 ft, diameter of 300 ft, salt roof thickness of 75 ft, and cavern spacing of 600 ft. The entire HEC site could hold ~24 salt caverns with individual cavern storage capacity of 10.6 mcf.

Table 1: Cavern design parameters for HEC and GEEC sites. What data that are available for Teeside (UK), the only other hydrogen storage cavern in bedded salt, are provided for comparison (Laban, 2020).

Parameter	GEEC		HEC		Teeside (UK)	
	(US)	(SI)	(US)	(SI)	(US)	(SI)
Cavern Height	100 ft	30.5 m	150 ft	45.7 m		
Cavern Diameter	200 ft	61.0 m	300 ft	91.4 m		
Roof Thickness	50 ft	15.2 m	75 ft	22.9 m		
Cavern Spacing	400 ft	121.9 m	600 ft	182.9 m		
Cavern Volume	3.0 MCF	0.09 M m^3	10.6 MCF	0.32 M m^3	7.4 MCF	0.21 M m^3
Max Pressure	300-400 psi	2-2.8 MPa	400-500 psi	2.8-3.4 MPa		
Min Pressure	90-120 psi	0.6-0.8 MPa	150-180 psi	1.0-1.2 MPa		
Pressure Range	210-280 psi	1.4-2.0 MPa	250-320 psi	1.8-2.2 MPa	653 psi	4.5 MPa

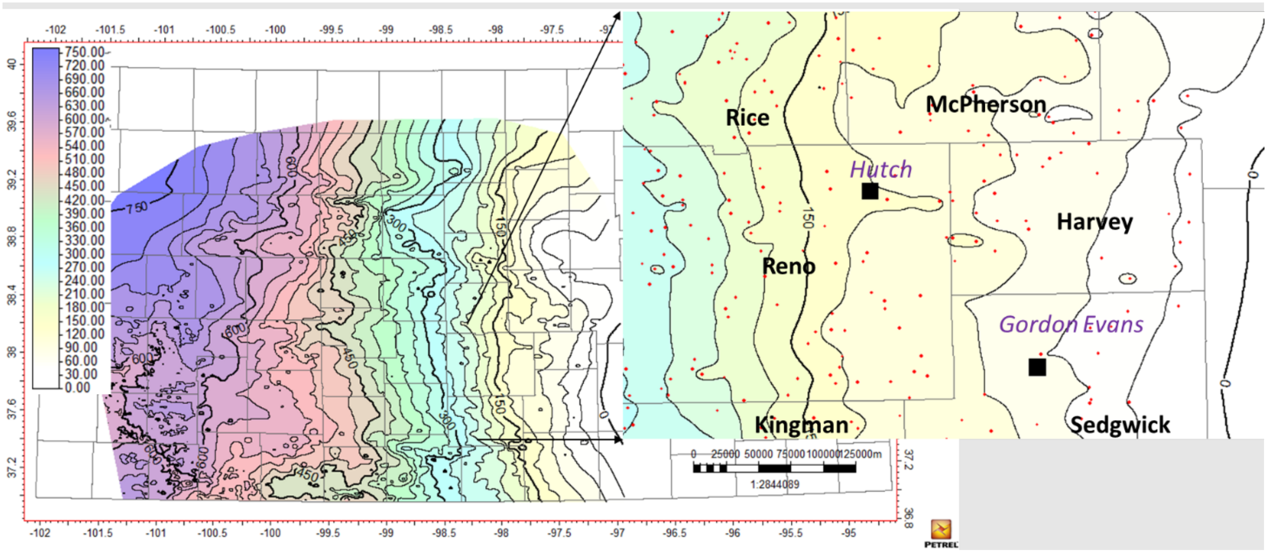

Figure 30. Contour map of recommended minimum cavern pressure to minimize risk of cavern closure and roof collapse during hydrogen storage.

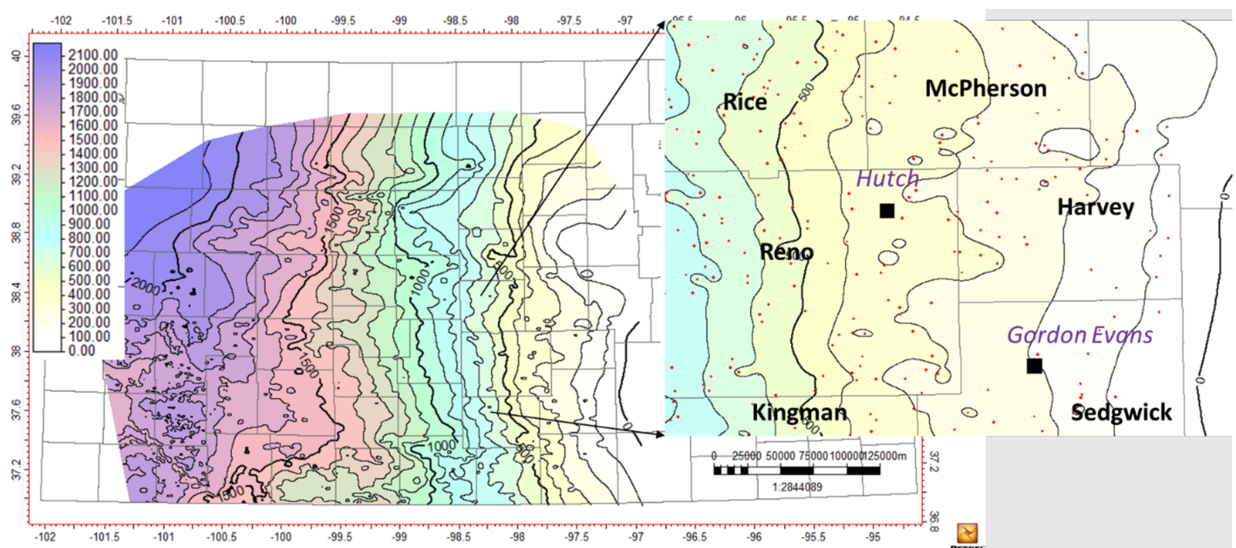

Figure 31. Contour map of recommended maximum operation pressure to minimize risk of tensile fractures during hydrogen storage.

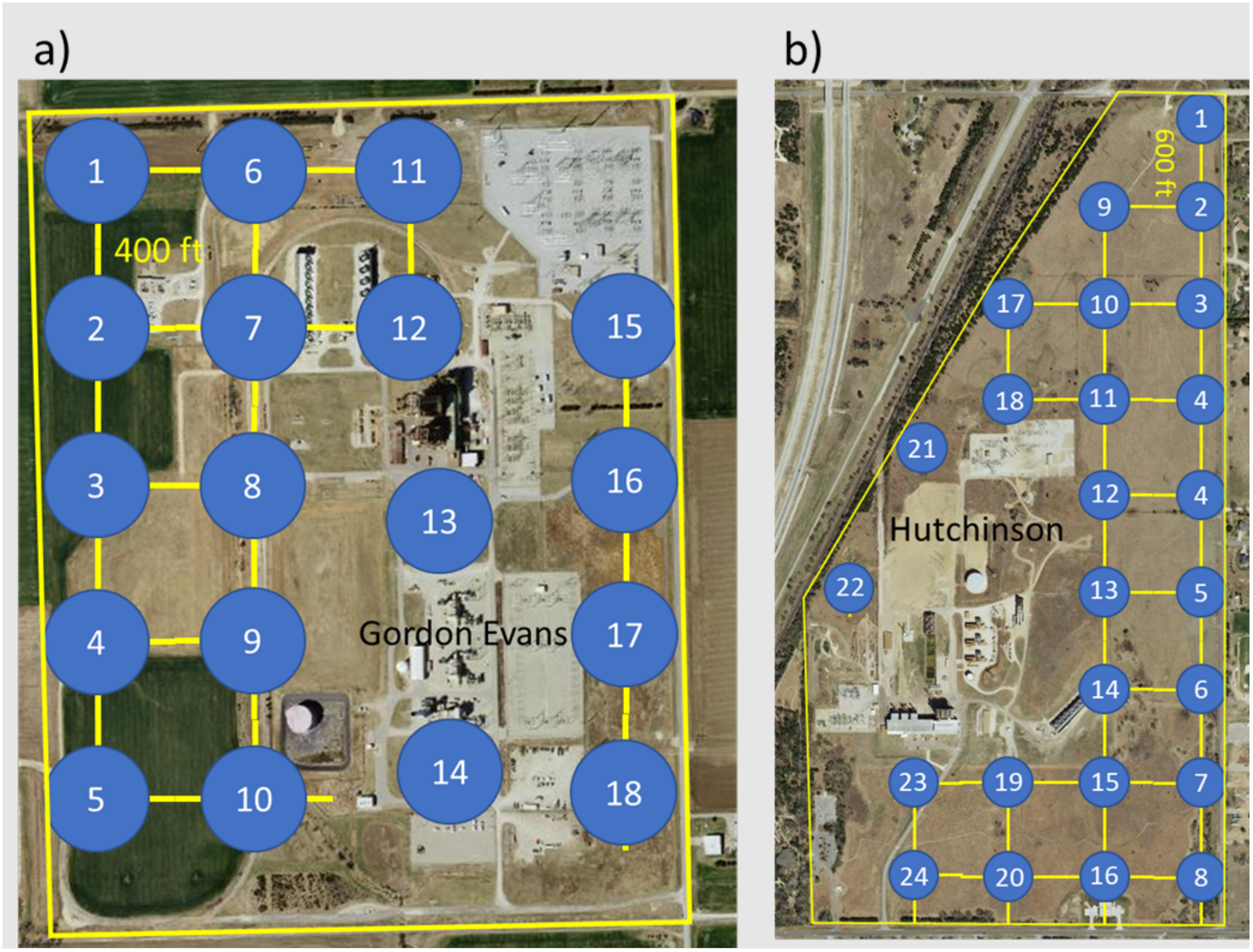

Figure 32. Idealized distribution of the salt caverns at a) GEEC and b) HEC. Air photos from KGS Website (2021).

Risk Assessment

Assessment of risk likelihood and severity are an important part of storage cavern assessments (Hnottavange-Telleen et al., 2011). The two sites evaluated in this study were assessed on based on five-category Likelihood and Severity scales (Figure 33). Based on this evaluation, no major stability issue is existed at our study area. By safely control the pressure and cavern design parameters, cavern closure, roof collapse, tensile fractures and multiple caverns can be avoided during the hydrogen storage operation. Nevertheless, because both sites contain bedded salt instead of domal salt, interbed slip may occur during the storage operations.

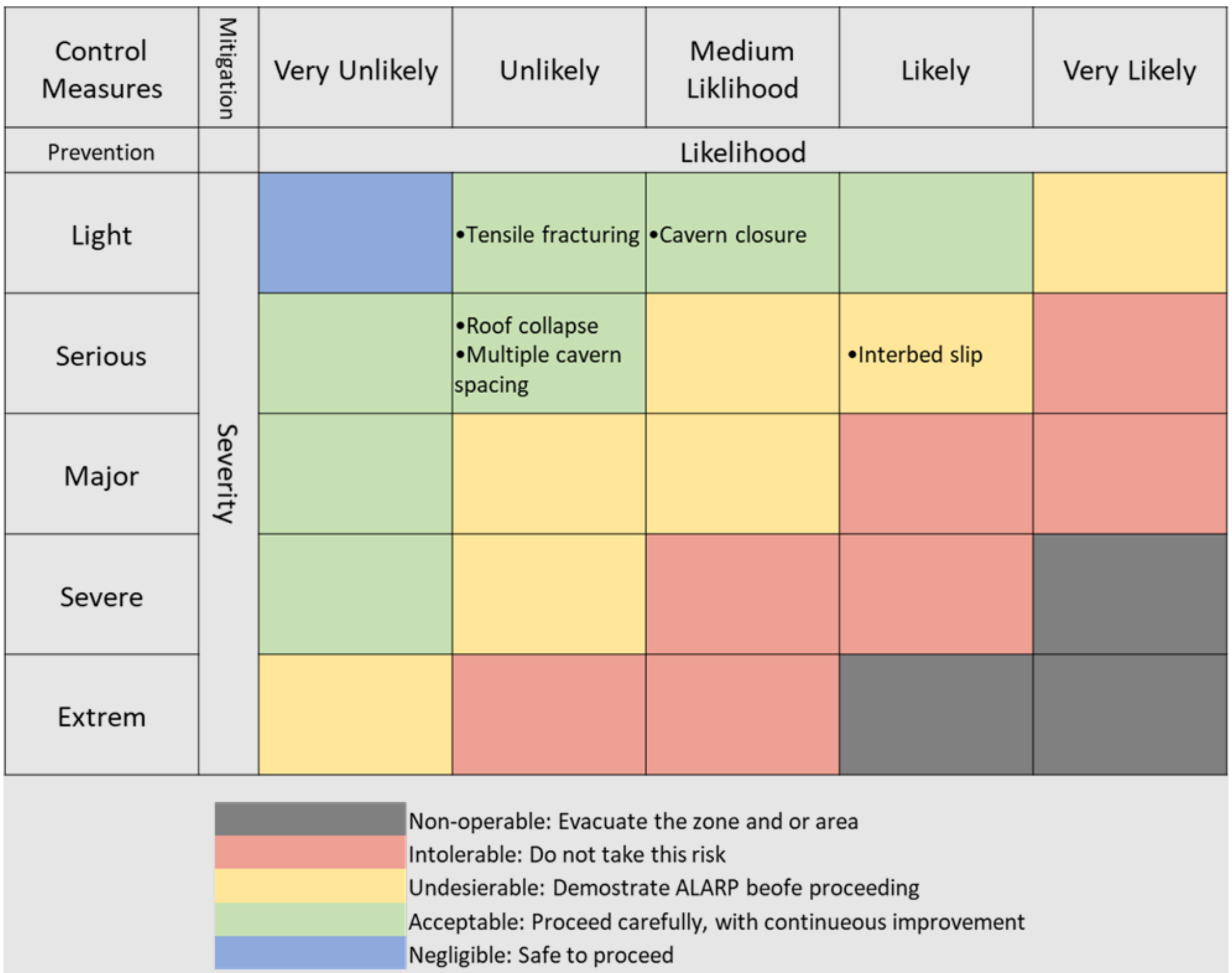

Figure 33. Risk matrix based on five-category Likelihood and Severity scales for the major cavern stability issues. Modified after Schlumberger Hazard Analysis and Risk Control Standard SLB-QHSE-S020.

Recommendations for future work

Based on the mapping undertaken in Phase I of this study, the geological chance of success for having enough salt of to support salt cavern storage system is high at both locations, GEEC and HEC. In the Phase II study meant to precede a full front-end engineering and design study (pre-FEED), it is recommended that a stratigraphic test well to collect data essential for a cavern design study. In this well, core should be collected to provide samples for laboratory core studies of its geomechanical, mineralogical, and petrophysical properties. Wireline logs should also be collected continuously from total depth to the surface to fully characterize the salt formation, its caprock, and any superjacent beds up to the surface casing. Should budget permit, 2D or 3D seismic surveying would be recommended to investigate the distribution of existing fractures in the salt and non-salt beds to prevent reactivation of the fractures during the operation.

Specific analyses that should be performed in Phase II on core and wireline log data include:

- Detailed lithological and petrophysical analysis from wireline logs and cores are needed to understand the salt depth, thickness, porosity, and permeability. This can provide guidance for salt caverns location and parameter design, such as cavern diameter, height, and spacing.
- Lithology, thickness, and frequency of interbeds can also be obtained to define the associated slip potential.
- Geomechanical lab tests, including unconfined compressional strength (UCS), tensile strength (TS), and tri-axial compressional strength (TCS) should be run on the salt and interbed formations to obtain rock mechanical properties for pre-FEED cavern design modeling.
- A creep test should be run on the salt beds to understand the difference of the non-salt beds for preventing potential interbed slip.
- Stress analysis should be performed to acquire accurate in-situ stress orientation, magnitude, and formation pressure onsite for controlling the operation pressure.

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Appendix B: Conceptual Cavern Design Report

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

27 September 2021

AWARD NUMBER: DE-FE0032015

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Disclaimer

Introduction

The project team has conducted a preliminary technical design for the integration of a hydrogen storage salt cavern with the Gordon Evans Energy Center (GEEC) located in Colwich, KS. The GEEC is a 294 megawatt (MW), natural gas-fired, electric generating facility owned and operated by Evergy, Inc. The facility was originally commissioned in 1961. In addition to the three existing combustion turbines at the site, the facility also included two natural gas and one oil-fired steam electricity generating units known as Units 1 and 2, respectively, which were retired in 2018. A preliminary design has been completed based on the storage needs of the GEEC and the geological suitability of available salt beds near the site. The design considers the depth and thickness of the salt cavern and the operating pressure envelope to assess the need for multiple wells based on the storage capacity of a single cavern. A basis for the design was determined using salt cavern data provided by the Kansas Department of Health & Environment (KDHE) with information from all 753 known salt storage caverns in Kansas.

Existing Cavern Data from KDHE

Based on reliable data provided by KDHE, Figure 1 shows the representative mass of H2 that could be contained in each existing cavern. The mass in each cavern is based on the molar quantity estimated using the differential operating pressure (max. operating pressure – min. operating pressure), cavern volume, and an average cavern temperature of 20°C. The effect of compressibility for H2 was verified to be negligible for the given pressure range, so the ideal gas equation was used for mass calculations. The mass of H2 that can be stored in existing Kansas salt caverns is between 8,800 kg and 144,000 kg of H2, with an average of ~50,000 kg of H2.

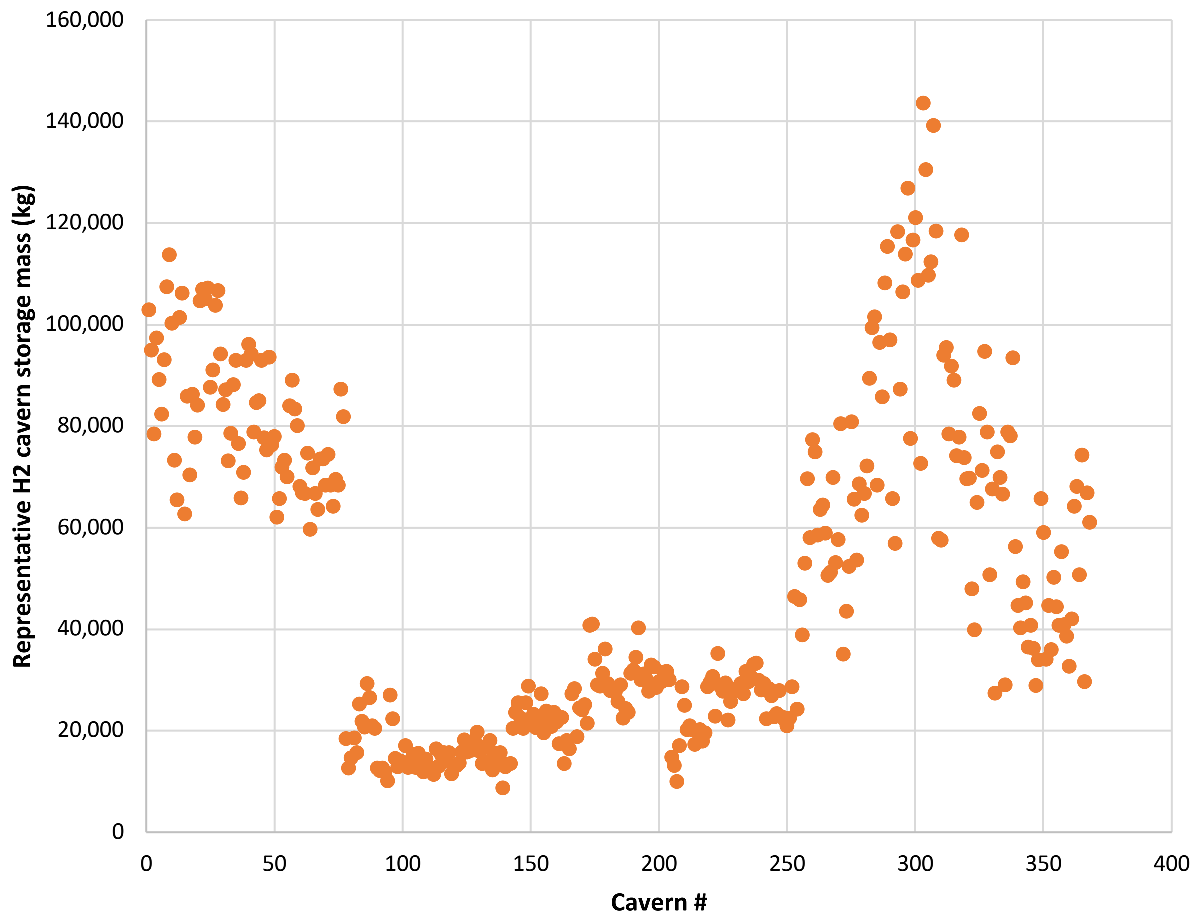

Figure B1: Representative potential H2 cavern storage mass (kg) based on data from KDHE.

Figures B2-B4 depict the cavern top of salt depth (ft), roof thickness (ft) and effective casing seat (ft), respectively, for each existing cavern where reliable data is available in the KDHE database. The cavern height ranges from 362 ft to 977 ft, the roof thickness ranges from 24 ft to 328 ft, and the effective casing seat ranges from 405 ft to 1,098 ft. For clarification, the casing seat is the depth at which the casing is set into an impermeable and stable formation. The casing is the structural component of a wellbore that protects the wellbore from caving and enables entry and exit of downhole equipment and production lines.

Each cavern's maximum allowable operating pressure (MAOP) (psia) is depicted in Figure B5 and ranges from 211 psia (14.5 bara) to 693 psia (47.8 bara). The minimum wellhead pressure for each cavern is assumed to be 50 psia (3.4 bara) based on the existing cavern storage data from KDHE.

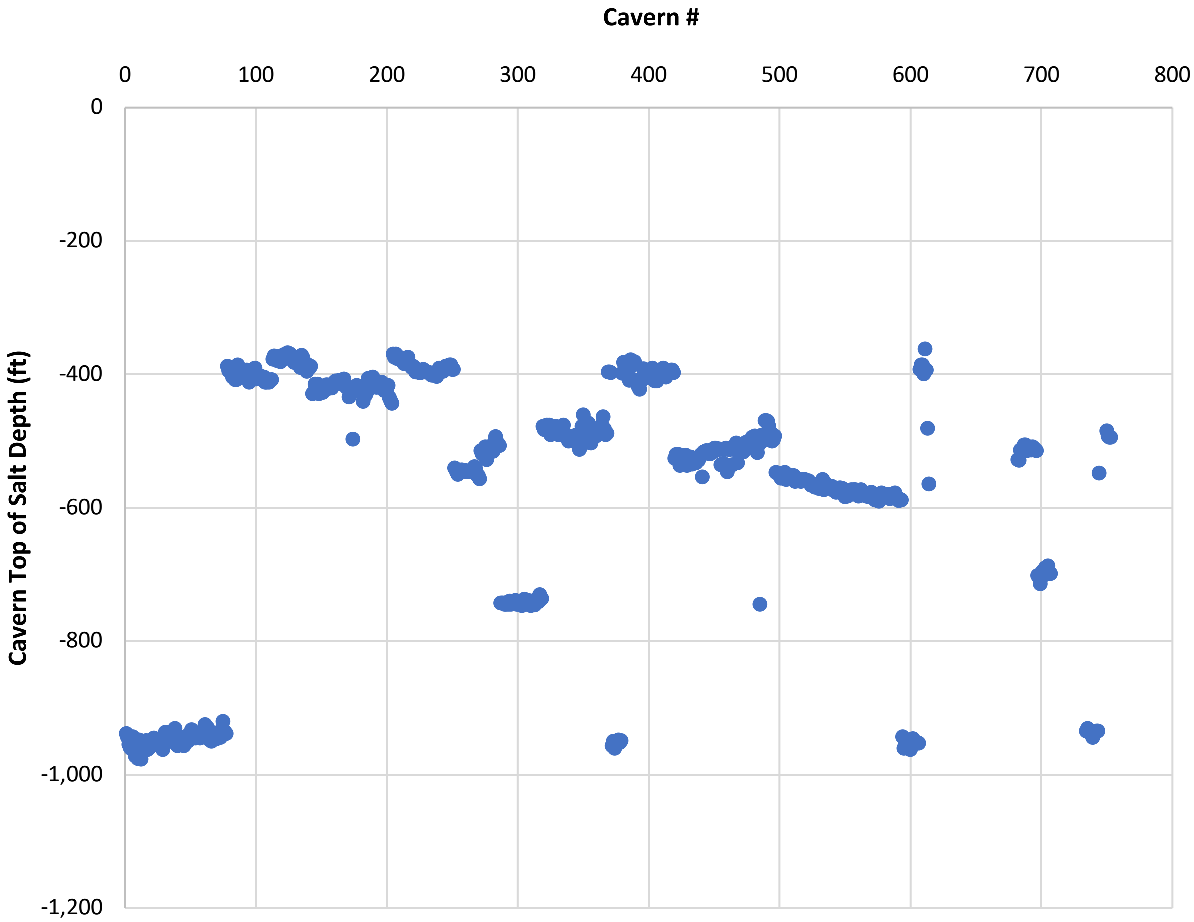

Figure B2: Depth (in ft with respect to surface) of top of salt in for existing salt caverns in Kansas.

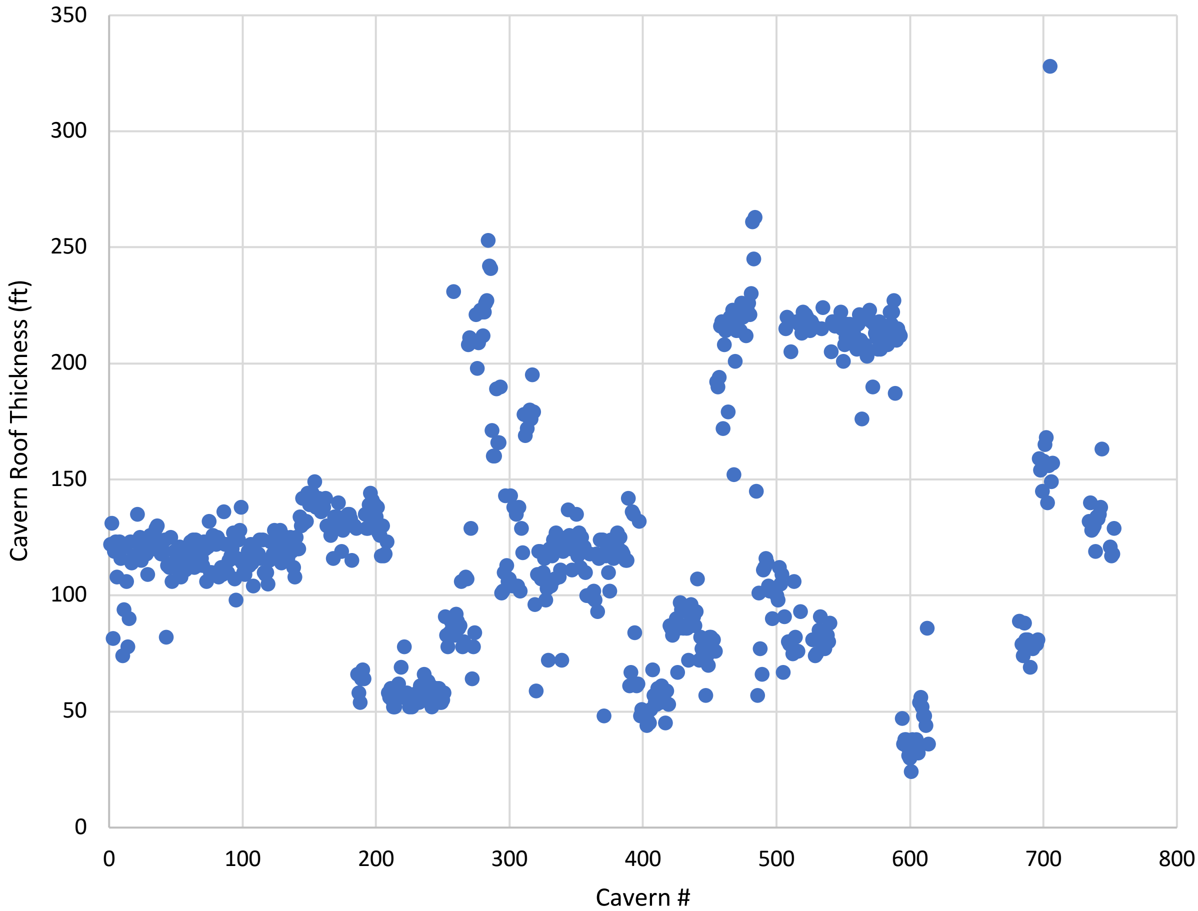

Figure B3: Salt cavern roof thickness (ft) for existing salt caverns in Kansas.

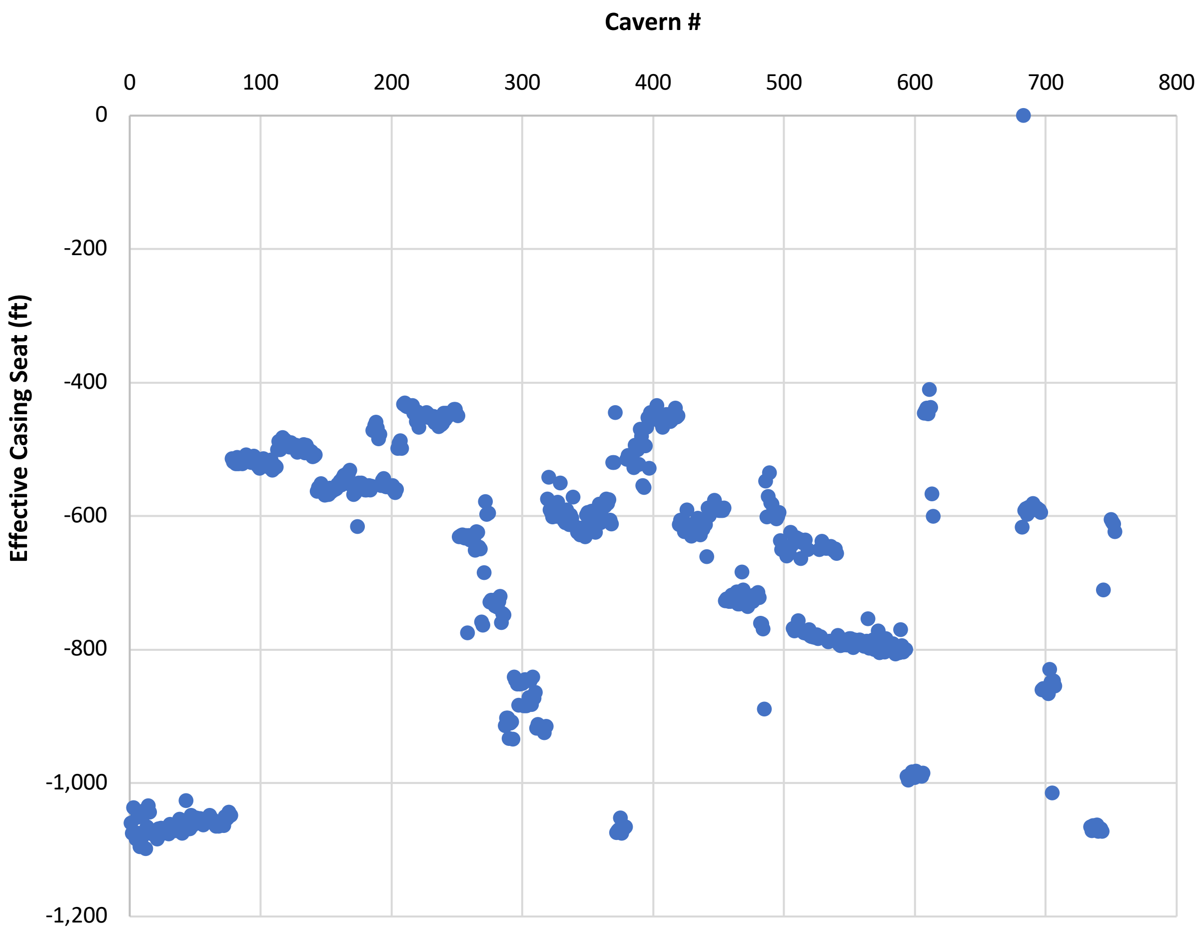

Figure B4: Existing Kansas salt cavern effective casing seat (ft).

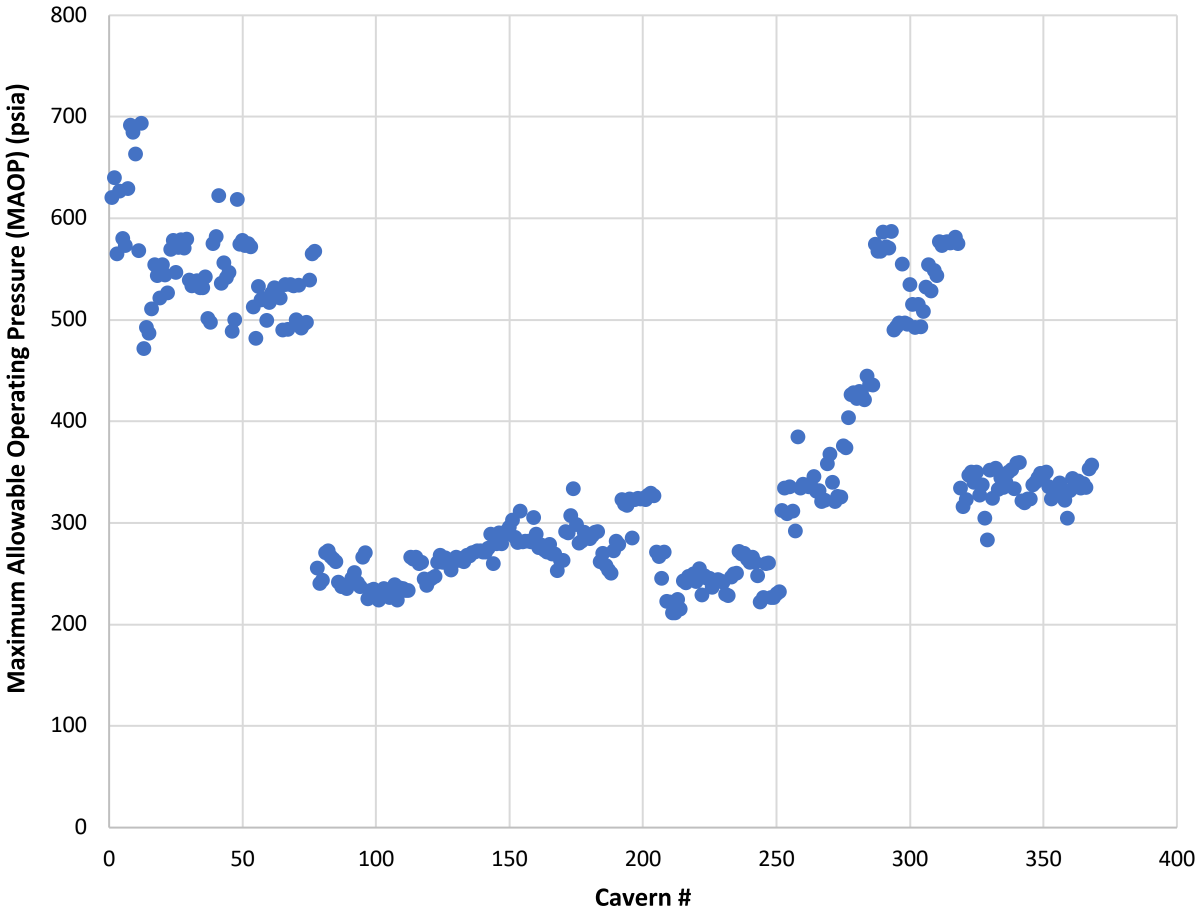

Figure B5: Existing Kansas salt cavern maximum allowable operating pressure (MAOP) (psia).

Conceptual H_2 Cavern Storage Scenarios

Single Cavern Storage

Results from a preliminary H2 production and cavern storage model have been evaluated for a 1-year period (all of 2020) using real-time hourly locational marginal electricity prices and natural gas prices provided by the GEEC. Multiple operating scenarios have been evaluated including variable H2 production rates, H2-burning in the NG turbine only when electricity prices are above a user-defined threshold price along with H2 storage, and continuous H2 burning in the NG turbine with H2 storage. The continuous H2-burning and storage case was determined to be the most applicable to the current GEEC operating protocol, which is based on peak shaving as opposed to base load electricity generation. In this scenario, H2 is produced only when electricity prices are below a user-defined threshold price but is continuously burned in the NG turbine at a rate based on a user-defined percentage of volumetric flow to the turbine. Based on the existing cavern data provided by KDHE and an assumed H-2-SALT system electrolyzer production rate of 200 kg H_2/hr, an H_2 cavern storage mass of 100,000 kg was determined to be the most suitable size for continuous H_2 burning and storage in the case of a single cavern. A representative plot of stored H_2 over the course of one year is depicted in Figure B7 and shows how the cavern's storage capacity is nearly filled towards the middle of the year as electricity prices were generally slightly lower in the first half of the year and slightly higher in the second half of the year (Figure B8).

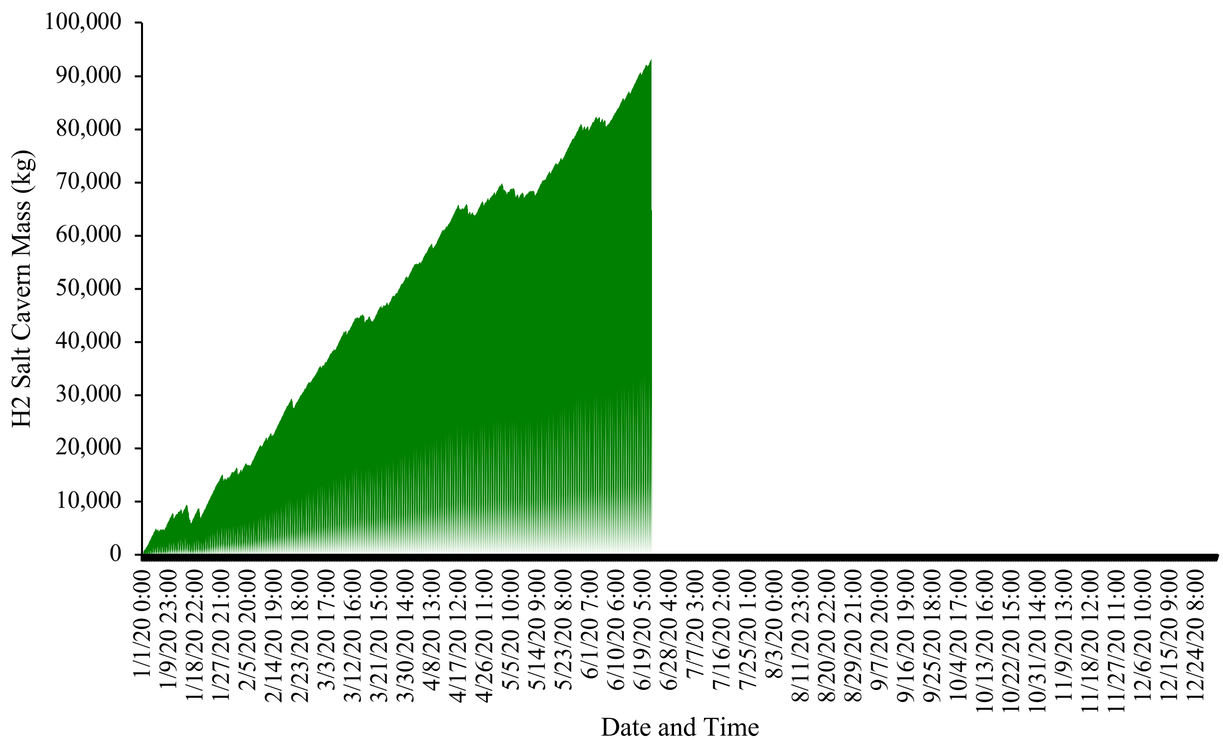

Figure B7: Representative H_2 cavern storage (kg H_2) over a 1-year period based on an electrolyzer production rate of 200 kg H_2/hr and a maximum cavern storage mass of 100,000 kg of H_2.

