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SHASTA
Subsurface Hydrogen Assessment, Storage, and Technology Acceleration

Local-Scale Framework for Techno-Economic Analysis of Subsurface Hydrogen Storage

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Prepared for the U.S. Department of Energy, Office of Fossil Energy and Carbon Management by:

Sandia National Laboratories: Shruti Khadka Mishra

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Executive Summary

The energy sector is evolving toward increased reliance on renewable energy technologies to meet state, national, and organization decarbonization goals. This trend is creating challenges and opportunities with meeting current and future energy demand under the variable supply conditions that most renewables provide. Hydrogen (H_2) is a promising energy carrier that may meet the need for both on-demand and long-duration storage to maintain energy security and resilience. Underground hydrogen storage (UHS) is a method of storing H_2 in subsurface geological systems, such as depleted hydrocarbon reservoirs, salt caverns, saline aquifers, hard rock, and other engineered systems. UHS has the potential to store large quantities of H_2 over time, providing a reliable source of energy while minimizing surface footprints at a lower investment cost compared to surface storage. Earlier work estimated that, if converted and retrofitted, existing underground natural gas storage (UGS) facilities in the U.S. can store approximately 327 TWh, or 9.8 million metric tons, of pure H_2. However, a shift to pure H_2 would decrease the collective working-gas energy of the UGS facilities by approximately 75% due to physical and chemical differences between natural gas and hydrogen. The same work also suggests that almost 75% of the existing UGS facilities in the U.S. could maintain current energy demand buffering using a blend of only 20% H_2 to 80% natural gas, by volume at surface conditions. If we can take advantage of the suite of mature technologies of existing UGS facilities and natural gas utility systems to accelerate the transition to a hydrogen economy in the U.S., a 20% H_2 blend could lead to a 6-7% reduction of greenhouse gas emissions for energy delivered through natural gas utility systems.

As governments and industries around the world accelerate investment in H_2 technologies and the supporting infrastructure needed to enable the transition to a low-carbon economy, the capital and operational costs of UHS will become a critical consideration in the development of a sustainable and economically viable H_2 economy. This work expands on previous research by developing a framework for UHS cost estimation that reflects the granularity that a gas storage operator might use to assess their existing infrastructure or to identify opportunities to develop new facilities. For a comprehensive UHS techno-economic analysis (TEA), we also consider local H_2 demand because existing geological storage volume may not directly translate to the size of the market as it evolves. For this report, we developed a site-specific TEA framework for UHS and applied our framework to analyze the potential for UHS in the state of Pennsylvania under a set of demand scenarios. Pennsylvania was selected because of its diverse geology and existing fleet of UGS facilities and related natural gas infrastructure. Not every state will have suitable geologies or complementary infrastructure; however, TEA analysis using the framework developed through this work can be conducted at state or national levels. We evaluated levelized costs of hydrogen storage (LCHS) for facilities with a range of storage capacities based on estimates of the H_2 working gas volume of existing UGS facilities within Pennsylvania. The levelized cost methodology is a way to present the anticipated capital and operational expenditures of a UHS facility over its lifetime in units equivalent to the pricing of the H_2 commodity ($/kg).

We found that, generally, the LCHS for a single-well, salt-cavern storage site is higher than for an equal volume, single-well depleted hydrocarbon reservoir storage site, but this relationship is not a strict cost dominance in favor of depleted hydrocarbon reservoirs across all our sensitivity scenarios. We also found that storage costs could be significantly reduced by procuring the electricity required to run the UHS facility and cushion gas at lower prices. With a 50% reduction in the price of electricity, the LCHS could be reduced by 12-29%, and the use of H_2 produced by fossil fuels or another, less expensive cushion gas alternative (to renewably sourced H_2) like nitrogen could decrease the LCHS by 17-36%.

In the Pennsylvania case study, we developed an initial techno-economic screening process for potential UHS site conversion using the sites' working-gas volumes, estimated county-level H_2 demands, and the costs of storage as the initial set of decision criteria. Our results suggest that if existing UGS facilities in

Pennsylvania were converted to store pure H_2 rather than natural gas, approximately 88% of the state's need for annual H_2 demand buffering in 2050 might be satisfied if those facilities operate like current UGS facilities.

Our analysis is based on a set of engineering assumptions, secondary data, and information on various components collected from literature surveys. This approach introduces uncertainties in our estimates. Future steps of this work might include validation of engineering and economic assumptions with industry stakeholders, incorporation of simulation or experimental research approaches or results to assess the effect of leakage and gas losses by aboveground and belowground UHS system components, and application of econometric and human behavior methods to enhance demand projections.

Acknowledgments

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Portions of this work were performed under the auspices of the U.S. Department of Energy's National Nuclear Security Administration by Sandia National Laboratories. Sandia National Laboratories is a multi-mission laboratory managed and operated by National Technology and Engineering Solutions of Sandia, LLC, a wholly owned subsidiary of Honeywell International, Inc., for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-NA-0003525.

Portions of this work were performed under the auspices of the U.S. Department of Energy by Pacific Northwest National Laboratory under contract DE-AC05-76RL01830.

Acronyms and Abbreviations

AMI	area median income
Bcf	billion cubic feet
CAPEX	capital expenditures
CCC	compressor capital cost
CCS	CO_2 capture and storage
CF	capacity factor
CGCC	cushion gas capital cost
COMC	compression cost
CRF	capital recovery factor
DRI	direct reduction of iron
EIA	U.S. Energy Information Administration
EQC	equipment capital costs
HDV	heavy-duty vehicle
LCHS	levelized cost of hydrogen storage
LDV	light-duty vehicle
LEAD	Low-Income Energy Affordability Data
LTCC	levelized total capital cost
MDV	medium-duty vehicle
Mcf	thousand cubic feet
MMcf	million cubic feet
MMkg	million kilograms
MMT	million metric tons
NG	natural gas
O&M	operations and maintenance
OPEX	operations and maintenance expenditures
SDC	site development cost
SLO	social license to operate
TCC	total capital cost
TEA	techno-economic analysis
UGS	underground natural gas storage
UHS	underground hydrogen storage
WC	well capital cost
WOMC	well operations and maintenance cost

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1.0 Introduction

Addressing the need to reduce greenhouse gas emissions has increased emphasis on research, development, demonstration, and deployment of technologies that enable a transition toward a carbon-free economy. The energy sector, specifically, is evolving toward increased reliance on renewable energy technologies to meet national, state, and organization decarbonization goals. This trend is creating challenges and opportunities with meeting current and future demand under the intermittent supply conditions that most renewables provide (Goodman et al., 2022; Muhammed et al., 2022). One challenge is the need for both on-demand and long-duration storage (e.g., seasonal balancing) to maintain energy security, reliability, and resilience. Energy storage technologies that can only engage on daily or hourly timescales are not enough to achieve this balance. Hydrogen (H_2) is a promising energy carrier to meet these challenges and serve a variety of difficult-to-decarbonize end uses. H_2 can be generated using existing carbon-based or renewable energy technologies (Peng et al., 2016; Tarkowski, 2019; Zivar et al., 2021), and large-capacity underground hydrogen storage (UHS) has the potential to meet seasonal supply/demand imbalances while enabling decarbonized heating, electric power generation, and transportation.

UHS is a method of storing gaseous H_2 in underground geological systems, such as depleted hydrocarbon reservoirs, salt caverns, and saline aquifers (Chen et al., 2022; Lord et al., 2014). Other unconventional underground storage options could include abandoned coal mines, lined hard rock caverns, and refrigerated mines (Muhammed et al., 2022; Zivar et al., 2021). UHS is an attractive option because underground formations can store large quantities of H_2 over time, providing a reliable source of energy withdrawal when needed with minimal surface footprint and lower investment cost compared to aboveground storage (Coyle, 2022). Underground storage can provide a high level of safety and security, as H_2 is stored in a closed, isolated system. Subsurface storage further enables the containment of H_2 at high pressure, critical to high energy-storage density and efficiency for transmission to various uses, such as in fuel cells and industrial applications (Singh, 2022).

A potential H_2 future could leverage domestic experience with underground natural gas storage (UGS), and the United States could drive global adoption and the growth of both H_2 supply and demand in the coming years. While UGS is a concept that has been applied at commercial scale in the U.S. natural gas (NG) industry for many decades, storage and operational differences due to inherently unique physical and chemical properties of H_2 need to be considered (Buscheck et al., 2023). For UHS, like UGS, stored gas in an underground reservoir consists of an amount (typically referred to as a volume) of working gas, which is cycled into and out of storage, and cushion gas, which remains in storage to maintain pressure for structural integrity of the system (e.g., to prevent pore or cavern collapse, reduce water intrusion, and support injection/withdrawal cycles and limit pressure swings).

Lackey et al. (2023) adapted a method to estimate the amount of pure H_2 and H_2-methane-blend working gas that could be stored in existing operational UGS facilities in the U.S. They estimated that, if converted, existing facilities can store approximately 327 TWh, or 9.8 million metric tons (MMT), of pure H_2, but a shift to pure H_2 would decrease the collective working-gas energy of the UGS facilities by approximately 75%. The authors also suggest that almost 75% of the existing UGS facilities in the U.S. could maintain current energy demand buffering using a blend of only 20% H_2 to 80% NG, by volume at surface conditions. If we can take advantage of the suite of mature technologies of existing UGS facilities and NG utility systems to accelerate the transition to a hydrogen economy in the U.S., this 20% H_2 blend could lead to a 6-7% reduction of greenhouse gas emissions for energy delivered through NG utility systems (Baldwin et al., 2022).