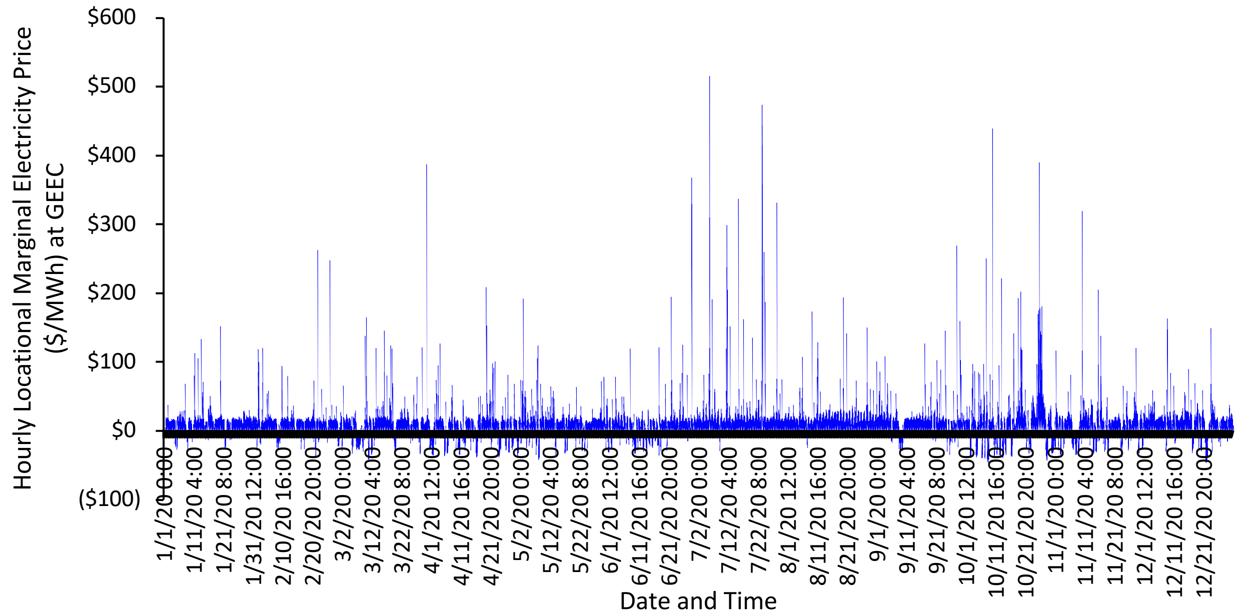

Figure B8: Hourly locational marginal electricity prices over a 1-year period at GEEC.

Using the existing cavern data provided by KDHE, a single cavern with a top of salt depth of 976 ft, a salt roof thickness of 74 ft, an effective casing seat of 1,050 ft, a volume of 28,920 m^3, and a maximum allowable operating pressure of 663 psia (45.7 bara) would provide 100,000 kg of H_2 storage, which is equivalent to 3,330 MWh of energy storage based on H_2's lower heating value of 33.30 kWh/kg.

Design parameters and a schematic of a typical Kansas salt cavern are shown in Figure 9, based on the KDHE dataset.

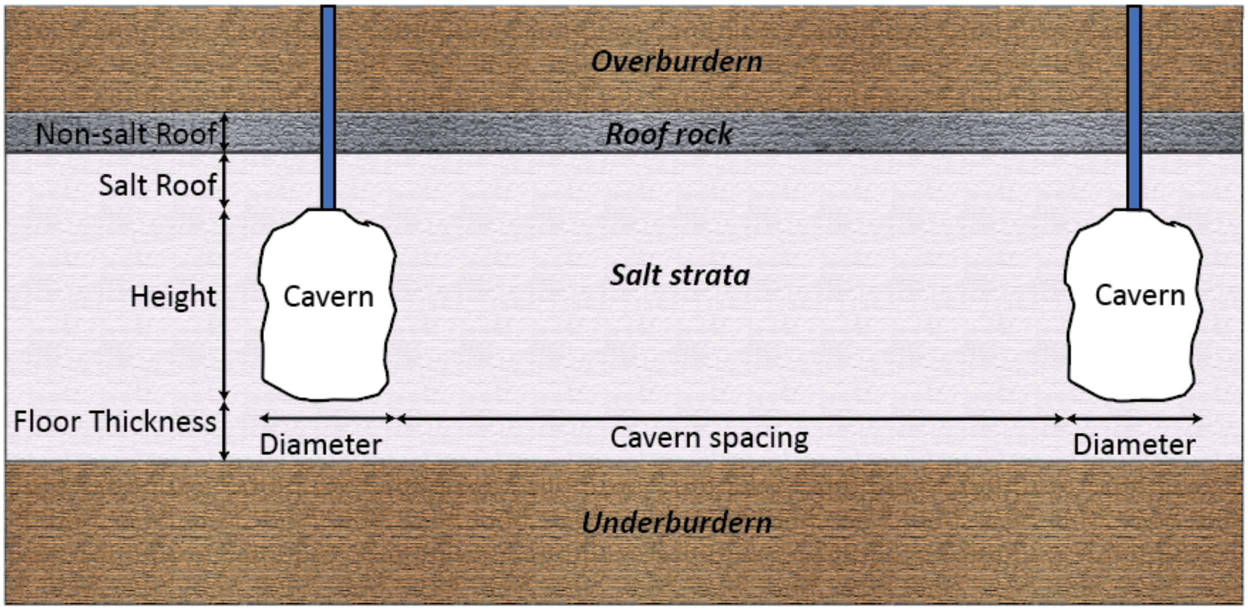

Figure B9: Design parameters and schematic of a typical Kansas salt cavern

Existing Kansas cavern and geological data indicate that a bedded salt cavern would be required as opposed to a domal salt cavern. Other hydrogen salt cavern design constraints include a maximum cavern diameter of 400 ft to prevent salt roof collapse. Horizontal cavern designs are also being evaluated for larger scale storage in a single cavern (Li et al., 2020).

Multiple Cavern Storage

Due to geological limitations, an H_2 salt cavern system constructed in Kansas with a capacity suitable for long-term commercial scale use (2,000,000+ kg of H_2), such as Linde's high purity gulf coast cavern with a capacity of ~2,360 tonnes of H_2, would require multiple smaller caverns to meet large-scale storage demands. 20 caverns storing 100,000 kg of H_2 each would be needed to fulfill a large-scale commercial storage requirement of 2,000,000 kg H_2. An illustration of each of the 20 potential caverns that could represent a 2,000,000 kg H_2 salt cavern storage system located at the GEEC is provided in Figure B11. According to KDHE guidelines, a minimum spacing distance of 100 ft is required between each new build cavern for safety and constructability reasons.

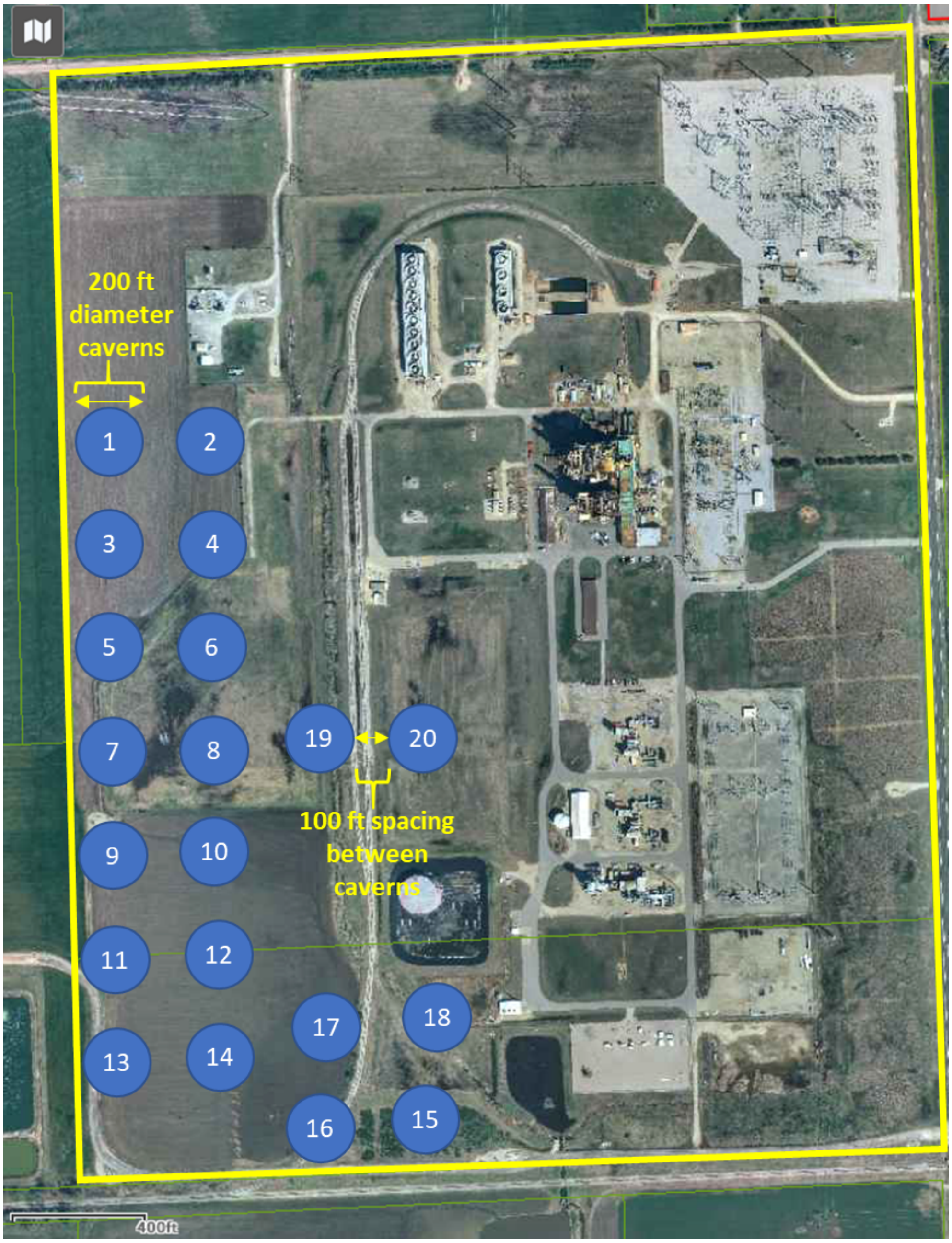

Figure B10: Aerial view of the GEEC with 2,000,000 kg H_2 cavern storage system comprised of 20 caverns, each 100 ft apart and containing approx. 100,000 kg of H_2.

H-2-SALT Cavern Operation

Typically, hydrogen is supplied to customers under agreements that require availability and on-stream times for the water electrolyzer, steam methane reformer, or hydrogen recovery plant for hydrogen production. When a hydrogen production plant is taken off-line for unplanned or extended maintenance, the result could be a violation of such agreements. Having a storage facility to supply back-up hydrogen to the pipeline supply is therefore desirable in connection with hydrogen pipeline operations. Such a storage facility can also be used for electricity production in the case of the H-2-SALT system designed for this project. Considering that hydrogen production plants on average have production capacities that are roughly 50 million standard cubic feet per day (118 tonnes H_2/day) or greater, a storage facility for hydrogen that would allow a plant to be taken off-line, to be effective, would need to have storage capacity in the order of 1 billion standard cubic feet (2,360 kg H_2) or greater.

Utilizing a salt cavern to assist in the supply of higher-purity hydrogen of at least 95% purity or greater can be challenging. Stored hydrogen within the salt cavern can become contaminated by intrusion of several components, including water vapor, hydrocarbons, sulfur-containing compounds, and/or carbon dioxide. Contamination of the stored hydrogen requires removal of one or more contaminants from the stored hydrogen when withdrawn as a crude hydrogen stream from the salt cavern. Methods have been implemented to ensure that impurities imparted by the salt cavern to the stored hydrogen do not deleteriously impact the hydrogen product in the pipeline (Oates, 2017). For example, U.S. Pat. No. 7,078,011 (Morrow et al., 2006) removes at least carbon dioxide and water vapor from a crude hydrogen stream withdrawn from a salt cavern to produce a hydrogen product stream having an impurity level at or below a product purity specification. U.S. Patent Pub. No. 2013/021349 removes crude hydrogen from a salt cavern and then dilutes the crude hydrogen with higher purity hydrogen from a hydrogen pipeline to form a resultant hydrogen product stream at or below a product purity specification. U.S. Pat. Nos. 8,425,149 (Drnevich, 2013) and 8,757,926 (Drnevich, 2014) maintain a minimum quantity of stored hydrogen within the salt cavern to create a stagnant layer having carbon dioxide contained therein. A portion of stored hydrogen is withdrawn from the salt cavern without disturbing the stagnant layer to prevent carbon dioxide from being drawn into the stored hydrogen stream, thereby allowing the stored hydrogen stream to be reintroduced into the hydrogen pipeline without carbon dioxide removal. The methods disclosed in U.S. Patent Publication No. 2013/021349 and U.S. Pat. Nos. 7,078,011, 8,425,149, and 8,757,926 require additional processing steps, which can add complexity to the hydrogen flow network that is in communication with the salt cavern, as well as potentially increasing capital and operating expenditures.

Additionally, the ability to utilize a salt cavern to assist in the supply of higher purity hydrogen without leakage through the salt cavern walls can be difficult based on the properties of hydrogen. Hydrogen is the smallest and lightest element with an atomic radius measuring 25 pm ± 5 pm. Consequently, higher purity hydrogen is typically considered one of the most difficult elements to contain within underground salt formations without measurable losses through the salt cavern walls (Oates, 2017). For example, storing large quantities (e.g., greater than 100 million standard cubic feet) of pure (e.g., 99.99%) gaseous hydrogen in underground salt caverns consisting of a minimum salt purity of 75% halite (NaCl) or greater without measurable losses of the stored hydrogen from the salt cavern can present challenges. Methods for containing hydrogen within a salt cavern without incurring significant leakage have been addressed. U.S. Pat. No. 8,690,476 (Oates, 2014)) creates a permeation barrier along the walls of the cavern that allows high purity hydrogen to be stored therein. U.S. Patent Pub. No. 2014/0161533 (Oates, 2016) discloses monitoring and regulating the pressure of the stored hydrogen in the salt cavern between a predetermined lower limit and a predetermined upper limit.

Based on U.S. Patent No. 9718618B2 (Oates, 2017), a method for pre-treating a moisture-containing hydrogen product to be stored in a salt cavern is described. The storage pre-treatment comprises:

1. removing hydrogen product from a hydrogen pipeline or hydrogen production plant such as a water electrolyzer,
2. compressing the hydrogen product to produce a compressed hydrogen product,
3. cooling the compressed hydrogen product to condense at least a portion of water vapor prior to the compressed hydrogen product entering the salt cavern,
4. removing the water vapor condensate to produce a compressed and chilled hydrogen product, and

5. introducing the compressed and chilled hydrogen product into the salt cavern to produce chilled and stored hydrogen within the salt cavern.

The H-2-SALT cavern storage system is comprised of:

1. a compressor configured to pressurize hydrogen product within the salt cavern to form stored hydrogen,
2. an aftercooler situated downstream of the compressor that is configured to remove the heat of compression from the pressurized hydrogen product,
3. a chiller downstream of the aftercooler configured to impart additional cooling beyond the heat of compression to condense water vapor from the hydrogen product,
4. a liquid-vapor separator vessel configured to collect and accumulate the removed water vapor condensate that is located downstream of the chiller, and
5. a flow network positioned between the salt cavern and the compressor, the chiller and the collection vessel. The first segment in the flow network will introduce the hydrogen product into the salt cavern to form stored hydrogen that is chilled to a temperature sufficient to remove a portion of water vapor to produce a chilled and stored hydrogen product. The second segment in the flow network is connected to a hydrogen pipeline and will withdraw the stored and chilled hydrogen from the salt cavern for use in the hydrogen pipeline or NG turbine.

To maintain hydrogen purity according to pipeline and end-use specifications (as in the case of injection into a NG turbine), the H-2-SALT cavern system will be operated using analytical instrumentation to detect the presence of one or more contaminants (e.g., water vapor, hydrocarbons, sulfur-containing compounds, and/or carbon dioxide) in a crude hydrogen stream withdrawn from the cavern that may exceed product purity specifications. If excessive product impurities are identified, the rate of cooling of the compressed hydrogen stream that is sent to the salt cavern and the rate of cooling of the crude hydrogen stream that is withdrawn from the cavern can be increased. The increased rate of cooling and resulting reduced cavern storage temperature can be used as a strategy to lower the concentration of contaminants to within standard product purity specifications. The stored, sufficiently cooled H2 exhibits coolant properties that the U.S. Pat. No. US9718618B2 recognizes can be utilized for cooling the salt cavern walls. At least a portion of the chilled, stored hydrogen contacts a localized portion of the salt cavern walls from which heat is extracted to reduce the cavern wall temperature. Because of the cooling of the cavern walls, the one or more layers of the localized portion of the cavern walls attains a stabilized state whereby contaminant release from the walls is suppressed. This effect is due to constriction of the walls to a point where certain localized regions of the walls acquire an inherent porosity between its layers that is too small for contaminants such as hydrocarbons, water vapor and carbon dioxide to infiltrate. In addition, the viscoplastic slippage of the layers is reduced upon cooling by the chilled stored hydrogen gas such that movement of the layers relative to each other is suppressed. Less movement of the layers results in less release of contaminants from the layers into the salt cavern. The reduction in movement can cause a substantial portion of potential contaminants to remain entrapped between layers of the cavern walls. Excessive movement of layers of the cavern walls and elevated salt cavern temperatures may lead to contaminant infiltration into the purified hydrogen within the salt cavern. Hence, based on the invention described in US9718618B2, the proposed design can be used to mitigate direct contamination of the hydrogen in the cavern from components contained within the layers of the cavern's walls.

Conclusion

The project team has defined technical parameters for a typical H_2 cavern in Kansas including top of salt, roof thickness, cavern thickness, slat thickness, effective casing seat, base of salt, and mean cavern diameter, as depicted in Figure B9. A bedded salt cavern would be required as opposed to a domal salt cavern, as illustrated in Figure B10. Details on cavern operation have been evaluated and proposed for the final cavern design, including methods to pretreat the hydrogen before injection into the cavern and prevent contamination by impurities existing in layers adjacent to the cavern's walls. A large dataset provided by KDHE quantifying all existing hydrocarbon storage caverns in Kansas has provided a range of cavern design parameters that will be considered for the final H-2-SALT system cavern design.

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Morrow, J. M., Corrao, M., & Hylkema, S. (2006). Method of Storing and Supplying Hydrogen to a Pipeline (U.S. Pat. No. 7,078,011). U.S. Patent and Trademark Office.

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Appendix C: Techno-Economic Analysis Report

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

30 November 2021

AWARD NUMBER: DE-FE0032015

FUNDING OPPORTUNITY ANNOUNCEMENT: DE-FOA-0002332

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National Energy Technology Laboratory
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Disclaimer:

Executive Summary

This topical report presents the techno-economic evaluation of a 727 MWe (net) natural gas combined cycle power plant (NGCC), integrated with a commercial-scale Linde proton exchange membrane (PEM) based electrolyzer and an H_2 storage salt cavern designed to accommodate the scale of H_2 production based upon experience. The process simulation and modeling for this report is performed using UniSim Design R440 as well as actual electricity price data from January – December 2020 obtained from Evergy on their Gordon Evans Energy Center (GEEC), a 120+ MW_e (net) NGCC plant located in West Colwich, KS. Technical and cost information for the Linde electrolyzer and H_2 storage salt cavern have been determined using proprietary internal operating data, simulation models as well as commercial quotes and proposals. The Linde case presented is compared against the DOE-NETL Case B31A reference (James et al., 2019), a 727 MWe (net) NGCC plant without CO_2 capture.

The results of the techno-economic assessment show the energy demand for the electrolyzer, the incremental NG fuel requirement, and the net higher heating value (HHV) efficiency of the NGCC power plant integrated with the electrolyzer system compared to the DOE-NETL reference case. A comparison of the capital and operating costs for each electrolyzer plant configuration corresponding to a 727 MWe (net) NGCC plant is also presented.

Overall, the net efficiency of the integrated 727 MWe supercritical pulverized coal (PC) power plant without CO_2 capture changes from 53.60% with the DOE/NETL Case B31A reference to 51.14% with the integrated NGCC, Linde electrolyzer, and cavern storage system. The Linde electrolyzer and cavern system results in an integrated cost of electricity (COE) of $45.77/MWh, compared to $43.33/MWh for the Case B31A reference, and a total cost of H_2 production and storage of **$1.78/kg H_2** based on the modeling inputs used. The loss in efficiency and higher electricity costs are compensated by reduction in CO_2 emissions by addition of the H_2 electrolyzer and cavern storage system.

Because it is relevant for the project goals to demonstrate the feasibility and environmental benefits of low-cost, large-scale, electrolyzer-based H_2 production, storage and use, the final section of this report provides performance modeling and cost analysis of an integrated NGCC plant, electrolyzer, and cavern storage system at a much larger H_2 production scale that significantly reduces the CO_2 footprint of the NGCC asset, while still providing reliable power to the grid.

Introduction

This topical report, prepared in accordance with the DOE requirements (cite which requirements), consists of an Executive Summary, six sections, and a References section. Section 2 briefly outlines the evaluation basis used in this study, including the methodology of calculating the COE. Section 3 provides background information related to the development of the Linde electrolyzer technology and describes in detail the proposed design and operation of the electrolyzer and salt cavern storage system. Section 4 presents a brief description of the overall process and key assumptions for the NGCC Case B31A reference. Section 5 provides the detailed results of the techno-economic assessment (TEA) including COE and cost of H_2 for the Linde case presented. The comparative energy and cost performance results of a 727 MWe (net) NGCC power plant integrated with the Linde electrolyzer and H_2 storage cavern are presented. This section also provides detailed material balances for the overall integrated NGCC power plant with electrolyzer and cavern storage system. The performance summary details all elements of auxiliary power consumption along with net plant efficiencies of the Linde electrolyzer technology. Evaluation of the COE and cost of H_2 for a 727 MWe (net) NGCC power plant integrated with a Linde electrolyzer, and cavern storage system starts with a presentation of the methodologies used to estimate the total plant cost (TPC) for the electrolyzer plant and H_2 storage cavern, and the TPC and total overnight cost (TOC) of an NGCC plant integrated with electrolyzer and H_2 storage. Section 6 concludes the report by providing an additional modeling analysis case demonstrating the significant CO_2 footprint reduction provided by an integrated NGCC and electrolyzer system that still meets the demand for reliable electricity and low-cost, large-scale H_2 production and salt cavern storage.

Evaluation Basis

For each case presented in this study, Honeywell's UniSim Design R440 software has been used as a generalized platform for the rigorous mathematical modeling, simulation, design, and optimization of the integrated NGCC plant, H_2 electrolyzer, and H_2 storage salt cavern. Linde's proprietary electrolyzer performance and operating data have been utilized for the detailed analysis and optimization of the H_2 electrolyzer. In addition, Linde's commercial experience from operating its H_2 storage cavern in the U.S. Gulf Coast provided detailed insights into the cost assessment of the cavern storage system. The resulting key process performance indicators have been used to determine the incremental capital charges for the NGCC power plant utilizing estimated scaling parameters, while the capital cost estimate for the electrolyzer and cavern storage system technology is based on in-house proprietary costing tools and proposal development on large projects, which include vendor data. Within UniSim, the ASME Steam property package is utilized for calculations involving the NGCC plant steam cycle and the Peng-Robinson property package is used for modeling the NG combustion reactions and gas turbine. Site characteristics, raw water usage, and environmental targets are identical to those detailed in Section 2 of the DOE/NETL Case B31A reference. The methodology for calculating the COE over a period of 20 years used in this study is, again, identical as in the DOE/NETL Case B31A reference.

$$COE = \frac{(CCF \times TOC) + OC_{FIX} + (CF \times OC_{VAR})}{(CF \times AMWh)} \qquad \textit{Equation 1}$$

where:

1) COE is the cost of electricity
2) CCF is the capital charge factor, 0.1243 was used for COE calculations.
3) TOC is the total overnight cost
4) OC_{FIX} is the fixed operating costs
5) CF is the capacity factor
6) OC_{VAR} is the variable operating costs
7) AMWh is average megawatt-hours

The economic assumptions used to derive the above values are summarized in Section 5.2.6 of the DOE/NETL Case B31A reference. Consequently, the calculated COE has been expressed in 2018$ to be able to consistently evaluate the influence of the Linde electrolyzer technology and cavern storage system on NGCC cost and operations. Additionally, for this study, the total overnight cost (TOC) of the entire NGCC plant integrated with electrolyzer and storage system is calculated using the same methodology as in the DOE/NETL Case B31A reference:

$$TOC = TPC + PPC + IC + ICCC + LOOC + FC \qquad \textit{Equation 2}$$

where:

1) TPC is the total capital cost of the complete NGCC plant
2) PPC (*Preproduction Costs)* are the sum of costs of 6 months labor, 1 month maintenance materials, 1-month non-fuel consumables, 1 month waste disposal, 25% of 1 month's fuel cost, and 2% of TPC
3) IC (*Inventory Capital)* are the costs of 60-day supply of fuel and consumables at 100% CF plus 0.5% of TPC in spare parts
4) ICCC (*Initial Cost for Catalyst and Chemicals)* is the cost of 0% of TPC
5) LOOC (*Land & Other Owner's Costs)* are the costs of 0.0464% of TPC (Land) plus 15% of TPC for other owner's costs
6) FC (*Financing Costs)* are the costs equivalent to 2.7% of TPC

ITM-Linde Electrolyzer Technology

The Linde H_2 electrolyzer offering is based on ITM electrolyzer technology through a recent joint venture, ITM-Linde Electrolysis. This advanced electrolyzer technology is the result of comprehensive, ongoing R&D efforts since 1995 to develop advanced electrolyzer components for efficient H_2 production. From 1995 – 2003, laboratory studies were conducted to develop low-cost polymer materials with higher electrical conductivity than previous state-of-the-art PEM systems. In September 2003, ITM was granted a UK patent (No. 2380055), which protects its core technology. This technology focuses on: (1) replacement of the membrane material (normally a perfluorinated membrane) with a low-cost hydrocarbon hydrophilic material, (2) replacement of the complex and cumbersome discrete cell and cell stack production process by an in-situ process, and (3) further development of the patented “alkaline” hydrophilic membrane material, with the objective of facilitating the use of non-platinum catalyst systems. From 2004 – 2012, engineering demonstrations of the electrolysis technology were conducted at the 1-MW scale inside a 20-ft container using surplus electricity, producing up to 400 kg H_2 a day. In 2011, a first small-scale PEM-based hydrogen production system was demonstrated at the University of Nottingham (UK), making 4 kg H_2/day. As of 2021, a 2 MW capacity electrolyzer system has been commercialized and is built based on modules of three power stacks. These are built on a skid frame suitable to be housed indoors. Each 2 MW module can operate independently of one another allowing for greater flexibility in load control and rolling maintenance. The 2 MW modules are deployed alongside vital sub-systems required for operation. Input water and output H_2 purification options are available depending on specific customer requirements. Newer 5-MW modules are in development and expected to be available in the next few years. These are used as the basis for modeling electrolyzer H_2 production in this report. As of 2020, Linde operates over 80 commercial hydrogen electrolysis plants worldwide. More recently Linde has announced that it will build, own, and operate the world’s largest PEM electrolyzer plant at the Leuna Chemical Complex in Germany. With climate change becoming an increasing concern globally, Linde is actively leveraging its expertise to become a leading contender in the race to make large-scale electrolytic H_2 production, storage and use broadly available across all industries.

Electrolysis Plant & H_2 Salt Cavern

The H_2 electrolysis plant is designed to produce high-purity H_2 from demineralized water, purify it (> 99.99 vol% H_2) by removing water with a dryer and residual oxygen with a downstream deoxidation unit, and compress it to 80 bara (1160 psia). The electrolysis plant is comprised of individual 5 MW electrolyzer modules that are designed using the latest proprietary technology and stacked together into containers with interconnections to utilities (an electricity source, demineralized water for electrolytic H_2 production, and cooling water for cooling the electrolytic cells). As individual components, the major sections of the electrolysis module are: a PEM-based electrolytic cell, an internal dryer and deoxidation unit, and an internal compressor to compress the product H_2 up to 44.5 bara (645 psia). Following internal compression, the product H_2 is sent to a larger dehydration, intercooling, and compression system for H_2 storage at the required cavern storage pressure of 1160 psia.

Linde currently operates an H_2 storage network in Texas using salt cavern storage with a 40 million m^3 working capacity (1.4 bcf) and an integrated 350-mile H_2 pipeline from Texas City, TX, to Lake Charles, LA. This pipeline connects 50 customers and supplies H_2 at a rate of 600 mscf/day on a steady-state basis with peaking capacity of 700 mscf/day. Linde's salt cavern has been in commercial operation since 2007, providing customers with H_2 during periods of planned and unplanned peak demand, as well as during maintenance of the H_2-producing system (Praxair, 2020). Details regarding operation and maintenance of a commercial-scale H_2 salt cavern storage system are described below.

Typically, H_2 is supplied to customers under agreements that require availability and on-stream times for a water electrolyzer, steam methane reformer, or hydrogen recovery plant for H_2 production. When an H_2 production plant is taken off-line for unplanned or extended maintenance, having a storage facility available to supply back-up hydrogen to the pipeline supply is desirable to support hydrogen pipeline operations. Such a storage facility can also be used for electricity production in the case of the H-2-SALT system designed for this project. Considering that hydrogen production plants on average have production capacities that are roughly 50 million standard cubic feet per day (118 tonnes H_2/day) or greater, for a hydrogen storage facility to be effective enough to allow a plant to be taken off-line, it would need to have storage capacity on the order of 1 billion standard cubic feet (2,360 kg H_2) or greater. Utilizing a salt cavern to assist in the supply of higher-purity hydrogen (95% purity or greater) can present challenges. Stored hydrogen within the salt cavern can become contaminated by intrusion of several components, including water vapor, hydrocarbons, sulfur-containing compounds, and/or carbon dioxide. Contamination of the stored hydrogen requires removal of one or more contaminants from the stored hydrogen when withdrawn as a crude hydrogen stream from the salt cavern, as in the case of supply to a designated hydrogen storage and transport pipeline. Methods have been implemented to ensure that impurities imparted by the salt cavern to the stored hydrogen do not deleteriously impact the hydrogen product in the pipeline (Oates, 2017). For example, U.S. Pat. No. 7,078,011 (Morrow et al., 2006) removes at least carbon dioxide and water vapor from a crude hydrogen stream withdrawn from a salt cavern to produce a hydrogen product stream having an impurity level at or below a product purity specification. U.S. Patent Pub. No. 2013/021349 removes crude hydrogen from a salt cavern and then dilutes the crude hydrogen with higher purity hydrogen from a hydrogen pipeline to form a resultant hydrogen product stream at or below a product purity specification. U.S. Pat. Nos. 8,425,149 (Drnevich, 2013) and 8,757,926 (Drnevich, 2014) maintain a minimum quantity of stored hydrogen within the salt cavern to create a stagnant layer having carbon dioxide contained therein. A portion of stored hydrogen is withdrawn from the salt cavern without disturbing the stagnant layer to prevent carbon dioxide from being drawn into the stored hydrogen stream, thereby allowing the stored hydrogen stream to be reintroduced into the hydrogen pipeline without carbon dioxide removal. The methods disclosed in U.S. Patent Publication No. 2013/021349 and U.S. Pat. Nos. 7,078,011, 8,425,149, and 8,757,926 require additional processing steps, which can add complexity to the hydrogen flow network that is in communication with the salt cavern, as well as potentially increasing capital and operating expenditures.

Additionally, the ability to utilize a salt cavern to assist in the supply of higher purity hydrogen without leakage through the salt cavern walls can be difficult based on the properties of hydrogen. Hydrogen is the smallest and lightest element with an atomic radius measuring 25 pm ± 5 pm. Consequently, higher purity hydrogen is typically considered one of the most difficult elements to contain within underground salt formations without measurable losses through the salt cavern walls (Oates, 2017). For example, storing large quantities (e.g., greater than 100 million standard cubic feet) of pure (e.g., 99.99%) gaseous hydrogen in underground salt caverns consisting of a minimum salt purity of 75% halite (NaCl) or greater without measurable losses of the stored hydrogen from the salt cavern can present challenges. However, methods for containing hydrogen within a salt cavern without incurring significant leakage have been addressed. U.S. Pat. No. 8,690,476 (Oates, 2014) creates a permeation barrier along the walls of the cavern that allows high purity hydrogen to be stored therein. U.S. Patent Pub. No. 2014/0161533 (Oates, 2016) discloses monitoring and regulating the pressure of the stored hydrogen in the salt cavern between predetermined lower and upper limits.

Based on U.S. Patent No. 9,718,618B2 (Oates, 2017), a method for pre-treating a moisture-containing hydrogen product to be stored in a salt cavern is described. The storage pre-treatment comprises:

1) removing hydrogen product from a hydrogen pipeline or hydrogen production plant, such as a water electrolyzer,
2) compressing the hydrogen product to produce a compressed hydrogen product,
3) cooling the compressed hydrogen product to condense at least a portion of water vapor prior to the compressed hydrogen product entering the salt cavern,
4) removing the water vapor condensate to produce a compressed and chilled hydrogen product, and
5) introducing the compressed and chilled hydrogen product into the salt cavern to produce chilled and stored hydrogen within the salt cavern.

The H-2-SALT cavern storage system is comprised of:

1) a *compressor* configured to pressurize hydrogen product within the salt cavern to form stored hydrogen,
2) an *aftercooler* situated downstream of the compressor that is configured to remove the heat of compression from the pressurized hydrogen product,
3) a *chiller* downstream of the aftercooler configured to impart additional cooling beyond the heat of compression to condense water vapor from the hydrogen product,
4) a *liquid-vapor separator vessel* configured to collect and accumulate the removed water vapor condensate that is located downstream of the chiller, and
5) a *flow network* positioned between the salt cavern and the compressor, chiller, and collection vessel. The first segment in the flow network introduces the hydrogen product into the salt cavern to form stored hydrogen that is chilled to a temperature sufficient to remove a portion of water vapor to produce a chilled and stored hydrogen product. The second segment in the flow network is connected to a hydrogen pipeline and will withdraw the stored and chilled hydrogen from the salt cavern for use in the hydrogen pipeline and/or injection into a NG turbine, as used in the H-2-SALT system.

To maintain H_2 product purity according to pipeline and end-use specifications (as in the case of injection into a NG turbine), the H-2-SALT cavern system will be operated using analytical instrumentation to detect the presence of one or more contaminants (e.g., water vapor, hydrocarbons, sulfur-containing compounds, and/or carbon dioxide) in a crude hydrogen stream withdrawn from the cavern that may exceed product purity specifications. If excessive product impurities are identified, the rate of cooling of the compressed hydrogen stream that is sent to the salt cavern and the rate of cooling of the crude hydrogen stream that is withdrawn from the cavern can be increased. The increased rate of cooling and resulting reduced cavern storage temperature can be used as a strategy to lower the concentration of contaminants to within standard product purity specifications. The stored, sufficiently cooled H_2 exhibits coolant properties that the U.S. Pat. No. US9718618-B2 (Oates, R. M., 2017) recognizes can be utilized for cooling the salt cavern walls. At least a portion of the chilled, stored H_2 contacts a localized portion of the salt cavern walls from which heat is extracted to reduce the cavern wall temperature. Because of the cooling of the cavern walls, the one or more layers of the localized portion of the cavern walls attains a stabilized state whereby contaminant release from the walls is suppressed. This effect is due to constriction of the walls to a point where certain localized regions of the walls acquire an inherent porosity between its layers that is too small for contaminants such as hydrocarbons, water vapor and carbon dioxide to infiltrate. In addition, the viscoplastic slippage of the layers is reduced upon cooling by the chilled stored hydrogen gas such that movement of the layers relative to each other is suppressed. Less movement of the layers results in less release of contaminants from the layers into the salt cavern. The reduction in movement can cause a substantial portion of potential contaminants to remain entrapped between layers of the cavern walls. Excessive movement of layers of the cavern walls and elevated salt cavern temperatures may lead to contaminant infiltration into the purified H_2 within the salt cavern. Hence, based on the invention described in US9718618B2, the proposed design can be used to mitigate direct contamination of the H_2 in the cavern from components contained within the layers of the cavern's walls. This approach has been demonstrated commercially as a safe and effective operating principle for maintaining the purity of commercial-grade hydrogen within the walls of an H_2 storage salt cavern system.

NGCC Power Plant without CO_2 Capture

This study evaluates a 727 MWe (net) NGCC power plant without CO_2 capture, using DOE/NETL Case B31A as a reference for the power plant steam cycle design and flue gas conditions. Brief process highlights and major assumptions used in this study are presented below.

Brief Process Description

Figure C1 as well as Tables C1 and C2 highlight the major process units and streams of an NGCC plant without CO_2 capture. Ambient air (stream 1) and natural gas (stream 2) are introduced into the compressor-expander NG turbine. Flue gas from the NG turbine then enters the heat recovery steam generator (HRSG) system where heat is recovered from the hot flue gas to create high pressure steam used in the steam turbine system.

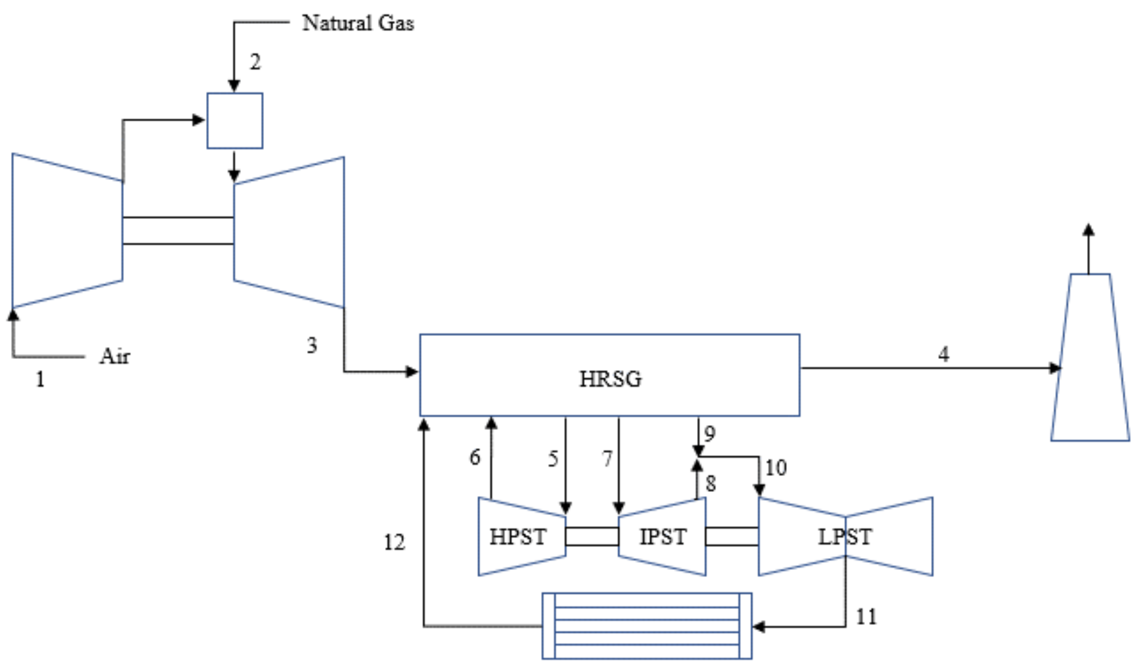

Figure C1. Block flow diagram for DOE-NETL Case B31A Reference Case.

Table C1. NGCC Stream material balance for DOE-NETL Case B31A Reference Case.

Stream #	1	2	3	4
Mass Flow (lb/hr)	8,452,800	205,630	8,658,430	8,658,430
Pressure (psia)	14.8	421	15.5	14.8
Temperature (°F)	59	365	1,156.00	181
Composition (mol frac)				
N_2	0.7732	0.016	0.7429	0.7429
O_2	0.2074	0	0.12	0.12
Ar	0.0092	0	0.0088	0.0088
CO_2	0.0003	0.01	0.0408	0.0408
H_2O	0.0099	0	0.0875	0.0875
H_2	0	0	0	0
CH_4	0	0.931	0	0
C_2H_6	0	0.032	0	0
C_3H_8	0	0.007	0	0
C_4H_{10}	0	0.004	0	0
Total	1	1	1	1

Table C2. HRSG steam cycle material balance for DOE-NETL Case B31A Reference Case.

Stream #	5	6	7	8	9	10	11	12
Mass Flow (lb/hr)	1,071,010	1,071,010	1,237,117	1,237,117	160,051	1,397,168	1,397,168	1,398,910
Pressure (psia)	2,393	542	509	587	538	581.38	0.98	0.98
Temperature (°F)	1,085	672	1,084	74	74	74	101	101
Phase (L or V)	V	V	V	V	V	V	V	L

Key System Assumptions

Table C3 summarizes the key system assumptions used in this study, which are identical to those used in the DOE/NETL Case B31A reference case.

Table C3. NGCC Plant Study Configuration Matrix.

Property	Value
Steam Cycle, MPa/°C (psig/°F)	16.4/585
Fuel	Natural Gas
Fuel Pressure at Plant Battery Limit MPa (psia)	3.0 (430)
Condenser Pressure, mm Hg (in Hg)	50.8 (2)
Cooling water to condenser, °C (°F)	16 (60)
Cooling water from condenser, °C (°F)	27 (80)
Stack temperature, °C (°F)	82 (181)
SO_2 Control	Low Sulfur Fuel
NOx Control	LNB and SCR
SCR Efficiency, %	85.4%
Ammonia Slip (end of catalyst life), ppmv	10
Particulate Control	N/A
Mercury Control	N/A

Techno-Economic Evaluations

Modeling Approach and Validation

Figure C1 highlights the major process units and streams of an NGCC plant without CO_2 capture integrated with a Linde electrolyzer and H_2 salt cavern storage system (referred to as Linde Case 1). Detailed techno-economic evaluations have been performed utilizing UniSim Design R440 software as a generalized computational platform for rigorous calculations of physical and thermodynamic properties of water, steam, and multi-component mixtures, along with related material and energy balances around each individual unit operation of the integrated power plant with electrolysis and H_2 storage cavern system. The first step in validating the modeling approach was to reproduce material streams and related energy balances of the NGCC plant as reported in the DOE/NETL Case B31A reference, including tuning of the isentropic efficiencies of all turbines. This tuning enables consistent energy performance comparisons of the Linde technology presented in this study against the DOE/NETL Case B31A reference.

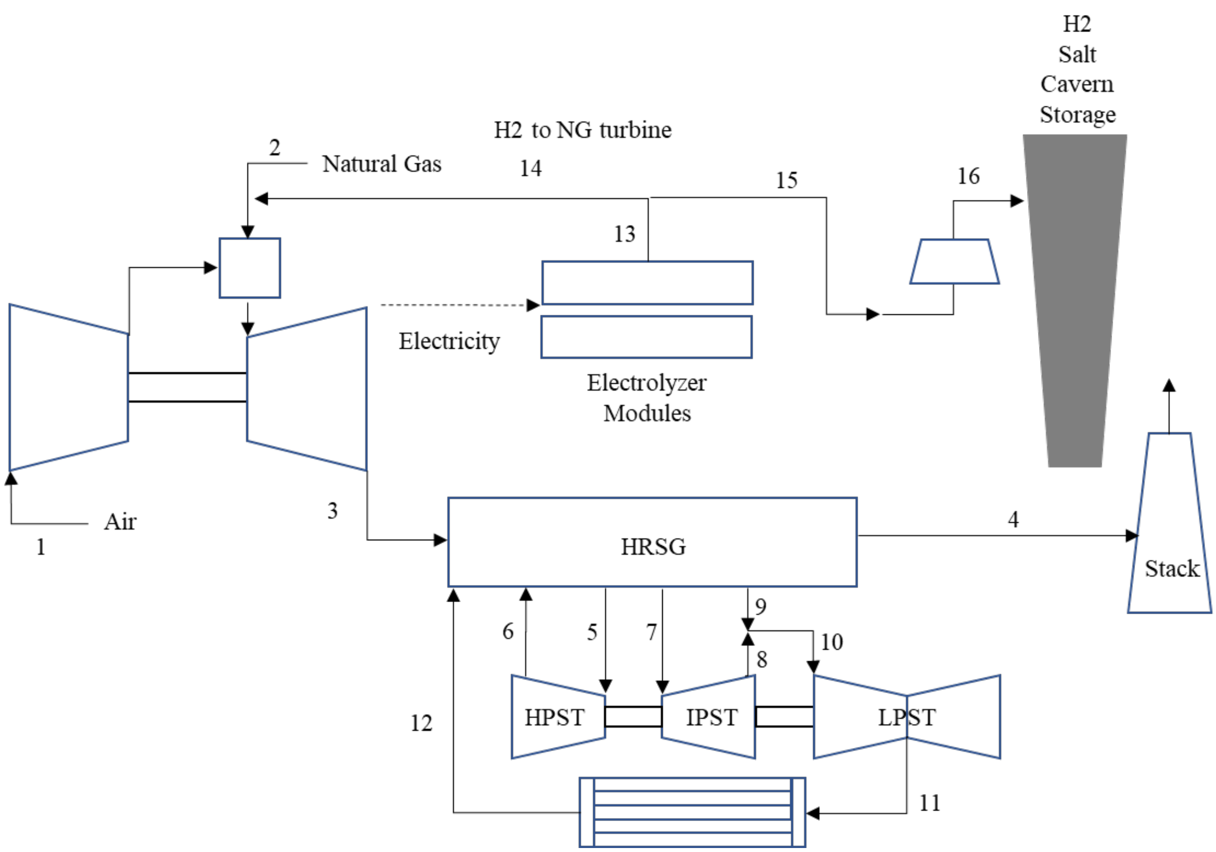

Figure C2. Block Flow Diagram for Linde Case 1.

Table C4. NGCC and H_2 Stream material balance for Linde Case 1.

Stream #	1	2	3	4	13	14	15	16
Mass Flow (lb/hr)	8,853,629	215,396	9,069,413	9,069,413	505	388	117	117
Pressure (psia)	14.8	421	15.5	14.8	645.42	645.42	645.42	1,160.30
Temperature (°F)	59	365	1,156.00	181	104	104	77	77
N_2	0.7732	0.0161	0.7431	0.7431	0	0	0	0
O_2	0.2074	0	0.1209	0.1209	0	0	0	0
Ar	0.0092	0	0.0088	0.0088	0	0	0	0
CO_2	0.0003	0.01	0.0402	0.0402	0	0	0	0
H_2O	0.0099	0	0.0869	0.0869	0	0	0	0
H_2	0	0	0	0	1	1	1	1
CH_4	0	0.9309	0	0	0	0	0	0
C_2H_6	0	0.032	0	0	0	0	0	0
C_3H_8	0	0.007	0	0	0	0	0	0
C_4H_{10}	0	0.004	0	0	0	0	0	0
Total	1	1	1	1	1	1	1	1

Table C5. HRSG steam cycle material balance for Linde Case 1.

Stream #	5	6	7	8	9	10	11	12
Mass Flow (lb/hr)	1,128,772	1,128,772	1,303,826	1,303,826	168,672	1,472,497	1,472,497	1,472,497
Pressure (psia)	2,393.00	542	509	587	538	581.38	0.98	0.98
Temperature (°F)	1,085.00	672	1,084.00	74	74	74	101	101
Phase (L or V)	V	V	V	V	V	V	V	L

Performance Results

Comparative simulation performance results of the DOE-NETL Case31A reference case and Linde Case 1 are provided in Table C6.

Table C6. HRSG steam cycle material balance for Linde Case 1.

Process Case	**DOE NETL Case B31A**	**Linde Case 1**
COMBUSTION AND STEAM TURBINE POWER, MWe	**740**	**752**
AUXILIARY LOAD SUMMARY		
Circulating Water Pumps, kWe	2,810	2,943
Combustion Turbine Auxiliaries, kWe	1,020	1,068
Condensate Pumps, kWe	150	157
Cooling Tower Fans, kWe	1,460	1,460
Feedwater Pumps, kWe	4,830	5,059
Groundwater Pumps, kWe	260	260
Miscellaneous Balance of Plant, kWe	570	570
SCR, kWe	2	2

Steam Turbine Auxiliaries, kWe	200	200
Transformer Losses, kWe	2,250	2,357
Electrolysis System Power, kWe	0	12,315
Salt Cavern Storage System Power, kWe	0	0
TOTAL AUXILIARIES, kWe	**13,552**	**26,392**
NET POWER, MWe	**726**	**726**
CO_2 Capture	**0%**	**0%**
HHV Net Plant Efficiency	53.6%	51.1%
Condenser Cooling Duty (GJ/hr)	1,405	1,472
CO_2 Captured (MT/hr)	0	0
CONSUMABLES		
NG Fuel, kg/hr	93,273	97,255
H_2 Fuel, kg/hr	0	176
HHV Thermal Input, kWt	1,354,905	1,419,252
Annual Air Emissions (85% Capacity Factor)		
NO_x (MT/Year)	56	59
Particulates (MT/Year)	29	30
Hg (kg/Year)	0	0
SO_2 (MT/Year)	15	16

Capital Cost Estimates

Detailed capital costs for the DOE-NETL B31A base case and Linde Case 1 are shown in Table C7, including Total Plant Cost (TPC) and Total Overnight Cost (TOC). Table C8 shows comparative fixed and variable operating costs for the two cases.

Table C7. Itemized Total Plant Capital Cost ($x1000, 2018$ price basis).

Capital Cost Element	DOE-NETL Case B31A	Linde Case 1
Feedwater System	$8,360	$8,624
Water Makeup & Pretreating	$9,014	$9,298
Other Feedwater Subsystems	$2,183	$2,252
Service Water Systems	$14,921	$15,391
Other Boiler Plant Systems	$721	$744
Natural Gas Pipeline and Start-Up System	$13,807	$14,242
Wastewater Treatment Equipment	$11,608	$11,974
Miscellaneous Plant Equipment	$33,561	$34,619
Combustion Turbine Generator	$105,735	$109,069
Combustion Turbine Accessories	$3,845	$3,966
Compressed Air Piping	$1,467	$1,513
Combustion Turbine Foundations	$2,714	$2,800
Heat Recovery Steam Generator	$66,055	$68,138
Heat Recovery Steam Generator Accessories	$24,739	$25,519
Ductwork	$2,383	$2,458
Stack	$15,936	$16,438
Heat Recovery Foundations	$2,120	$2,187
SCR System	$4,057	$4,185
Steam Turbine Generator & Accessories	$58,632	$60,481
Steam Turbine Plant Auxiliaries	$660	$681
Condenser & Accessories	$14,270	$14,720
Steam Piping	$18,230	$18,805
Turbine Generator Foundations	$4,781	$4,932
Cooling Towers	$14,730	$15,194
Circulating Water Pumps	$1,572	$1,622
Circulating Water System Auxiliaries	$12,791	$13,194
Circulating Water Piping	$6,080	$6,272
Make-up Water System	$955	$985
Component Cooling Water System	$831	$857
Circulating Water System Foundations	$2,049	$2,114
Generator Equipment	$6,243	$6,440
Station Service Equipment	$4,409	$4,548
Switchgear & Motor Control	$6,803	$7,017
Conduit & Cable Tray	$5,438	$5,609

Wire & Cable	$5,830	$6,014
Protective Equipment	$640	$660
Standby Equipment	$1,730	$1,785
Main Power Transformers	$9,763	$10,071
Electrical Foundations	$478	$493
NGCC Control Equipment	$465	$480
Combustion Turbine Control Equipment	$892	$920
Steam Turbine Control Equipment	$745	$768
Other Major Component Control Equipment	$1,249	$1,288
Signal Processing Equipment	$656	$677
Control Boards, Panels & Racks	$271	$280
Distributed Control System Equipment	$9,639	$9,943
Instrument Wiring & Tubing	$3,861	$3,983
Other Instrumentation & Controls Equipment	$1,773	$1,829
Site Preparation	$17,180	$17,722
Site Improvement	$5,770	$5,952
Site Facilities	$4,888	$5,042
Combustion Turbine Area	$729	$752
Steam Turbine Building	$11,209	$11,562
Administration Building	$852	$879
Circulation Water Pumphouse	$115	$119
Water Treatment Buildings	$824	$850
Machine Shop	$1,246	$1,285
Warehouse	$947	$977
Other Buildings & Structures	$746	$770
Waste Treating Building & Structures	$2,773	$2,860
Linde Electrolysis System	$0	$13,213
H-2-SALT Cavern Storage System	$0	$2,303
Total Plant Cost (TPC)	$566,971	$600,362
Preproduction Costs	$20,036	$21,510
Inventory Capital	$3,134	$4,799
Initial Cost for Catalyst and Chemicals	$847	$897
Land	$300	$318
Other Owner's Costs	$85,046	$90,054
Financing Costs	$15,308	$16,210
Total Overnight Costs (TOC)	$691,642	$734,150

Table C8. Fixed and Variable Costs (2018$).

Cost Element	DOE-NETL Case B31A	Linde Case 1

Total Fixed Operating Cost	$19,487,999	$21,188,150
Maintenance Material Cost	$6,463,464	$6,770,427
Consumables	$2,761,306	$3,722,686
Total Variable Operating Cost	$9,224,770	$10,493,113
Total Fuel Cost	$152,160,153	$158,944,724

Cost of Electricity

The COE for each case is shown in Figure C3 and the itemized breakdown of COE by category is shown in Figure C4. Figure C5 shows a plot of actual hourly electricity prices at the GEEC used for the analysis described in following subsequent electrolysis and cavern storage system cost and operations performance plots. For the analysis presented in Figures C6 through C13, electricity prices and electrolyzer and salt cavern modeling data are shown for full year 2020 (January 1 – December 31).

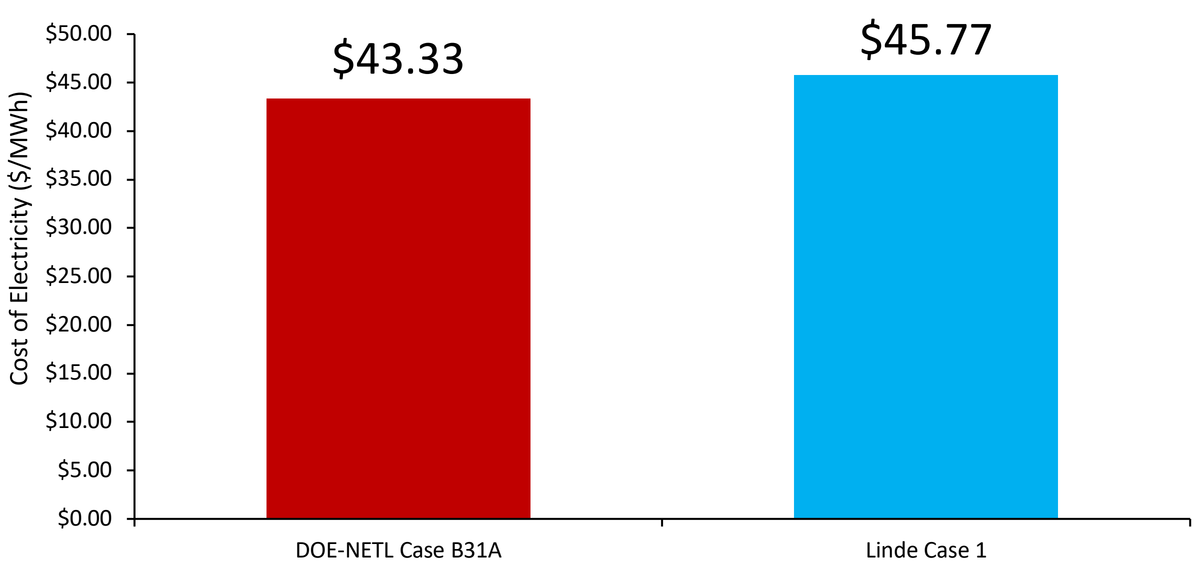

Figure C3. Cost of Electricity (COE) (2018$).

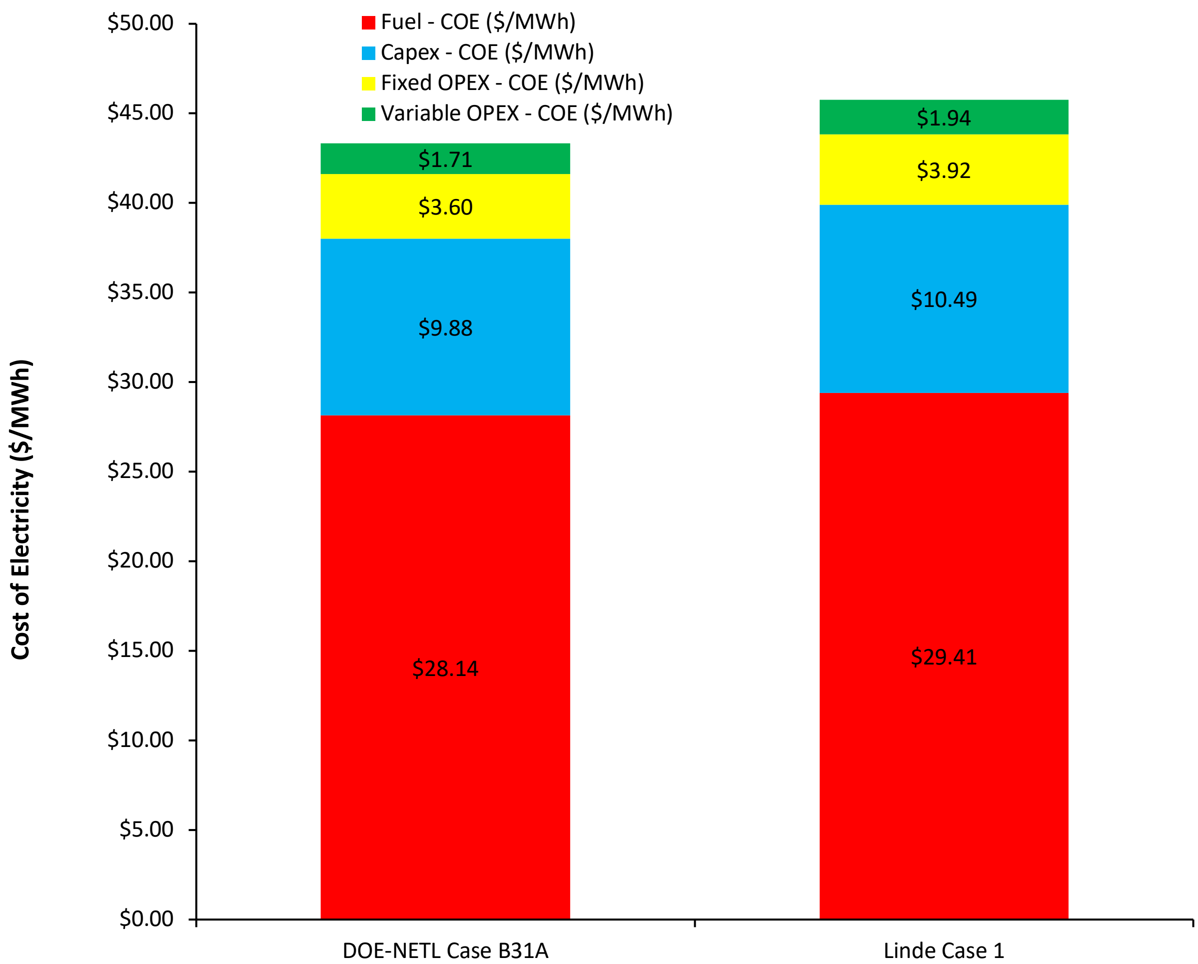

Figure C4. Itemized COE Breakdown by Category (2018$).

Cost of Hydrogen for integrated H-2-SALT System

For the selected case, the optimum electricity price threshold is $20/MWh, and this enables a total cost of large-scale H_2 production and storage of $1.78/kg (Figure C13), which is very competitive with the cost of commercial-scale H_2 produced by traditional steam methane reforming, which varies from $1.25 to $3.50/kg H_2 based on a NG price of $0.30/kg and depending on scale (Ball and Weeda, 2016). The $1.78/kg H_2 cost includes the capital and operating costs for the water electrolyzer and H_2 storage cavern over a period of 25 years. Instead of varying the rate of Hydrogen co-firing in the NG turbine and changing the power output of the NGCC, for the purposes of consistent comparison against the DOE-NETL reference, the H_2 produced in the Linde Case 1 scenario is continuously burned in the NG turbine at a constant rate of 176 kg/hr (2.45 vol% Hydrogen co-firing with NG). This is the calculated optimum Hydrogen co-firing rate that allows full use of the 114,507 kg H_2 cavern storage without overfilling the cavern or leaving the cavern empty for a large portion of the year. The 114,507 kg H_2 cavern storage size represents 500 hours of electrolyzer H_2 production at 229 kg/hr. For this case, when activated, the water electrolyzer system produces H_2 at a rate of 229 kg/hr and consumes 12 MW of electricity. The electrolysis system is comprised of three full-scale electrolyzer modules each consuming 4 MW of electricity.

For each analysis shown, the user-defined threshold electricity price ($/MWh) is the price below which the electrolyzer is activated to produce H_2 (leveraging lower-priced electricity to minimize operating costs) and above which the electrolyzer is deactivated. By defining this operating assumption in the model, there is a trade-off that occurs between availability or on-time hours of the electrolyzer and electricity cost of the electrolyzer operation as well as a fine interplay between H_2 production and storage. If the threshold price is set too low, the overall electricity cost is lower but the electrolyzer availability decreases and the total annual H_2 production is lower, so these factors raise the total cost per kg H_2. In contrast, if the threshold price is set too high, the annual electricity cost is higher but the electrolyzer availability and total H_2 production are also higher, so these effects serve to offset the higher electricity operating expense and lower the cost per kg H_2. In addition, the cavern storage size and ratio of H_2 production rate to storage size have a large impact from an operating perspective. If the electricity price threshold is set too high, the storage volume can be completely filled in the first few months of operation. Once the maximum storage capacity has been reached, then the electrolyzer cannot be operated to produce H_2 if the system requires H_2 to be stored first and the only option is to burn H_2 in the NG turbine to allow more storage space to open up for H_2 to be produced by the electrolyzer. If even lower electricity prices are encountered later in the year, then potential reductions in electrical cost for the electrolyzer operation are not realized and the downtime for the electrolyzer reduces its availability, leading to an increase in the cost per kg H_2. Alternatively, if the threshold price is set too low, then the availability of the electrolyzer decreases and the cavern storage does not fill up enough to justify its cost. Moreover, not having enough storage capacity at certain times of the year limits the ability to send H_2 to the NG turbine, and therefore the carbon footprint reduction benefits of the H-2-SALT system on the NGCC operation are not sufficiently achieved. The sensitivity of these interplays is evaluated with the threshold price analysis to provide a comprehensive assessment of operations and cost for the H-2-SALT system integrated with an NGCC power generation plant. The cost information presented below excludes the capital and operating costs of the NGCC unit to independently highlight the attractive, competitive costs of the H-2-SALT system.

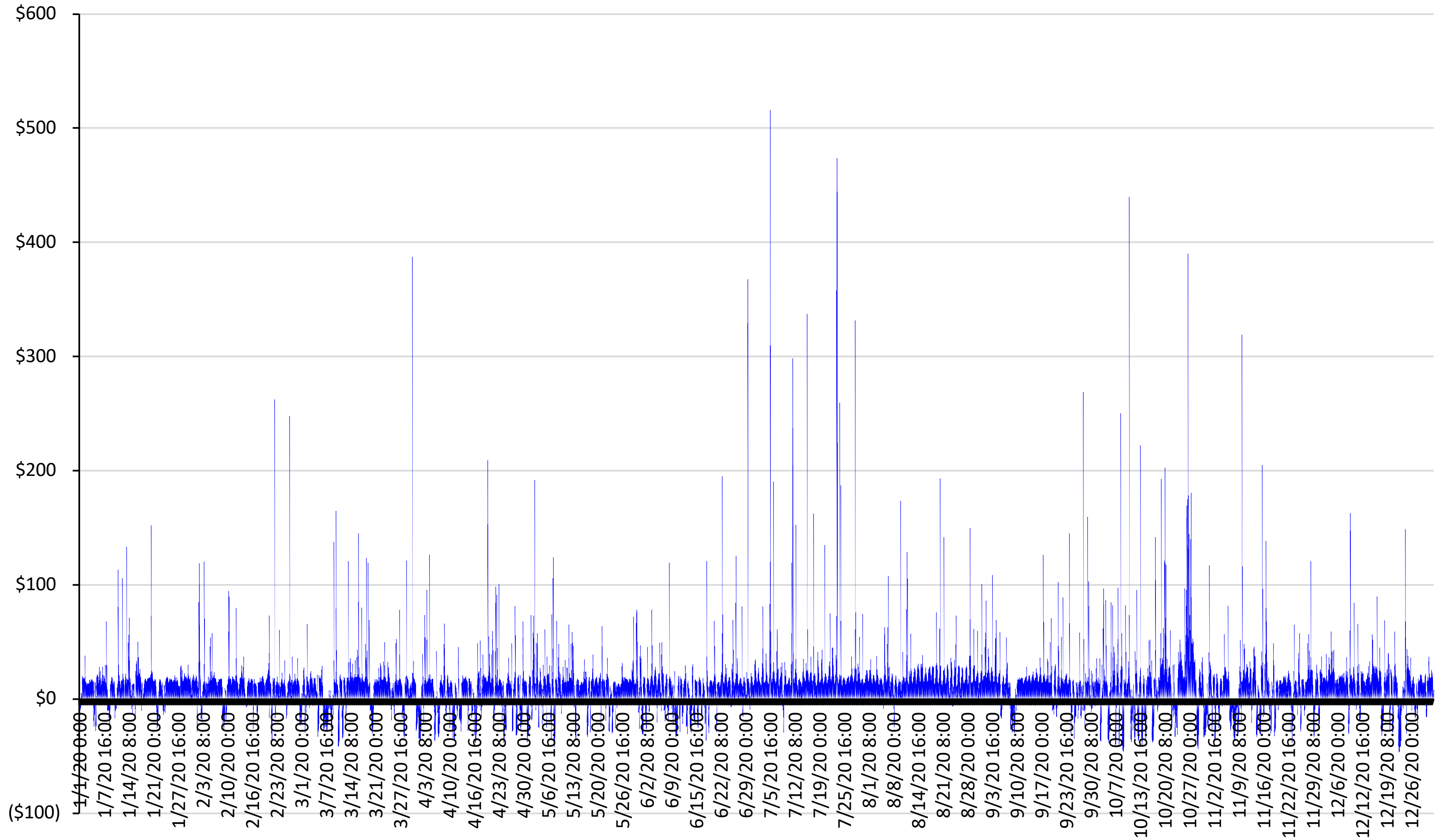

Figure C5. Hourly electricity price ($/MWh) for full year 2020 at the GEEC.

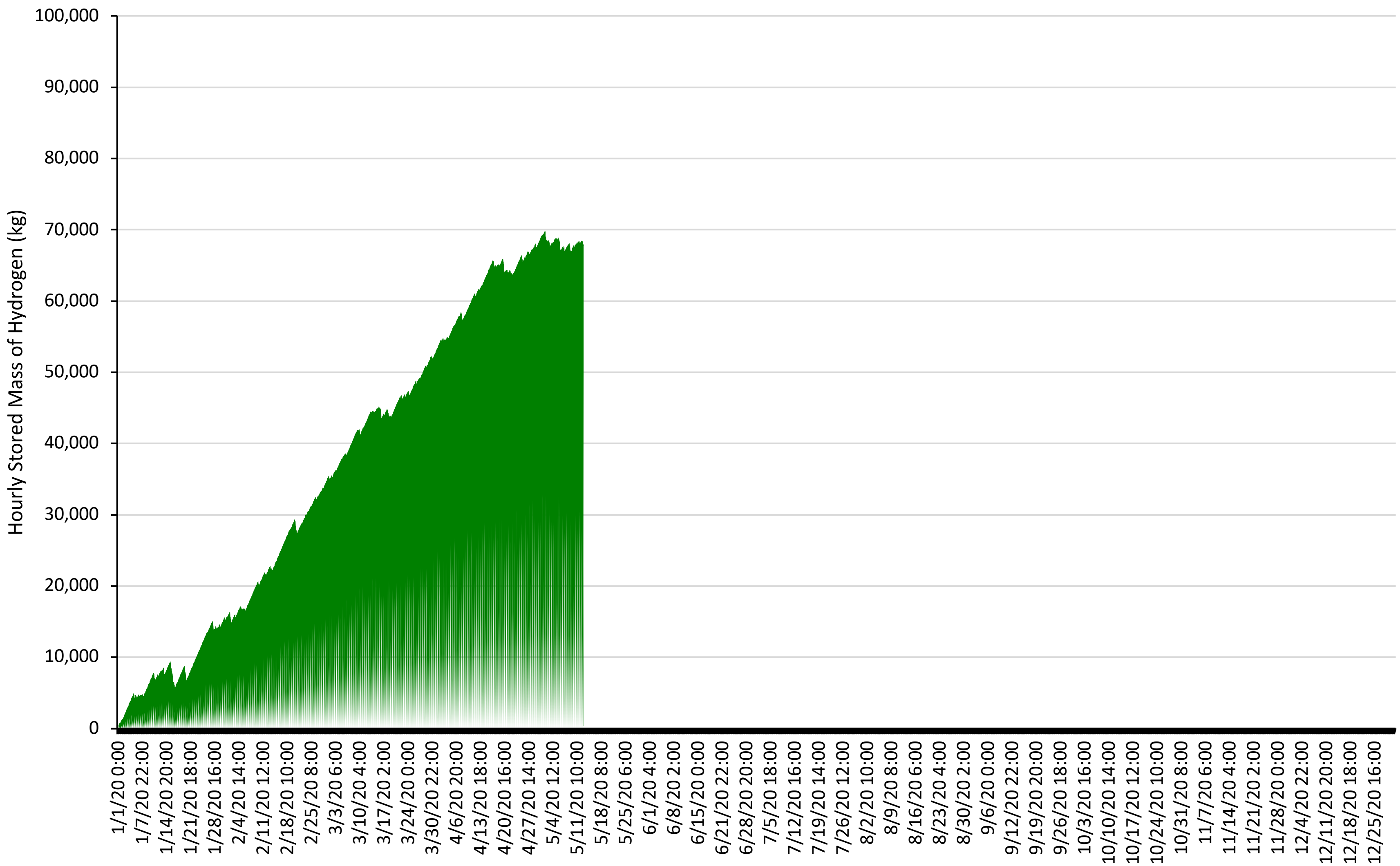

Figure C6. Hourly hydrogen storage mass in a salt cavern (kg).

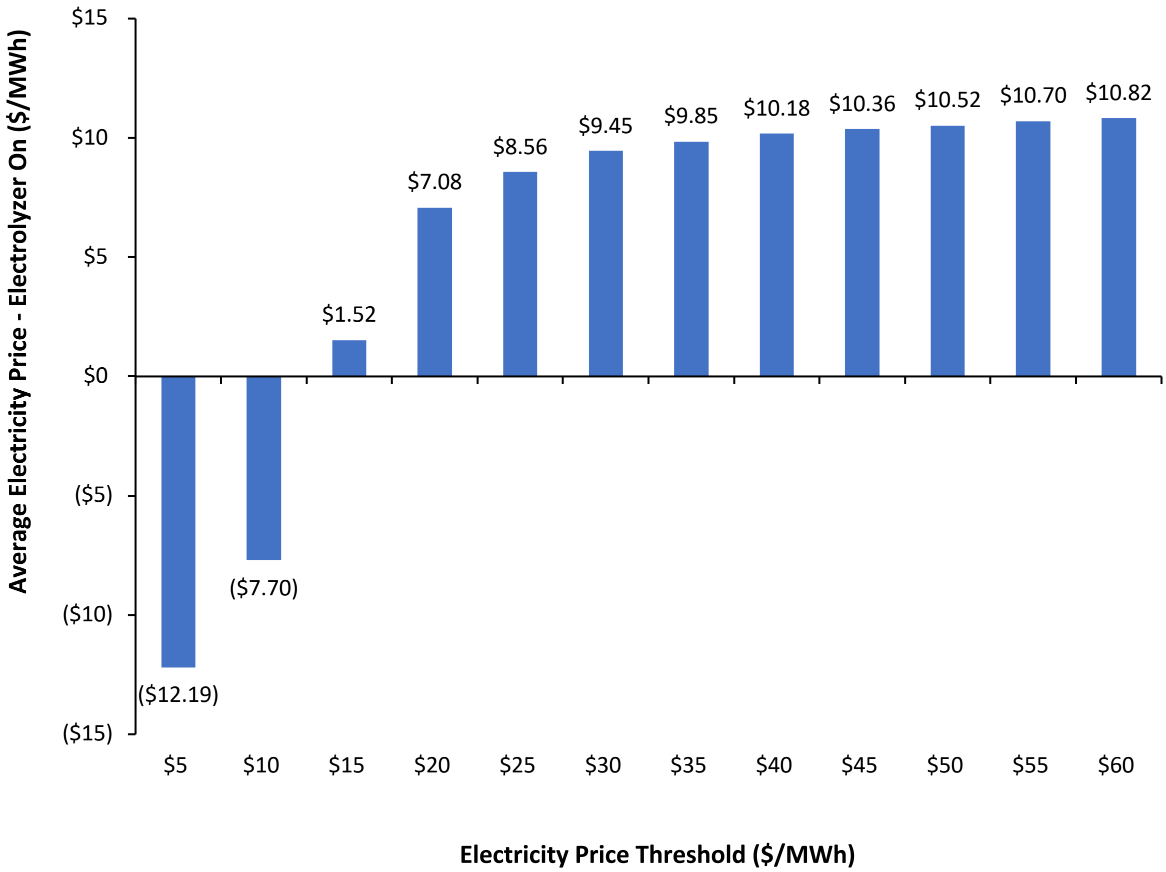

Figure C7. Average hourly electricity price when the Linde electrolyzer is operating as a function of the user-defined electricity price threshold ($/MWh)

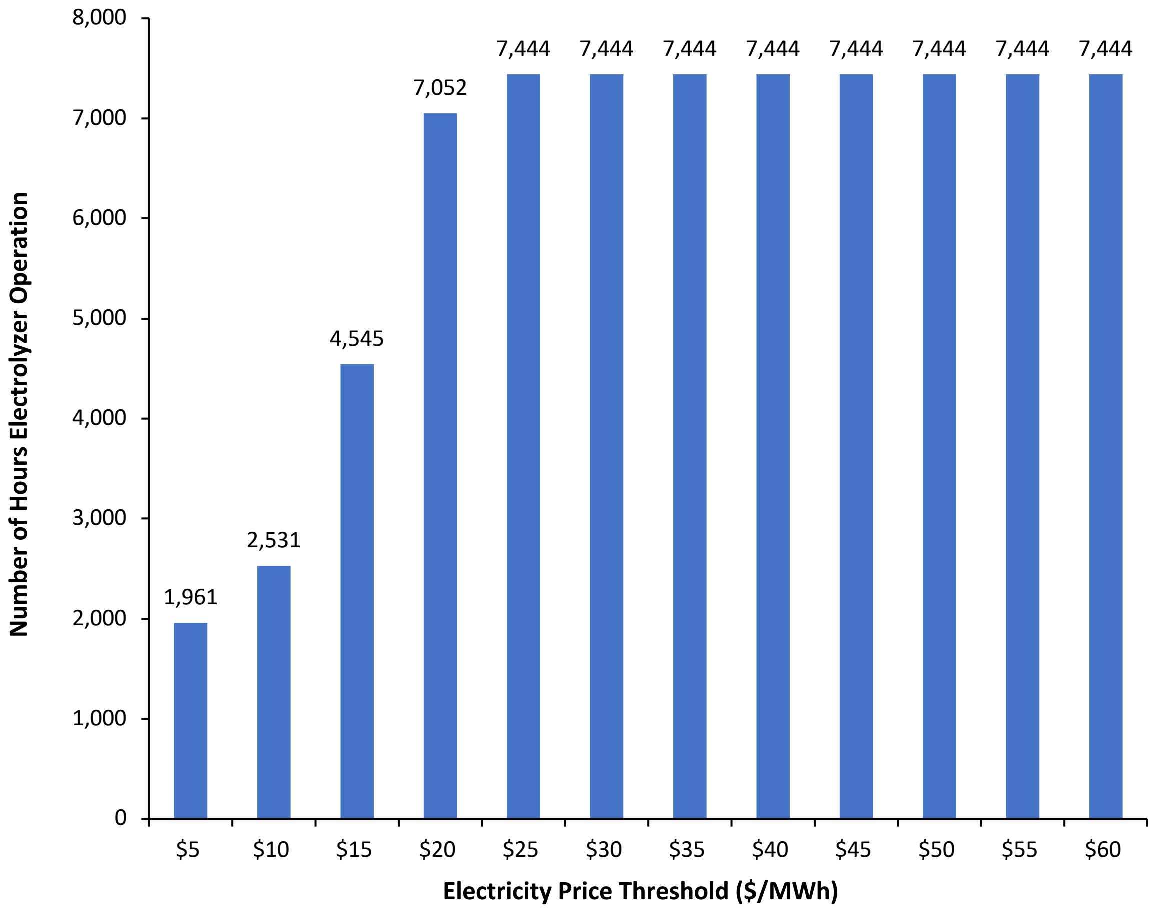

Figure C8. Number of hours when electrolyzer is operating (in one full year) as a function of the user-defined electricity price threshold ($/MWh)

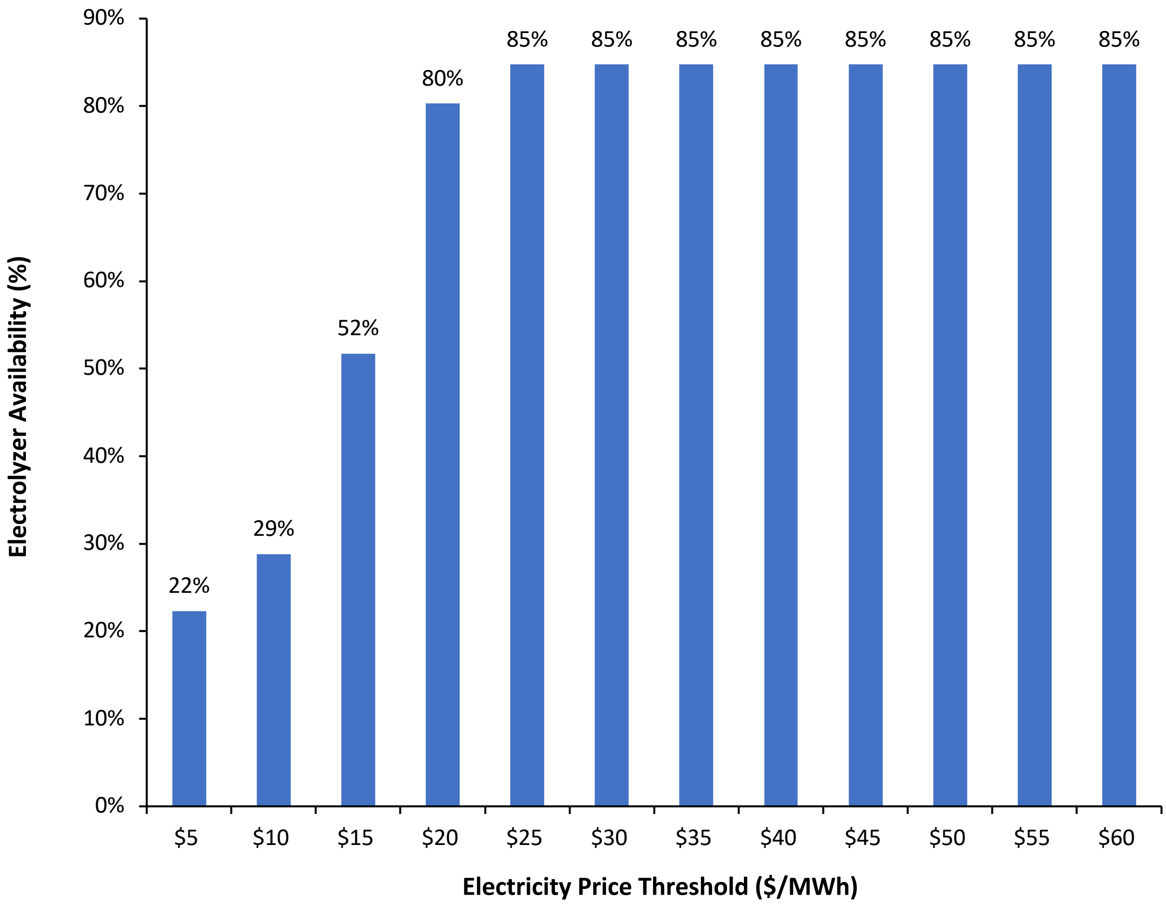

Figure C9. Electrolyzer availability as a function of the user-defined electricity price threshold ($/MWh)