Large-scale UHS represents a significant opportunity to use curtailed variable renewable power generation available during periods of low demand. The H_2 economy is defined as an economy that relies on H_2 as a major commercial fuel that would deliver a substantial fraction of a nation's energy and services while also generating jobs and stimulating economic growth (Nehrir & Wang, 2016). As governments and industries around the world begin accelerating their investments in H_2 technologies and infrastructure to enable the transition to a low-carbon economy, the cost of UHS will become a critical consideration in the development of a potentially sustainable and economically feasible H_2 economy. One of the key challenges of large-scale deployment of H_2 is the cost of storage and how it affects planning decisions on whether to leverage existing UGS facilities or build new UHS sites based on predicted H_2 prices and demand growth. However, the techno-economics of UHS and its role in the larger energy system are not well understood.

This has led to an increasing interest in UHS cost analysis in the scientific literature (Gorre et al., 2020). According to recent articles, several factors can influence the cost of UHS, including the geological characteristics of the storage site, the H_2 injection and withdrawal rates, and the type and amount of infrastructure development required to support the storage system (Muhammed et al., 2023; Muhammed et al., 2022; Coyle, 2022; Chen et al., 2022). Prior work on H_2 storage costs focused on various aspects of the storage system, at varying levels of cost aggregation, to calculate the levelized cost of hydrogen storage (LCHS). The cities of Detroit, Houston, Pittsburgh, and Los Angeles were the focus of one of the earliest U.S.-focused studies that demonstrated a method to calculate LCHS for UHS (Lord et al., 2014). A few other contemporaneous studies (Michalski et al., 2017; Le Duigou et al., 2017) provide base frameworks to assess the whole H_2 supply chain with less detailed cost granularity for storage than Lord et al. (2014). Papadias & Ahluwalia (2021) also computed the cost of UHS, but aggregated costs to a level that does not allow system optimization at the individual facility level. Chen et al. (2022) followed Lord et al. (2014) by calculating the LCHS for the U.S. Intermountain West region. Both studies (Lord et al. and Chen et al.) found depleted hydrocarbon reservoirs to be the most cost-effective storage types in their study regions. Singh (2022) found that storage in inactive horizontal shale gas wells was the most cost-effective option for UHS in the Haynesville (Texas) oil- and gas-producing region, while the next most cost-effective option was salt caverns. Coyle (2022) focused on the capital costs for salt cavern-based storage in the Appalachian and Michigan Basin regions and did not include operation and maintenance (O&M) costs nor costs for other types of storage systems.

Our work expands on previous studies by establishing a framework for cost estimation and local demand projection for UHS projects that strives to more closely reflect the granularity that an operator might use to assess its own existing facilities or inform the development of new sites. Our approach focuses on allowing system optimization and cost reduction at the site level. We focus on addressing other gaps in the literature. We did not find prior work that includes an estimate of the costs associated with cycle H_2 losses, material failure or new material selection due to embrittlement, or socioeconomic factors. Our framework can parameterize and consider these factors. Another gap exists in our understanding of the associated costs and benefits of integrating large-capacity UHS with renewable energy sources, such as wind and solar. Our framework is meant to be modular so it can be used with other models representing other portions of the energy system. When used in concert with other H_2 models funded by the U.S. Department of Energy, like HD-SAM (Argonne National Laboratory, 2006), H2A (National Renewable Energy Laboratory, 2018), or HESET (Pacific Northwest National Laboratory, 2022), our framework could enhance the technical rigor applied to the storage segment of the supply chain and improve understanding of new storage technologies and the extent to which those advancements would lower the total cost of H_2 and energy.

To advance our understanding of the techno-economics of UHS, we also evaluate local H_2 demand because existing storage volume or geological potential may not directly translate to size of the local market. The volumetric makeup of a typical UGS site includes 30-70% cushion gas and 30-70% working gas that can be used for storage services. For an economically driven process of expansion for UHS, the working-gas capacity that is needed at a storage site should not only depend on the technically possible working-gas capacity of the facility, but also on the portion of that capacity that would be needed to serve local demand. A long-employed principle for expansion in the NG industry in the U.S. has been to "size for growth," especially during NG price peaks. Large-capacity additions of UGS have not occurred in some time. But, when development does occur, most U.S. UGS facilities tend to consist of many co-located wells. A staged, demand-driven conversion of only the wells required to meet local H_2 demand is likely an economically favorable approach for UHS development and expansion.

The purpose of this report is to demonstrate how a framework can be built, starting with projecting H_2 demand using market size estimates, that captures all the participating agents and carries that information through to the supply side to estimate the cost of adopting UHS technology. We illustrate this framework's application by analyzing the potential for UHS development in the state of Pennsylvania. The remainder of this report discusses the approach, our baseline assumptions, and results of our calculations of the levelized costs of UHS facilities; quantifies the marginal changes in the costs due to changes in various inputs; and ties those factors together with demand projections and UHS potential estimates for the state of Pennsylvania to develop an illustrative set of site screening criteria informed by techno-economic principles. We present this analysis for two types of UHS systems: salt caverns and depleted hydrocarbon reservoirs.

2.0 Approach

Combining cost estimation and demand projection into one structured assessment framework, techno-economic analysis (TEA) is an important tool to assess the feasibility of various UHS development pathways. Generally, TEA tools allow researchers to seek answers to key questions regarding the cost drivers, commercially viable technology pathways, and their cost effectiveness while potentially highlighting opportunities for and magnitudes of cost reduction. We build on the approach of Lord et al. (2014) and contribute additional cost items that were missing in prior TEA frameworks presented in the literature to conduct a more comprehensive assessment of UHS storage cost that is more reflective of the level of detail that a storage operator might require when assessing their own UGS facilities for UHS conversion or prospecting for new storage development opportunities. The framework we developed consists of a model to project H_2 demand, an assessment of potential UHS working gas volume using the approach of Lackey et al. (2023), and a quantification of the cost of UHS. We applied the framework to a use case based on data for existing UGS facilities in the Commonwealth of Pennsylvania.

Pennsylvania is an ideal state for an illustrative application of this framework because of the large amount of data available for UGS facilities and potential consumers of H_2 in the state, the state's long history of oil and gas production, and its robust NG transmission and distribution infrastructure systems. It is also home to multiple major east-west and north-south rail and over-the-road freight routes that could be used for bulk H_2 transportation. Pennsylvania's geology may also be suitable for the development of new UHS facilities because of its oil and gas reservoirs, salt deposits, and sedimentary basins (Figure 1). Pennsylvania also has many existing UGS facilities operating to support its NG infrastructure today (Figure 2).

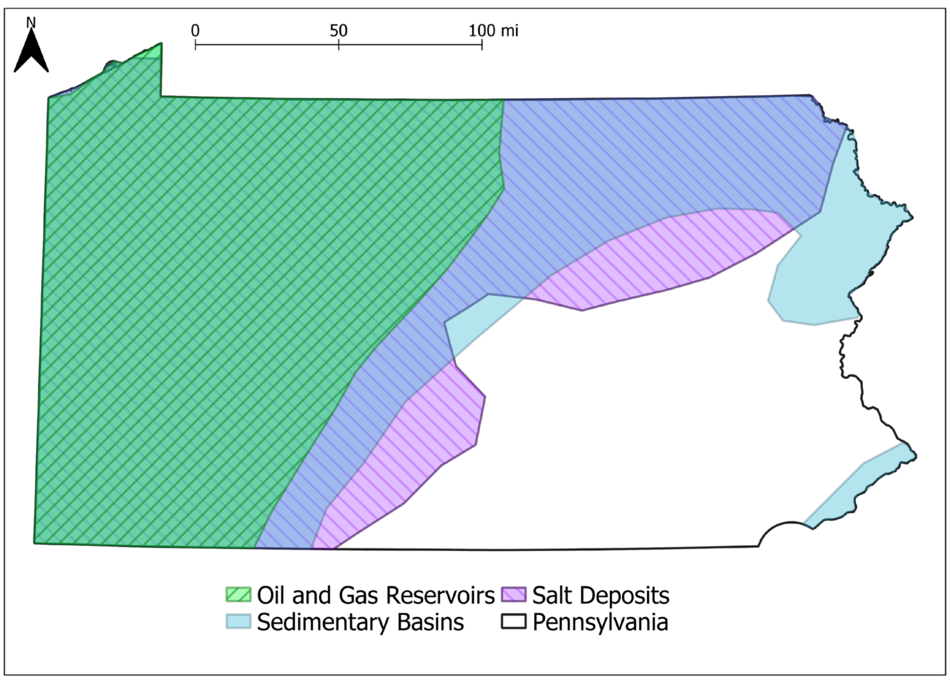

Figure 1. Geologic units in the state of Pennsylvania that may be suitable for UHS (adapted from Lord et al., 2014)

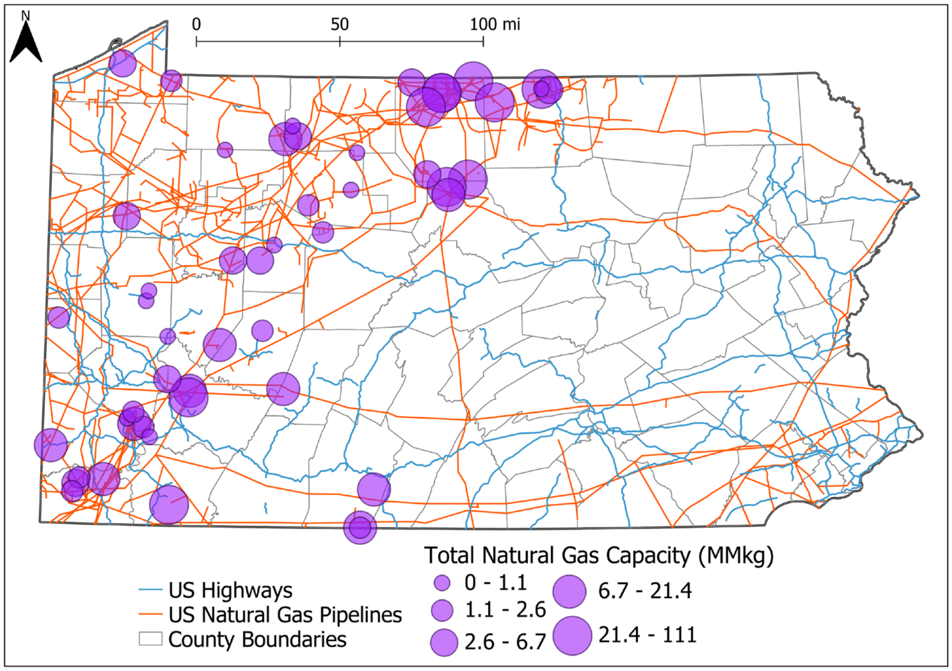

Figure 2. Existing UGS facilities, natural gas transmission pipelines, and major highways in Pennsylvania

2.1 Demand Analysis

We developed or adapted available data to create projections of county-level H_2 demand for the U.S. economy in 2050. We aggregated demand to four main end-use sectors: (1) residential – including homes and apartments; (2) commercial – including facilities like offices, stores, hospitals, hotels, and restaurants; (3) industrial – including facilities and equipment used for manufacturing, agriculture, mining, and construction; and (4) transportation – including vehicles that transport people or goods, like cars, trucks, trains, aircraft, and ships.

In their report *The Technical and Economic Potential of the H2@Scale Hydrogen Concept within the United States,* Ruth et al. (2020) estimated each county's "serviceable consumption potential." Serviceable consumption potential is "the quantity of hydrogen that would be consumed to serve the portion of the market that could be captured without considering economics (i.e., if the price of hydrogen were $0/kg over an extended period)." They also conducted an economic potential estimation in the same report that considers an equilibrium price for multiple scenarios based on technology and market assumptions. As only the serviceable consumption potential estimations are available publicly and do not depend on economic assumptions, we use these values to approximate the ceiling for the H_2 demand in each county of the U.S.

To supplement these upper-bound data, we curated datasets and developed methods to consider adoption drivers more closely for our residential and commercial sector projections.

2.1.1 Residential Sector Demand in 2050

Literature suggests that adoption of H_2 by the residential sector is strongly correlated with income, and the ability to switch to low-carbon fuels may not be possible for low-income households because of high initial investments (Wang et al., 2022; Scheller et al., 2021; Gustafson et al., 2020; Graziano et al., 2019;

Cornwell et al., 2016). Other factors like inefficient appliances and poor thermal performance of the dwellings further impede adaptive capacity (Heaton, 2017; Nelson et al., 2019). In Australia, recent research concluded that the transition to an H_2 economy may not be equitable for residential energy consumers (Sandri et al., 2021). To address this domestically, the U.S. Department of Energy is working to increase diversity, equity, inclusion, and accessibility and environmental justice through outreach, initiatives, and funding opportunities where least 40% of the overall benefits of certain federal investments flow to disadvantaged communities that are marginalized, underserved, or overburdened by pollution.

Given these observations, our estimate of the future market for H_2 in the residential sector is guided by measures of household income. Additionally, in the near- to mid-term, we assume that if H_2 is used by the residential sector for heating and cooling purposes, it must be blended with NG. This implies that the demand for H_2 by the residential sector will closely follow the demand for NG. Our work presents a functionalization where a user enters the blend percentage to assess various scenarios and H_2 demand is informed by trends in NG demand.

We used the Low-Income Energy Affordability Data (LEAD) tool from the National Renewable Energy Laboratory (Ma et al., 2019) as the starting point of our analysis. The LEAD tool uses U.S. Census American Community Survey microdata samples to estimate residential housing energy use, including electricity, gas, and other fuels, grouped into “cohorts,” where each cohort is assumed to have homogenous energy-use characteristics. For the residential sector, cohorts are groups of households based on location, occupancy, physical characteristics (building age, number of housing units, etc.), and demographics (Ma et al., 2019). To estimate county-level H_2 demand for Pennsylvania, we constructed an estimate of NG consumption (using reported “utility gas” values as a proxy for NG) by area median income (AMI) grouped by household count in each income class for each county. The LEAD tool classifies households into five AMI groups: 0-30% of AMI, 30-60%, 60-80%, 80-100%, and 100%+. We apportioned the state average distribution of households by AMI using NG for heating to each AMI category in each county. This allowed us to estimate the number of households in each AMI group in each county that consume NG.

The LEAD tool also provides a means of estimating the average annual NG expenditure (in \$) by county ($TE_{NG,County}$) using the following relationship:

$$TE_{NG,County} = H_{County} * EC_{County} * X_{NG,County} \tag{1}$$

where H_{County} is the number of households in the county; EC_{County} is the average annual energy consumption (in thousand cubic feet, Mcf) in the county; and $X_{NG,County}$ is the proportion of energy expenditure on NG in the county.

Next, we obtained the NG prices for Pennsylvania (P_{NG}) from the U.S. Energy Information Administration (EIA) for the year 2018 (U.S. Energy Information Administration, 2023a) and used it to estimate the demand for NG in each county and AMI group ($D_{NG,county,AMI}$) in units of Mcf at 14.73 psia and 60°F) as follows:

$$D_{NG,county,AMI} = \frac{TE_{NG,County}}{P_{NG}} \tag{2}$$

Using the measures computed above, we developed two income-driven scenarios to project the demand for H_2 using the estimated demand for NG. To construct these scenarios, we assume that H_2 is consumed by residential households as a blend with NG and is delivered through the local NG distribution network.

We parameterize both the uptake amount by income group and the volumetric blend ratio of H_2 with NG to provide a framework that can flexibly accommodate scenario analysis based on changes in technical assumptions. As our focus in this portion of the work is on estimating demand to assess viability of UHS facilities, we make no assumption about the location of separation stations throughout the local delivery network.

In Scenario 1, we assumed that only the top two income groups would adopt H_2 in their homes, and in Scenario 2, we assumed that the top four income groups would adopt H_2 in their homes. Further, we created two variations of volumetric blend ratio of H_2 to NG. For the first sub-scenario (variant A), we assumed a 1:1 blend of H_2 and NG, or a 50-50 volumetric blend. In the second variation (B), we assumed a 2:1 volumetric ratio of H_2 to NG, or a 66.6-33.3 blend. These blend ratios are parameterized in the framework and can be adjusted to analyze relevant end-use and system-level questions like "how do changes in energy content and input fuel requirements of equipment affect economic viability of storage?" and "how do the system-level or infrastructure component H_2 tolerances constrain uptake by end users?" The defaults in these scenarios could represent advanced H_2 technologies becoming available over the next few decades that are more efficient than their NG counterparts. Taking these variations into consideration, in total we constructed four different projections using the scenarios presented in Table 1.

Table 1. Residential H_2 adoption scenarios

Scenario	1a	1b	2a	2b
H_2-NG Volumetric Blend	1:1	2:1	1:1	2:1
AMI Group	**X% of NG demand converted to blend ratio**			
0% - 30%	-	-	-	-
30% - 60%	-	-	5	5
60% - 80%	-	-	5	5
80% - 100%	5	5	5	5
100%+ AMI	15	15	15	15

While existing NG pipeline infrastructure is not designed to transport 100% H_2 because of material and component design limitations, it is possible to introduce hydrogen as a low-level blend with NG. For the past 50 years, Hawai'i Gas has been delivering a mixture of synthetic NG containing up to 15% hydrogen to its customers in Oahu (Hawai'i Gas, 2022). It may be possible to apply blends on a magnitude similar to Hawai'i in the conterminous US within the next few years. According to a recent study by Oak Ridge National Laboratory (Kass et al., 2023), NG blends with up to 8% H_2 can be transported without concern using existing U.S. NG infrastructure.

2.1.2 Commercial Sector Demand in 2050

Estimating commercial sector H_2 demand by county requires an estimate of the size of the commercial sector in each county and a basis for future projections of H_2 consumption. The Commercial Buildings Energy Consumption Survey publishes the characteristics of buildings (type, size, age, etc.) by census region and the corresponding amount of energy consumption (U.S. Energy Information Administration, 2018). The National Renewable Energy Laboratory (2021) used this data to estimate the number of buildings of each type and age by county.

To estimate the potential demand for H_2, we started with current and historical NG consumption because our demand scenarios assume that H_2 will, at least initially, be consumed as a blend with NG for most commercial business types. The EIA maintains a data repository of NG deliveries to commercial customers by state. Using this data and forecasting with a linear model allows us to estimate the demand for NG by the commercial sector (Figure 3). This forecast is roughly equivalent to the EIA Annual Energy Outlook's "high economic growth" scenario (U.S. Energy Information Administration, 2023b).