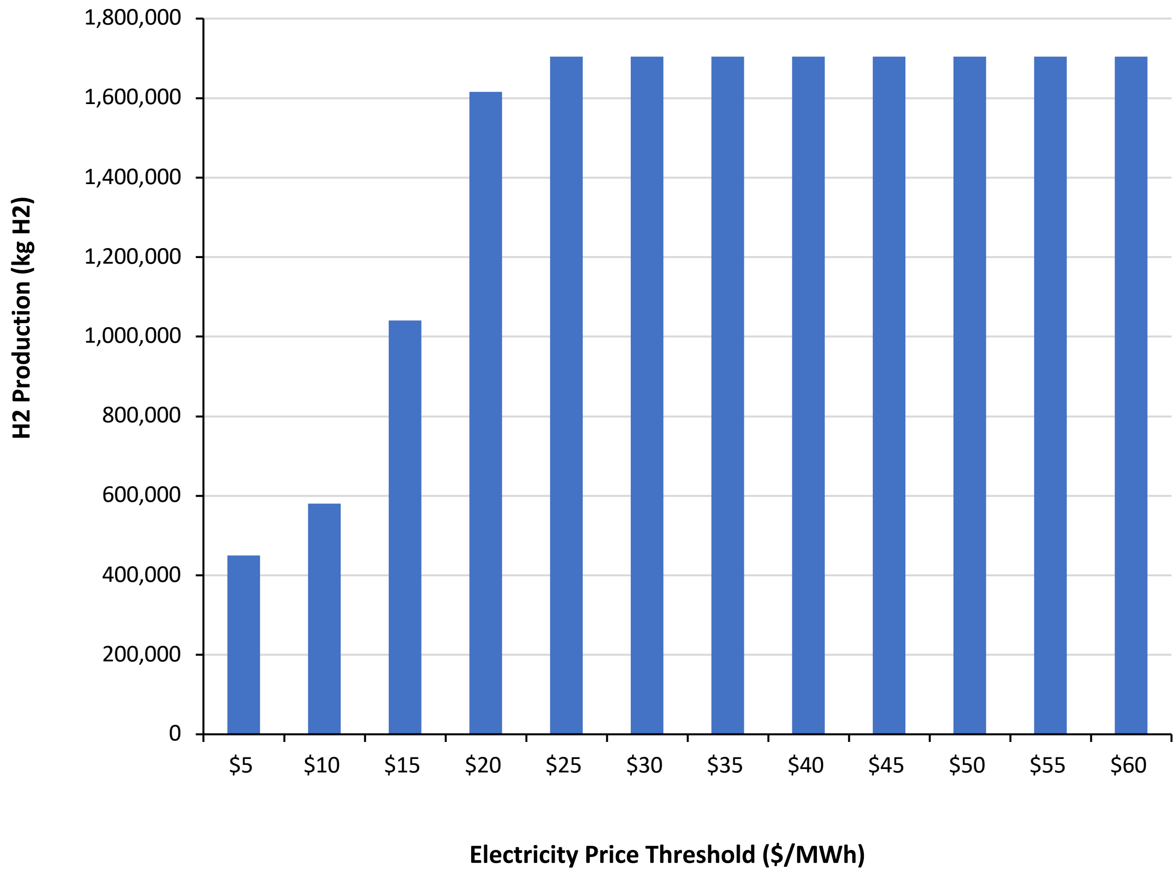

Figure C10. Annual hydrogen production as a function of the user-defined electricity price threshold ($/MWh)

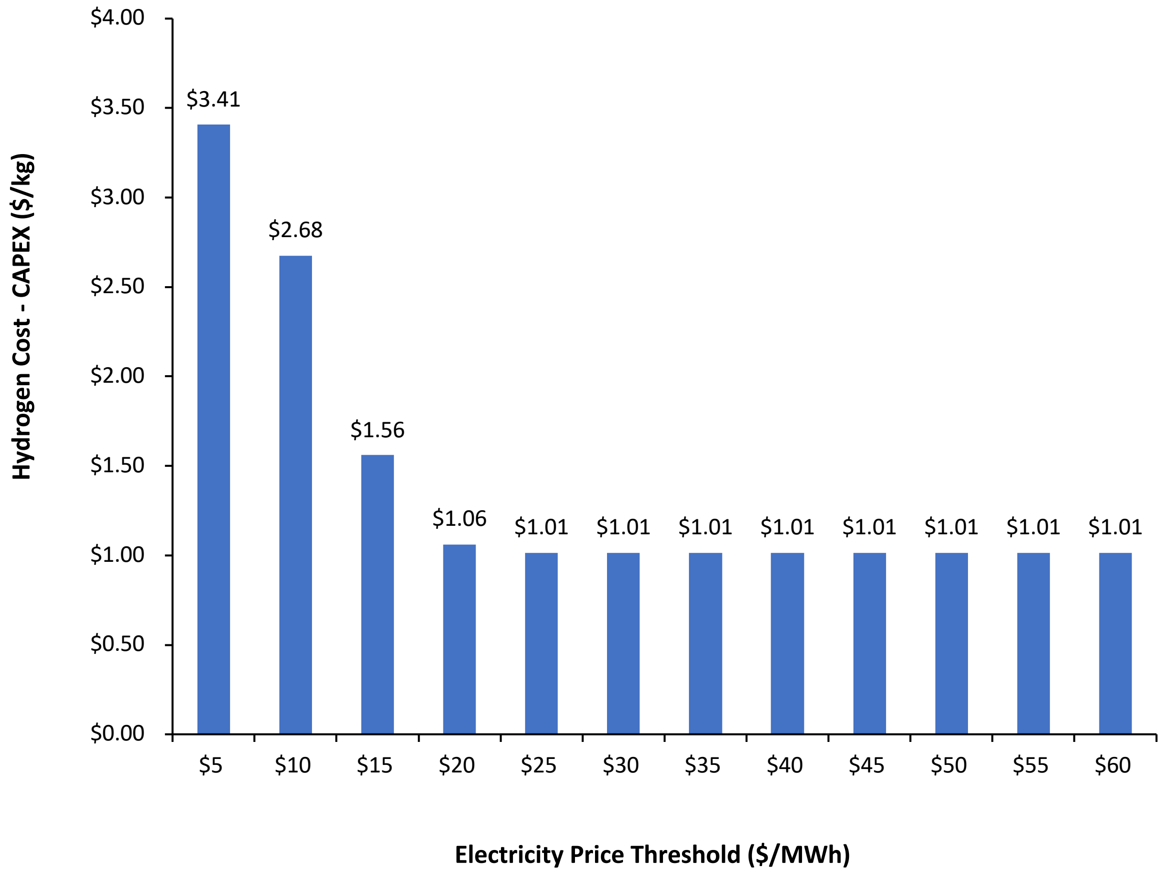

Figure C11. Specific capital cost for hydrogen production and storage ($/kg H_2) as a function of the user-defined electricity price threshold ($/MWh)

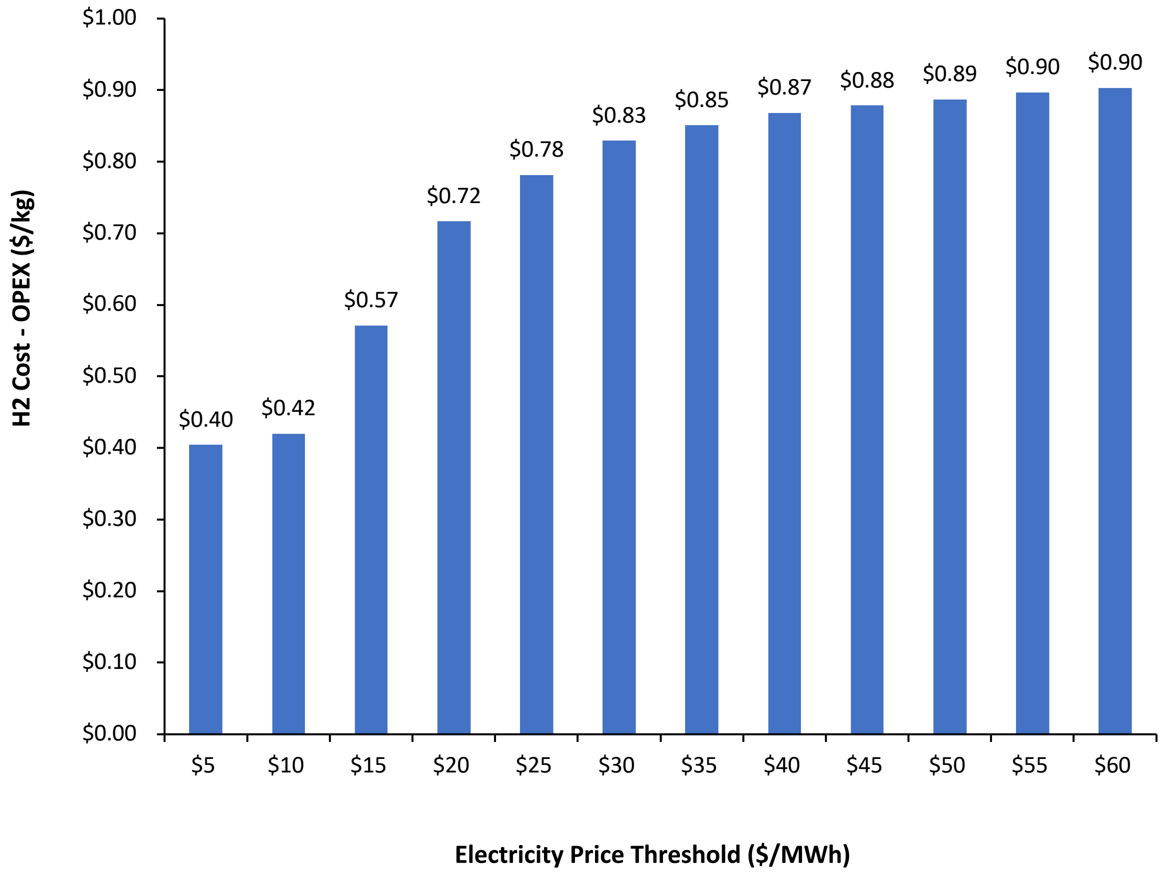

Figure C12. Specific operating cost for hydrogen production and storage ($/kg H_2) as a function of the user-defined electricity price threshold ($/MWh)

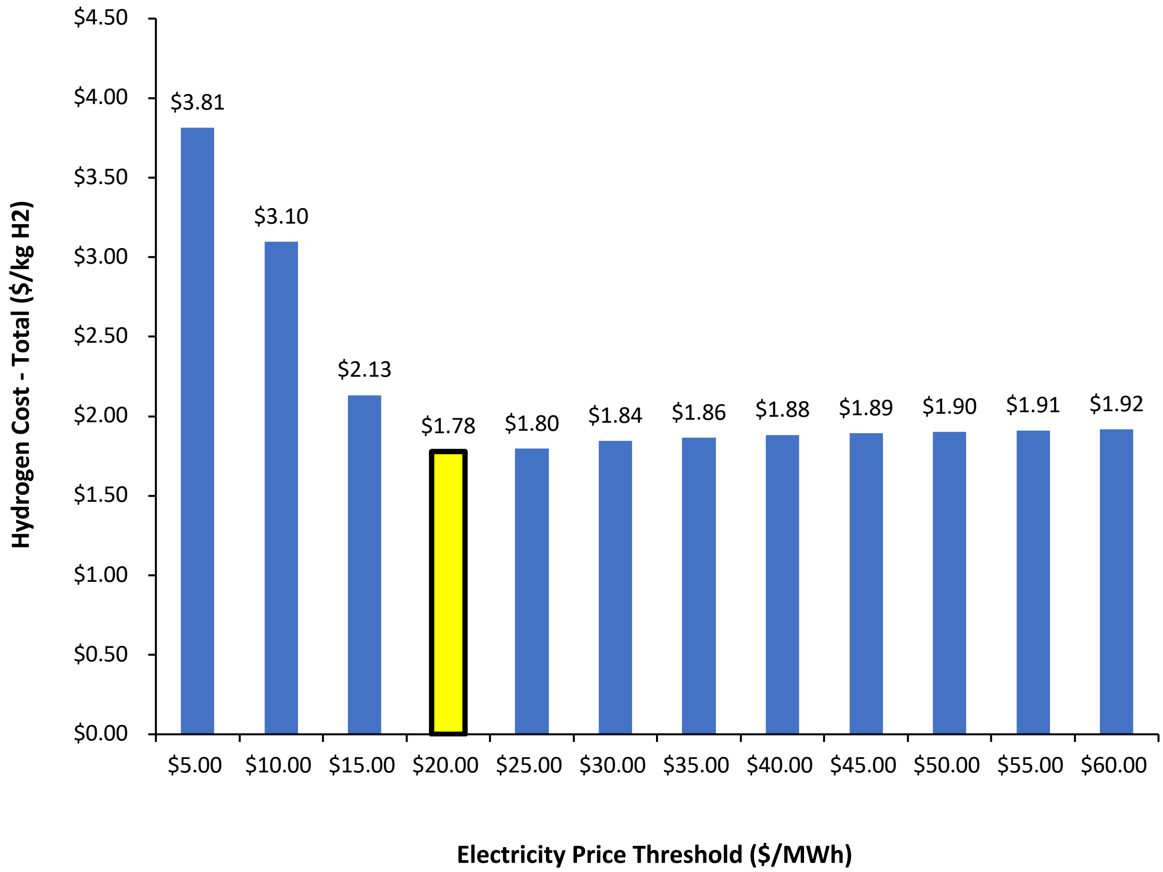

Figure C13. Specific total system cost for hydrogen production and storage ($/ kg H_2) as a function of the user-defined electricity price threshold ($/MWh)

Carbon Footprint Reduction Benefits of Large-Scale H-2-SALT Production and Storage

For the last part of this TEA study, a larger H-2-SALT production and storage system with a different operating assumption was evaluated for integration with the NGCC Case B31A reference to maximize the potential for CO_2 emissions reduction from the NGCC unit. Here, the power plant model operates under either of two modes:

1) full-scale power production at 727 MW (net) using 2,001 kg/hr of Hydrogen co-firing in the NG turbine (20 vol% Hydrogen co-firing) during higher-priced electricity periods, or
2) 128 MW (net) of power production during lower-priced electricity periods using a slightly lower continuous Hydrogen co-firing injection rate of 1,901 kg/hr

Due to the higher Hydrogen co-firing rates, both a larger electrolyzer and a larger H_2 storage volume are required. This larger storage volume can be accommodated by a larger cavern or by multiple caverns. For this analysis, the H_2 production has been set at 2,443 kg/hr H_2 and utilizes 32 electrolyzer modules (each 4 MW) that collectively consume a total electrical power of 128 MW. The storage cavern is based on 450 storage hours and is sized to contain a maximum of 1,099,264 kg of H_2.

The operating scenario described above allows both a greater co-firing rate of H_2 to maximize electrical energy production from H_2 and therefore the displacement of NG within the combustion turbine as well as a higher availability of the electrolyzer and storage system to minimize their overall cost at the larger scale. The analysis depicted in Figure C14 through C24 describes the operations and cost assessment of a large-scale hydrogen production and storage operating scenario that serves to maximize the environmental benefits of the H-2-SALT system from a CO_2 emissions reduction perspective. The same full year (2020) of electricity price data from the GEEC was used for this analysis.

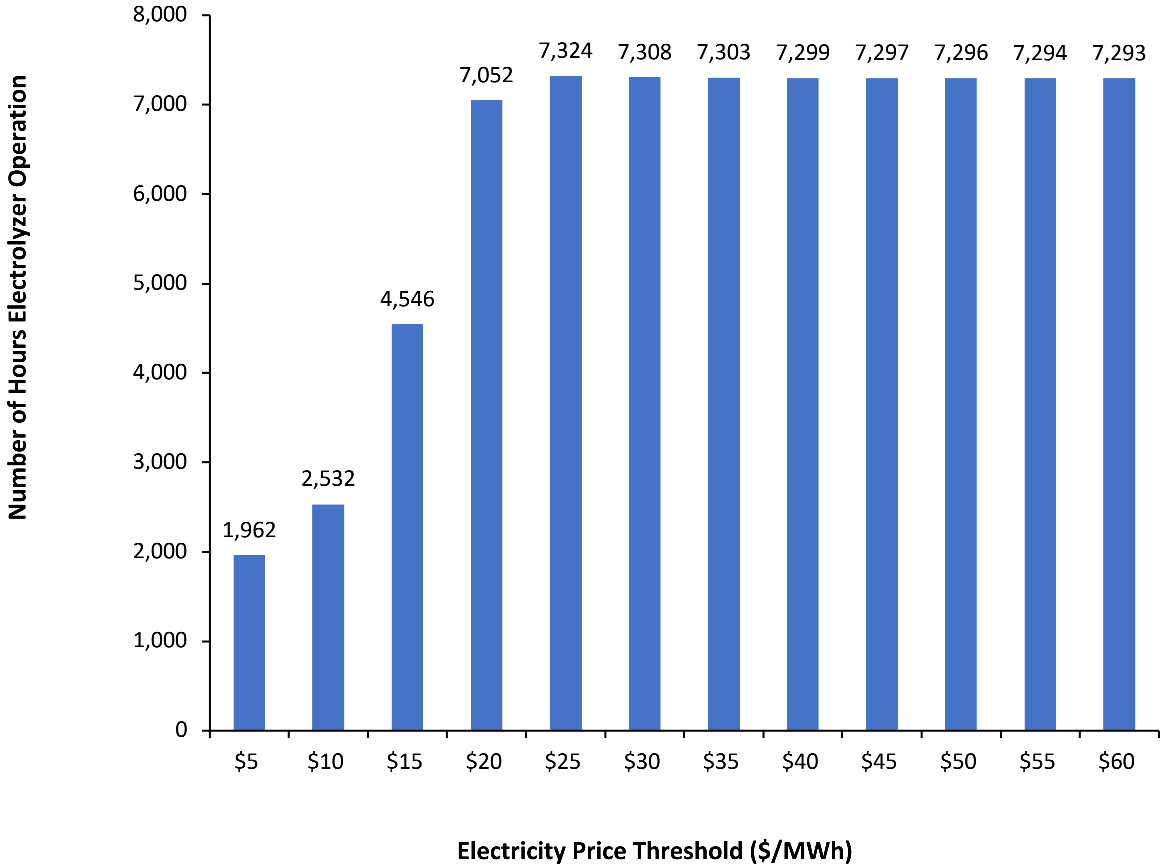

Figure C14. Number of hours of electrolyzer operation as a function of the user-defined electricity price threshold ($/MWh).

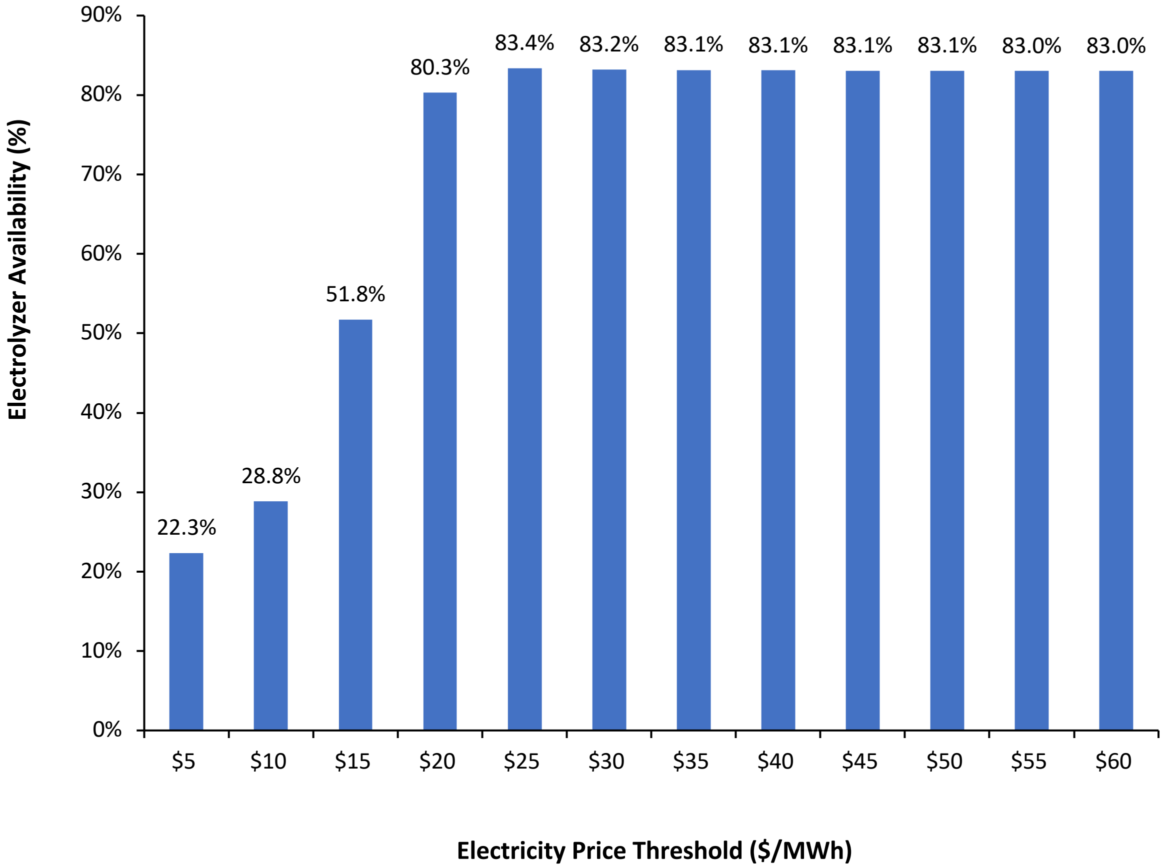

Figure C15. Electrolyzer availability as a function of the user-defined electricity price threshold ($/MWh).

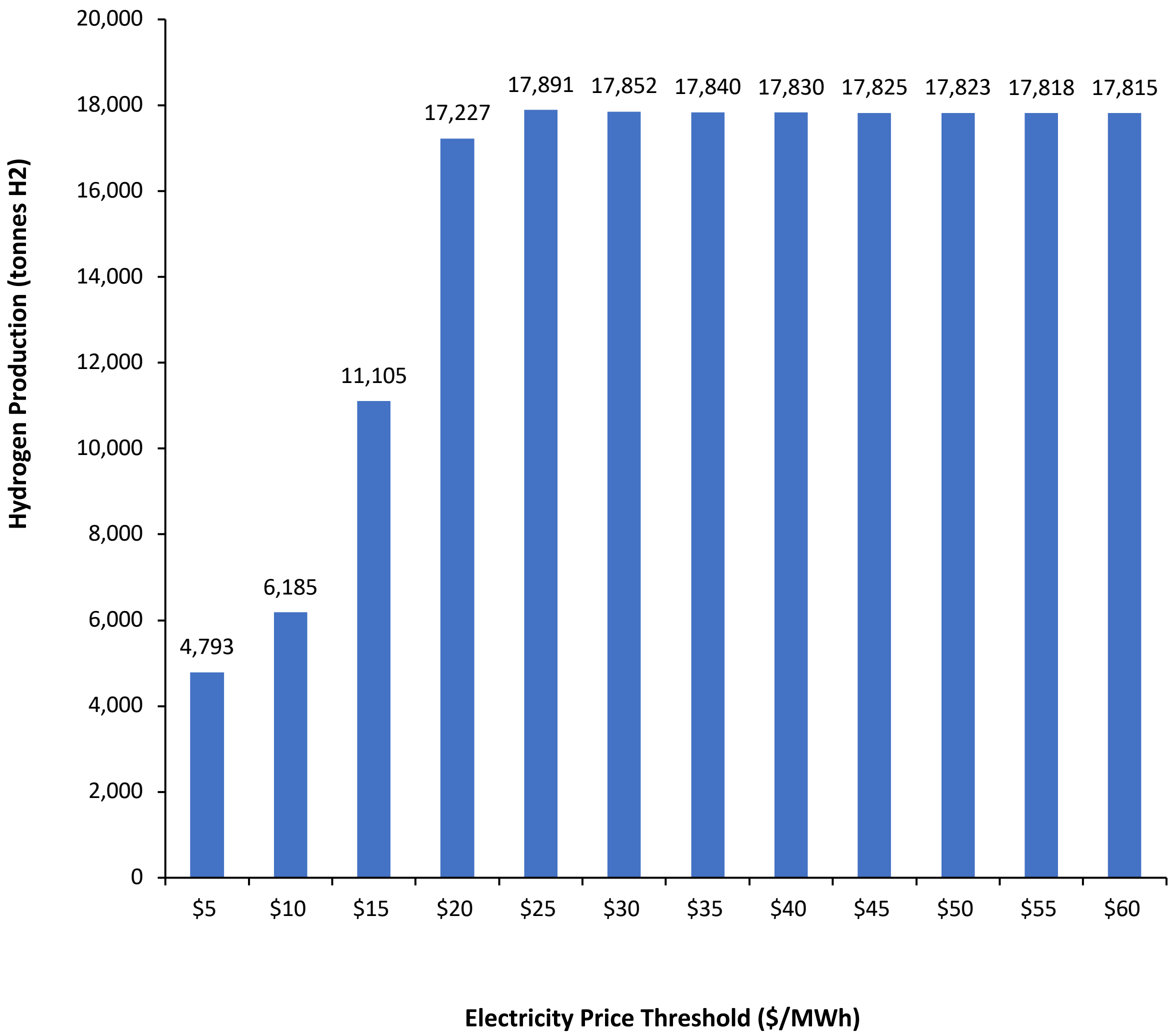

Figure C16. Annual H_2 production (metric tonnes H_2) as a function of the user-defined electricity price threshold ($/MWh).

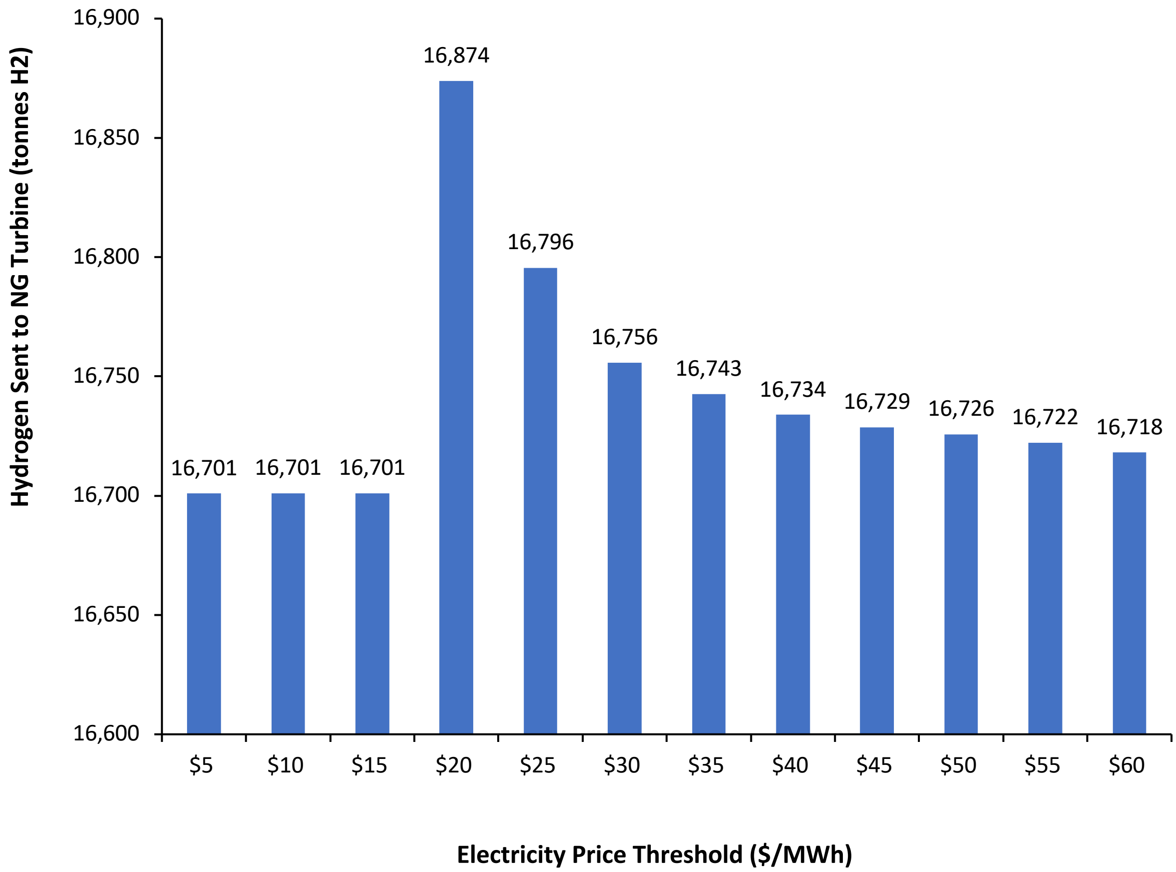

Figure C17. Annual hydrogen mass co-fired in natural gas turbine as a function of the user-defined electricity price threshold ($/MWh).

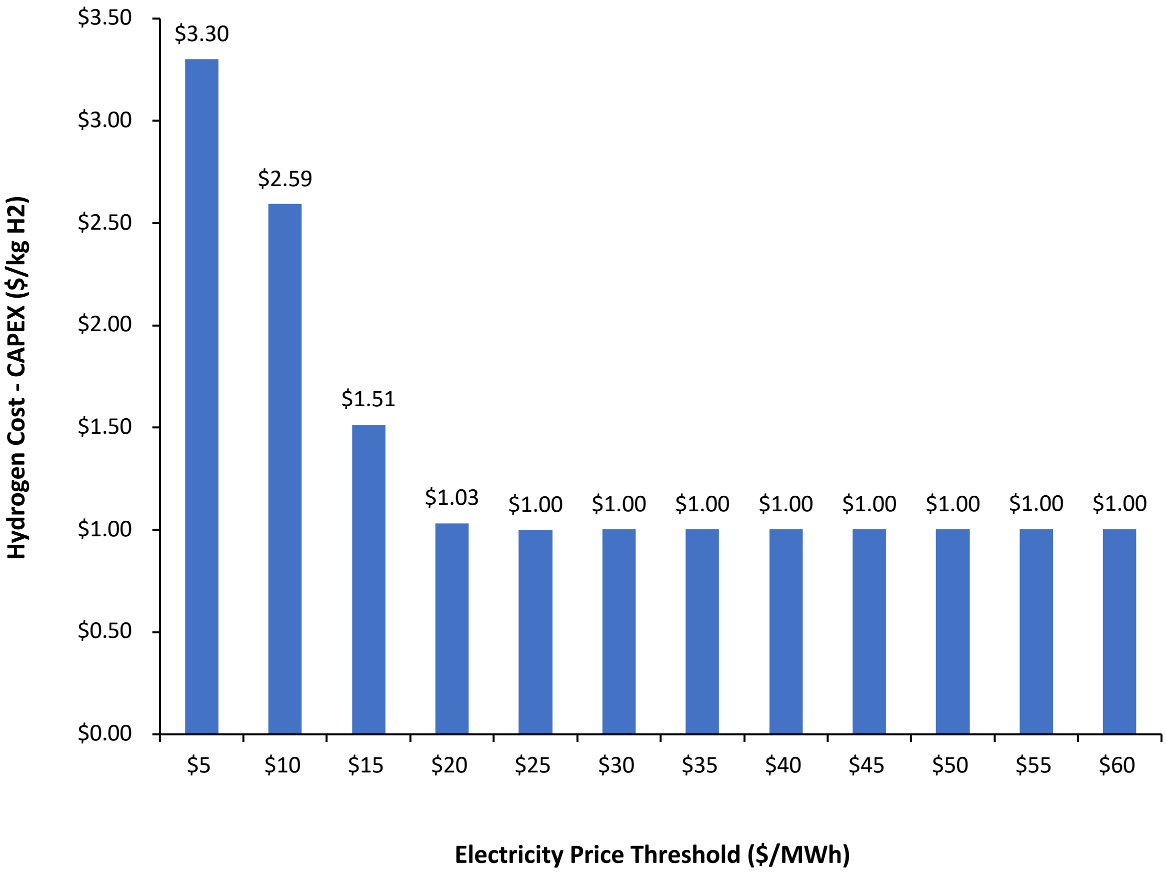

Figure C18. Specific capital cost for H_2 production and storage ($/kg H_2) as a function of the user-defined electricity price threshold ($/MWh).

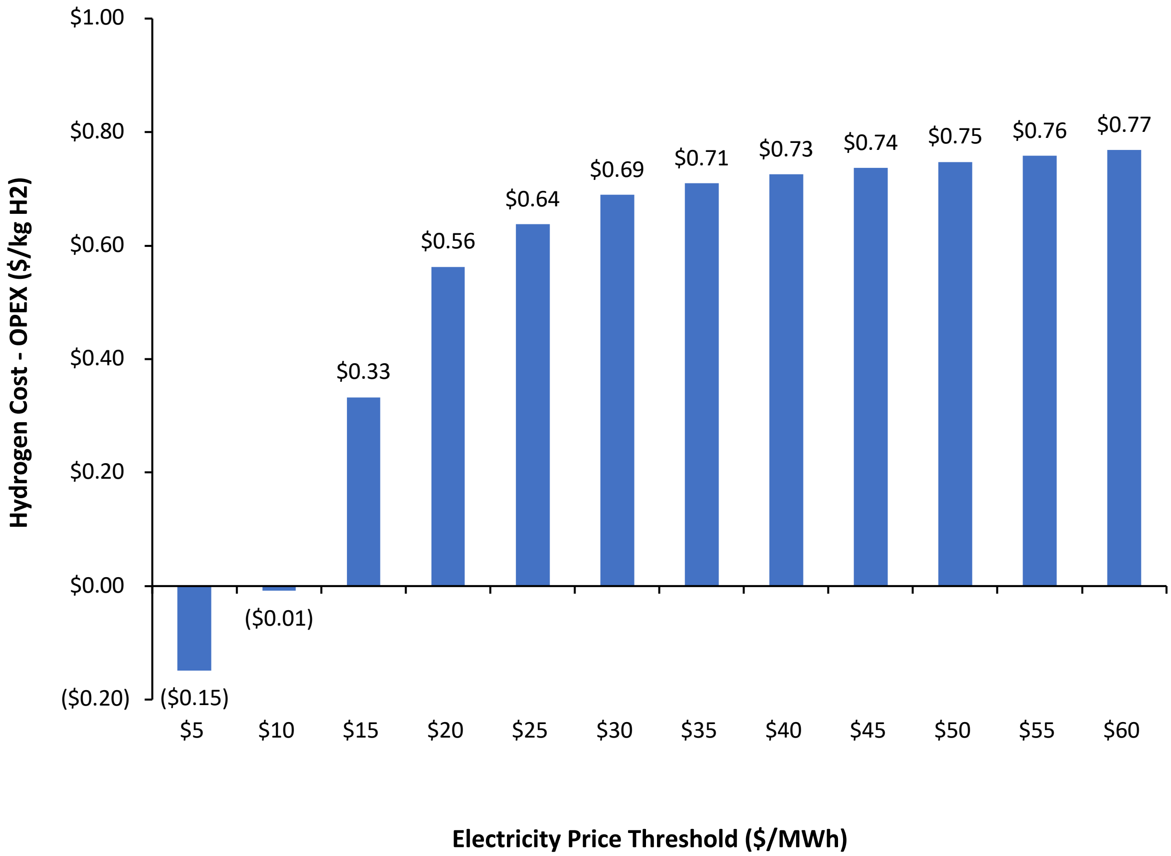

Figure C19. Specific operating cost for H_2 production and storage ($/kg H_2) as a function of the user-defined electricity price threshold ($/MWh).

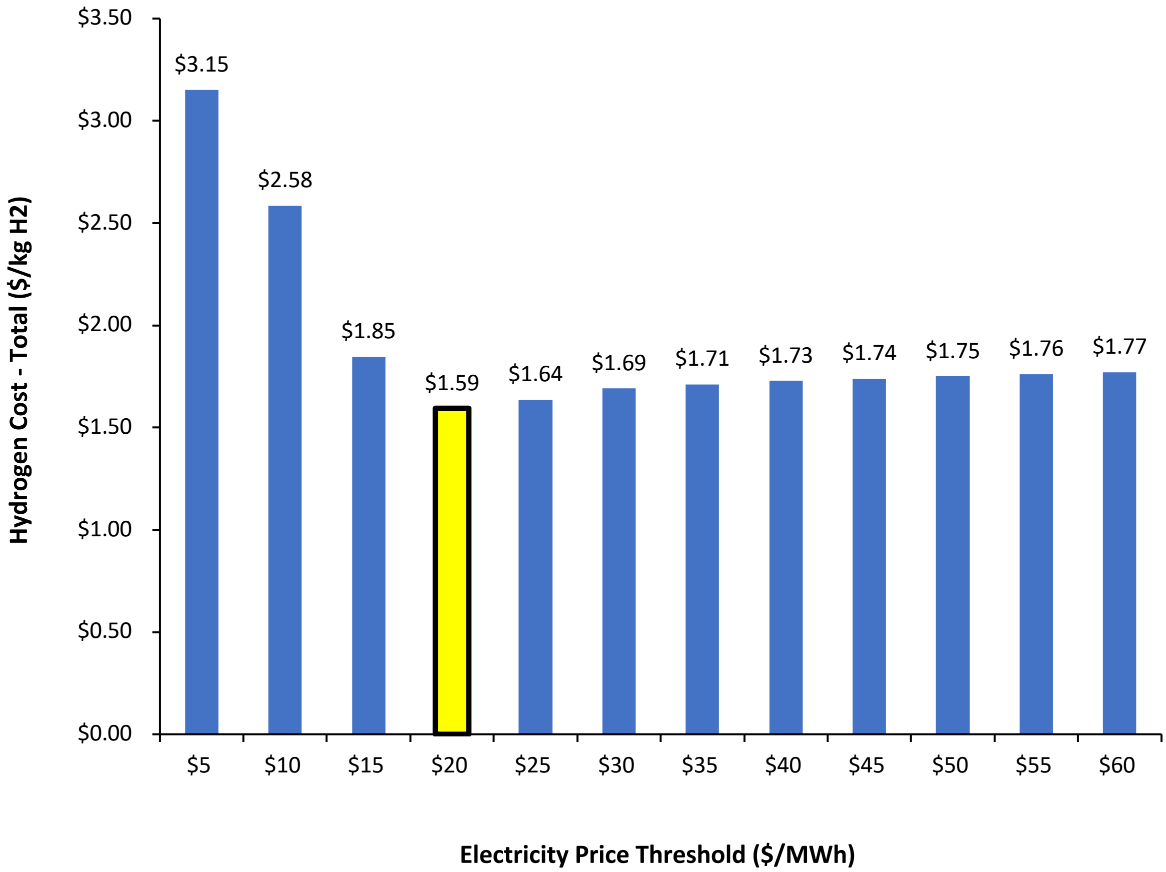

Figure C20. Specific total system cost for H_2 production and storage ($/kg H_2) as a function of the user-defined electricity price threshold ($/MWh).

The following analysis plots demonstrate the significant CO_2 emission reduction benefits provided by the H-2-SALT system integrated with an NGCC plant (Hydrogen co-firing case) as described above in comparison to the same NGCC plant operating under the same two modes (727 MW and 128 MW) during periods of high and low-priced electricity relative to the user-defined electricity price threshold without Hydrogen co-firing (no co-firing case). The same total power production (both gross and net) is provided to the electrical grid for each case, providing a consistent cost basis for comparison. As Figure C24 demonstrates, generally the higher the electricity price threshold, the higher CO_2 emissions reduction potential since there is higher availability of the electrolyzer and therefore H_2 production for use in the NG turbine, although there is a maximum emissions reduction benefit of 16.6% achieved at $25/MWh based on the specific electricity price data set used for this analysis. The 16.6% CO_2 emissions reduction is based on a maximum co-firing rate of 20 vol% H_2 to limit modifications required to the NGCC turbine. The CO_2 emissions potential increases significantly if the rate of Hydrogen co-firing is increased beyond 20 vol% H_2. A time plot of the H_2 storage cavern mass is shown in Figure C6.

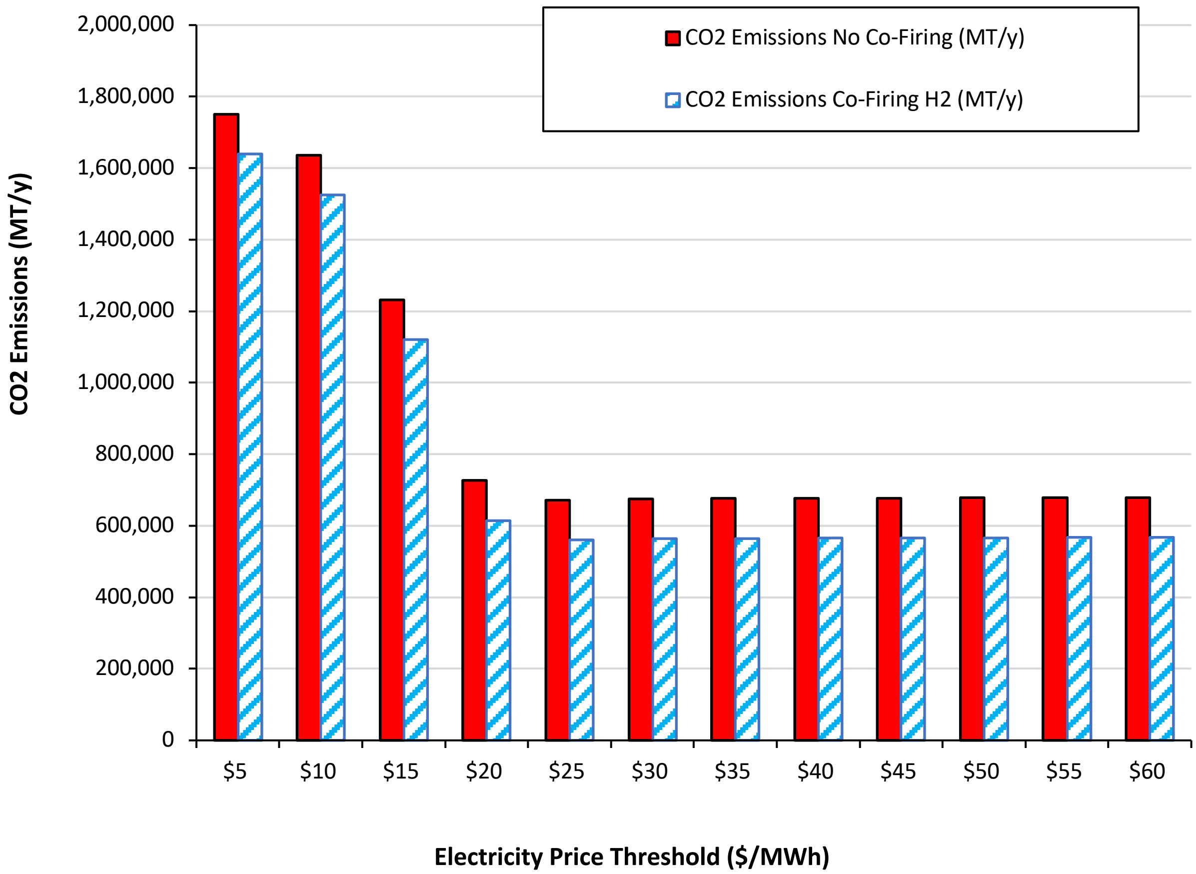

Figure C21. Total annual CO_2 emissions (metric tonnes/year) as a function of the user-defined electricity price threshold ($/MWh)

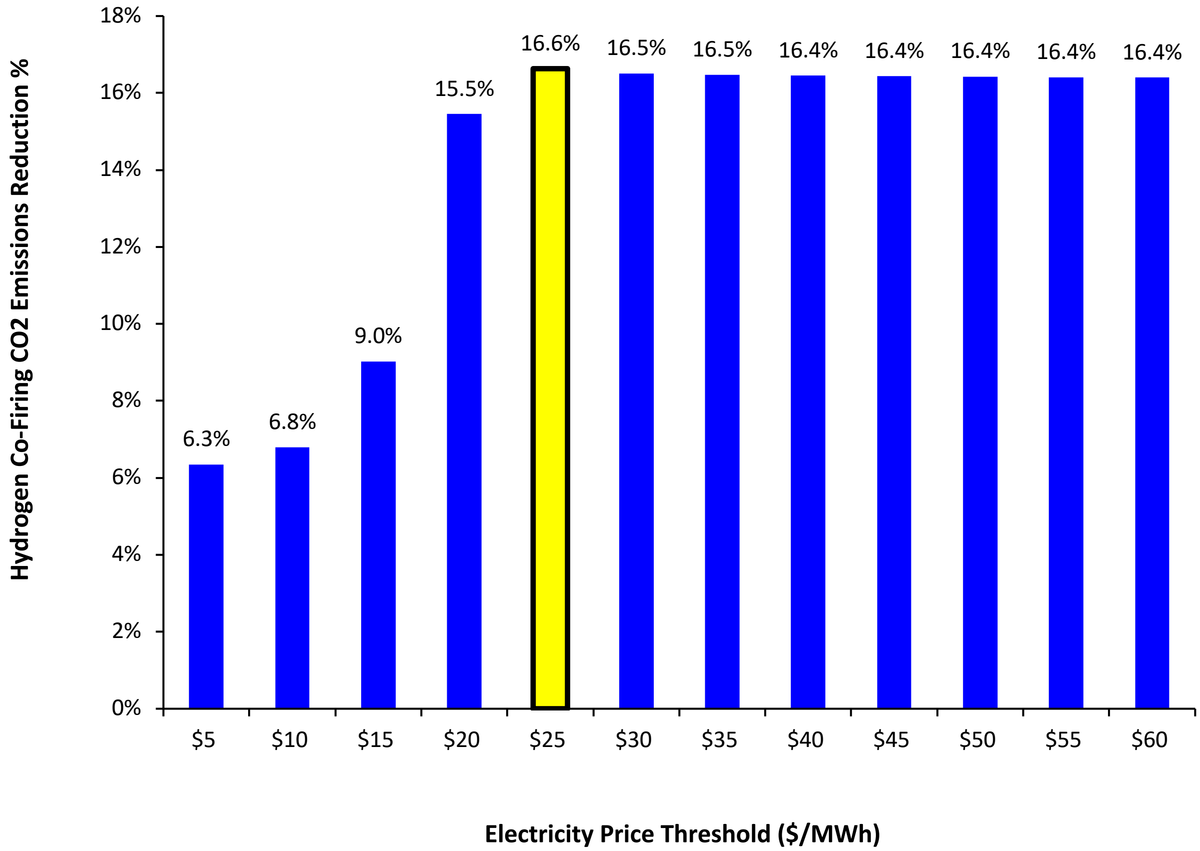

Figure C22. Relative CO_2 emissions reduction percentage from the hydrogen co-firing case as compared to the no hydrogen co-firing case as a function of the user-defined electricity price threshold ($/MWh)

Conclusion

The analysis presented here demonstrates both the low cost and significant CO_2 emissions reduction potential achieved by integrating a NGCC plant, an electrolyzer, and a H2 salt cavern storage system at medium and full commercial scales. Linde's extensive commercial cavern operating experience coupled with its deep technical understanding of electrolyzer system design and operation provide substantial credibility to the performance and cost assessment demonstrated herein. This study reinforces the commercial viability and competitiveness of large-scale, electrolytic H_2 production and storage that can be used for both electrical power supply to the grid during high-priced electricity periods (including co-firing with NG and fuel cell power production) and sale of H_2 for various industries, such as petrochemicals or transportation. The commercial potential of the H-2-SALT system is also relatively high because each of its components operate commercially today.

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Appendix D: Technology Gap Assessment

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

28 February 2022

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National Energy Technology Laboratory

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Disclaimer

Current state-of-the-art

This section documents the current state-of-the-art for the electrolytic production of hydrogen, cavern storage of hydrogen, and re-combustion of hydrogen in a natural gas combustion turbine.

Cavern storage of hydrogen is one of several energy storage technologies that include:

- Electrochemical storage devices such as batteries (lead acid, lithium ion, nickel/metal hydride, sodium/sulfur), flow batteries (vanadium-redox, zinc/bromine), and capacitors
- Electromechanical storage devices including steel and composite rotor flywheels
- Electrical storage devices such as superconducting magnetic energy storage
- Pumped hydroelectric energy storage
- Compressed air energy storage

These technologies offer energy storage in a wide range of system power ratings and discharge times at required levels of power (Figure D1).

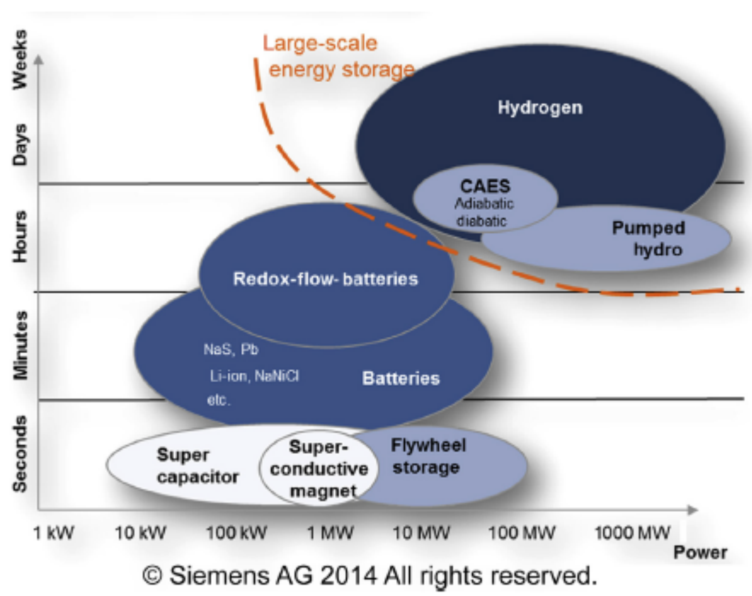

Figure D1: Regimes of energy storage technologies based on power and discharge times (Tarkowski, 2019).

Battery Energy Storage Systems (BESS)

Batteries, particularly Li-ion batteries, convert electrical energy to chemical potential energy. They are versatile in their application and are the most widely used energy storage technology today but can be limited in terms of power system rating (absolute volume of power delivered) compared to large-scale hydrogen storage. Li-ion batteries excel in energy efficiency, having long cycle lives, and have relatively high energy density, yet are known to be a high-cost solution that can be prone to fire due to the presence of an organic electrolyte (Chen et al., 2020). Global supply chains for lithium production are still in their infancy (Sun et al., 2019). Despite these concerns, Li-ion batteries have been deployed at grid-scale in places like Australia (Keck et al., 2019). Redox-flow batteries (Weber et al., 2011) are optimized for grid-scale storage offering large number of charge-dissipate-recharge cycles, many years of life, reasonable construction costs, and ability to rapidly respond to changes in input/output. Costs for Li-ion BESS have been estimated at ~$600/kWh (Albright et al., 2012).

Electromechanical storage devices

Electromechanical storage devices are “rapid response” energy storage systems that store excess electrical energy in the form of the kinetic energy of a moving mechanism, like a flywheel (Boyes and Clark, 2000; Arani et al., 2017). They are in commercial use today. They have a low energy density and a high-power density (Arani et al., 2017). These are useful in managing power quality but are only useful on the time scale of seconds. Benefits include small size, low cost, large number of charge/dissipate cycles, and a lack of chemical or flammable components. Mechanical failure of the system can impart significant damage to physical facilities from the uncontrolled movement of the moving parts. Flywheel system have been estimated to have relatively high capital costs (~$5000/kWh) but have low annual O&M costs (~$19/kW-year) (Luo et al., 2015).

Electrical storage devices

Superconducting magnetic energy storage (SMES) systems store electricity directly as electrical energy by combining cryogenically cooled superconductive materials with power electronics to store energy (Mukherjee and Rao, 2019). Like the electromechanical systems described above, they have low energy density, but high power density (Tixador, 2008). They can release energy quickly with efficiency >95%. They are still at the research stage but have been envisioned as predominantly useful for power stability (Mukherjee and Rao, 2019).

Pumped hydroelectric energy storage (PHES)

PHES takes advantage of elevation gradients to convert electrical energy to gravitational potential energy. Today, it accounts for the vast majority (~96%) of energy storage capacity (Blakers et al., 2021). Pumped hydroelectric energy storage is useful in load management and provides needed power during periods of peak demand. These systems typically pump water uphill when electrical energy is in excess and allow the water to flow back downhill with the pump running backwards as an electrical generator. PHES has the benefit of being relatively simple needing only an elevated reservoir and either a lower reservoir or a river. In some cases, natural lakes can be used as either reservoir further reducing construction costs. The main concern with these systems arises from their impact on the natural surface environment where the cycling may affect the expectations of people and wildlife for using the component reservoirs and/or rivers. In addition, there can be competing users for the land and water needed for these systems (Blakers et al., 2021). The upper reservoir of a PHES system in Missouri, USA, failed in 2005 when a significant rainfall event led to the water level overtopping the dam that was supporting the upper reservoir (NWS, 2022). More novel systems have been envisioned that use abandoned mine shafts, but all take advantage of an elevation gradient to store electrical energy as gravitational potential energy.

Compressed air energy storage (CAES)

CAES converts excess electrical energy to compressed air for storage in an underground storage vessel. The two operational systems in the world (Huntorf, Germany; McIntosh, Alabama) use salt caverns as their underground storage reservoirs. In addition, underground aquifers have been investigated for CAES. A DOE-funded project in Iowa was unsuccessful in finding a reservoir with sufficient permeability despite a nearby commercially successful underground natural gas storage field at Redfield that has been in operation since the 1950s (Kolst et al., 2012).

Hydrogen

When determining the overall power system rating for very large-scale hydrogen energy storage, as in the case of a hydrogen cavern, the rating can easily shift into the GW scales as the size and volume of the particular cavern storage use case expands. Hydrogen cavern storage is therefore an extremely versatile energy storage technology and was selected for this project relative to alternatives due to its scalability and potential for combined high-power rating and discharge time.

Today, hydrogen is essential to produce ammonia, methanol, various petroleum products, a variety of polymers, and many other chemicals and materials. Most hydrogen used in the industrial sector is currently produced by steam methane reforming of methane, which creates CO2 emissions. Water electrolysis technology provides a CO2 emissions-free option to produce H2 for both distributed on-demand and on-site generation applications.

The industrial application of water electrolysis began in the late 1800s. By 1902, more than 400 electrolysis units using alkaline electrolytes were in operation. Three main technologies for the electrolysis of water are currently available – alkaline electrolyzers (AEL), proton exchange membrane electrolyzers (PEMEL), and solid oxide electrolyzers (SOEL). PEMEL was selected for the H-2-SALT system due to its ability to respond to rapid changes in electrical input.

AEL and PEMEL operate near ambient temperature conditions (up to 90°C), whereas high-temperature SOECs are typically operated at temperatures from 600-900°C. Small water electrolysis units (<10 kW) are used for gas chromatography, hydrogen welding, meteorology, or on-demand hydrogen production for use in laboratory settings. Larger electrolysis units are used in metallurgy, pharmaceuticals, the food and beverage industry, and glass & electronics production, among many others. In the energy sector, electrolytically produced H2 is used as a cooling medium for turbine generators, and it is also used in the bubble chambers of nuclear power plants. The demand for electrolytically produced H2 is growing rapidly due to the need for the storage of energy produced by intermittent renewable sources and nuclear energy sources, improvement of smart-grid energy flexibility, and the development of fueling stations for hydrogen vehicles.

Table D1: Comparison of Water Electrolysis Technologies

Types of water electrolyzers	**Alkaline Water Electrolyzers (AWE)**	**Proton Exchange Membrane Cell Electrolyzers (PEM)**	**Solid Oxide Electrochemical Cells (SOEC)**
Technology status	mature technology	commercially available, newer technology	lab-scale, R&D stages
Temperature range (°C)	ambient - 120		600 – 900
Charge carrier	OH^-	H^+	O^{2-}
Overall reaction	$H_2O \rightarrow H_2 + ½ O_2$		
Anode reaction	$2OH^- \rightarrow ½ O_2 + H_2O + 2e^-$	$H_2O \rightarrow ½ O_2 + 2e^- + 2H^+$	$O^{2-} + 2e^- \rightarrow ½ O_2$
Cathode reaction	$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$	$2H^+ + 2e^- \rightarrow H_2$	$H_2O + 2e^- \rightarrow H_2 + O^{2-}$
Anode catalyst	Ni_2CoO_4, La-Sr-CoO_3, Co_3O_4	Ir/Ru oxide	(La,Sr)MnO_3, (La,Sr)(Co,Fe)O_3
Cathode catalyst	nickel foam/Ni-stainless steel Ni-Mo/ZrO_2-TiO_2	platinum	Ni-YSZ or Ni-GDC Cermet
Separator	asbestos, polysulfone-bonded polyantimonic acid, ZrO_2 on polyphenylsulfone, NiO, polysulfone impregnated with Sb_2O_5 polyoxide metallic	PFSA polymer membrane	YSZ or GDC ceramic
Sealant	metallic	synthetic rubber/flouroelastomer	glass and vitro-ceramics
Current distributor	Ni	titanium	ferritic stainless steel
Containment material	nickel-plated steel	stainless steel	stainless steel
Pressure range (bar)	1 - 200	1 – 350 (up to 700)	1 – 5
Conventional current density (A/cm^2)	0.2 – 1	0 – 5	0 – 2
Efficiency (%)	60 – 80%	80%	100%
Capacity (Nm^3/hr)	1 - 2000	1 - 1000	1-50
Durability (hours)	100,000	80,000	10,000
H_2O specification	>0.2 MΩ.cm	>1 MΩ.cm	steam
Load cycling	medium	good	good

Stop/go cycling	weak	good	weak
T cycling	weak	good	weak

Alkaline Electrolyzers (AEL)

Hydrogen production by AELs is a well-established technology and electrolysis installations in the MW scale of electric power are available commercially from companies like NEL (Norway), McPhy (France), PERIC (China), THE (China), ThyssenKrupp (Germany), Sunfire (Germany), Asahi Kasei (Japan), and others.

AEL stacks use an aqueous solution of KOH as the liquid electrolyte. A key component of an alkaline electrolysis cell is the diaphragm separator and new diaphragm materials have been developed in recent decades as alternatives to the original asbestos-based diaphragms banned after the mid-1970s due to health concerns related to asbestos, in particular the Zirfon Perl diaphragm marketed by Agfa (Agfa, 2022). Most of the research in the field of AELs has been focused on the optimization of catalyst and electrode materials. Performance of current materials could be increased but it will be difficult to achieve significant performance/efficiency and durability improvements in this area since the modification or replacement of inexpensive alkaline electrolysis catalysts (e.g., Ni or Fe) with more expensive materials or rare metals is not an economically viable option. Conventional liquid electrolyte AEL has operational limitations including a maximum current density of ~0.5 A/cm2. This current density limitation occurs because at elevated current densities the generated gas bubbles that tend to flow upwards along the electrode surface, due to gravity, can form a continuous and nonconductive film of gas over the entire electrode surface and this resulting screening effect increases energy consumption and favors gas transport in both directions across the diaphragm. In modern AELs, the electrodes are made of porous grids that are pressed against the diaphragm to minimize the distance and reduce ohmic resistances. Such zero-gap AEL configurations have improved process efficiency. Using advanced concepts, current densities of up to 2 A/cm2 and pressures of over 200 bar can be envisioned with AEL systems.

Currently, the capital cost of AEL systems is estimated to be in the range of $800 to 1,000/ kW for large systems, but according to the Clean Hydrogen Joint Undertaking (CHJU) of the European Commission (EC) the total system capital cost including power supply and installation is projected to be less than $650/kW by 2024 and less than $500/kW by 2030.

Solid Oxide Electrolyzer (SOEL)

Thermodynamic analysis of the water spitting reaction shows that the Gibbs free energy change of the reaction (and hence the equilibrium cell voltage) decreases when the cell temperature is increased. It is therefore plausible that splitting water at elevate temperatures (800 – 1000°C range) would reduce energy consumption and boost efficiency. The energy balance is obtained by providing high-temperature heat as the necessary complementary amount of energy. A reduction in specific electrical energy consumption of ~one-third is achieved with SOECs compared to ambient-temperature electrolysis systems and kinetics of reactant/product transportation and the electrochemical reaction itself are also improved at higher temperatures. Efficiencies close to 100% can be reached at current densities of practical interest (~1A/cm2).

SOEL systems are the lowest TRL electrolysis technology and are not yet commercialized, but they have been developed and demonstrated at the laboratory and experimental/test plant scale. Despite several significant advantages, there are also many drawbacks to SOECs that limit market applications. Common issues of SOECs include a rather long turn-on and turn-off procedure due to the difference in thermal expansion coefficients of components and a rather rapid degradation (up to several percent over 1000's of hours of operation) because of the high temperature interdiffusion of the cell (stack) components and poisoning by the corrosion products of construction materials. The viability of operating SOECs at elevated pressures for the direct storage of hydrogen also remains limited due to the difficulty in developing stacks that can sustain significant pressure differences.

Proton Exchange Membrane Electrolyzers (PEMEL)

PEM electrolyzers have demonstrated several key advantages compared with other water electrolysis technologies including high load flexibility and ability to provide grid balancing services. For example, the largest SILYZER 300 system developed by Siemens AG demonstrates a full range (0-100%) of load dynamics in 10%/s and a minimum load of greater than or equal to 5%. PEM electrolyzers have achieved high current densities (up to 10 A/cm2) and hydrogen purities (up to 99.999%) and can be optimally integrated into e-mobility and e-fuel markets with Power-to-X technologies and infrastructure. The high maneuverability and operational flexibility, rapid start/stop and control response capabilities also allow PEM electrolyzers to be suited for fast-responding energy storage applications, as needed for storing energy during daily peak hours from renewable electricity sources like solar and wind. PEM electrolyzers can produce pressurized H_2 and O_2 gases at pressures up to 350 bar directly in self-pressurized electrolysis stacks, a technique that does not require further compression for storage or transportation and therefore can greatly reduce capital and operating costs. Most notably, the operation of PEM stacks at pressures up to only several tens of bars reduces energy consumption for electrolysis. This is useful since it eliminates the need for the most-demanding first compression stage (0 to 30-50 bar) of mechanical hydrogen compressors.

PEMEL technology is commercially available at the multi-MW scale, from companies like Cummins, Plug Power and ITM Linde Electrolysis, but several improvements are still needed to lower the cost of hydrogen produced by PEM-based water electrolysis. One existing cost challenge is the replacement of electrocatalysts containing platinum group metals (PGMs) by non-noble electrocatalysts (e.g., using transition metals or their oxides). In addition to cost, the high sensitivity of platinum to trace amounts of mineral and organic impurities found in feed water is also one issue with the use of PGMs in PEM electrolyzers.

One challenge of PEM electrolyzers (as well as AEL) is that that the cell separators (the diaphragm and polymer membrane) are not 100% gas proof. There are microscopic phenomena that occur, which reduce the faradaic efficiency of these cells. The situation can be analyzed by calculating the value of the parasitic current densities associated with these different effects.

The first effect is due to the diffusion of hydrogen from the cathodic to the anodic cell compartment. This effect is enhanced at higher operating pressures due to the Fick equation, resulting in a negative impact on cross-permeation phenomena and gas purity. A second phenomenon that contributes to gas cross-permeation is that hydrogen (oxygen) solubility in water increases with pressure and, as a result, there is an increase in hydrogen transport through the membrane/diaphragm, with water molecules hydrating the ions. This leads to the recombination of oxygen and hydrogen at the electrode surface and decreases current efficiency. For a cell operating a current density of 1 A/cm2 and 30 bar, such effects reduce the current density by about 0.005A/cm2, and this reduction increases with further pressure increases.

In terms of catalysts for PEM systems, the acidic properties of PEMs result in electrocatalysts having stability issues; here, mainly precious metals and precious-metal-based compositions (alloys) are used. For the cathode, Pt is still the best catalyst for use in acidic media. Some Pt alloys—in particular Pt-Pd and Pt-Ni—can demonstrate even higher activity. To reduce the use of precious metals loading, electrocatalysts on carbon carriers (carbon black, carbon nanotubes and nanofibers, graphene, etc.) have been found to be very efficient. One main problem with PEM electrolysis is the anode electrocatalysts. The anode overvoltage is rather high and the electrocatalyst durability may determine the lifespan of the electrolysis stack. It is well known that, as an anode electrocatalyst for PEM electrolysis, Ru (Ru dioxide) is the most active, but it is not sufficiently stable. The best electrocatalysts for anode (besides RuO_2) are Ir and Ir-based compositions. Carbon carriers are not sufficiently stable as anode electrocatalysts.

The capital cost for PEMEL technology is currently in excess of $1000/kW for large systems but the EU Clean Hydrogen Joint Undertaking expects this to fall to below $900/kw by 2024 and to $600/kW by 2030. Due to its increased flexibility and operational advantages PEMEL is expected to capture a significant share of the electrolyzer market from the currently dominant AEL technology over the next decade.

A comparison of the main performance metrics of typical PEM electrolyzers produced by different companies is shown in Figure D6.

Table D2: Performance comparison of different PEM electrolyzer technologies

Manufacturer	Country of origin	Capacity range (kg H_2/hr)	Capacity range (Nm^3 H_2/hr)	Pressure (bar)	Energy consumption range (kW*h/kg H_2)
ITM-Linde Electrolysis (selected for H-2-SALT system)	UK	10 - 170	110 – 1,900	1 to above 30	45 – 60
Siemens	Germany	100 – 2,000	1,000 – 22,400	1 - 35	45 – 65
Hydrogenics (now Cummins)	Canada	0.5 - 450	4 – 5,000	1 - 8	55
AREVAH2Gen	France	0.5 - 35	5 - 400	1 - 45	45 – 55
Giner (now Plug Power)	USA	3 - 20	30 - 300	1 -40	45 - 55

A typical performance comparison of AEL, PEM, and SOEL systems is shown in Figure D7. For PEM and AEL cells operating at near ambient temperature conditions in aqueous media, a standard water electrolysis voltage E° of 1.23 V is required to initiate the reaction. For SOECs, an E° of only 0.85 V is needed. Conventional alkaline cells can be operated close to 100°C because the high KOH concentration increases the boiling point of the electrolyte. However, kinetics is not always optimized and the cell resistance (resulting from cell materials, and from the gas production and screening effects) is large. As a result, the cell voltage and specific energy consumption for ALEs tend to increase rapidly, and the maximum operating current density is limited to a few hundred mA/cm2. AEL cells can be pressurized, but the management of pressure differences between both sides is not trivial and can potentially be dangerous. ALE technology is the least expensive of the three technologies and is well suited for operations where high power density and compactness of design are not required, and preferably for operation in stationary conditions. PEMEL platinum-group metal (PGM) electrocatalysts and the thin, high conductivity protonic membrane of PEM electrolyzers make the kinetics of PEM electrolyzers much more efficient. The cell is more compact and can be operated in the multi-A/cm^2 range with high efficiencies. PEM electrolyzers are also highly flexible and the technology is the best suited electrolyzer type for providing grid stabilization services and use in large scale energy storage capacity, including H2 cavern storage. PEM cells can be operated at pressures up to 80 bars. This is an advantage for several reasons including that (1) the capital and operating costs of downstream hydrogen compression are reduced, and (2) the balance of plant design is simpler. PEMEL technology is more expensive than alkaline technology, but efforts are ongoing to reduce per-unit costs, including increased stack size (>MW scale) and replacement of rare metals with less expensive materials. In general, the SOEL technology is currently more expensive than AEL or PEMEL systems and is the least developed in terms of size, productivity, and commercial readiness.

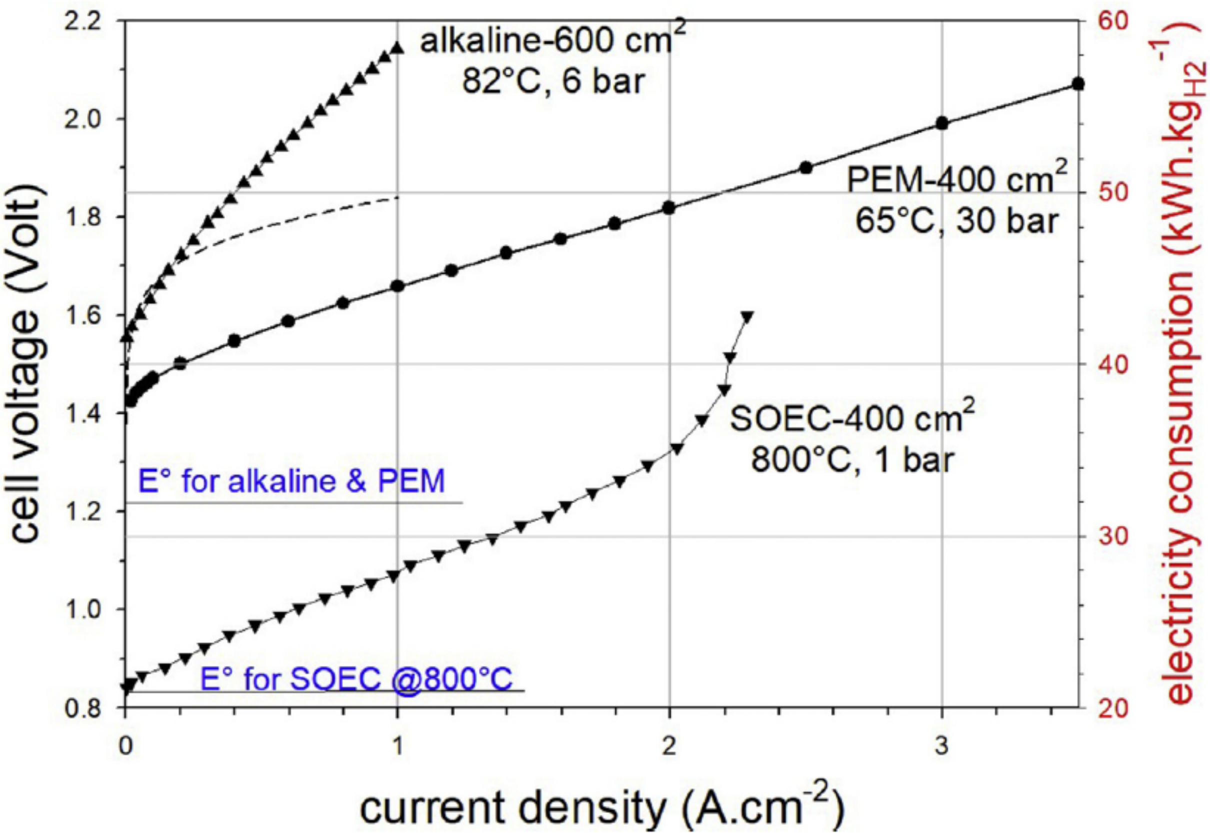

Figure D2: Comparison of i-V curves for AEL, PEMEL and SOEL water electrolysis cells.

Figure D2 provides a comparison of techno-economic characteristics of different electrolyzer technologies. Table D3 shows further techno-economic characteristics of AWE and PEM water electrolyzers.

Table D3: Comparison of techno-economic characteristics of different electrolyzer technologies

	AEL			PEMEL			SOEL		
	Today	2030	Long-term	Today	2030	Long-term	Today	2030	Long-term
Electrical efficiency (%, LHV)	63 to 70	65 to 71	70 to 80	56 to 60	63 to 68	67 to 74	74 to 81	77 to 84	77 to 90
Operating pressure (bar)	1 to 30			10 to 80			1 to 3		
Operating temperature (°C)	60 to 80			50 to 80			650 to 1000		
Stack lifetime (operating hours)	60,000 to 90,000	90,000 to 100,000	100,000 to 150,000	30,000 to 90,000	60,000 to 90,000	100,000 to 150,000	10,000 to 30,000	40,000 to 60,000	75,000 to 100,000
Load range (%, relative to nominal load)	10 to 110			0 to 160			20 to 100		
Plant footprint (m^2/kW_e)	0.095			0.048			TBD		
CAPEX ($\$/kW_e$)	\$500 to \$1400	\$400 to \$850	\$200 to \$700	\$1,100 to \$1,800	\$650 to \$1,500	\$200 to \$900	\$2,800 to \$5,600	\$800 to \$2,800	\$500 to \$1,000

Table D4: Techno-economic characteristics of AEL and PEMEL water electrolyzers with a 20-year system lifetime

Technology	**AEL**		**PEMEL**	
	2017	2025	2017	2025
Efficiency (kWh/kg H_2)	51	49	58	52
Efficiency (LHV, %)	65	68	57	64
Lifetime Stack (operating hours)	80,000	90,000	40,000	50,000
CAPEX – total system cost including power supply and installation costs ($/kW)	$860	$550	$1,380	$800
OPEX (% of initial CAPEX per year)	2%	2%	2%	2%
CAPEX – stack replacement ($/kW)	$390	$250	$480	$240
Typical output pressure (bar)	1-30	30	30	60

A basic process flowsheet of a typical PEM water electrolyzer is shown in Figure D10 (Grigoriev et al., 2020).

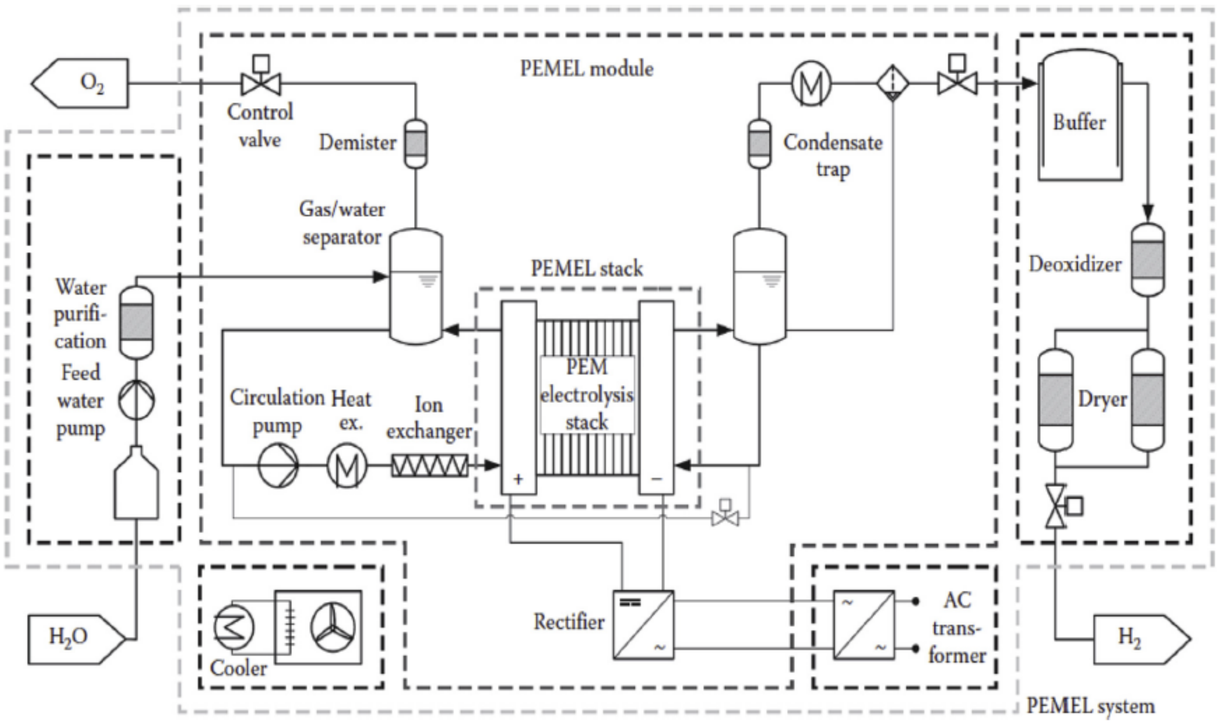

Figure D3: PEM water electrolyzer process flowsheet (after Grigoriev et al., 2020)

Overcoming challenges and limitations

This section documents how the proposed integrated system technology will overcome the shortcomings, limitations, and challenges in the relevant field and application.

The ITM-Linde Electrolysis electrolyzer technology is a PEMEL-based system and its benefits compared to other electrolysis technologies include: energy performance/efficiency, scalability, flexibility, and fast ramp up/ramp down capabilities necessary for an energy storage application. ITM Linde Electrolysis are designing systems optimized for projects at the hundreds of MW scale, minimizing capital, manufacturing, and operating costs, and maximizing lifespan.

ITM Power have also completed the construction of one GW/a capacity factory and have recently announced the intent to construct additional similar manufacturing facilities to maximize the benefits of manufacturing at scale to reduce costs.

Controlled integrated operation of the H-2-SALT system provides stable electricity generation and H2 production for sale to industrial markets in addition to co-firing with natural gas. The H-2-SALT system has the potential to reduce CO2 emissions by over 16% and helps promote environmentally sustainable continued use of natural gas assets as future CO2 emissions regulations are likely to be implemented worldwide. The combined operational and engineering, construction, and procurement (EPC) experience of Linde with its portfolio of hydrogen plants and underground H2 storage cavern will minimize development costs and timelines and reduce commercial risks for the technology. Linde's hydrogen storage cavern is a big differentiator among competitors and Linde has extensive intellectual property in the space of underground storage of H2.

Linde's hydrogen storage cavern is located in a salt dome near Liberty, Texas. Linde's hydrogen production sites all produce very pure H_2 (i.e., containing less than 1 ppm CO, hydrocarbons (HC), etc.). Typically, Linde injects pure, untreated H2 into the cavern with a compressor. There is some salt, water and CO2 in the cavern (the salt has some HC dissolved in it) and some HC migrates into the H2 stored in the cavern. When H2 is pulled out of the pipeline, it is treated to remove HC. Linde's outlet purification system uses two dryer beds with molecular sieves to remove water and CO2, producing clean and dry H2. It is hard to remove all the HC from the cavern outlet gas, but the H2 purity specification is always met for end-users. When the cavern pressure is very low (about 1000 psig), particularly at bottom of cavern, there is higher potential for HC contamination in the H2. Linde process manages that potential contamination based on customer demand and can fine-tune the operation of the dryer beds to meet H2 product purity specifications. It is very important to select the right type of salt chemistry and the right salt cavern geometry & design. Salt density and chemical properties of the salt are critical to prevent contamination by impurities. At higher pressures, impurities entering the H2 are reduced due to interaction of pressure with salt and impurities contained in the salt.