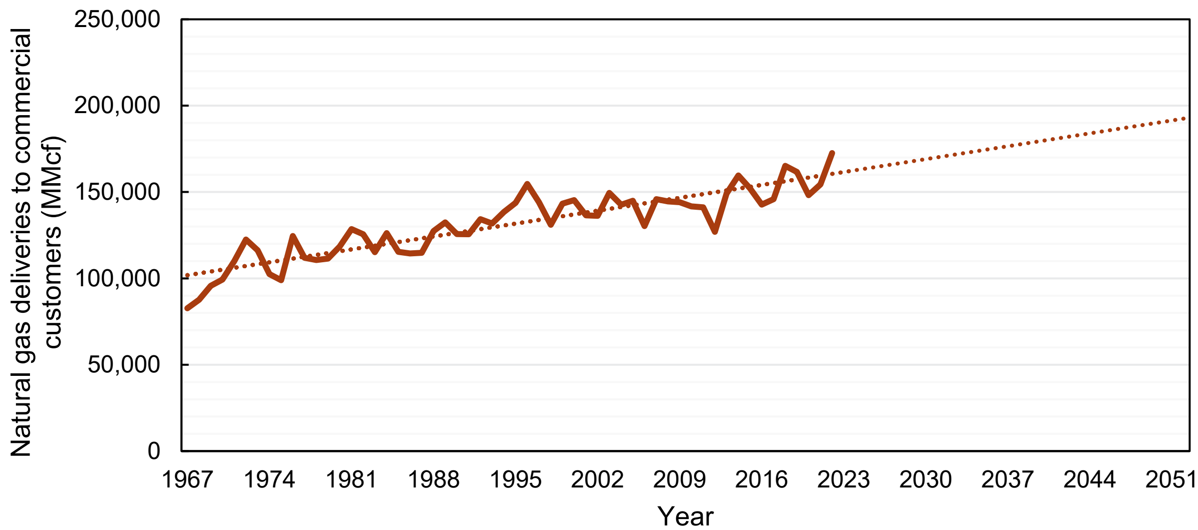

Figure 3. Natural gas deliveries to commercial consumers in Pennsylvania. Data source: https://www.eia.gov/dnav/ng/hist/n3020pa2a.htm

To project the demand for H_2 by the commercial sector, using the demand for NG as a basis, we made the following simplifying assumptions. We assume that 15% of the projected NG consumption we compute for the year 2050 will instead be served by H_2 blended into the NG delivery system. Realistically, the amount of adoption in the commercial sector would depend largely on the evolution of construction trends, appliance standards, building codes, and policy incentives to accommodate an H_2 blend. The assumption of 15% by volume uptake can be adjusted as an input variable to the TEA framework to explore other scenarios informed by users. As with the residential sector analysis, we created two blending scenarios for 2050. Those assumptions mirror the residential analysis – i.e., a 50-50 blend and a 66.6-33.3 blend of H_2 with NG. We also assume that the current building stock, irrespective of age, will be able to support use of a blend. This is an implicit assumption that appliances and appliance standards will be unaffected. This is perhaps the largest simplification, and a more thorough commercial sector demand estimation would require an understanding of building ages and types that can accommodate various levels of blends versus the ages and types that cannot.

2.1.3 Industrial Demand in 2050

Ruth et al. (2020) computed the upper bounds of county-level 2050 H_2 demand estimates by the industrial and transportation sectors in work conducted for the H2@Scale Initiative. We use H2@Scale's county-level estimates directly for all industrial sectors except for ammonia production and metals refining. H2@Scale estimated H_2 demand for ammonia production, based on existing and planned U.S. ammonia plants (Brown, 2018), as analyzed by Elgowainy et al. (2020). Although Pennsylvania has several industrial establishments that use ammonia to produce fertilizers (Pennsylvania Department of Community & Economic Development, 2023), none of them appear to directly produce any ammonia (Statistica, 2023). Therefore, demand for the ammonia production sector is set to zero. For metals refining, we allocated H2@Scale's serviceable consumption estimate to Pennsylvania counties based on state-level gross domestic product numbers to achieve a consistent spatial granularity with our other data. The data used here are baseline assumptions and do not factor in prospective facility additions or retirements in the state of Pennsylvania that might affect county-level demand for H_2. A user of this approach could update the tabulated values presented by Ruth et al. (2020) to include new projects or decommissioning of facilities of interest for scenario analysis.

Oil refining

H_2 is used as a feedstock to refine crude oil into finished petroleum products. H2@Scale estimated the 2050 serviceable consumption potential for oil refining for the entire U.S. to be 7.5 MMT/yr. They apportioned this demand based on the 2017 refinery capacity data from the EIA. For Pennsylvania, refinery H2 serviceable consumption values totaled approximately 0.8 million kilograms (MMkg) per year, which was allocated to refineries in Delaware (0.36 MMkg/yr), McKean (0.01 MMkg/yr), Philadelphia (0.33 MMkg/yr), and Warren (0.065 MMkg/yr) counties.

Metals refining

H2@Scale estimated serviceable consumption potential of H_2 for metals refining as the total quantity of H_2 that could be required by the U.S. steel manufacturing industry for use as a reducing gas in the direct reduction of iron (DRI) process. For DRI, they allocated the demand to U.S. locations based on expert input from Idaho National Laboratory. This split demand evenly among three primary regions for metals refining: (1) Minnesota, (2) Lake Michigan and Lake Erie, and (3) Birmingham (Alabama) (Ruth et al., 2020).

Since our objective was to downscale to a county-level estimate for Pennsylvania, we assumed that states and counties that border Lake Erie (Ohio, New York, and Pennsylvania) comprise the total of the "Lake Erie" estimate in the H2@Scale work. We apportioned the Lake Erie demand to each state based on its gross domestic product. For Pennsylvania's share, that demand was allocated to Erie County and was 160 MMkg/yr. This is a baseline assumption that could be updated by users of the framework with more specialized knowledge of the industrial landscape for the state being analyzed.

Biofuels

H2@Scale allocated H_2 demand "according to the distribution of biomass resource availability by state. For example, "if a state has 10% of the biomass resource, [they assumed] the state has 10% of demand for biofuel production." They further assumed the county location of biofuel production facilities based on the presence of similar regional industrial facilities because of the infrastructure in those areas. Using their assumptions, Pennsylvania biofuel production H_2 demand totaled 165 MMkg/yr statewide and was allocated to Allegheny (18 MMkg/yr), Butler (18 MMkg/yr), Elk (18 MMkg/yr), Monroe (18 MMkg/yr), Delaware (56 MMkg/yr), and Erie (37 MMkg/yr) counties (Ruth et al., 2020).

Synthetic hydrocarbons

H2@Scale estimated the serviceable consumption potential for H_2 that could be used with carbon dioxide to produce synthetic hydrocarbons. They assumed that the regional distribution of H_2 for synthetic hydrocarbon production would be located at the concentrated carbon dioxide sources from ethanol and steam methane reforming facilities (Elgowainy et al., 2020). Based on these assumptions, they allocated 41 MMkg/yr of demand to an ethanol plant in Clearfield County.

2.1.4 Transportation Sector Demand in 2050

In our framework, we adopt H2@Scale conventions to allocate H_2 demand in 2050 across classes of vehicles using two groupings: light duty vehicles (LDVs) and an aggregation of both medium- and heavy-duty vehicles (MDVs and HDVs, respectively). H2@Scale computed the serviceable consumption potential for LDVs assuming fuel cell electric vehicles will constitute 41% of the LDV fleet in 2050. (This equates to approximately 66 million out of a total of 163 million cars and 63 million out of a total of 153 million light-duty trucks in Pennsylvania.) H2@Scale estimated the serviceable consumption potential of the MDV and HDV H_2 market assuming that 35% of the fleet will be fueled by H_2 (Ruth et al., 2020). Based on these assumptions, the H_2 demand for LDVs and the combined total for MDVs and HDVs for Pennsylvania were 700 and 290 MMkg/yr, respectively.

2.2 H_2 Storage Potential in Pennsylvania

We paired the demand projection methodology presented above with work by Lackey et al. (2023) to assess whether existing UGS facilities are adequate to buffer anticipated regional H_2 demand at levels comparable to today's amount of seasonal energy buffering provided by UGS. This is a refinement and extension of the analysis from Lackey et al. (2023), using economic principles to construct demand scenarios.

According to Lackey et al. (2023), the Pipeline and Hazardous Materials Safety Administration has information about 51 existing UGS facilities in Pennsylvania. All 51 are depleted hydrocarbon reservoir facilities with reservoir midpoint average depths between 699 and 7,830 ft (median of 2,610 ft) and volumetric total gas capacities between <1 and 111 billion cubic feet (Bcf), with NG working-gas volumes between <1 and 72 Bcf with a median of 2.4 Bcf. Table 2 provides summary statistics of the UHS potential of existing UGS facilities in Pennsylvania by H_2 blend percentage. Figure 4 presents a histogram of UGS facility surface condition working gas volumes in Pennsylvania if the existing facilities were converted to store pure H_2 rather than NG.

Table 2. H_2 working-gas volume (Bcf) in existing UGS sites in Pennsylvania by blend scenario from Lackey et al. (2023)

H_2 %	0.5	5	10	20	50	90	100
Min	<.001	.001	.002	.004	.009	.02	.02
Mean	.01	0.1	0.2	0.5	1.1	1.9	2.1
Median	.04	0.4	0.8	1.6	3.7	6.4	7.0
Max [Bcf]	0.4	3.6	7.2	14.2	34.9	61.2	67.7
Sum [Bcf]	2	20	40	79	187	318	348