Competitors have tried to build and operate other salt domes, but Linde is currently the only industrial gas company that has been able to build and operate a full-scale commercial H2 salt storage cavern. 20 different SMR plants supply H2 to the Linde salt cavern. The hydrogen plants use proprietary SMR technology with pressure swing adsorption (PSA) purification units on the back end to remove all impurities (water, CO, CO2, HC, any sulfur components, etc.) and produce high purity pipeline-grade H2 for delivery either directly to customers or the salt cavern. Byproduct crude H2 from a third-party cracker unit or alkyl unit can also be processed and purified with a PSA unit to clean it up before it is supplied to the cavern. Autothermal reforming (ATR) and partial oxidation (POX) technologies can also be used. PSA unit is typically the best commercial technology for H2 purification.

There is no current product that simultaneously provides reliable, steady low-carbon electricity at affordable prices and that enables existing NGCC power providers to continue operations in the context of future CO2 emissions regulation for the power industry. While renewable energy sources with low or zero carbon footprints are being rapidly installed today, the intermittency of these electricity sources make it difficult to maintain system reliability and affordability. To meet the peak demand during periods of low renewable power generation, the grid relies on dispatchable generation from fossil fuel power plants that can adjust their power output on demand. However, relying on fossil fuel power plants to stabilize the grid leads to undesirable CO2 emissions. As a first-of-its-kind technology integration, the H-2-SALT system provides a novel way to meet the needs of stable electricity production at commercial scales while simultaneously reducing CO2 emissions and enabling continual use of new or existing fossil fuel assets. To the project team's knowledge, there is no current competing technology offering such a solution.

Additionally, the H-2-SALT system provides the flexibility to not only store and consume H2 in natural gas turbines, but also sell H2 for use in a wide variety of commercial applications including petrochemical refining and methanol production, steel production, ammonia production, glass, and semiconductor processing, and the growing H2 fuel cell-based transportation industry. Linde's commercial expertise and strong existing business channels and customer relationships in traditional and growing H2 markets provide superior advantages for minimizing commercial risk and maximizing the return on investment for a H-2-SALT demonstration. The ability to diversify the H2 product sales channels and leverage Linde's key commercial strengths bolsters the feasibility and impact of the H-2-SALT system. Green H2 produced with renewable resources costs between $3/kg and $6.55/kg, according to the European Commission's July 2020 hydrogen strategy. The ability to use low-priced, low-emission electricity for H2 production and compete against green H2 producers with favorable H2 pricing provides further commercial advantage and a unique marketing opportunity.

Key technical issues associated with the proposed technology

Key technical risks and issues associated with the proposed technology are summarized in Table D5.

Table D5: H-2-SALT's key technical risks/issues.

System Component	Technical Risks	Explanation of Risk
Electrolyzer	Manufacturing cost not reduced sufficiently	Manufacturing the PEMEL technology at scale does not deliver the expected cost reductions and PEMEL capex is not competitive with other electrolysis technologies like AEL.
Electrolyzer – compressor train	H_2 production train not robust to intermittent operation	Hydrogen production train (electrolyzer and compressor(s)) cannot withstand multiple stop-starts from cold without increased degradation/O&M costs.
Turbine	Turbine unsuitable for co-firing with H_2	Turbine cannot accept addition of H_2 at the concentrations necessary to deliver energy storage objectives. Material changes, alternate system configurations, and increased safety measures need to be implemented to increase the % of co-firing of H_2 in a natural gas turbine above 20 vol%.

Cavern	Leakage	Contaminant leakage into the H_2 product is always a concern, especially in areas where the geological storage volume contains high levels of CO, sulfur components, CO_2, and THC.
Cavern	Managing cavern growth	Cavern growth over time contributes to the potential contaminant leakage issue.

Perceived technology gaps and R&D needed for commercialization by 2030

Table D6: H-2-SALT's Perceived technology gaps and R&D needed

System Component	Perceived technology gaps	R&D needed for commercialization by 2030
Cavern	Geological, petrophysical, and geomechanical analysis of salt and shale often require highly specialized analytical procedures. The boom in shale gas/oil drilling has led to somewhat better development of methods for shales, but salt procedures are less developed.	Inter-laboratory comparison studies of geological, petrophysical, and geomechanical property measurements as well as methods for petrographic analysis.
Cavern	There is little literature examining the effects of long-term interaction between Hydrogen, brine, and air with the host rocks in a salt cavern system. Stress associated with injection/withdrawal cycles will perform work on the cavern walls.	Lab-scale studies are needed to simulate the long-term effects of repeated pressurization/depressurization cycles on host rocks
Cavern	Hydrogen at the low temperatures in a salt cavern may support microbial activity that could alter the gas composition in the cavern.	Lab-scale studies are needed to identify the types of microbes that may thrive in a H2 storage cavern and their effect on stored gas compositions.

Development pathway description

This section provides the development pathway description for the subject concept that will overcome key technical risks/issues, including need for and size of site-specific engineering scale prototype

The transition from lab-scale experiment to commercial deployment in the short-term (5-10 years) requires engineering, construction, and validation of a full-scale demonstration system including scale-up and optimization of the integrated unit operations as well as full control system optimization using inputs from the electrical grid and energy consumption performance metrics from each operating component. The eventual product will be a fully optimized and controllable H-2-SALT design that can be retrofitted to any existing NGCC plant or included in new constructions in selected geographies that maximize market size. Linde will target locations where both CO2 revenue incentives and large differences in peak demand and surplus supply electricity prices exist. The operational and design learnings from this demonstration plant will drive further improvements for the final commercial H-2-SALT configuration.

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Abbreviations

AEL................ Alkaline electrolyzer

ATR .... Autothermal reforming

CAES.............. Compresses air energy storage

CHJU .... Clean hydrogen joint undertaking

EC.................. European Commission

EPC................ Engineering, construction, and procurement

GW................ Gigawatt

HC .... Hydrocarbon

O&M .... Operations and maintenance

PEMEL........... Proton exchange membrane electrolyzer

PGM.............. Platinum group metals

PHES .... Pumped hydroelectric energy storage

POX............... Partial oxidation

PSA................ Pressure swing adsorption

SMES............. Superconducting magnetic energy storage

SOEL.............. Solid oxide electrolyzer

Appendix E: Commercialization Plan

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

28 February 2022

AWARD NUMBER: DE-FE0032015

FUNDING OPPORTUNITY ANNOUNCEMENT: DE-FOA-0002332

SUBMITTED BY
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SUBMITTED TO

U.S. Department of Energy
National Energy Technology Laboratory

Overview

Linde will lead the project's technology to market strategy. As a major international industrial gas and engineering company, Linde has the capabilities to commercialize this technology and can leverage its existing network of customers to gain knowledge of market needs and identify commercial prospects for deployment. The company continuously engages with customers for opportunities to engage in risk-managed approaches to commercial applications at scale for its water electrolysis technology developed with ITM Power. If the proposed H-2-SALT technology for hydrogen generation and storage is economically attractive, it can leverage these existing channels for commercial launch.

Overall Transition Plan

Technology Transition

The proposed technology is an integrated process that enables cost-effective low carbon power production for natural gas combined cycle (NGCC) power plants using ITM Linde Electrolysis technology and salt cavern storage. At the heart of the H-2-SALT system are ITM Linde Electrolysis's proton exchange membrane electrolyzer (PEMEL) technology, hydrogen compression system, and cavern storage of H2.

In its 2018 sustainability targets, Linde made a commitment to invest more than $1 billion in decarbonization initiatives by 2028, which has encouraged the commercialization of technologies like this one. Linde's "go to market" strategy could be sale of equipment through Linde Engineering or a "Build-Own-Operate" (BOO) model that is typically employed by Linde Gas. In the BOO model, Linde would build, own, and operate the facility and charge the customer based on every ton of CO2 avoided. In the "sale of equipment" business model, Linde would engineer, procure, and construct a turnkey plant for the customer who would own and operate it themselves. Having diverse pathways to commercialization allows the technology to be fit to the business model of the customer. These pathways to commercialization will follow the normal business approach with staged milestones or gates. This will allow the team to address any gaps either in performance, business case, or market evaluation.

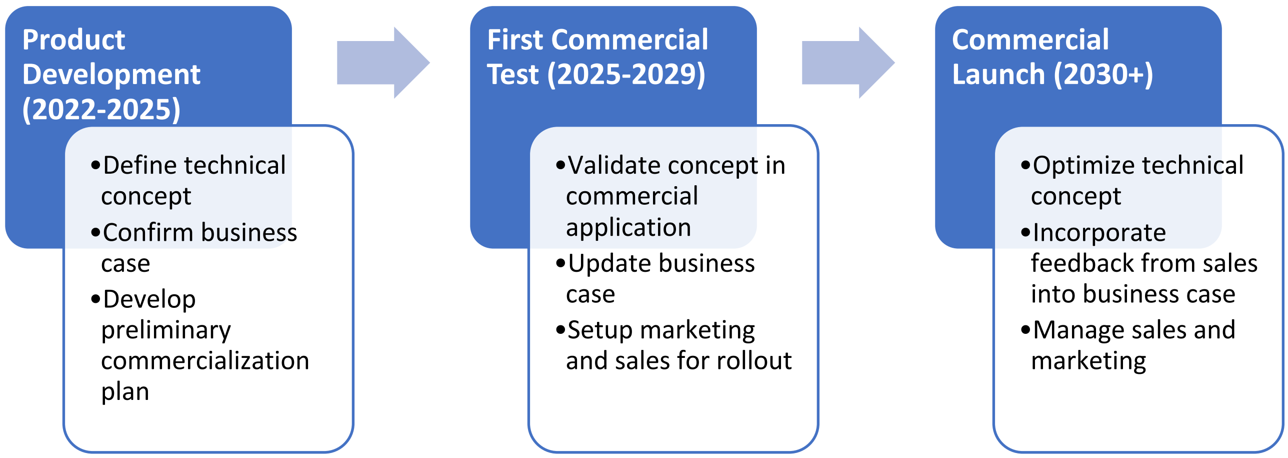


Figure E1. Commercialization Roadmap for H-2-SALT.

The transition from lab-scale experiment to commercial deployment in the short-term (5-10 years, Figure E1) requires engineering, construction, and validation of a full-scale demonstration system including scale-up and optimization of the integrated unit operations as well as full control system optimization using inputs from the electrical grid and energy consumption performance metrics from each operating component. The eventual product will be a fully optimized and controllable H-2-SALT design that can be retrofitted to any existing NGCC plant or included in new constructions in selected geographies that maximize market size. Linde will target locations where both CO2 revenue incentives and large differences in peak demand and surplus supply electricity prices exist. The operational and design learnings from this demonstration plant will drive further improvements for the final commercial H-2-SALT configuration.

Long-term (8+ years ahead), Linde will work with its project partners to fully deploy the final H-2-SALT design for selected customers and geographies as well as develop and strengthen key commercial relationships that support future business development. Linde and ITM will co-own all intellectual property and licenses for the water electrolysis system, providing market access freedom and entry barriers for competition. Likewise, foreground intellectual property to be generated for the use of the H-2-SALT design in this specific application will further support market penetration. Key commercial risks include reduced electricity market prices or demand, field and/or fabrication shop construction cost, and technical scale-up challenges and related costs for the electrolysis system. Key resources will be experienced engineers and project managers for the design phase and well-trained operations personnel for continuous commercial use.

Commercial Readiness Level

Based on the current market status of the individual components of the H-2-SALT technology, the current Commercial Readiness Level (CRL) for the H-2-SALT system has been defined to be 4. This CRL has been determined based on the current achievement of

1. Deep understanding of target applications
2. Clear definition of the final product
3. Development of a basic cost-performance model, and
4. Insight into potential suppliers, partners, and customers along the value chain.

Target applications include:

- injection of electrolytically produced H2 into a new or existing natural gas combustion turbine for electricity production,
- conventional H2 uses in industry including hydrocracking, hydrotreating, and methanol synthesis in petrochemical refining or chemical plants, ammonia production for fertilizers used in agriculture, and heat treatment for glass and semiconductor industries, and
- emerging markets such as H2 use for fuel cell electric vehicles, direct reduced iron for steel production, and pipeline injection into local natural gas grids for residential and commercial heating and/or electricity generation.

The final product is currently well-defined in terms of its individual components and already commercialized or near-commercial status of these components. The project team has also developed a basic cost-performance model to support the value proposition and provide initial insight into design trade-offs. As a major industrial gases and chemicals company, Linde not only has very strong existing relationships with key H_2 customers in traditional industries but also developing industries such as fuel cells for transportation. These relationships extend globally and provide numerous opportunities for growth and ease of market entry for the H-2-SALT technology.

The CRL expected to be achieved at the end of the project would be 5, as specified in the Technology Maturation Plan. Technical targets required to achieve this CRL would be rigorous optimization of the final product design including further understanding of operations requirements and specific components or design features needed for integrating the H-2-SALT system with analysis of cost implications. The timeline needed to achieve the technical targets would be 1-2 years. Commercial targets include clearly defined partnerships with key stakeholders across the value chain evidenced by development agreements and further refinement of financial models used to evaluate net present value (NPV) and overall margin projections in line with current and future business needs. The timeline to achieve the commercial targets would be 5+ years.

Table E1. Commercialization partners

Commercial Partner	Role	Expertise
Linde	Design for system integration and optimization. EPC for H_2 compression and purification system prior to salt cavern injection.	Decades of commercial industrial gas process plant EPC and operations experience
ITM-Linde Electrolysis	PEMEL technology provider. Linde is now strategic investor in ITM Power to co-develop technology.	ITM Linde Electrolysis will leverage ITM Power's modular PEM electrolysis technology and Linde's world class EPC expertise
KGS	Provide subsurface geoscience and engineering data and interpretations	Subsurface geoscience and engineering
Evergy Inc.	Host site and electricity provider	NGCC plant operations experience and electricity pricing model development

As shown in Table E1, the key players across the value chain include Linde, ITM Linde Electrolysis, and Evergy, along with other potential NGCC power systems providers. As an example, the project team has an ongoing business and technology development relationship with the US-based power utility Southern Company through current and previous work on DOE-funded research projects. Additional players include potential direct-use H_2 customers such as oil and gas companies, steel producers, glass and semiconductor manufacturers, ammonia-based fertilizer producers, and fuel cell providers. These potential customers play a critical role in generating additional revenue for the technology and supporting the business case for H-2-SALT long-term. Further, the diversification of potential customers and uses of stored H_2 other than electricity production (e.g., transportation, manufacturing, pipeline gas) can effectively reduce future business and financial risk in the presence of market uncertainty.

Value Proposition and Market Advantage

There is no current product that simultaneously provides reliable, steady low-carbon electricity at affordable prices and that enables existing NGCC power providers to continue operations in the context of future CO_2 emissions regulation for the power industry. While renewable energy sources with low or zero carbon footprints are being rapidly installed today, the intermittency of these electricity sources make it difficult to maintain system reliability and affordability. To meet the peak demand during periods of low renewable power generation, the grid relies on dispatchable generation from fossil fuel power plants that can adjust their power output on demand. However, relying on fossil fuel power plants to stabilize the grid leads to undesirable CO_2 emissions. As a first-of-its-kind technology integration, the H-2-SALT system provides a novel way to meet the needs of stable electricity production at commercial scales while simultaneously reducing CO_2 emissions and enabling continual use of new or existing fossil fuel assets. To the project team's knowledge, there is no current competing technology offering such a solution.

Additionally, the H-2-SALT system provides the flexibility to not only store and consume H_2 in natural gas turbines, but also sell H_2 for use in a wide variety of commercial applications including petrochemical refining and methanol production, steel production, ammonia production, glass and semiconductor processing, and the growing H_2 fuel cell-based transportation industry. Linde's commercial expertise and strong existing business channels and customer relationships in traditional and growing H_2 markets provide superior advantages for minimizing commercial risk and maximizing the return on investment for a H-2-SALT demonstration. The ability to diversify the H_2 product sales channels and leverage Linde's key commercial strengths bolsters the feasibility and impact of the H-2-SALT system. Green H_2 produced with renewable resources costs between $3/kg and $6.55/kg, according to the European Commission's July 2020 hydrogen strategy. The ability to use low-priced, low-emission electricity for H_2 production and compete against green H_2 producers with favorable H_2 pricing provides further commercial advantage and a unique marketing opportunity.

Intellectual Property, Competitive Analysis, and Risks Analysis

Intellectual Property

This technology leverages existing intellectual property that is owned by Linde and partners. The novelty, however, lies in the combination of different unit processes to achieve lower CO2 intensity electricity and hydrogen production simultaneously. The technology will make use of internal water electrolyzer operating and cost data, as well as cost and technical performance information related to H2 compression and cavern storage. For example, a provisional patent for the process development of this integrated solution of an electrolyzer with an NGCC power plant that also includes post-combustion CO_2 capture is already in place. Based on the results of this effort, additional intellectual property may be generated. Any intellectual property generated will be owned by Linde plc. A preliminary patent analysis did not reveal any existing technologies that simultaneously produce electricity and hydrogen with low carbon footprint. Since the component pieces of the technology are owned by Linde, the team expects freedom to operate this technology if commercialized and does not foresee any path for competitors to limit deployment.

Competition

Competitors to the ITM Linde Electrolysis technology that produce and sell PEM electrolyzers include Cummins Inc. (who acquired Hydrogenics in 2019), Siemens, and Plug Power (who acquired Giner ELX in 2020). These companies have commercial product offerings for large-scale electrolyzer modules up to 5 MW in size. These modules can be stacked together for large-scale H_2 production. Similarly, ITM –Linde Electrolysis is a leader in PEM electrolysis technology with equal capabilities to produce and operate electrolyzer modules of up to 5 MW capacity. The combined experience of Linde as a major global industrial gases and engineering company with ITM Power in the ITM Linde Electrolysis joint venture provides superior capabilities for engineering and design related to electrolyzers, H_2 storage, and downstream H_2 purification and conditioning that may be required to meet customer demands in all markets, industries, and geographies. With the direct support and resources of Linde, the ITM Linde Electrolysis technology offers competitive advantage for enhanced system integration at customer sites, engineering and design for installations, and future technology development opportunities related to materials research, energy consumption reduction, CO_2 intensity reduction, and capital cost reduction.

Based on review of current public information, there is no existing competitor developing or offering the same system as H-2-SALT including all the capabilities of ITM Linde Electrolysis for the electrolysis component and existing expertise and technology portfolio of Linde for H_2 production and storage.

Manufacturing and Scalability

The manufacturing approach at full-scale requires a detailed understanding of requirements to optimally integrate the individual components. This will largely involve optimization of system operations but also specific components such as robust control systems, potential modifications to existing NGCC turbines to safely and effectively combust a mixture of H2 and natural gas, and an understanding of the most efficient H_2 storage volumes based on net-present-value (NPV) optimization and overall system capacity. Assembly of individual components will be based on best industry practices and previous experience. However, the most cost-effective manufacturing approach when integrating the individual components needs to be determined. For example, the project team needs to perform cost analysis of field vs. fabrication shop construction and installation for the integrated system. The project team will complete a quantitative cost/performance model to evaluate operations scenarios and identify solutions that maximize NPV. This model will include cost data for all work required for engineering, design, manufacturing, construction, installation, and commissioning of the integrated H-2-SALT system.

The H-2-SALT system can be deployed domestically or internationally depending on geological suitability of the region for cavern storage (i.e., presence of salt deposits of suitable thickness, areal extent, and quality) and proximity to operating NGCC plant assets. Further research could assess the suitability aquifer storage of H_2, which would open even more geography to application of this system.

Domestic areas of the United States with abundant salt deposits (Figure E2) include:

- South Central Kansas to West Texas
- Gulf Coast
- Lower Peninsula of Michigan and Northwest Ohio
- Appalachian Basin (Pennsylvania, New York, Eastern Ohio, West Virginia)
- Williston Basin (Montana, North Dakota, South Dakota)
- Rocky Mountain Intermontane Basins (Colorado, New Mexico, Arizona, Utah, Wyoming)
- Western Nebraska and Western Kansas

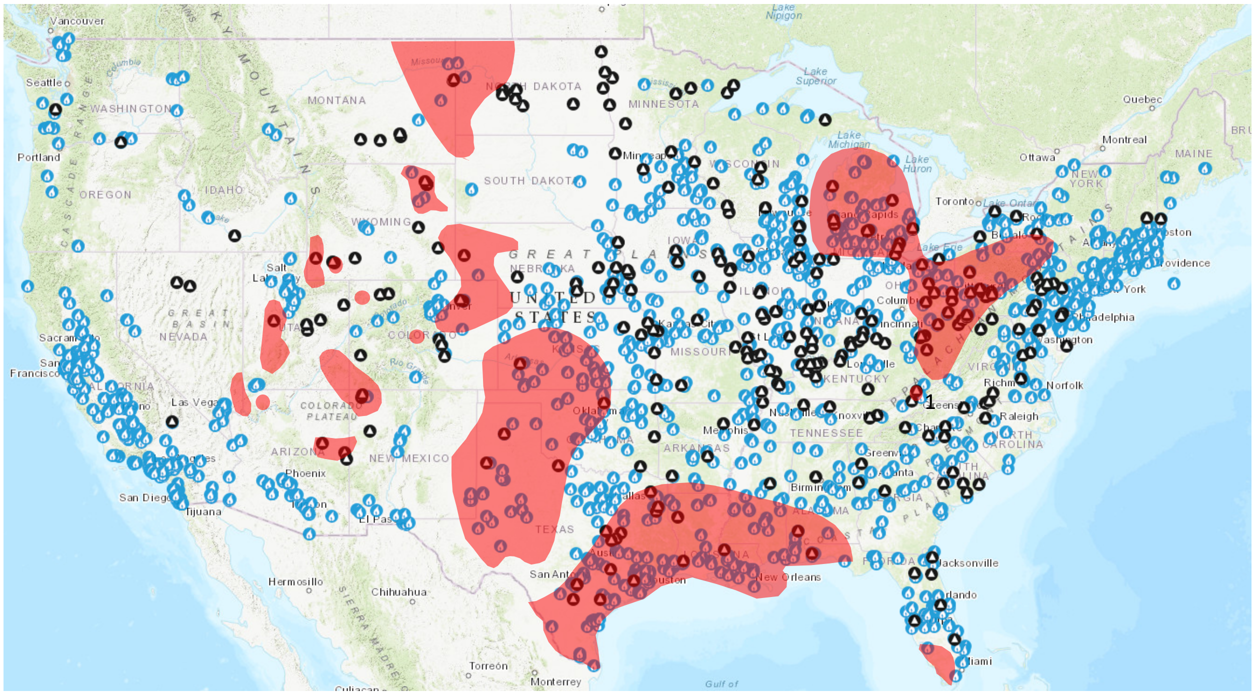


Figure E2. Map of United States showing distribution of salt beds (red polygons), natural gas electricity generating units (blue circles with flame), and coal-fired electricity generating units (black circle with triangle). Base map courtesy US Energy Information Agency.

Estimated Additional Revenue

Based on a preliminary evaluation of the H-2-SALT system, as described in the TEA report, a discounted cash flow analysis based on annual electricity revenue and operating costs as well capital costs for the electrolyzer and H_2 cavern sized for 114.5 tonnes of H_2 storage (small-scale but suitable for caverns in Kansas). This incorporates actual electricity prices from January – December 2020 obtained from Evergy from their Gordon Evans Energy Center (GEEC), a 120 + MWe (net) NGCC plant located in Colwich, KS.

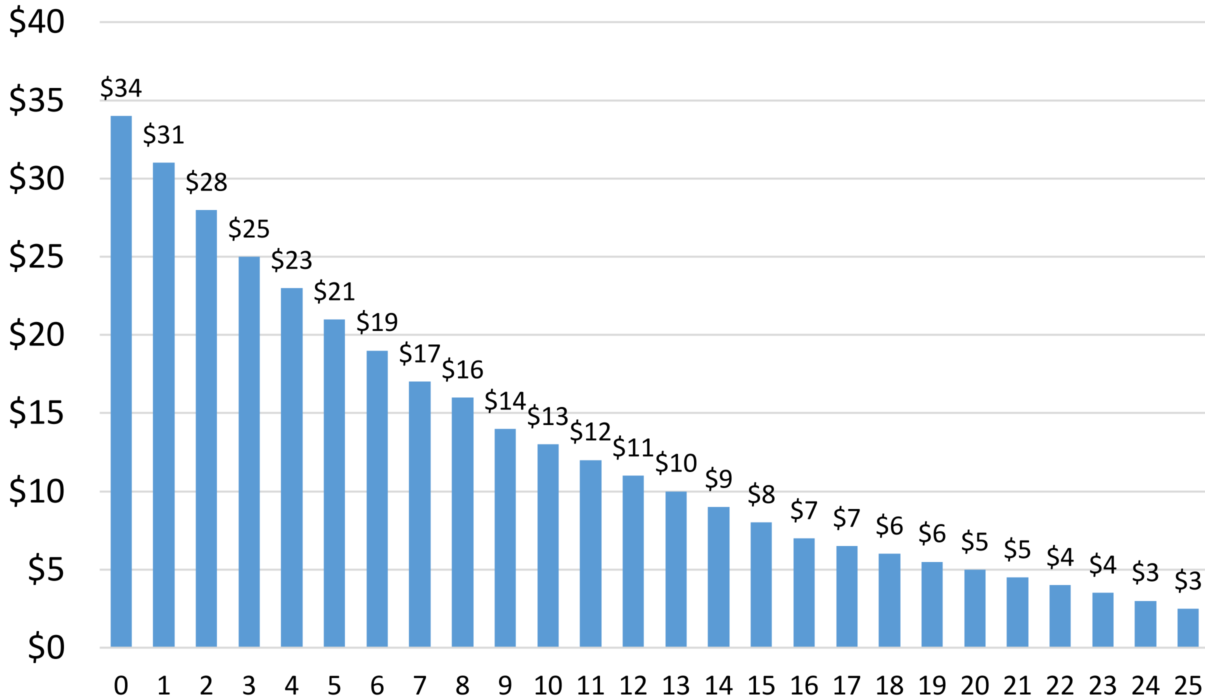


Figure E3: Discounted Cash Flow Analysis for an H-2-SALT system.

Estimated Additional Non-Financial Benefits to the Asset Owner

The main additional non-financial benefit to the asset owner is reduction of the CO_2 footprint of the NGCC asset long-term, especially considering expectations for more stringent regulations on greenhouse gas emissions globally in the coming years and decades. The following analysis plots demonstrate the significant CO_2 emission reduction benefits provided by the H-2-SALT system integrated with an NGCC plant (Hydrogen co-firing case) as described the TEA report in comparison to the same NGCC plant operating under the same two modes (727 MW and 128 MW) during periods of high and low-priced electricity relative to the user-defined electricity price threshold without Hydrogen co-firing (no co-firing case). The same total power production (both gross and net) is provided to the electrical grid for each case, providing a consistent cost basis for comparison. As Figure demonstrates, generally the higher the electricity price threshold, the higher CO_2 emissions reduction potential since there is higher availability of the electrolyzer and therefore H_2 production for use in the NG turbine, although there is a maximum emissions reduction benefit of 16.6% achieved at $25/MWh based on the specific electricity price data set used for this analysis. The 16.6% CO_2 emissions reduction is based on a maximum co-firing rate of 20 vol% H_2 to limit modifications required to the NGCC turbine. The CO_2 emissions potential increases significantly if the rate of Hydrogen co-firing is increased beyond 20 vol% H_2.

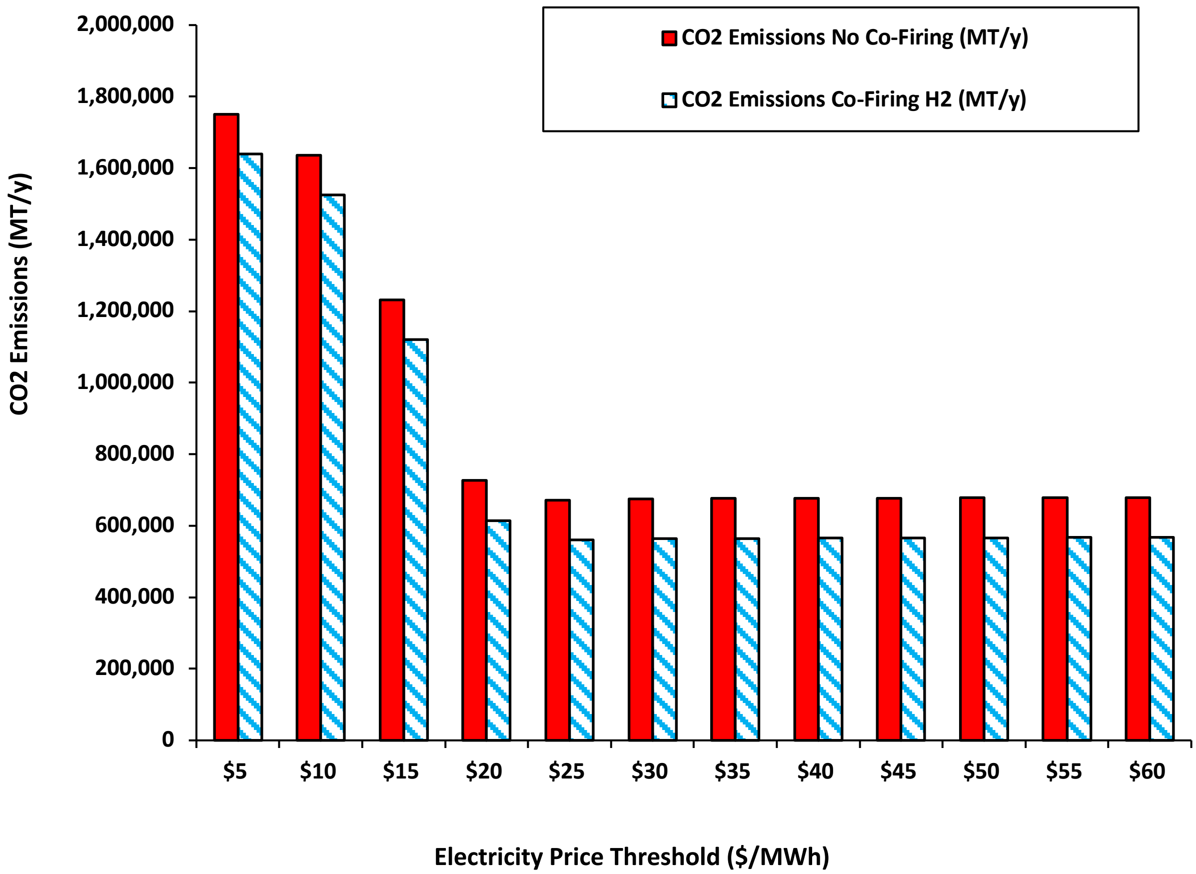


Figure E4: Total annual CO_2 emissions (metric tonnes/year) for the H-2-SALT system with and without hydrogen co-firing in the NGCC turbine as a function of the user-defined electricity price threshold ($/MWh).

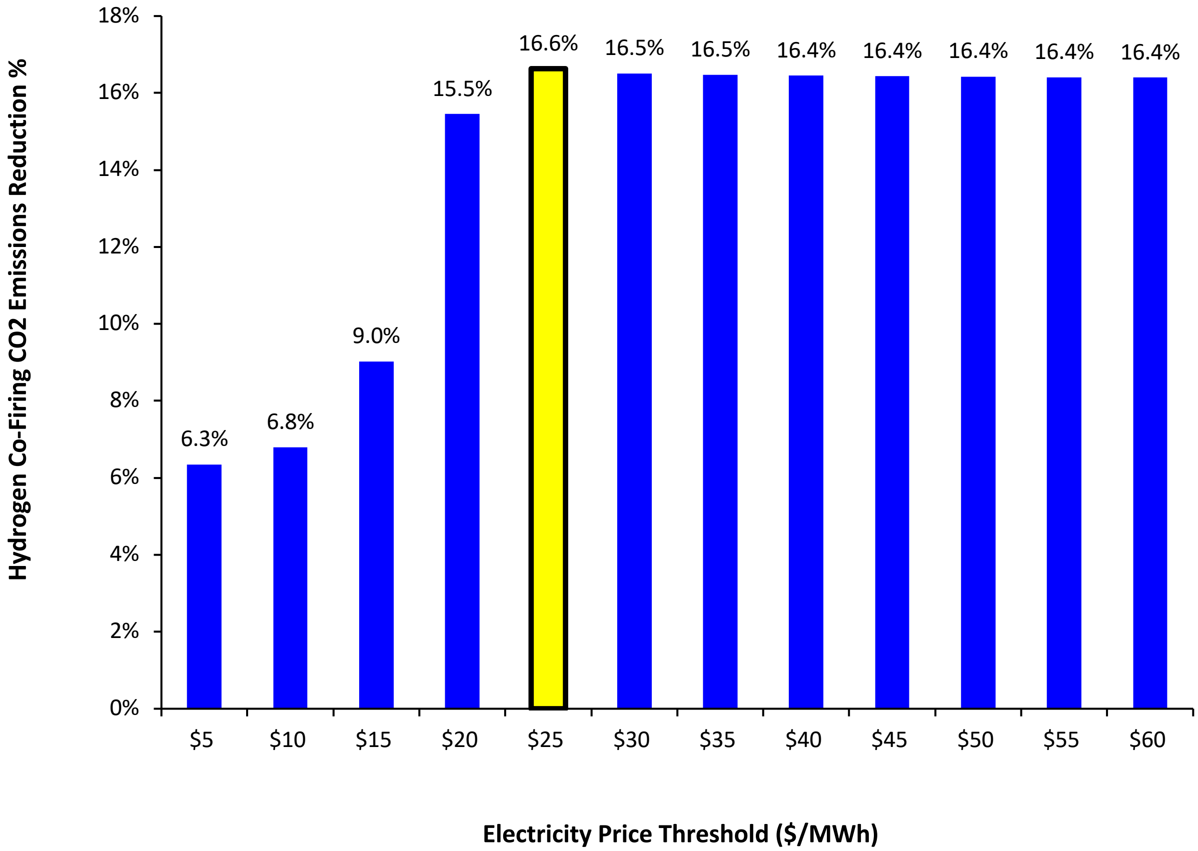


Figure E5: Relative CO_2 emissions reduction percentage from the Hydrogen co-firing case as compared to the no Hydrogen co-firing case as a function of the user-defined electricity price threshold ($/MWh)

Market Scenarios

In the U.S., approximately two-thirds of wholesale electricity sales occur in competitive markets. The wholesale electricity market is managed on a regional basis by entities called Regional Transmission Organizations (RTOs) or Independent System Operators (ISOs). There are seven RTOs/ISOs in the US:

- California ISO (CAISO)
- Electricity Reliability Council of Texas (ERCOR)
- Midwest ISO (MISO)
- Southwest Power Pool (SPP)
- New York ISO (NY-ISO)
- New England ISO (NE-ISO)
- Pennsylvania, New Jersey, and surrounding areas (PJM)

Each region is broken down further into electricity nodes, zones, and hubs. Within the market for renewable electricity Texas, California, and Kansas have been the primary areas of focus. Since the focus for this project is to use existing or new NGCC plants for electricity generation, we analyzed market data to show a comparison of renewable electricity vs. electricity produced by natural gas plants to see the market potential for natural gas electricity production and use into the future.

There is no doubt that renewable energy is rapidly growing in the U.S. and internationally. Renewable energy sources are variable by nature, leading to random spikes and shortages in the supply of electricity. By incorporating the impact of renewable electricity on electricity pricing for an H-2-SALT energy production and storage system, we believe that renewable electricity pricing can create favorable price variation for arbitrage for operating an H-2-SALT system. Two regions with the largest contribution from renewable energy are Texas and California Similarly, although it has a smaller absolute wind power generation due to its smaller population size and needed market for electricity, Kansas has a high capacity for growth and is in the top 5 states for overall wind energy contribution. As illustrated in Figure E8, natural gas is projected to be the largest source of generated electricity in the U.S. from 2022 through 2040. Based on electricity pricing and the impact of renewables on pricing, particular regions of interest for a commercial H-2-SALT project include California, Texas, and Kansas.

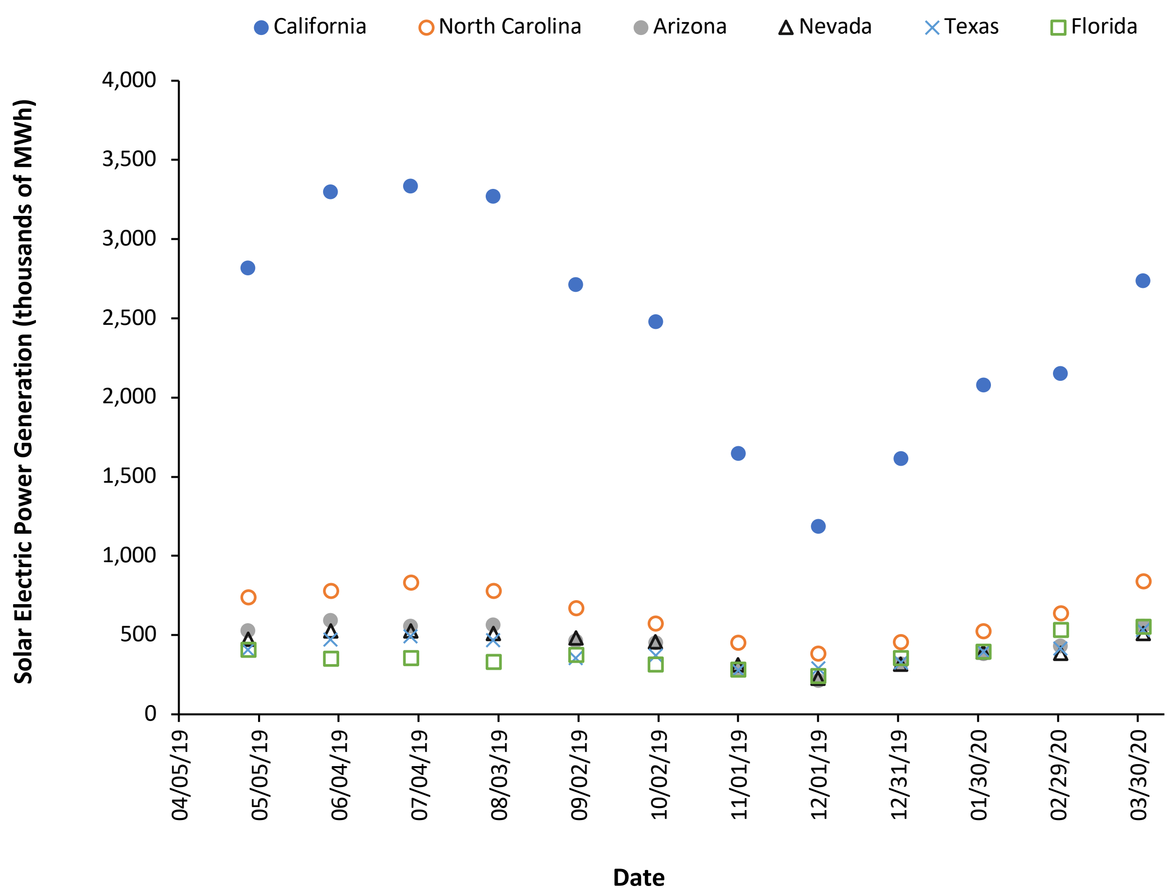
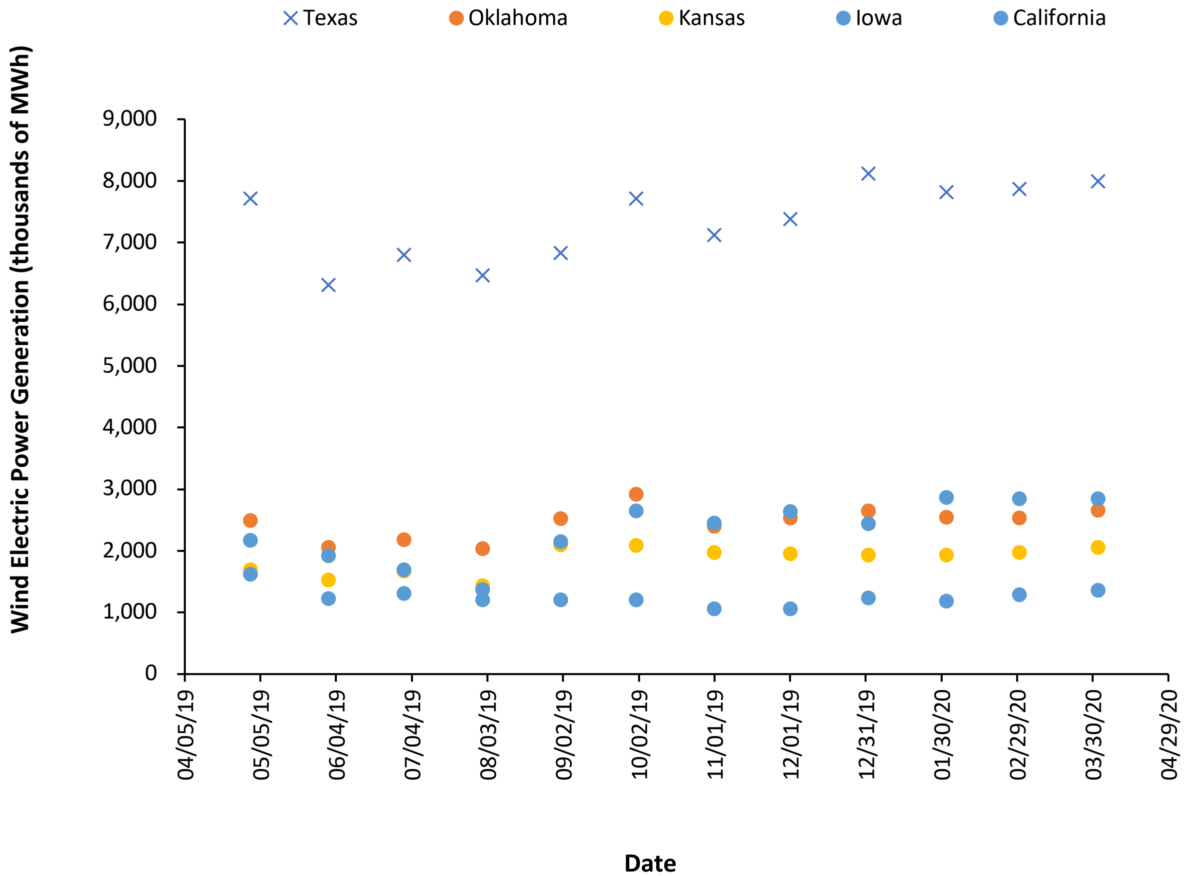


Figure E6: States with the largest solar energy contribution (USEIA, 2020).