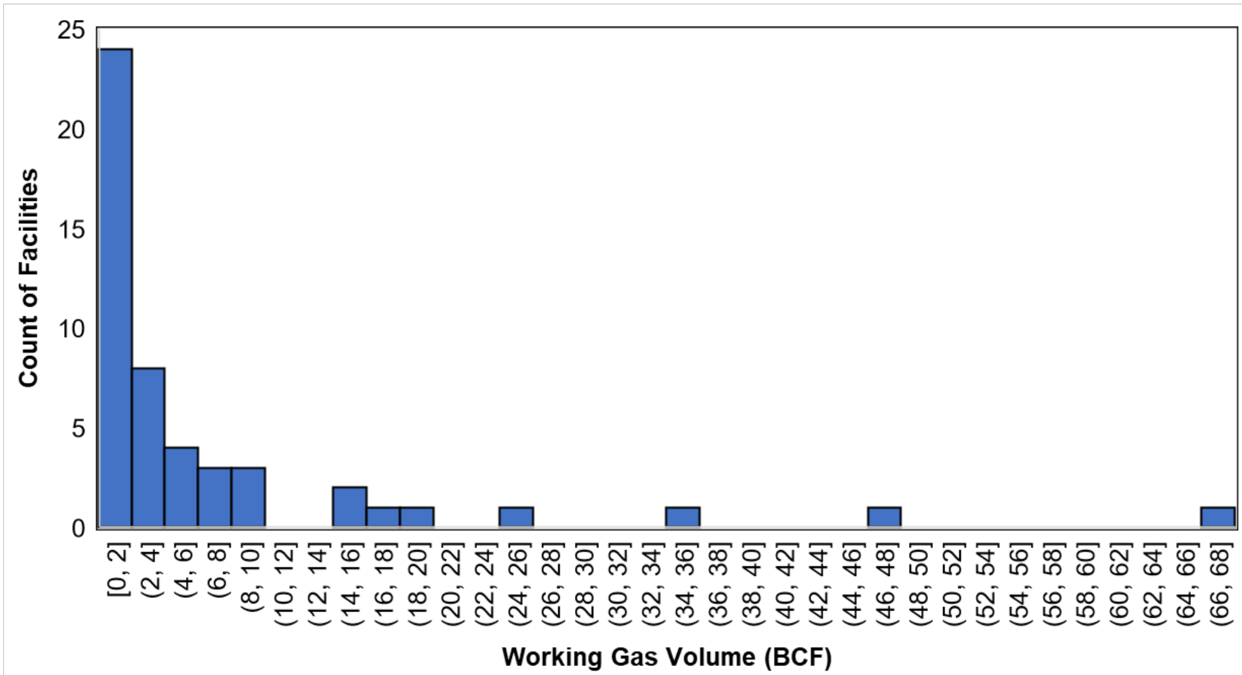

Figure 4. Count of UGS facilities in Pennsylvania by 100% H_2 working gas volume at surface conditions

2.3 Storage Cost Analysis

Based on the storage potential assessment and data from literature sources, we conducted a cost analysis for UHS systems within a set system boundary. Our analysis includes cost estimations for site characterization, underground engineering, and construction such as well(s) and caverns, cushion gas, and aboveground equipment. Figure 5 presents a generalized representation of the aboveground and underground equipment that could comprise a UHS facility and is considered for costing purposes in the TEA framework.

O&M costs of wells that reflect the processes that unfold at UGS facilities (including compression, injection, withdrawal, and monitoring) are also included. Figure 6 identifies the key steps in the UHS process that were considered to guide our literature analysis and data gathering for O&M costs. We present results of our calculations using example parameters for salt cavern and depleted hydrocarbon reservoir storage types and analyze the existing UGS facilities in Pennsylvania to demonstrate our TEA framework. The framework presented here can be adapted to different reservoir types with slight modification.

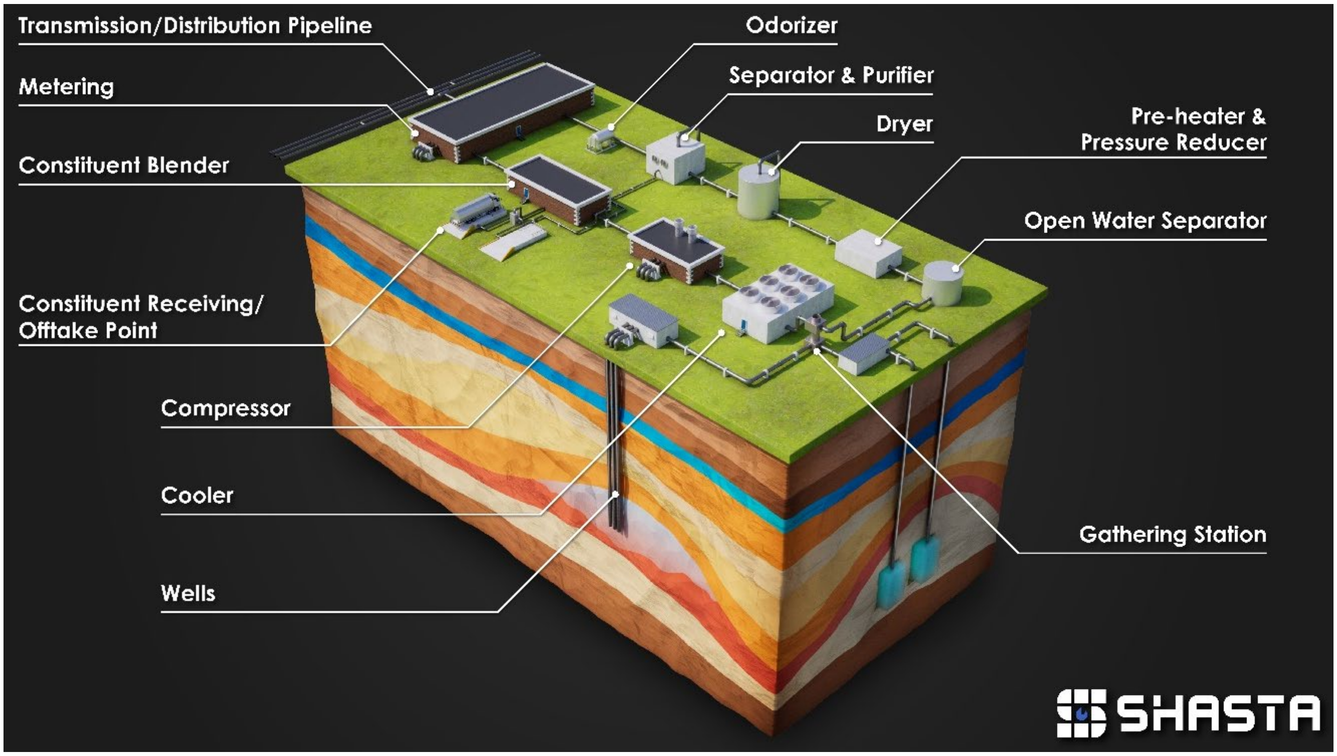

Figure 5. Illustrative diagram of a generalized UHS facility

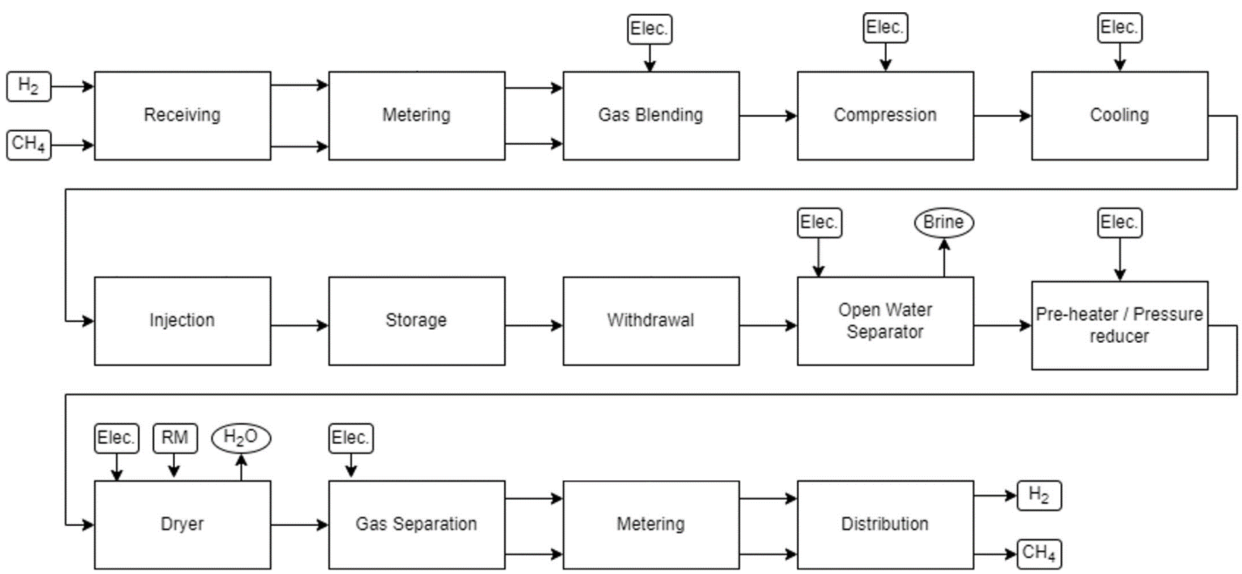

Figure 6. Process diagram for UHS used as a basis for computing O&M costs

2.3.1 Cost Formulation for Underground Hydrogen Storage

Capital expenditures (CAPEX) and operations and maintenance expenditures (OPEX) are the two major UHS cost categories in our framework. CAPEX is incurred initially for developing the storage site and OPEX is recurring to operate the site and to inject and withdraw H_2. The LCHS (\$/kg H_2) is calculated using Eq. (3). In our formulation, we further categorize CAPEX and OPEX into more-detailed sub-categories, as discussed below, and show how cost components influence the calculation of levelized cost of storage.

$$LCHS = LTCC + COMC + WOMC \tag{3}$$

where *LTCC* is the levelized total capital cost, and *COMC* and *WOMC* are O&M costs for compressors and wells, respectively. The LTCC is the annualized total capital cost (TCC) calculated by using the capital recovery factor (CRF) and capacity factor (CF) as follows:

$$LTCC = (TCC * CRF)/CF \tag{4}$$

A CF of 0.90 is used assuming that the plant operates 90% of the year and may be offline for the remaining 10% of the time due to regularly scheduled and incidental maintenance. The CRF is calculated using the discount rate and lifetime of the H_2 storage facility as follows:

$$CRF = \frac{r \cdot (1+r)^t}{(1+r)^{t-1}} \tag{5}$$

We used a discount rate (r) of 10% based on the discount rate used for TEA of H_2 energy systems in the literature and a well lifetime (t) of 30 years. Our framework presents a means to analyze sensitivity of LTCC (and LCHS) to a range of possible discount rates.

2.3.2 Capital Expenditures

Capital expenditures are categorized into storage site development costs (SDCs), well capital costs (WCs), salt-cavern-specific costs (SCs), compressor and other equipment capital costs (EQCs), and cushion gas capital costs (CGCCs) (Table 3).

Storage Site Development Costs

Storage SDCs include the costs of site characterization and permit application, social licensing, retrofitting or drilling wells, activities in the cavern (mining, leaching plants, and salt water disposal), and mechanical integrity tests. Mechanical integrity tests are required, on average, every five years depending on cycling frequency and state regulations. Site characterization costs also include labor (for geologists, engineers, and other specialists), equipment for surveys, geo-mechanical and geochemical analysis, seismic surveys, and report and permit application preparation. These costs vary according to the geology and scale of the storage facility.

Table 3. Capital cost categories

Cost Code	Cost Category	Cost Variables
SDC	Site characterization Environmental impact studies	1. Site survey (wells, salt thickness, cap rock, seismic survey) 2. Regulatory requirements
	Permit application	
WC	Underground engineering and construction	1. Well drilling 2. Rig mobilization/demobilization
	Aboveground installations	1. Well head and surface equipment installation 2. Testing
SC	Salt cavern specific costs (if applicable)	1. Cavern creation 2. Mining 3. Leaching and salt water disposal
EQC	Compressors	1. Cost based on quantity of H_2 and depth 2. Cost based on compressor power and unit cost per hp (kW)
	Other equipment	Dehydrator
CGCC	Cushion gas	1. Percentage of cushion gas 2. Market price for cushion gas (renewable-based H2, fossil-based H_2 with carbon capture, fossil-based H_2 without carbon capture, or other cushion gas such as nitrogen)

For storage SDCs, some of the costs of items in Table 3 are applied differently depending on storage type and operational status. For instance, some costs might not be applicable for existing site conversions and other costs may be reduced significantly because an existing site might only require an upgrade or retrofit. The costs for site characterization, well drilling, and equipment are usually significantly lower if a UHS site is developed at a depleted hydrocarbon reservoir. Storage site development in a saline aquifer, on the other hand, typically calls for extensive analyses to understand the geology and shape of the storage structure (reservoir or cavern) as well as the top seal (impermeable cap rock over the storage reservoir). For UHS in existing salt cavern UGS sites, companies can discount the cost of mining and leaching, which is a significant CAPEX.

Well Capital Costs

UHS systems require injection/withdrawal well(s), and the costs vary based on well depth, thickness of the reservoir, geologic type and characteristics of the reservoir, and drilling technique. The number of wells needed also varies by storage type. For salt caverns, one well is required per cavern, and for depleted hydrocarbon reservoir sites, one well is required per 3 MMkg/s H_2 (Chen et al., 2022). The same well is used for injection and withdrawal. The wells for depleted hydrocarbon reservoirs cost the least because of the existing infrastructure and the detailed information on the sites from prior operations. While hydrocarbon reservoirs already have large-scale porous reservoir formations, overlain by impermeable seals (Tarkowski, 2019; Singh, 2022), these sites can still be costly due to impurities in the depleted site (Kobos et al., 2011; Chen et al., 2022). Salt caverns are created by injecting water in salt-rich formations (Lemieux et al., 2020) and require a freshwater well, brine-disposal well, and a gas-injection/withdrawal well. The major capital cost items for well development include drilling rig rental, fluids and supplies for drilling, labor/specialized contractors, well casing/cementing, and completion costs.

The American Petroleum Institute conducts an annual survey on drilling costs. Based on data gathered in 2006, they published a joint association survey in 2008 that provides equations for calculating the drilling costs for various regions within each of the surveyed states in the U.S. (American Petroleum Institute, 2008). The capital cost for drilling wells is calculated using the following equations:

$$y = \propto e^{\beta x} \tag{6}$$

$$y = \beta_2 x^2 + \beta_1 x + \propto \tag{7}$$

$$y = \beta x + \propto \tag{8}$$

where y is the well drilling cost in thousands of dollars, x is the depth, β_1 and β_2 are place-based coefficients derived from a regression analysis, and $\propto$ is the place-based intercept. We used the following equation and values for the intercept and coefficients, as recommended by the American Petroleum Institute (2008), for our study site in Pennsylvania:

$$y = 0.00009 * x^2 + (-0.0287) * x + 97.971 \tag{9}$$

The drilling cost obtained for the year 2006 is then inflated to 2022 dollars using the consumer price index (in this case, 1.47). We compared the costs of well drilling with the cost estimated by Lord et al. (2014).

Salt caverns are created by solution mining and have unique costs associated with those activities. After completion of site characterization, a borehole is created, and casing is installed. Freshwater is injected and brine water is removed before gas is injected to complete brine removal. Brine disposal is an additional cost in the salt cavern development process. Singh (2021) estimated a brine disposal cost of \$0.03 per kg of H_2 produced using a disposal cost of \$2 per barrel (~159 L). Michael et al. (2019) and Capper (2019) estimated a disposal cost of \$2+ including transportation. For mining and leaching plants, we used a cost of \$41.65/m^3 and \$6.77/kg H_2, respectively, following Lord et al. (2014). Developed caverns in salt domes are 190 to 790 ft (60 to 240 m) long (Papadias & Ahluwalia, 2021). The pressure increases by 0.156 bar per meter of depth (Murray et al., 2018). Because of these conditions, developed salt caverns also incur a cost for mechanical integrity testing. The mechanical integrity test cost used for this study is \$2.3/kg.

Compressor and Equipment Capital Costs

The equipment required for H_2 storage and withdrawal includes blending units, compressors, water-cooling units, pumps, dehydration and separation units, heating and light systems, and monitoring and alarm systems.

Compressor capital cost (CCC) is one of the major capital costs for H_2 storage. Coyle (2022) derived an equation for calculating the cost of compressors based on the Papadias & Ahluwalia (2021) compressor cost per kg of H_2 considering depth as follows:

$$CCC = (0.0037 * Z + 3.421) * m \tag{10}$$

where m is the mass of working H_2 in kg and Z is the compressibility factor.

Lord et al. (2014) suggested using the cost of compressor per kilowatt, compressor size, and number of compressors to calculate the capital cost of compressors. We used 3,700-kW compressors following Lord et al. (2014) and conducted a sensitivity analysis using compressors of various sizes. A typical storage station contains several reciprocating compressor units ranging in size from 750 to 4,500 kW each (White et al., 2019). Use of a backup compressor is a common practice in the industry; as such, we included that in our sensitivity analysis.

Factors that can influence the cost of UHS storage compressors include the type of compressor technology used (e.g., reciprocating, rotary, or centrifugal), the materials and components used in the compressor, the level of automation and control, and the level of safety and reliability features incorporated into the design. In general, compressors used for UHS are required to operate at high pressures, typically in the range of 20 to 28 MPa (2,900 to 4,000 psi), and must meet strict safety and reliability standards.

Cushion Gas Capital Cost

CGCC depends on the percent of cushion gas required according to the storage type. Desired percentages of cushion gas are 30%, 50%, and 50%, respectively, for salt caverns, depleted hydrocarbon reservoirs, and saline aquifers. The second factor is the cost of cushion gas. H_2 production cost ranges from $3 to $6.55/kg H_2 (van Renssen, 2020). H_2 prices vary according to the feedstock and method of H_2 production. Feedstock prices range from $2.11 to 5.14 per gigajoule (GJ). For example, as of 2022, Illinois No. 6 coal had a delivered cost of $2.11/GJ, NG was $4.19/GJ, and torrefied woody biomass was $5.14/GJ (Lewis et al., 2022). H_2 produced using fossil-based methods without carbon capture is estimated to cost $2/kg, fossil-based production with carbon capture is $3/kg, and renewable-based production is approximately $5/kg (KPMG, 2021; SG H2 Energy, n.d.; U.S. Department of Energy, n.d.). Lewis et al. (2022) estimated that fossil-based H_2 production costs are between $1.06 and $3.64/kg. Based on these sources, we used $2.5/kg and $5/kg as base assumptions in our analyses.

Other Capital Costs

There are costs for constructing surface pipelines to transport compressed H_2 from a receipt point(s) to the compressor, then to the wellhead for injection. The pipeline capital costs are based on the distance between the H_2 source and the injection site. To account for the significant technical hurdles and unknowns associated with the development of H_2 pipeline systems, we based our capital cost calculation on the formulation suggested by McCollum & Ogden (2006) for CO_2 pipeline development. Here, CO_2 pipelines are used as a proxy technology because significant uncertainty still exists in costing and deployment techniques for CO_2 pipelines in the U.S. Their cost estimation equation is as follows:

$$PCC = 9970 * m^{0.35} * L^{0.13} \tag{11}$$

Where *PCC* is pipeline capital cost, *m* is the mass flow rate [tonnes/day], and *L* is pipeline length [km]. The calculated costs are in year 2005 U.S. dollars per kilometer, which is then inflated to 2022 dollars ($/km). For existing UGS facilities that are converted to H_2, these costs could be significantly reduced or eliminated if the offtake pipeline is suitable for transporting H_2 or H_2-NG blends. We assume this to be the case in our example application of this framework but include the description here for reference.

2.3.3 Operations and Maintenance Expenditures

OPEX includes the costs associated with blending, compressing, transporting, injecting, withdrawing, and separating gas as it proceeds through the entire storage cycle as shown in Figure 6. Input costs for these processes include electricity, water, and cooling costs, and sometimes other materials costs (e.g., desiccant drying materials) need to be incorporated as input costs for these processes. Periodic testing, monitoring, and reporting costs are also part of OPEX.