FigureE7: States with Largest Wind Energy Contribution (USEIA, 2020).

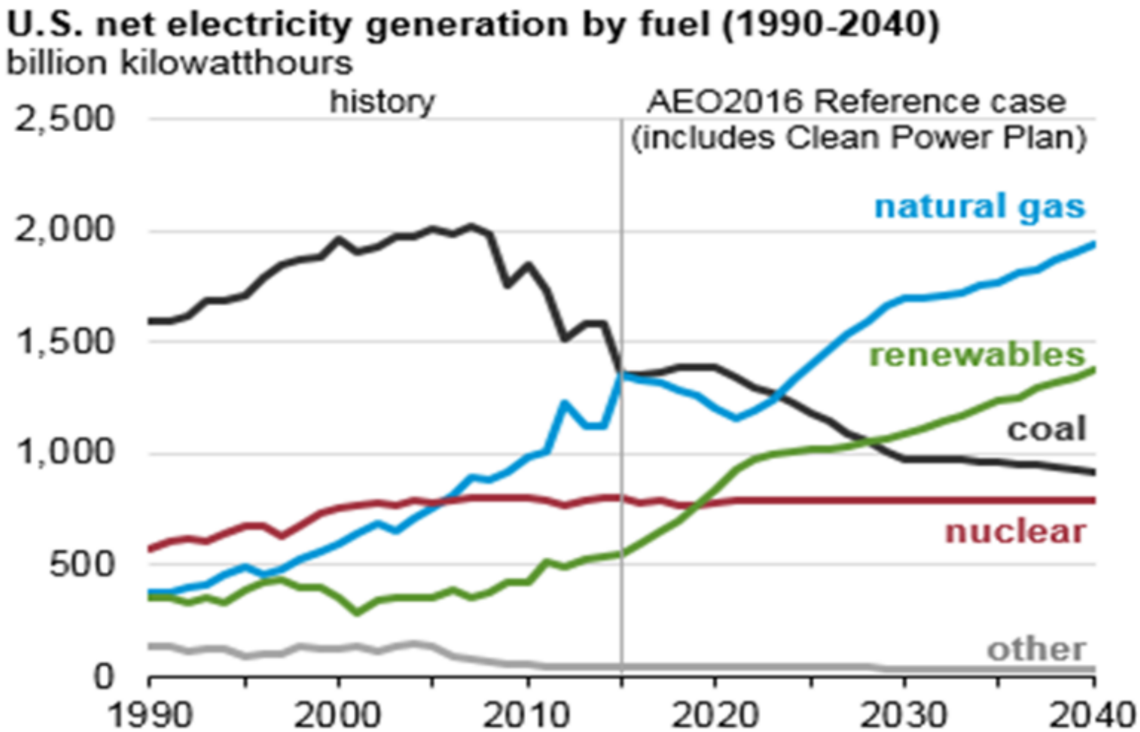


Figure E8: U.S. Net Electricity Generation by Fuel (1990 – 2040) (USEIA, 2020).

Conclusions

This document lays out a commercialization plan for the H-2-SALT system that first continues product development through 2025. This is followed by first commercial test from 2025-2029, followed by widespread commercial launch post-2030. In this way H-2-SALT would go from this paper study to commercial deployment. At the completion of this project, the Commercial Readiness Level moves from 4 to 5.

Technoeconomic Analysis (TEA) showed that the H-2-SALT system has a cost per kg H_2 of $1.75. This is within the DOE "Hydrogen Shot of $1-2 per kg H_2. The H-2-SALT system provides the flexibility not only to store and consume H_2 in natural gas turbines, but also sell H_2 for use in a wide variety of commercial applications (e.g., chemicals/refining, manufacturing, transportation, pipeline gas).

Intellectual property for H-2-SALT's electrolyzers is owned by Linde. Competition in the electrolyzer field includes Cummins Inc., Siemens, and Plug Power. However, there is no competition organization that provides a system similar to H-2-SALT. Manufacturing and scalability of the electrolyzer will rely on optimizing current manufacturing systems, while for the cavern it will rely on suitable geology as well as drilling program execution. Additional research is needed in the field of aquifer storage of H_2.

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U.S. Energy Information Administration, Midterm Progress Report, 2020.

Abbreviations

- BOO .... “Build-own-operate”
- CRL................ Commercial readiness level
- DOE................ US Department of Energy
- GEEC .... Gordon Evans Energy Center
- ISO .... Independent system operator
- NGCC............. Natural gas combined cycle
- NPV .... Net present value
- PEMEL........... Proton exchange membrane electrolyzer
- RTO .... Regional transmission organization
- TEA................ Techno-economic analysis

Appendix F: Technology Maturation Plan

for

H-2-SALT: Storing Fossil Energy as Hydrogen in Salt Caverns

28 February 2022

AWARD NUMBER: DE-FE0032015
FUNDING OPPORTUNITY ANNOUNCEMENT: DE-FOA-0002332

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SUBMITTED TO

U.S. Department of Energy
National Energy Technology Laboratory

Technology Readiness Level (TRL)

The current TRL of the H-2-SALT process can be assessed in terms of the TRL of each of its key components that have been developed from the technology's conception. Table F1 shows the current TRL of each component of the H-2-SALT technology along with the work completed to achieve each TRL along the R&D path. Based on this summary, the H-2-SALT technology has achieved an overall TRL of 4 per DOE TRL definitions.

Table F1: Current TRL of the components of the H-2-SALT process as a transformational energy storage system.

Key process component	Current TRL	Year achieved	Work to achieve each TRL along R&D path
1 NGCC Power Plant	9	2000 CT1 and CT2; 2001 CT3	Gordon Evans Energy Center, located in Colwich, Kansas (near Wichita), is a 294 megawatt (MW) natural gas-fired electric generating facility owned and operated by Evergy, Inc. The facility was originally commissioned in 1961. In addition to the three existing combustion turbines, the facility also included two natural gas and one oil-fired steam electricity generating units known as Units 1 and 2, respectively, which were retired in 2018.
2 H_2 Combustion Turbine	8	1990s-2015	Developed as part of a U.S. DOE program, GE's DLN 2.6e combustion system on its GE's HA-class turbines can burn fuel containing up to ~50% H_2 by volume. GE's turbines have nearly 30 years of operational experience burning a variety of fuels that contain H_2, totaling over 6 million operating hours. GE's aeroderivative and B/E class technologies are capable of operating on a wide range of H_2 concentrations up to ~100% by volume (Noon, 2019).

			Turbine retrofits for H_2 combustion have less commercial certainty at scale and therefore lower TRL. There is also the need to work with OEMs for custom-built units, which may not always have guaranteed performance.
3 **ITM Linde Proton Exchange Membrane (PEM) Electrolyzer**	8	2013-2021	Prior to 2017 ITM Power had sold 5.25 MW of large-scale electrolyzers operating in the full range of expected conditions. As of 2020, Linde has installed over 80 commercial H_2-producing electrolysis plants worldwide. Linde has announced it will build, own, and operate the world's largest PEM electrolyzer plant at the Leuna Chemical Complex in Germany (ITM Power, 2021). As of 2021, ITM Linde Electrolysis has commercialized a 2 MW-capacity electrolyzer module consisting of three stacks. These are built on a skid frame suitable to be housed indoors. Each 2 MW module can operate independently, allowing for greater flexibility in load control and rolling maintenance. The 2 MW modules are deployed with necessary sub-systems required for operation. Input water and output H_2 purification options are available depending on specific customer requirements.
	6 and 7	2004-2012	Engineering/pilot-scale demonstrations completed followed by full-scale demonstrations of 1 MW electrolyzers that can be installed inside a 20-ft

			container using surplus electricity to produce 400 kg of H_2/day. In 2011, ITM Power sold its first small-scale PEM-based hydrogen production system to the University of Nottingham (UK) making 4 kg H_2/day. [Hydrogen Journal, 2012]
4 **H_2 Storage Salt Cavern**	7	2007-2021	Linde currently operates an H_2 storage and distribution network in Texas anchored by salt cavern storage with 40 million m^3 working capacity (1.4 bcf) and a 350-mile H_2 pipeline from Texas City, TX, to Lake Charles, LA. This pipeline connects 50 customers and supplies H_2 at a rate of 600 mscf/day on a steady-state basis with peaking capacity of 700 mscf/day. Linde's salt cavern has been in commercial operation since 2007, providing customers with H_2 during periods of planned and unplanned peak demand. Linde has experience with new-build, commercial-scale storage caverns, for which there is a TRL of 9 (including within Kansas, where ~750 such storage caverns have been constructed). However, hydrogen storage caverns are rarer with only two in the US and one in the UK. There are gaps in our understanding of how geological variation in the host salt might affect permeability with respect to hydrogen. In addition, interactions between cavern the kinetics of microbial interactions with injected hydrogen and host geology are poorly understood. Additional lab-scale experiments and instrumented monitoring programs at active hydrogen

			storage caverns are needed to reduce uncertainty about these factors.
	1 - 6	pre-2007	Engineering studies and field demonstrations have been completed to develop and validate the design of a hydrogen salt cavern energy storage system. System components include: removal of H_2 product from an H_2 pipeline, compressing the H_2 product, cooling the compressed H_2 product to a temperature sufficient to condense water vapor, removing the condensed water to produce a compressed and chilled H_2 product, and introducing the H_2 product into the salt cavern (Linde, 2007).
5 Integrated Energy Storage System	1 - 4	2021	• Preliminary models have been developed to evaluate integration of system components. • Research is still required to understand profiles for pure H_2 vs. NG/H_2 mix for combustion and emissions; work needed to evaluate impacts. • Research is still required to assess use cases (e.g., pipeline injection) and to determine if caverns can provide adequate product purity. • Development of controls system and optimization with electricity pricing is required. Specific development areas include balancing the low threshold for electrolyzer operation with the higher specific energy demand at higher capacity.

The target commercial applications of the H-2-SALT system include:

- H_2 production, storage, and use in an NGCC combustion turbine or designated H2 combustion turbine to produce electricity,

- H_2 use in a fuel cell for electricity production (reversible fuel cell is another option),
- H_2 use in H_2 fueling stations for fuel cell vehicles,
- H_2 use in new gas pipelines or injection into the natural gas grid for residential and commercial heating and/or electricity generation, and
- H_2 use in industrial applications (e.g., sulfur treatment, hydrocracking, and methanol synthesis in the petrochemical refining and chemical industries, direct reduced iron for steel production, ammonia production for fertilizers used in agriculture, heat treatment for glass and semiconductor industries, etc.).

Proposed Work

The known performance attributes of the H-2-SALT system are summarized in Table F2 along with their performance requirements. The performance requirements were determined from project team discussions and internal benchmarks based on Linde's commercial experience.

Table F2: Performance attributes and requirements of the H-2-SALT process

Performance attributes	Performance requirements
Power arbitrage for optimal electrolyzer operation	• Annual electrolyzer availability >60% based on proper electricity pricing arbitrage. • Minimize levelized cost of H_2 (LCOH) from electrolysis.
Product value and purity of H_2	• H_2 product no more than 50% more expensive than current H_2 market pricing from steam methane reforming (SMR) depending on price of variable renewable electricity. • H_2 purity consistent with standard commercial requirements.
Emissions reduction from H_2 combustion	• Reduce CO_2 emissions by 10-15% with H_2 combustion compared to baseline, based on 20 vol% H_2 replacement in natural gas. • Ensure H_2 combustion does not increase emissions of other pollutants (NO_x, SO_x, etc.).
Cavern Geology	• Ensure salt geology possesses low enough permeability to ensure hydrogen containment. • Ensure impurity levels do not affect H_2 product purity for end user.

NGCC plant availability	• Increased availability of fossil power plant in the context of CO_2 emissions reduction regulations.

The performance attributes that will were assessed during the project are detailed in Table F3 with performance requirements and the work needed to meet each requirement.

Table F3: Performance attributes to be tested and work needed to meet performance requirements

Performance attribute	Performance requirement	Work needed to meet performance requirement	Progress made during project
Power arbitrage for optimal electrolyzer operation	Annual electrolyzer availability >80% based on proper electricity pricing arbitrage.	Develop an H-2-SALT system operations model using real-time electricity price profiles to determine economically feasible periods for electrolyzer operation and H_2 storage.	As detailed in the TEA report for this project, electrolyzer availability of 85% can be achieved using electricity price thresholds of $25/MWh or greater.
	Minimize levelized cost of H_2 (LCOH) from electrolysis.	Evaluate LCOH from electrolysis based on model scenario analysis.	A minimum LCOH of $1.78/kg H_2 was determined for the H_2 production and storage system defined in this project's TEA report, which

			includes capital and operating costs for the water electrolyzer, compression system, H_2 purification system, and H_2 storage cavern over a 25-year period. This is compared to the cost of H_2 generated from steam methane reforming of \$1.25 – \$3.5/kg.
Product value and purity of H_2	H_2 product no more than 50% greater than current H_2 market pricing from steam methane reforming (SMR).	Perform techno-economic analysis for H_2 production and cavern storage.	Assuming a cost of H_2 produced by a typical large-scale steam methane reforming plant of \$1.25/kg [7], the minimum cost of H_2 for the H-2-SALT system described in the TEA report of \$1.78/kg H_2 represents a 42% increase in the cost of the H_2 product.
	H_2 purity consistent with standard commercial requirements.	Determine system requirements needed to meet H_2 purity standards.	System requirements have been described in the H-2-SALT Cavern Operation section of the Conceptual Cavern Design report. These are based on Linde's experience and technology development efforts from

			operating its H_2 cavern in the US Gulf Coast.
Emissions reduction from H_2 combustion	Reduce CO_2 emissions by 10% to 15% with H_2 combustion compared to baseline.	Evaluate CO_2 reduction with H_2 combustion for a variety of H_2/NG mixes.	The Carbon Footprint Reduction Benefits section of the TEA report demonstrates that CO_2 emissions reduction of 16.6% can be achieved with the H-2-SALT system compared to the reference natural gas combustion plant.
	Ensure H_2 combustion does not increase emissions of other pollutants (NO_x, SO_x, etc.).	Evaluate impact of H_2 combustion on emissions profiles other than CO_2.	This analysis requires field demonstration to confirm if there is any increase in emissions of other pollutants. The H-2-SALT system does not intrinsically introduce additional impurities into the H_2 product, but the presence of impurities will largely depend on feedstock conditions and site-specific conditions of the storage cavern where a potential field test or commercial project will be installed. Hence, field or pilot demonstrations of

			the H-2-SALT system need to be conducted to evaluate and quantify the impact of these effects on H_2 product purity and emissions of pollutants over time.
Cavern Geology	Ensure salt geology is presents low enough permeability to ensure H_2 containment.	Evaluate geological samples, data, and methods to ensure leak control and safe operation.	This analysis requires collection of geological samples from the proposed site so they can be analyzed in the lab to determine if their geomechanical and geological properties can support salt cavern storage of H_2.
	Ensure impurity levels do not affect H_2 product purity for end user.	Characterize salt beds though drilling, coring, and core analysis.	Similar to the system requirements needed to meet H_2 purity standards described above.
NG-EGU plant availability	Increased availability of plant in the context of CO_2 emissions reduction regulation.	Determine availability of NG-EGU with H_2 combustion as compared to baseline in the context of emissions regulation.	This greatly depends on current and future federal as well as state legislation and will be investigated in the next phase of the project.

The final TRL for each key component of the H-2-SALT technology at the end of the project (after Phase II) is listed in Table F4 along with the work needed to progress each technology component to the expected TRL. From this analysis, the overall TRL of the H-2-SALT technology is expected to increase from to 5 after the project is completed and after relevant learnings and process improvements have been incorporated into an updated design for the larger scale process in an operational power plant environment.

Table F4: Final TRL for each key component of the H-2-SALT technology and work needed to progress each technology component to the expected TRL.

Final TRL	Work needed to progress TRL to anticipated value as per project objectives and other relevant descriptions
1 **H_2 Combustion Turbine** **Final TRL: 8/9**	Evaluate current ability of OEMs to provide retrofits for NG turbines to H_2 combustion turbines and understand any technical, safety, and/or regulatory requirements. Determine accurate cost estimates for turbine retrofits and new builds.

2 **ITM Linde Electrolysis Proton Exchange Membrane (PEM) Electrolyzer** **Final TRL: 8/9**	Evaluate feasibility of increased electrolyzer stack module sizes (>5 MW) for large-scale H_2 production and storage. Determine technology gaps and requirements to progress to next scale.
3 **H_2 Salt Cavern** **Final TRL: 8**	Salt of sufficient thickness and lateral extent was found under the proposed fossil power plant site. Geomechanical modeling suggests a cavern of sufficient size can be constructed under the site and space exists on the site for additional caverns.
4 **Integrated Energy Storage System** **Final TRL: 5**	Evaluate optimal system operating scenarios based on real electricity price profiles.

Post-Project Plans

Post-project work needed to attain the next TRL involves all activities required to scale-up the H-2-SALT technology for commercialization. This work entails completion of detailed engineering assessments for: H_2 production from electrolysis, H_2 salt cavern storage (including coring and testing), and use at a commercial NGCC power plant, agreement from relevant stakeholders involved in a commercial project, and completion of cost estimations for large-scale H-2-SALT systems. Linde has conducted and is currently pursuing several post-combustion CO_2 capture engineering studies related to H_2 electrolysis and storage that will greatly support engineering work needed for commercial deployment. In-depth market assessments and deployment strategies for post-combustion CO_2 capture are necessary to reduce project risk and understand commercial value to Evergy, Linde, KGS, and the final customer.

Understanding and quantifying CO_2 emissions reduction that arise that result from the H-2-SALT system are also critical parameters for commercial success and social license to operate. Such post-project work was not part of this project because the defined project scope focused solely on studying the feasibility of a power-to-hydrogen system “inside the fence” of a fossil EGU. The purpose of the proposed work was to evaluate the H-2-SALT process for full-scale demonstration and further develop the process to suit commercialization and minimize technical risk. The project endpoint has set a good foundation for the next phase of work by showcasing the performance and benefits of the H-2-SALT technology at a scale large enough to be considered a small- to medium-sized reference for commercial demonstration.

A Phase II (pre-FEED) study will further refine the engineering design for the H-2-SALT system. In addition, the collection of salt core material from the proposed site has been proposed to gain valuable geomechanical and geological data that will aid in establishing the engineering design of the cavern. Following Phase II, a complete FEED study will specify electrolyzer and turbine design and finalize cavern metrics. Testing with H_2 can be piloted during Phase II. Mechanical tests on cavern geology can also be conducted to evaluate the feasibility of long-term H_2 cavern storage. Technical issues to address include optimal working pressure and minimum cavern pressure as well as depth-to-pressure ratio analysis.

Detailed engineering design, construction, and operation of a site-specific test along with budgets and schedules will be based on data and experience from previous commercial bids and proposals from Linde including appropriate project and process contingencies. As detailed in the Commercialization Plan, the product development process including final definition of technical concept, business case and relevant commercial plans will require 3-4 years after a first site-specific demonstration at the start of year 1. Relevant technical and performance findings from the demonstration test will inform final plans for the product development phase. The site-specific demonstration will be completed next to the Gordon Evans Energy Center (GEEC) located in Colwich, KS. Detailed engineering and construction will require approximately

12 months and operation of the site-specific test equipment will require a minimum of 6-12 months spanning a variety of seasons to demonstrate the impact of electricity pricing on system economics. The estimated capital cost for detailed engineering and construction of an electrolyzer system capable of $15-16 million (±30% error), as outlined in the TEA Report.

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Abbreviations

- CO_2.......... Carbon dioxide
- EGU......... Electricity generating unit
- FEED........ Front end engineering and design
- H_2............ Hydrogen
- LCOH....... Levelized cost of hydrogen
- MW......... Megawatt
- NG........... Natural gas
- NGCC........ Natural gas combined cycle
- OEM......... Original equipment manufacturer
- PEM .... Proton exchange membrane
- SMR .... Steam methane reforming
- TRL.......... Technology readiness level

Appendix G: Recommendations for Phase II Pre-FEED Study

Introduction

Natural gas combustion electricity generating units ("NG-EGUs") are very good at turning on and off to meet peak power demands. However, they are not very good at making money when they are not running. The conversion, by electrolysis, of excess energy to hydrogen and subsequent storage in salt caverns is one potential solution for storing large amounts of energy from NG-EGU's (Figure G1).

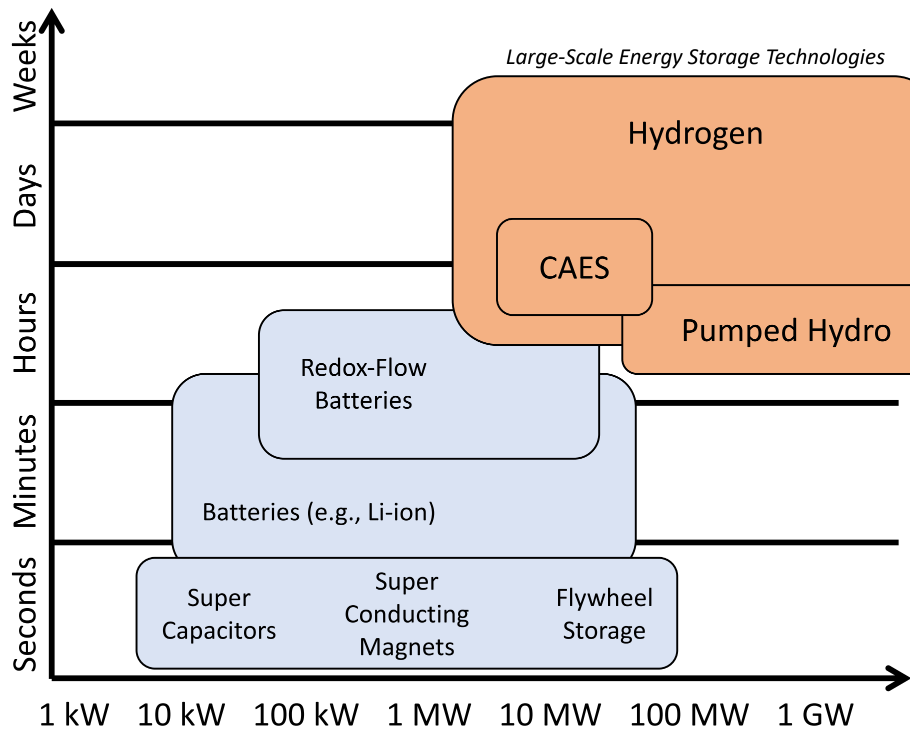

Figure G1: Time-scale vs Power storage plot showing H_2 storage as having the potential for significant energy storage (after Siemens figure in Tarkowski, 2019).

The system is composed of mature, viable components, that have yet to be integrated into a commercial system. Multiple geological hydrogen storage operations exist (e.g., Teeside, UK, since 1973, Clemmons, TX, since 1983, Moss Bluff, TX, since 2007: Tarkowski, 2019). Furthermore, hydrogen storage is seen as an ideal method to store large amounts of energy to balance production and usage (Crotogino et al., 2010). ***The objective of this proposal is to*** complete a pre-FEED study of a power-to-hydrogen system (Figure G2) “inside the fence” of Evergy’s Gordon Evans Energy Center (GEEC, a peaking plant near Colwich, KS), which serve’s Kansas’ largest city (Wichita).

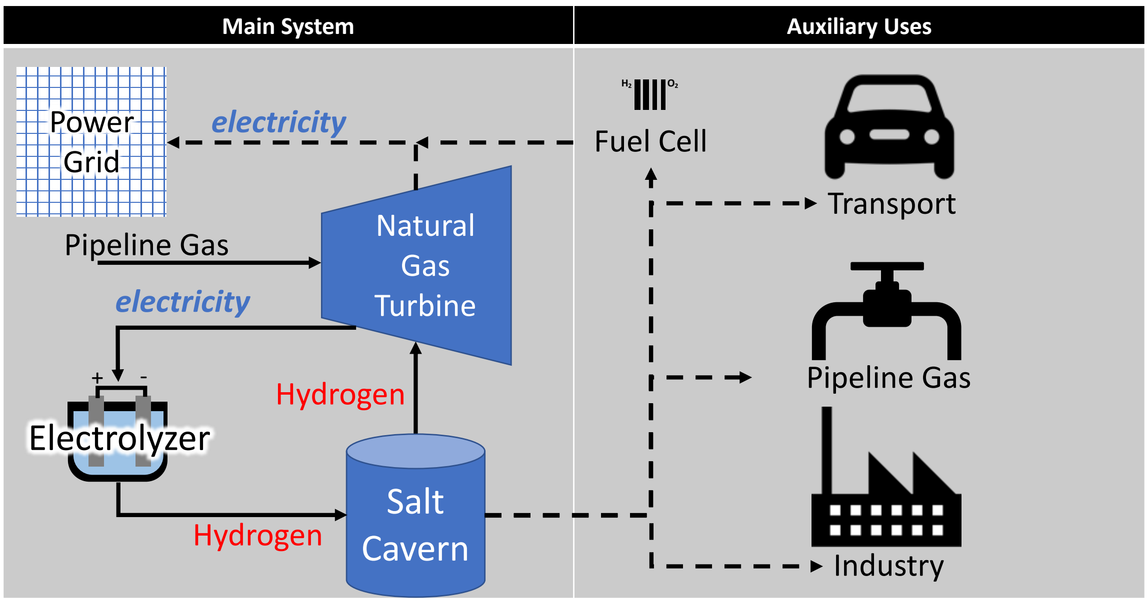

Figure G2: Diagram showing energy storage concept and auxiliary uses

Thick salt deposits underlie GEEC as well as much of south-central Kansas (Figure G3), which have resulted in a mature salt industry, including traditional mining, solution mining, and liquid hydrocarbon storage in salt caverns. ***Our rationale for undertaking this project is that*** hydrogen storage in salt caverns could be widely applied to fossil EGU’s ***across the USA*** to take advantage of their favorable storage properties of salt (e.g., large storage volumes, lowest levelized cost of storage, small surface footprint, security of storage: Wolf, 2015). ***KGS and its partners are well prepared to undertake this study*** due to their knowledge of Kansas subsurface geology, expertise in hydrogen salt cavern operations, salt cavern modeling, salt analysis, and previous track record of collaboration on DOE-funded studies on carbon capture/utilization/storage and petroleum resources. In addition, relationships with stakeholders in Kansas industries, communities, academia, and government will allow us to effectively execute outreach activities.

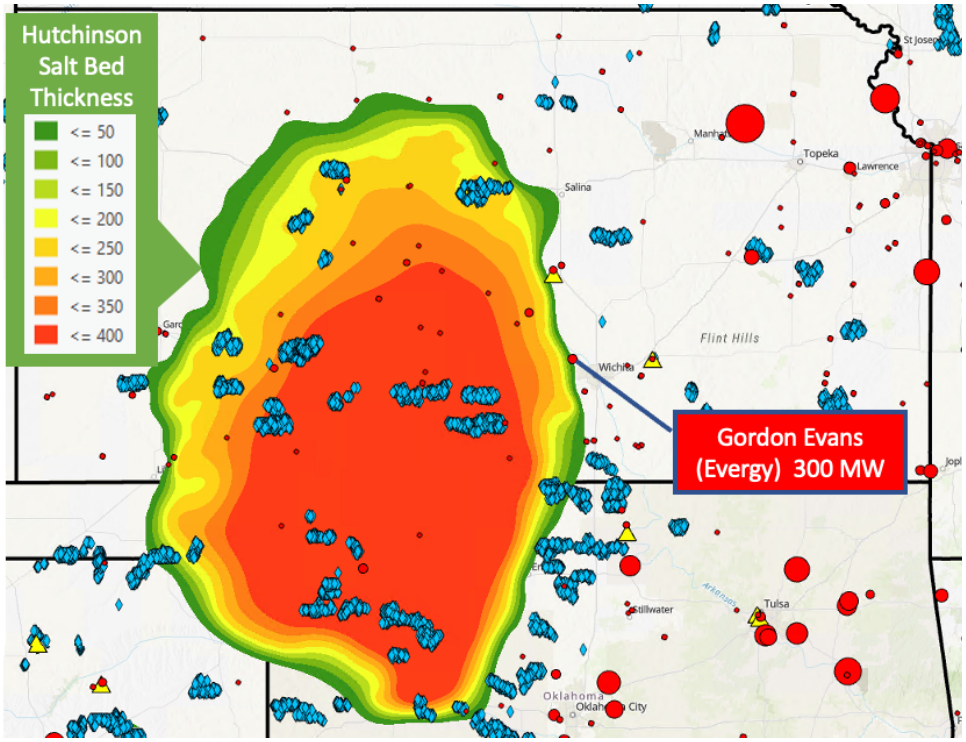

Figure G3: Map of Kansas showing thickness of Hutchinson salt bed, fossil EGU's (red circles), wind turbines (blue diamonds), refineries (yellow triangles).

Our specific goal is to support the decision of whether to move forward with a FEED study for construction and operation of a hydrogen energy storage system at GEEC. We will accomplish this by completing a **Pre-Feed Study** including 1) drilling, coring, logging, and core analysis of the salt formation "inside the fence" at GEEC, 2) bespoke engineering concept design, design basis, and process description of the hydrogen storage system, electrolyzer and turbine adjustments, and 3) analysis of performance and cost results. In addition, the project will update the Phase I Technoeconomic Analysis, Technology Gap Assessment, Technology Maturation Plan, and Commercialization Plan. Finally, in preparation for possible future pilot-scale system implementation, an Environmental Information Volume and list of project partners for construction and operation will be produced.

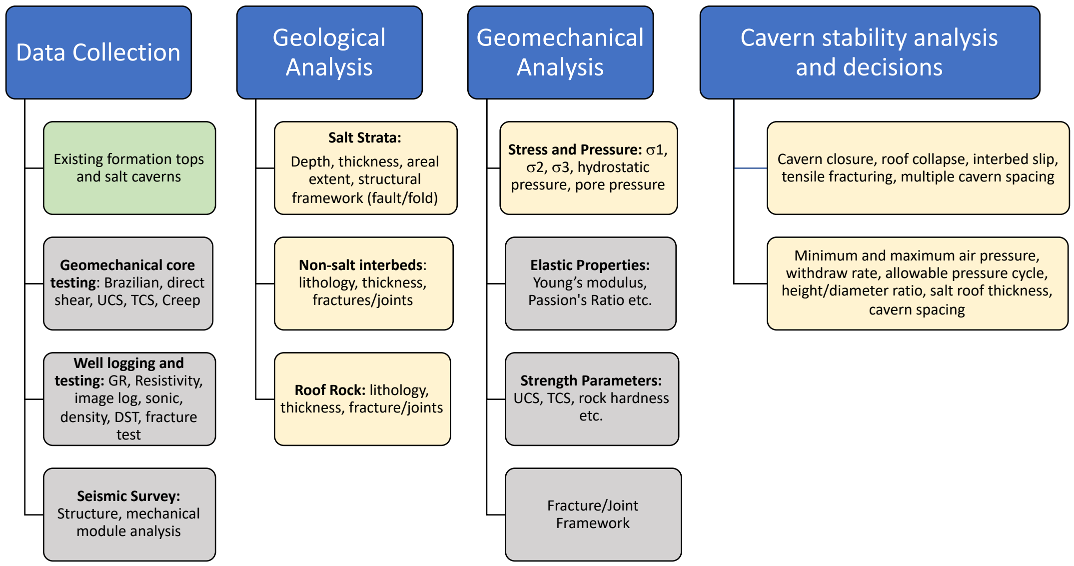

Figure G4. Workflow for Phase II analyses. Green task was completed in Phase I. Yellow tasks were begun in Phase I with legacy data, but require new data in Phase II. Gray tasks require new data in Phase II

Merit Review Criteria Discussion

MRC 1. Scientific, Technical, and Economic Criteria

A1. Arguments and details that clearly distinguish the proposed energy storage concept relative to prior work, and how it advances the current state-of-the-art

The H-2-SALT ***energy storage concept*** is to use excess electrical generation capacity to produce hydrogen for storage in an underground salt cavern. This system is composed of *three components* (a natural gas combustion turbine, an electrolyzer, and a salt cavern) that perform *three processes* (electricity production, hydrogen production, hydrogen storage), respectively (Figure 2). Optionally, electricity production may also be augmented by a fuel cell. Hydrogen may be blended into pipeline gas or distributed to industrial users as pure hydrogen. To date, these components—despite all being commercially available technologies separately— have not been integrated into a single energy storage system at a commercial scale. The ***basic operating principle*** of the system is that during times that an EGU would normally be shut down due to uneconomic conditions, the EGU would power an electrolyzer producing hydrogen for storage in a subsurface salt cavern. That stored hydrogen can be fed back into the EGU for combustion and energy generation. Alternatively, the hydrogen can be blended into pipeline gas or served directly to industrial users (e.g., chemical plants and refineries). The ***pre-project TRL*** *is* 5-6 because although each component technology is commercial, the combined system has not been commercialized.

A literature review of hydrogen energy storage analyses reveals many arguments for the coupling of hydrogen energy storage technologies with variable renewable energy sources and the resulting positive impact on the electricity market (e.g., Colbertaldo et al., 2019). However, the economic and technical consequences of hydrogen energy storage systems integrated with a fossil asset are not often studied. Furthermore, limited operational data exist on the long duration performance of hydrogen energy storage systems, as there are few demonstrations that integrate hydrogen production and storage with an EGU. This project endeavors to build on prior work by evaluating the feasibility of a potential demonstration at an actual site in Kansas. Moreover, the analysis goes further by exploring a storage medium—underground salt caverns—that are not often explored but which have the added benefit of flexibility for exploiting variations in daily, weekly, monthly, and seasonal electricity prices and demands. If feasibility is confirmed, the construction and operation of a hydrogen energy storage pilot in Kansas will provide meaningful information that can facilitate near-term deployment of these systems.

The analysis presented here demonstrates both the low cost and significant CO_2 emissions reduction potential achieved by an integrated NGCC plant, electrolyzer, and H_2 salt cavern storage system at medium and full commercial scales. Linde's extensive commercial hydrogen cavern operating experience coupled with their deep technical understanding of electrolyzer system design and operation provide substantial credibility to the performance and cost assessment demonstrated herein. This study reinforces the commercial viability and competitiveness of large-scale, electrolytic hydrogen production and storage that can be used for both electrical power supply to the grid during high-priced electricity periods (including co-firing with NG and fuel cell power production) and sale of hydrogen for various industries, such as petrochemicals or transportation. ***The commercial potential of the H-2-SALT system is also relatively high*** because each of its components operates commercially today.

Preliminary geological characterization focused on regional mapping of salt thickness and preliminary estimation of salt cavern dimensional characteristics. Top and base of the Hutchinson Salt Bed were mapped to identify the structural framework and reservoir distribution (Figure G5-7). The Hutchinson Salt exists in central to western Kansas dipping towards the west. The salt thickens towards south-central Kansas, where it reaches up to 615 ft (Figure G6). Depth of the top of Hutchinson Salt at GEEC is ~300 ft (Figure G5) and total thickness of the salt ~200 ft (Figure G6).

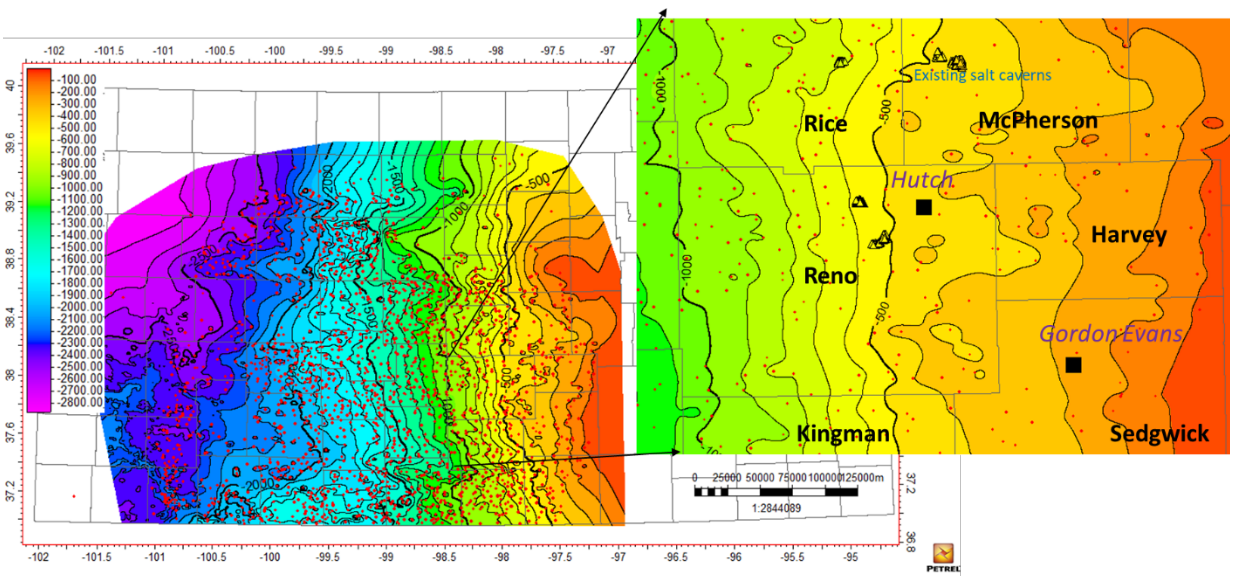

Figure G5. Map of the depth to the top of the Hutchinson Salt Member. Red dots represent well locations used in mapping; Black squares represent two potential sites for salt cavern storage; Triangles represent existing salt caverns.

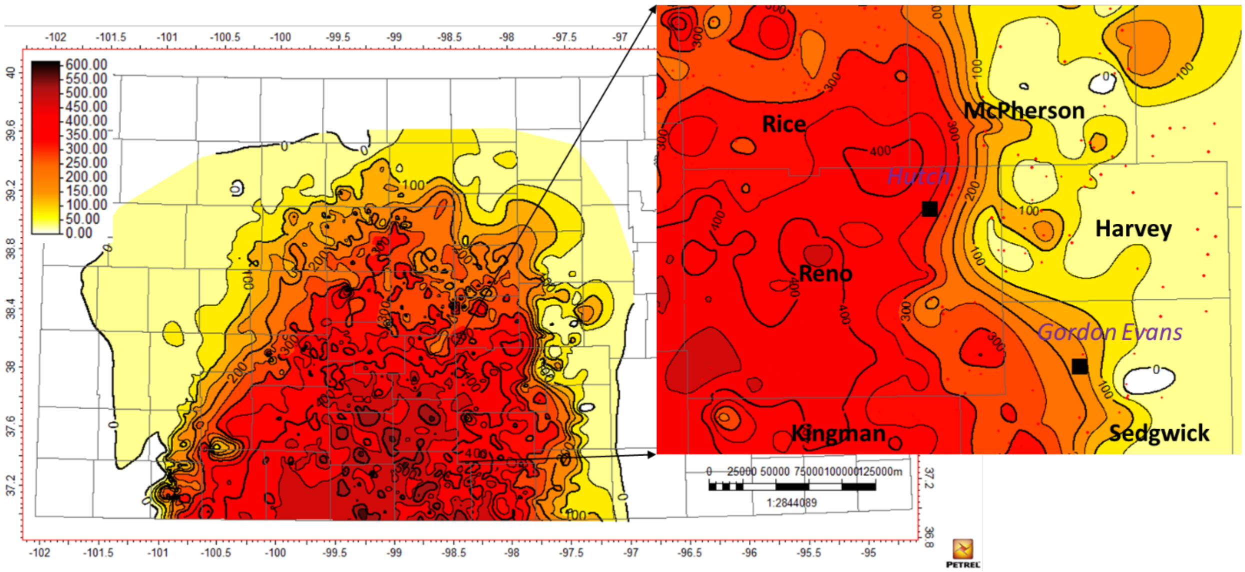

Figure G6. Thickness map of Hutchinson Salt Member. Red dots represent well locations Hutchinson Salt Member data; Black squares represent two potential sites for salt cavern storage evaluated in this project.

An initial geomechanical analysis was performed for GEEC to estimate the pressure and design parameters for a hydrogen storage cavern. Minimum and maximum cavern pressure was computed using a minimum cavern pressure of 25% of the lithostatic pressure. The lithostatic pressure gradient is 1.06 psi/ft at south-central Kansas (Schwab et al., 2017). The maximum operating pressure was estimated at 80% of the fracture pressure (or 90% of the lithostatic pressure). In this way, the minimum cavern pressure at GEEC was calculated to be in the range of 90-120 psi (Figure G7) and the maximum operating pressure 300-400 psi (Figure G8).

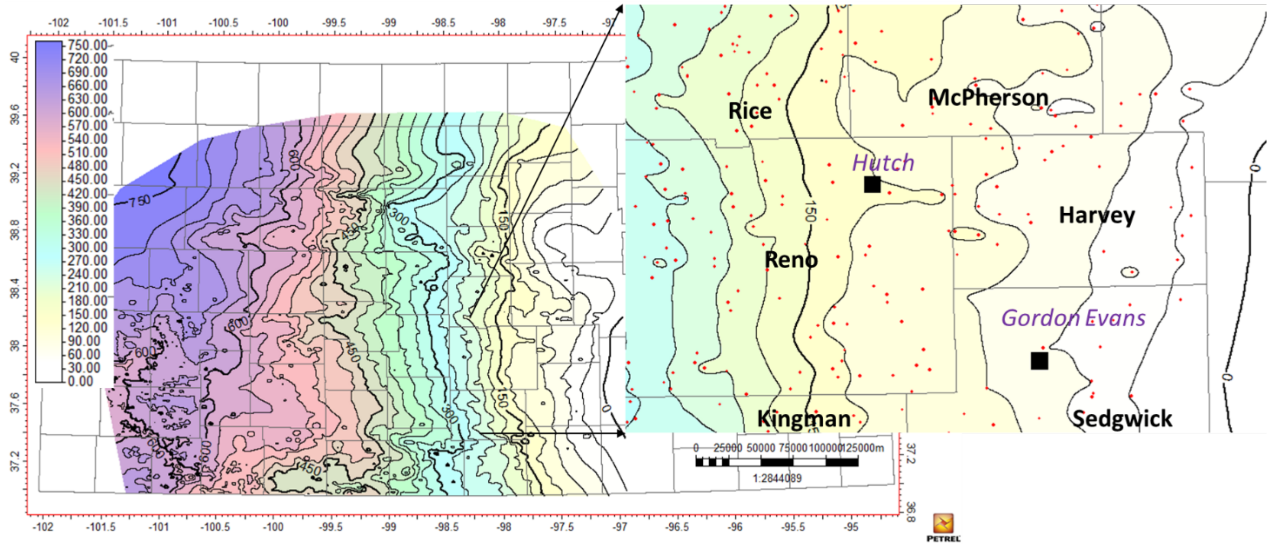

*Figure G7. Map of recommended **minimum** cavern pressure for avoiding the risk of cavern closure and roof collapse.*

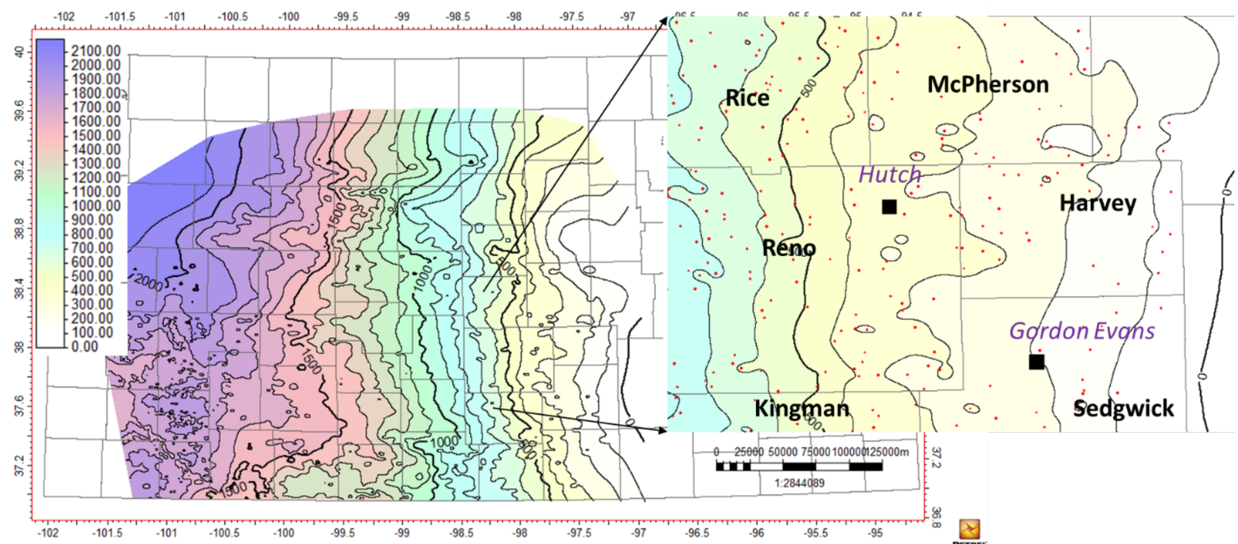

Figure G8. Map of recommended maximum pressure for avoiding the risk of tensile fracturing.

Risk associated with roof collapse, interbed slip, and inter-cavern spacing are controlled by the distribution of the salt. Salt depth at GEEC is deeper than 300 ft, which provide sufficient roof above the salt caverns. To meet the minimum requirement of stability, the design parameters of a salt cavern should have

- a minimum height-to-diameter ratio of 1:2
- a salt roof with thickness of at least one-quarter of the cavern diameter
- a spacing between caverns of at least of two-times the cavern diameter

Figure G9 shows an idealized salt cavern design at GEEC. The cavern parameters are designed to meet the minimum requirements for stability, an estimation of individual cavern storage capacity, and total numbers of caverns for each site are calculated with the same design of the cavern. At GEEC, the salt cavern is designed for height of 100 ft, diameter of 200 ft, salt roof thickness of 50 ft, and cavern spacing of 400 ft. The entire site could hold ~20 salt caverns (Figure 9) with individual cavern storage capacity of ~100,000 kg of H_2.

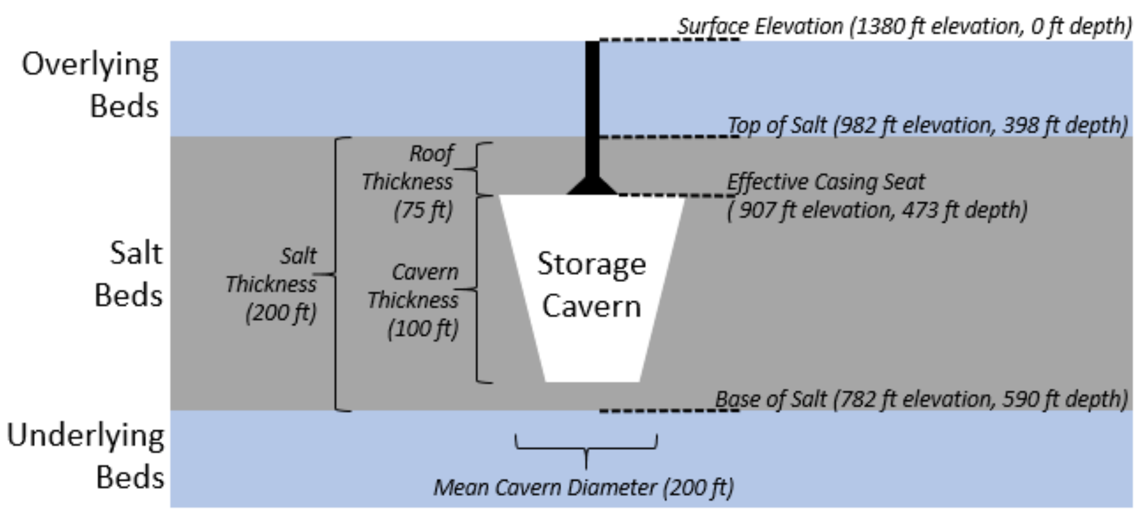

Figure G9. Design parameters and schematic of a typical Kansas salt cavern.

A2. Conceptual Study's description of the performance targets and benefits of integrating the subject energy storage technology to the site-specific fossil asset

Performance Target 1 (Benefit 1): The performance target set by this FOA was 10 MWh of storage. Each H-2-SALT cavern would be capable of storing as much as 100,000 kg of hydrogen. At 33.3 kWh per kg H_2, that would yield up to 3330 MWh of energy storage per cavern. ***Therefore, a single H-2-SALT cavern can store over 300x the performance target set in the FOA. This is also likely larger than any other project supported by this FOA.***

Performance Target 2 (Benefit 2): H-2-SALT increases fossil asset utilization by finding a use for low-cost power, when there is a lot of renewable power on the grid. This benefits customers in the form of lower utility rates and benefits operators who have made long-term investments in fossil power assets.

Benefit 3: H-2-SALT can scale at GEEC to store 2,000,000 kg of hydrogen. The area "inside the fence" (G10) of the GEEC could support a cavern storage system with a capacity suitable for long-term, commercial-scale use (20 caverns with 100,000 kg of hydrogen each would yield ~2,000,000 kg of total storage), similar to Linde's high purity Gulf Coast cavern (~2,360,000 kg of hydrogen).

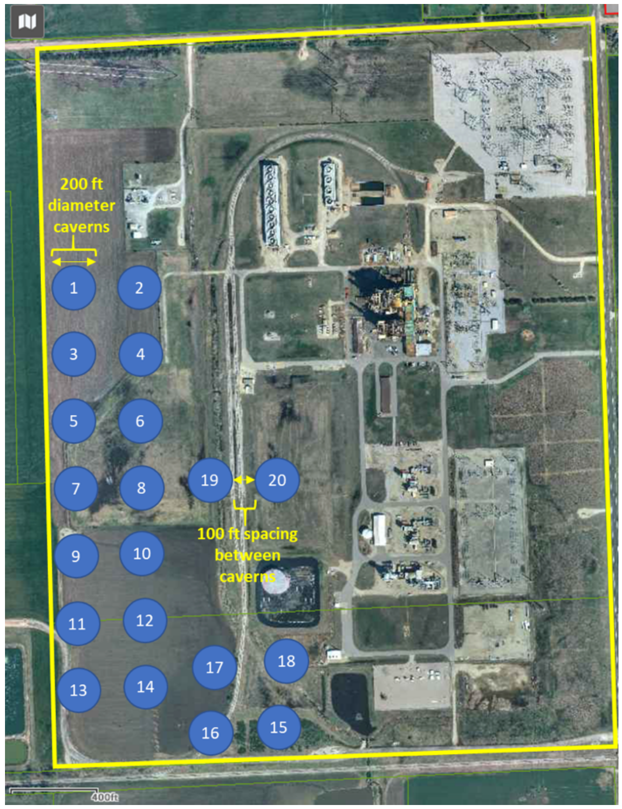

Figure G10: *Aerial view of the GEEC with 2,000,000 kg H_2 cavern storage system comprised of 20 caverns, each 100 ft apart and containing approx. 100,000 kg of H_2*

Benefit 4: H-2-SALT phase II tests hydrogen storage in bedded salt in the US. Two types of salt accumulations occur in nature—bedded and domal. Domal salt occurs in the US along the Gulf Coast and in some of the Rocky Mountain basins. In addition to Kansas, a positive test in Kansas support hydrogen storage in salt in places like Oklahoma, Michigan, Ohio, Indiana, New York, and Pennsylvania—areas hosting significant industrial activities. A hydrogen storage facility in bedded salt of the same geological age (Permian) has operated at Teesside, UK, since ~1972, so we are optimistic that ***hydrogen storage can work at GEEC***.

Benefit 5: H-2-SALT reduces carbon dioxide emissions by up to 16.6%, based on the Phase I Technoeconomic Analysis, compared to a traditional natural gas power plant when burning 20% hydrogen and 80% natural gas. Further CO_2 emission reduction can be obtained by increasing the hydrogen to natural gas ratio.

Benefit 6: H-2-SALT is climate resilient. All three currently operating hydrogen cavern storage systems are located near sea-level (two on the US Gulf Coast, on adjacent to the North Sea in the UK). an area prone to violent storms/hurricanes, subsidence, and rising sea-levels. Located far from these climate hazards, ***Kansas is an ideal place to develop large-scale hydrogen energy storage that is hedged against climate risk.***

Benefit 7: H-2-SALT benefits national security. H-2-SALT is located near Wichita, a major site of defense aviation production and home of McConnell Air Force Base. Evergy's power network also serves Fort Riley, Fort Leavenworth, and Whitman Air Force Base. The Department of Energy's National Security Campus is in Kansas City.

A3. Quantitative information regarding market potential for the energy storage technology from the Phase I Technoeconomic Study.

The technoeconomic assessment (TEA)—using a DOE base-case a 727 MWe (net) natural gas combined cycle power plant (NGCC)— integrated with a commercial-scale Linde proton exchange membrane (PEM) based electrolyzer and a hydrogen storage salt cavern designed to accommodate the scale of hydrogen production based upon experience. Process simulation and modeling were performed using actual electricity price data were used (January – December 2020 for GEEC). Technical and cost information for the Linde electrolyzer and hydrogen storage salt cavern have been determined using proprietary internal operating data and simulation models as well as commercial quotes and proposals. The Linde case presented is compared against the DOE-NETL Case B31A reference, a 727 MWe (net) NGCC plant without CO_2 capture.

Overall, the net efficiency of the integrated 727 MWe supercritical PC power plant without carbon dioxide capture changes from 53.60% with the DOE/NETL Case B31A reference to 51.14% with the integrated NGCC and Linde electrolyzer and cavern storage system. The Linde electrolyzer and cavern system results in an integrated cost of electricity (COE) of $45.77/MWh, compared to $43.33/MWh for the Case B31A reference (Figure G11), and a total cost of hydrogen production and storage of **$1.78/kg H_2** based on the modeling inputs used (Figure

G12). The loss in efficiency and higher electricity costs are countered by reduction of the carbon dioxide footprint by addition of the hydrogen electrolyzer and cavern storage system.

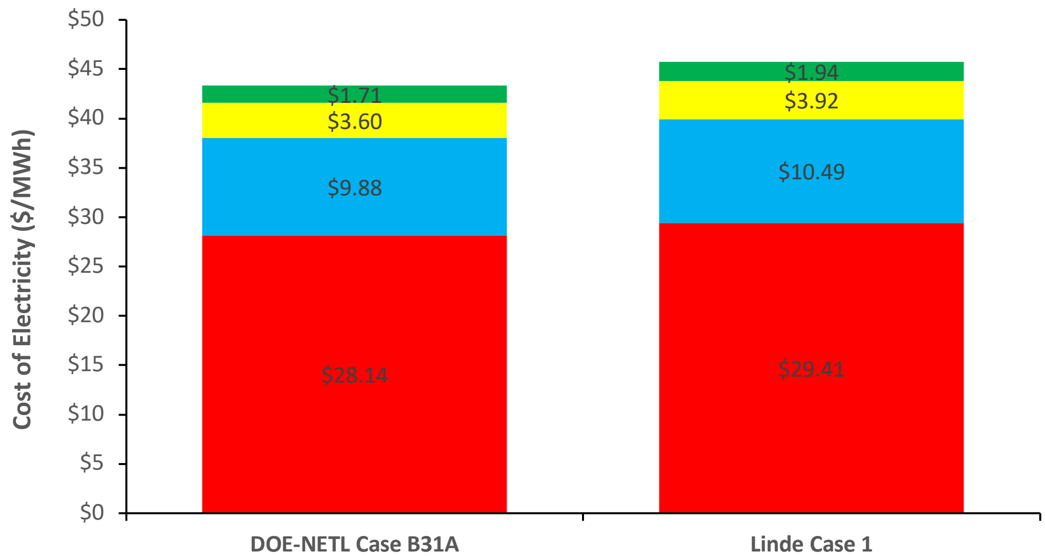

Figure G11. Itemized Cost of Electricity Breakdown by Category in 2018 dollars. Red is Fuel, Blue is CAPEX, Yellow is Fixed OPEX, and Green is Variable OPEX.

It was relevant for the project goals to demonstrate the feasibility and environmental benefits of low-cost, large-scale electrolyzer-based hydrogen production, storage, and use. The final section of the TEA provided modeling and cost analysis of an integrated NGCC plant, electrolyzer, and cavern storage system at a much larger H_2 production scale that ***reduces the CO_2 footprint of the NGCC asset by 16.6%*** compared to DOE-NETL Case B31A while still providing reliable power to the grid.

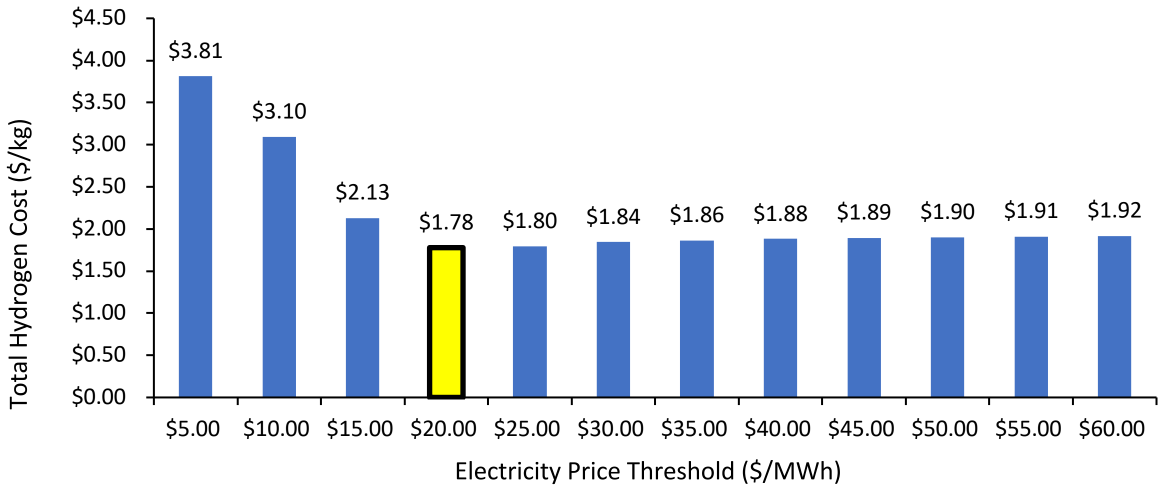

Figure G12: Specific total system cost (CAPEX+OPEX) for hydrogen production and storage ($/kg H2) as a function of the user-defined electricity price threshold ($/MWh).

A4. Technology Gap Assessment's description of the development pathway for the subject energy storage technology that will overcome key technical risks/issues of the current state of the art.

Comparison of the energy storage system against current state-of-the-art technologies for long term energy storage.

Only three technologies can store large amounts of energy (10 MW+) for long periods of time (8+ hours): hydrogen energy storage, compressed air energy storage (CAES), and pumped hydro (Tarkowski, 2019). Of these, only hydrogen has the capability for multi-day to month storage. Pumped hydro, despite being the most widely adopted large-scale energy storage technology, is limited by the availability of areas available 1) with enough topographic relief and 2) without competing users or ecological sensitivity. The two currently operating CAES systems are so-called "diabatic" systems that do not store the heat generated during air compression and thus must re-heat the air as it exits the cavern, adding significant CO_2 emissions from burning natural gas (Fuchs et al., 2015). Batteries, another common technology for energy storage that are being deployed by some utilities at grid-scale, are generally used for applications at the timescale of seconds to hours (Bowen et al., 2019) and the cost of batteries for anything over 8 hours of storage is excessive (e.g., Schmidt et al., 2019).

Identify key shortcomings of current state-of-the-art technologies and how the proposed integrated system technology will overcome these limitations.

The key components of this energy storage system (hydrogen storage salt cavern, PEM electrolyzer, natural gas combustion combined cycle turbine) all operate commercially today, albeit separately. One of the major shortcomings of the H-2-SALT technology is accurately modeling the integration of these components into a single operating system. Ongoing research and development at Linde are addressing 1) scaling of electrolyzers for hydrogen production to larger capacities and 2) reducing the capital cost of such systems. A pre-FEED study would further analyze the integration of these systems to provide greater clarity on the costs and benefits of H-2-SALT. Second, because there are only three other hydrogen storage caverns globally, it is vital to obtain new geomechanical and geological data to support the pre-FEED study's modeling of the size, shape, and operating pressures of the cavern part of H-2-SALT.

Key technical risks/issues associated with hydrogen energy storage in salt caverns and the perceived technology gaps and R&D needed for commercialization by 2030.

The key technical risk in H-2-SALT is the quality of the salt beds below the GEEC site. Bedded salt hosts 750+ caverns in Kansas currently and one of three currently operating hydrogen storage caverns is in bedded salt. While Phase I mapping activities have interpolated that there likely exists enough salt under GEEC, we do not know exactly how much or what the specific mechanical properties of the salt are—crucial factors that need to be known for further pre-FEED and FEED studies. Drilling, coring, logging, and core analysis activities in a pre-FEED study would ameliorate this key risk.

Development pathway that can overcome key technical risks/issues, including need for and size of site-specific engineering scale prototype.

The specific development pathway envisioned by this project involves collection of new geological and geomechanical data "within the fence" at GEEC to support a more detailed pre-FEED study of the engineering and financial performance of an H-2-SALT system during Phase II. This will reduce uncertainty concerning whether to pursue a full FEED study for construction and operation of an H-2-SALT system at GEEC.

A5. *Technology Maturation Plan's description of the engineering design, construction, and operation of the site-specific test and any subsequent work needed to advance the TRL to 9*

Post-project work needed to attain the next TRL involves all activities required to scale-up the H-2-SALT technology for commercialization. This work entails completion of conceptual and detailed engineering assessments for H_2 production from electrolysis, H_2 salt cavern storage, and use at a commercial NGCC power plant, agreement from relevant stakeholders involved in a commercial project, and completion of cost estimations for large-scale H-2-SALT systems. Linde has conducted and is currently pursuing several electrolyzer-based hydrogen production engineering studies that will greatly support engineering work needed for commercial deployment. In-depth market assessments and deployment strategies for large-scale electrolyzers are necessary to reduce project risk and understand commercial value to Evergy, Linde, and the final customer. Understanding and quantifying the value of the CO_2 emissions reduction because of the H-2-SALT system are also critical parameters for commercial success. The purpose of the proposed work is to evaluate the H-2-SALT process for full-scale demonstration and further develop the process to suit commercialization and minimize technical risk. The project endpoint sets the best foundation practical for the next phase of work by showcasing the performance and benefits of the H-2-SALT technology at a scale large enough to be considered a small- to medium-sized reference for commercial demonstration.

A6. *Commercial Assessment's identification of specific market sector targets and a compelling pathway to penetration and wide-scale deployment*

The commercialization potential of this technology is high because the system components are all in commercial operation. The development needs are site specific, and are related to the geology of the site, the technical and economic challenges of integrating the solution with the individual fossil asset and the local market conditions that would favor this hydrogen energy storage solution. To evaluate the commercial opportunity, an approach was taken to preliminarily assess the costs for hydrogen production using the ITM-Linde PEM electrolyzer. A simple energy arbitrage scenario was developed whereby the electrolyzer produces hydrogen when electricity prices are below the average hourly price and produced hydrogen is sold to the natural gas grid when electricity prices are above the average. Three key performance indicators (KPIs)—Sum Difference, Hours Above Multiplied Average and Hours Below Divided Average—help to visualize price variability to pinpoint weeks or even months when high differential prices occur. This variability results in an optimal scenario for an energy storage system to have economic viability and generate benefits. From the Sum Difference, it is clear that most of May 2019 showed high price variability for arbitrage. Hourly price data for the period from May 19 – May 25, 2019, was then used in an electrolyzer system model to determine the economics of an electrolysis and hydrogen salt cavern storage system, as if this weekly price profile was applied over a full year. In this case, the cavern provides a seasonal storage for hydrogen for use when the natural gas (which the hydrogen replaces as fuel) demand is high or for hydrogen use in industry or transportation in nearby markets.

In this approach, the price of the sold hydrogen is assumed to be the same as the local natural gas price on a relative heating value basis. Overall, in this scenario the operating costs to run the electrolyzer are more than the potential revenue that is generated from the hydrogen production. However, positive cash flows could be anticipated if 1) the market placed a higher value on hydrogen as a fuel compared to natural gas, due to its lower carbon intensity or 2) the spread in the variability of electricity prices was wider. A pre-FEED study would evaluate the most favorable circumstances for economic feasibility as part of the commercialization plan activity. An analysis of the performance of this technology in reference to competing alternatives will also shed light on its commercialization potential.

MRC 2. Technical Approach and Understanding

Applicant's approach to achieving the objectives of the AOI

The applicant has assembled a project team that brings together expertise in hydrogen production and storage (Linde) with a fossil EGU (Evergy) that overlies favorable geology (KGS). This combination increases the likelihood of success of the proposed project. To maximize the efficiency of the technical approach, the applicant has designed a concise and efficient structure. The project is broken down into seven work packages which are further divided in subtasks. The target of this structure is to meet the project's main concepts and objectives, as described in the SOPO. The work breakdown structure has been organized to ensure technical tasks are coordinated between KGS, Linde and Evergy based on the technical strengths of each organization. All collaborators worked successfully together on previous DOE funded projects, which increases the robustness of the project.

Feasibility, appropriateness, rationale, and completeness of the proposed Statement of Project Objectives (SOPO), such that there is a logical progression of work.

The SOPO provided by the Project Team is designed to reduce uncertainty through a coherent and consistent order of operations that will gather data necessary for DOE to make an informed decision on whether to proceed with a FEED study and possible pilot plant. The SOPO incorporates DOE-required project management and scope objectives (Tasks 1&2). ***A geological characterization well (Task 2.1)*** will test the quality of salt at the proposed site and support ***Subtasks 2.2 (Cavern Feasibility Study) and 2.3 (Site Characterization Study)***. Phase I geological characterization was based on data from legacy well logs, none closer than a half-mile away. Nor were there any geomechanical data available on salt in the vicinity of the project site. Both data types are essential in reducing uncertainty about the geological suitability of the salt under GEEC to support a salt cavern at the wellsite (Subtask 2.2) and across the entire GEEC site (Subtask 2.3). ***The engineering and financial study (Subtask 2.4)*** will analyze a single case for an integrated H-2-SALT system: one NG turbine, one PEM electrolyzer, and one salt cavern.

Based on the characteristics of the turbine and electrolyzer as well as the properties of the salt beds below GEEC, the major questions to answer will be: What is the optimal operating schedule of the system? What capacity cavern will meet the needs of the system? What is the maximum injection rate into the cavern?

Phase I assessments will be updated based on these findings (Tasks 3—Technoeconomics, 4—Technology Gaps, and 7—Commercialization). Planning for a FEED study, construction, and operation (Tasks 5, 6) will take place in parallel to provide DOE with a roadmap to implementation of a H-2-SALT system at GEEC.

Feasibility, appropriateness, rationale, and completeness of the proposed Technology Maturation Plan (TMP), such that there is a logical maturation of the subject technology.

The TMP that has been developed for this project outlines major steps needed to advance the TRL of the three component technologies of this system: the fossil asset (natural gas combined cycle turbine), the electrolyzer (ITM-Linde), and the cavern (bedded salt), as well as the overall energy storage system. The steps needed for these are outlined in the table below:

Anticipated TRL	Work needed to progress TRL to anticipated value as per project objectives and other relevant descriptions
H_2 Combustion Turbine **Expected TRL: 8/9**	• Evaluate current ability of OEMs to provide retrofits for hydrogen combustion turbines from NG turbines and understand any technical, safety, and/or regulatory requirements • Determine accurate cost estimates for turbine retrofits and new builds
ITM Linde PEM Electrolyzer	• Evaluate feasibility of increased electrolyzer sizes (>10 MW) for large-scale hydrogen production and storage

Expected TRL: 8/9	• Determine technology gaps and requirements to progress to next scale
Hydrogen Salt Cavern **Expected TRL: 8**	• Refine workflow for geological salt characterization • Evaluate feasibility of cavern retrofits to hydrogen and implications for safety, leak control, and product purity due to potential for reactions with impurities • Evaluate hydrogen compression and post-purification requirements for cavern storage and operations
Energy Storage System **Expected TRL: 5**	• Evaluate optimal system operating scenarios based on real electricity price profiles

B1. Project Management Plan (PMP) establishes baselines (technical scope, budget, schedule) and manages the project relative to those baselines; PMP defines 1) actions to be taken when baselines must be revised; and 2) identifies project risks and strategies for their mitigation.

The PMP provided by the Applicant has been designed under the core values of safety, integrity, and fiscal responsibility. It is meant to ensure the project is delivered on time and on budget to allow the DOE to make an informed decision on whether to proceed with a Phase II Pre-Feed Study. The team will establish efficient information exchange practices including regular organizational meetings, schedules, working routines, timelines, and go-no go points. The project plans are designed to calculate several target metrics that will ultimately decide whether H-2-SALT will work geologically (e.g., thickness/extent of salt), technologically (e.g., size of electrolyzer), and economically (e.g., cost of salt cavern construction, power price variability).

Statement of Project Objectives

This project is proposed in support of the Department of Energy's (DOE) Office of Fossil Energy (FE) goal to advance near-term, fossil-fueled asset-integrated, energy storage solutions toward commercial deployment. The overall objective is to conduct a pre-feed study for a power-to-X system "inside the fence" of a fossil EGU in Kansas. The scope of work under this area of interest will facilitate subsequent site-specific projects integrating combinations of relatively mature energy storage technologies with specific fossil fueled EGUs. The project team will leverage previous geologic assessments performed by the KGS and Linde's industrial experience with design, engineering and operations of electrolytic hydrogen generation systems and a hydrogen storage salt cavern to facilitate attainment of project objectives.

SCOPE OF WORK

The objective of this proposal is to complete a pre-FEED study of a power-to-hydrogen system "inside the fence" of Gordon Evans Energy Center (a peaking plant near Colwich, KS), which serve's Kansas' largest city (Wichita). Thick salt deposits underlie GEEC, as well as much of south-central Kansas, which have resulted in a mature salt industry, including traditional mining, solution mining, and liquid hydrocarbon storage in salt caverns. Our specific goal is to support the decision of whether to move forward with a FEED study for construction and operation of a hydrogen energy storage system at GEEC. We will accomplish this by completing a Pre-Feed Study including 1) drilling, coring, logging, and core analysis of the salt formation "inside the fence" at GEEC, 2) bespoke engineering concept design, design basis, and process description of the hydrogen storage system, electrolyzer and turbine adjustments, and 3) analysis of performance and cost results. In addition, the project will update the Phase I Technoeconomic Analysis, Technology Gap Assessment, Technology Maturation Plan, and Commercialization Plan. Finally, in preparation for possible future pilot-scale system implementation, an Environmental Information Volume and list of project partners for construction and operation will be produced.

TASKS TO BE PERFORMED

Task 1.0 — Project Management and Planning

Subtask 1.1 – ***Project Management Plan***: “The Recipient shall manage and direct the project in accordance with a Project Management Plan to meet all technical, schedule and budget objectives and requirements. The Recipient will coordinate activities in order to effectively accomplish the work. The Recipient will ensure that project plans, results, and decisions are appropriately documented, and project reporting and briefing requirements are satisfied.

“The Recipient shall update the Project Management Plan 30 days after award and as necessary throughout the project to accurately reflect the current status of the project. Examples of when it may be appropriate to update the Project Management Plan include: (a) project management policy and procedural changes; (b) changes to the technical, cost, and/or schedule baseline for the project; (c) significant changes in scope, methods, or approaches; or (d) as otherwise required to ensure that the plan is the appropriate governing document for the work required to accomplish the project objectives.

“Management of project risks will occur in accordance with the risk management methodology delineated in the Project Management Plan to identify, assess, monitor and mitigate technical uncertainties as well as schedule, budgetary and environmental risks associated with all aspects of the project. The results and status of the risk management process will be presented during project reviews and in quarterly progress reports with emphasis placed on the medium- and high-risk items.”

Subtask 1.2 – Technology Maturation Plan. “The Recipient shall develop a Technology Maturation Plan (TMP) that describes the current technology readiness level (TRL) of the proposed technology/technologies, relates the proposed project work to maturation of the proposed technology, describes the expected TRL at the end of the project, and describes any known post-project research and development necessary to further mature the technology. The initial TMP is due 90 days after award and should be updated as needed throughout the project period of performance. A final TMP should be submitted as an appendix to the Final Technical Report.”

Task 2.0 — Pre-Feed Study

Subtask 2.1 – Core Acquisition and Well Logging. A stratigraphic characterization well is planned at the Gordon Facility near Colwich, Kansas. The geologic target for this stratigraphic well is the Hutchinson Salt and overlying Wellington Shale. The well will be cored to approximately 700 feet below the ground surface. PQ-size core (3.35-inch diameter) will be collected, boxed, and logged at the well site. Geophysical wireline logging of the well will be performed to supplement core analyses and feasibility study. After coring and logging is complete, the well will be plugged with cement.

Subtask 2.2 – Core Scanning. KGS will transport cores from well site to KGS for core scanning using Geotek MSCL. Upon completion, cores will be shipped to RESPEC labs in Rapid City, SD.

Subtask 2.3 – Core Analysis. The core will be shipped to the RESPEC Materials Testing Laboratory in Rapid City, South Dakota. The strength of the salt and overlying and inter-bedded non-salts will be determined. Dilation (micro-fracturing) and time-dependent creep characteristics of the salt will also be determined. All core material will be returned to KGS after testing is completed.

Subtask 2.4 – Cavern Viability Study. Based on the critical rock properties obtained from the stratigraphic characterization well and laboratory testing, a thermodynamic and geomechanical feasibility modeling study will be performed to evaluate the storage performance, stability, and integrity of the hydrogen storage cavern. These feasibility modeling studies will help refine the cavern design (e.g., volume, shape, and depth) and the storage parameters (e.g., maximum/minimum pressure, withdrawal rates, and pressure cycle frequency). The study will begin with a thermodynamic simulation of the storage pressures, temperatures, injections/withdrawals, and hydrogen volumes. Based on the thermodynamic results, a geomechanical model will then be simulated to evaluate the response of the rock formation to the induced pressures and temperatures. The overall objective of the study will be to develop a preliminary storage cycle and cavern design that achieves the preferred storage performance while also maintaining cavern stability and integrity.

Subtask 2.5 – Site Characterization Study. New core and well log analysis data will be integrated with more distant well data and regional trends in the Hutchinson Salt bed to determine the suitability of GEEC to support a multi-cavern system.

Subtask 2.6 – Engineering and Financial Study. This subtask will develop a pre-FEED design, design basis, and process description for a Linde PEM electrolyzer and salt cavern storage integrated with the GE-FA 150 MW gas-fired combustion turbine at GEEC. The scenario will involve approximately 120 storage cycles per year and 100% of stored hydrogen being fed to the combustion turbine (fuel mix: 20% hydrogen, 80% natural gas). In addition, the engineering and financial performance of the proposed energy storage system will be analyzed.

Task 3.0 — Phase II Technoeconomic Assessment (TEA).

This task will update the generic TEA developed in Phase I for GEEC across specific market segments. System simulations will utilize a more detailed process model for the energy storage system compared with empirical data. The TEA will be of comparable detail to those found in NETL's Baseline Series and follow the NETL Quality Guide Energy System Studies (QGESS). Components, materials, or technologies not covered by the QGESS documents will be supported with additional justification and reference materials to substantiate assumptions and approach. Cost estimation will be either vendor-based or utilize a "bottom-up" costing approach for novel equipment.

Task 4.0 — Phase II Technology Gap Assessment (TGA)

Subtask 4.1: Update Phase I TGA. This subtask will update the Phase I TGA to include any additional learnings from Phase I.

Subtask 4.2: Identify Original Equipment Manufacturers. This subtask will Identify and describe the key technology Original Equipment Manufacturers (OEMs) including 1) commercially available equipment, 2) equipment requiring additional research and development, 3) describe work engineering procurement firms (EPCs) have done with OEMs of proposed equipment, 4) explanation of whether the EPC has access to information on the equipment in the proposed prototype.

Task 5.0 — Future Project Partnering Plan

This task will identify a list of partners for future construction and operation of the energy storage system at Gordon Evans Energy Center.

Task 6.0 — Environmental Information Volume (EIV)

The Environmental Information Volume will contain a description of the existing environment at Gordon Evans Energy Center, the proposed construction/operations activities, alternatives to the proposed construction/operations activities, as well as potential environmental, safety, health, and socioeconomic impacts of the proposed construction/operations activities.

Task 7.0 — Phase II Commercialization Plan

This task will update the Phase I Commercialization Plan for wide-scale deployment of hydrogen energy storage in underground salt caverns.

Relevance and Outcomes/Impacts

The objective of the program announcement was to identify a site for storage of 10+ MWh of energy within the fence of a fossil EGU. The effort outlined in ***this proposal meets all these conditions***. The EGU proposed to integrate energy storage burns natural gas, a fossil fuel. Salt cavern storage of hydrogen has been shown at a commercial scale in the US and UK to be ***capable of storing quantities of energy significantly more than 10 MWh, up to 3330 MWh for long durations (weeks)***. According to current information, the site identified in this proposal has thick enough salt deposits to support a salt cavern large enough for commercial scale hydrogen storage. The salt bed, the Hutchinson Salt, itself hosts such commercial cavern storage operations for petroleum liquids currently.

The proposed EGU is currently run as a peaking plant so having a storage system would improve the economics of the facility by allowing it to take advantage of arbitrage. In addition, the opportunity to feed hydrogen into 1) pipeline natural gas that meant for industrial and residential uses and 2) local and regional customers for pure hydrogen would improve the economics of the plant and support the development of a “hydrogen economy” in the Midwest. There are approximately 20 other fossil combination power plants EGUs that overlie the Hutchinson Salt in Kansas as well as another approximately 20 plants that overlie other salt beds further west in Kansas.

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