Compression Costs

COMCs are calculated using the following equations:

$$COMC = EC + WCC \tag{12}$$

$$WCC = WGC * WR * P_{WC} \tag{13}$$

$$COMC = WGC[(CP * P_e) + (Q_w * P_{wc})] \tag{14}$$

where *EC* is the site-dependent electricity cost from either grid or onsite generation sources, *WCC* is water-cooling cost, *WGC* is working-gas capacity, *CP* is compressor power (kWh/kg H_2), P_e is price of electricity ($/kWh), Q_w is water requirement (L/kg H_2), and P_{WC} is the unit price of water and cooling ($/L H_2O).

Pipeline Transportation Costs

If a pipeline is needed to connect the storage facility to a customer or offtake site, the pipeline capital cost *(PL_{fc})*, flow rate *(m)*, and pipeline length (*L*) are used to calculate the full pipeline transportation cost using the following equation (Lord et al., 2014):

$$PL_c = PL_{fc} * \left(\left(\frac{m}{445.9}\right)^{-0.52} * \left(\frac{L}{100}\right)^{1.24}\right) \tag{15}$$

For existing UGS facilities that are converted to H_2, these costs could be significantly reduced or eliminated if the offtake pipeline is suitable for transporting H_2 or H_2-NG blends. We assume this to be the case in our example application of this framework but include the description here for reference.

Well Operations and Maintenance (Injection) Costs

WOMCs are computed using the following equation:

$$WOMC = [(CRF * DC_w) + \{(CC_w + DC_w) * M_{O\&M}\}]/Q_{H_2} \tag{16}$$

where *CRF* is capital recovery factor, DC_w is the initial well drilling cost ($), CC_w is the overground capital costs for well, $M_{O\&M}$ is the well O&M multiplier, and Q_{H2} is the quantity of H_2 (kg) moving in and out of the well.

2.3.4 Other Costs of Operating UHS Facilities

Monitoring and safety measures are required to ensure the integrity of the storage system and prevent leaks or other hazards. This includes monitoring the pressure, temperature, and composition of the stored H_2 or H_2-NG blend. We used the capital costs of a monitoring system for geologic CO_2 sequestration as a proxy for the UHS monitoring system capital cost (CC_M) and used the CRF and quantity of H_2 stored to calculate the per kg monitoring cost:

$$C_M = CC_M * CRF/Q_{H_2} \tag{17}$$

Costs associated with the loss of H_2 and electricity during storage cycles are proportional to the CF (Kiessling, 2021). Carden & Paterson (1979) estimated that approximately 1% of the reservoir capacity is rendered unusable because of inefficiencies in the pumping cycle.

2.3.5 Socioeconomic Factors, Social Licensing, and Stakeholder Engagement Costs

While hydrogen may provide an opportunity to decarbonize space heating in countries that have supply chains in place to transport hydrogen to end users, consumers' willingness to adopt hydrogen-fueled appliances still depends on aspects like affordability and substitutability (between hydrogen and other low carbon technologies for heating and cooking). Socio-technical barriers to the adoption of hydrogen in homes include individual attitudes, socio-political status, market, community, and other behavioral factors (Gordon et al., 2022). Affordability is likely the highest barrier to social acceptance and large-scale adoption of hydrogen in homes, especially in areas that have a legacy of economic deprivation and stagnation (Scott & Powells, 2020a, b). Evidence from Australia and the Netherlands largely confirms that cost considerations are a major concern (Lambert & Ashworth, 2018; Fylan et al., 2020; Scott & Powells, 2019; Zachariah-Wolff & Hemmes, 2006; Martin et al., 2021; Ashworth et al., 2019; Delaney, 2021), leading to a general academic consensus that higher income groups would be more open to the adoption of hydrogen in homes (Wang et al., 2022; Scheller et al., 2021; Gustafson et al., 2020; Graziano et al., 2019; Cornwell et al., 2016).

Generally expanding on the idea of acceptance, a social license to operate (SLO) refers to "the perceptions of local stakeholders that a project, a company, or an industry that operates in a given area or region is socially acceptable or legitimate" (Raufflet et al., 2013). While there are many ways to define social licensing, common themes include:

- Social licensing is difficult to define, dynamic, intangible, and impossible to directly measure.
- Social licensing requires approval from community members.
- Social licensing is especially applicable to extractive industries that affect communities' land, water, and resources.
- Social licensing is rooted in beliefs, perceptions, and opinions held by local populations/stakeholders.
- Social licensing requires collaboration and trust between communities and companies.
- Social licensing requires jointly agreed upon indicators of success (e.g., sustained company-community relationships, improved health and education, jobs, infrastructure, environmental performance/protection, ethical business conduct, and transparency).

Consistent through all these themes is the notion that social licensing and stakeholder engagement represent a cost that must be incurred by the company and community for a new project to be viable. While there is limited research related to SLO and UHS, SLO literature exists related to CO_2 capture and storage (CCS) (Seigo et al., 2014; Tcvetkov et al., 2019). CCS technology has many similarities to UHS in terms of both components (capture, transport, and storage) and subsurface aspects. Findings from the literature indicate the need to build trust with a potential host community and to involve them early and often in the development process. This includes engaging with the historical and social context of a potential host community to understand if they have experienced negative consequences from industrial development in the past. Community engagement, as well as the evaluation thereof, can take many forms. While the SLO is not quantified in this framework, it is an area for future work; Figure 7 provides a draft evaluation framework for an SLO using a mixed methods approach. Other activities under development in the SHASTA project will build on and actionize this framework.

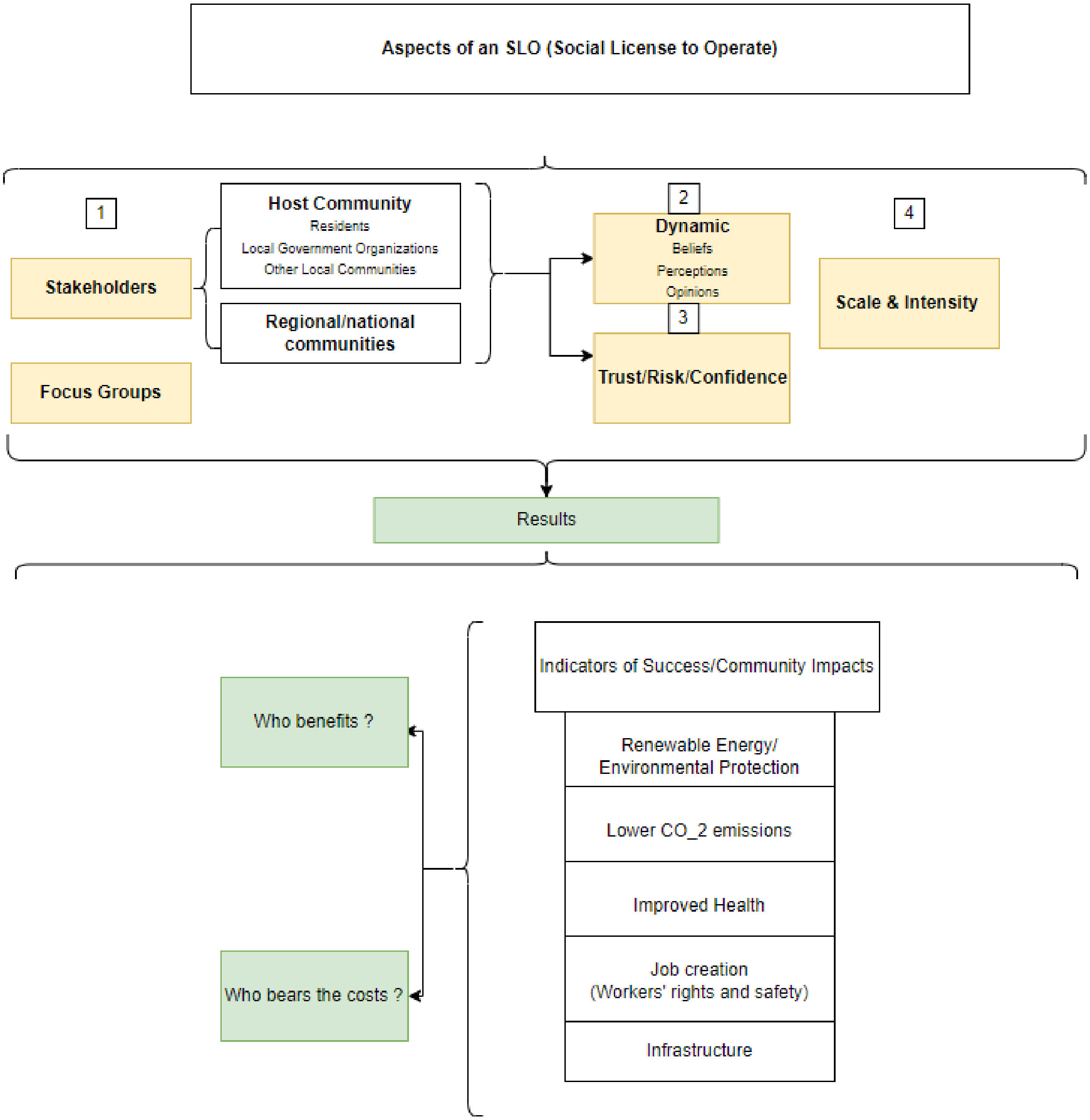

Figure 7. Draft Social License to Operate (SLO) Framework

2.3.6 Levelized Cost of Hydrogen Storage Equation

Taking all the previous formulations in the cost estimation methodology into consideration, the LCHS is calculated using the CAPEX and OPEX items in the following equation:

$$\begin{aligned} LCHS = {} & \left[\left((SDC + EQC + WC + CGCC) * (r * (1+r)^{t})/((1+r)^{t-1}) * CF)\right)/(WGC)\right] \\ & + \left[WGC * (CP * P_E) + \left(W_q u * P_w\right)\right] + \left[\left((CRF * WC)\right)/WGC\right] + MC + TC \\ & + SLC \end{aligned} \tag{18}$$

The first expression covers the capital costs (SDCs, EQCs, WCs, and CGCC), which are levelized using the CRF (calculated using the discount rate and lifetime of UHS) and the CF (which characterizes the number of days of operation per year). WGC is the working-gas capacity. The second expression is the compressor O&M cost (COMC from above) including compressor power (*CP*), price of electricity (P_E), price of water (P_w), and quantity of water ($W_q u$) required for cooling the compressors. The third expression is the well O&M cost. *MC* is the monitoring cost, *TC* transportation cost, and *SL*C the social licensing cost. All costs are $ per kg of H_2.

3.0 Results and Discussion

3.1 Residential Sector Demand Projections

For the residential sector, the demand projections for the four uptake scenarios (Table 1) are presented in Figure 8. The residential sector analysis shows that the total consumption of H_2 is higher in some relatively low median income counties (Figure 9). The resulting correlation between AMI and hydrogen uptake was computed to be 0.03, implying little to no correlation between the variables. This result refutes the literature-based hypothesis that higher incomes should correlate with higher hydrogen uptake because wealthier households can afford appliance upgrades and home upgrades that would accommodate an H_2-NG blend. This is because, in the absence of more detailed information on appliance standards and building codes, when the analysis was carried out, we forced uptake by a certain percentage of some AMI groups, and we assumed this same distribution across all counties irrespective of the county's median income. For counties with low median incomes or smaller wealth gaps between upper and lower income groups, this translated to more households converting to H_2. This is reflected in the Pennsylvania AMI data as we observed that counties with higher median incomes have more households (and a higher population density) within the higher AMI groups and counties with lower median incomes have more households in the lowest AMI groups. Additionally, barriers to adoption that can be overcome through access to finance are not captured here. Other variables that drive adoption of low-carbon technology include, but are not limited to, level of education (Wang et al., 2022), political leaning (Gustafson et al., 2020), and peer effects (Scheller et al., 2021; Graziano et al., 2019).

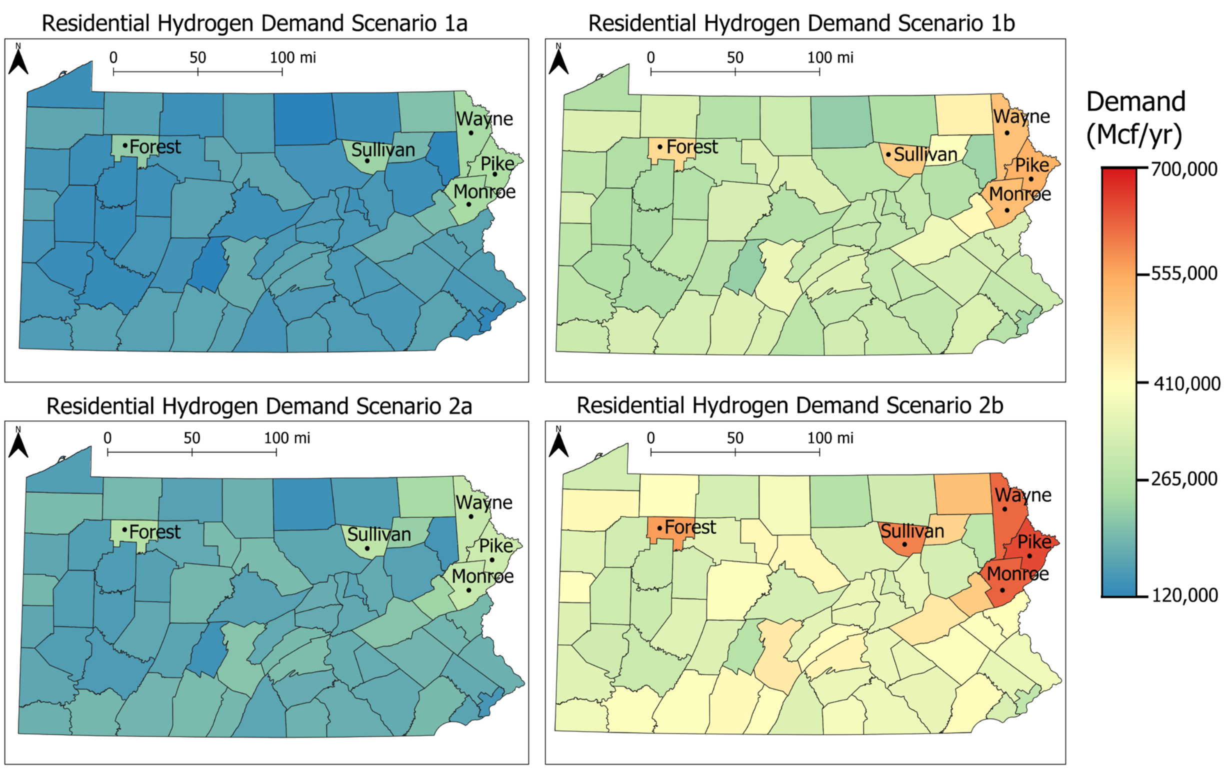

Figure 8. 2050 annual residential H_2 demand by county and uptake scenario. Top five counties are labeled with their names.

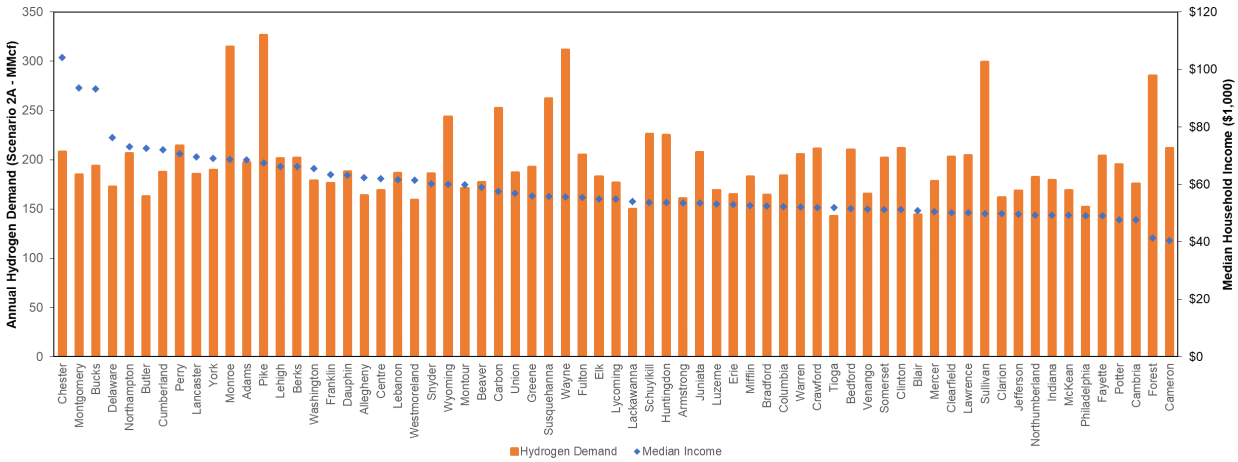

Figure 9. Scenario 2a county-level annual residential hydrogen demand and median household income arranged in order of decreasing income.

Table 4 presents estimates of the total annual residential H_2 demand in 2050 under the alternative uptake scenarios summarized in Table 1. It also presents upper and lower bounds on the amount of annual demand buffering that might be required from UHS if we consider the amount of NG buffering for existing NG operations as a close proxy for H_2 storage service demand within the context of total annual demand. The first is 11% and the second is 16% of annual demand buffering based on work by Lackey et al. (2023). These buffering fractions were applied to each of the scenarios developed for the residential sector to project how much annual volume of H_2 might be cycled through UHS facilities. We assume that H_2 for residential consumption is delivered to households through existing pipeline systems at a pressure of 0.5 psi within NG blends traveling at a temperature of 75°F. Given these assumptions and equations of state conversions, Table 4 also presents the demand for H_2 in million kg/yr by the residential sector in each of the scenarios.

Table 4. Estimates of the total Pennsylvania residential H_2 demand in 2050 and the amount of buffering that may be required by UHS based on current operational data from natural gas UGS. Current NG buffering amount is approximated to be 11-16% of total natural gas demand as reported in Lackey et al. (2023). This is applied consistently across each scenario as a proxy measure.

Scenario	**1a**		**1b**		**2a**		**2b**	
	Bcf/yr	MMkg/yr	Bcf/yr	MMkg/yr	Bcf/yr	MMkg/yr	Bcf/yr	MMkg/yr
Estimated total residential H_2 demand	11.1	0.79	22.1	1.56	13.2	0.93	26.4	1.87
11% residential H_2 demand buffering	1.22	0.09	2.43	0.17	1.45	0.10	2.9	0.21
16% residential H_2 demand buffering	1.76	0.13	3.54	0.25	2.11	0.15	4.22	0.30

3.2 Commercial Sector Demand Projections

Figure 10 shows the projected demand for commercial use of H_2 under each of the two scenarios: a 1:1 H_2-NG blend and a 2:1 H_2-NG blend. Philadelphia and Allegheny counties have the most commercial establishments at 23,513 (15% of the state's total) and 22,417 (14%), respectively. These are intuitive results, and a more accurate projection might factor in predictions for construction trends, insights from building codes, and appliance standards. Table 5 presents estimates of commercial H_2 demand under two alternative buffering scenarios: 11% and 16% annual demand buffering. We assume that H_2 for commercial businesses is delivered to facilities at a pressure of 5 psi within NG blends traveling through distribution pipelines at a temperature of 75°F. Assuming a delivery pressure of 5 psi likely creates an upper estimate of the mass of H_2 delivered to commercial customers, because all businesses do not require elevated delivery pressure, but we choose to be conservative in our estimate here. Based on these assumptions and using equations of state, Table 5 presents the demand for H_2 under these two scenarios in volumetric and mass terms.

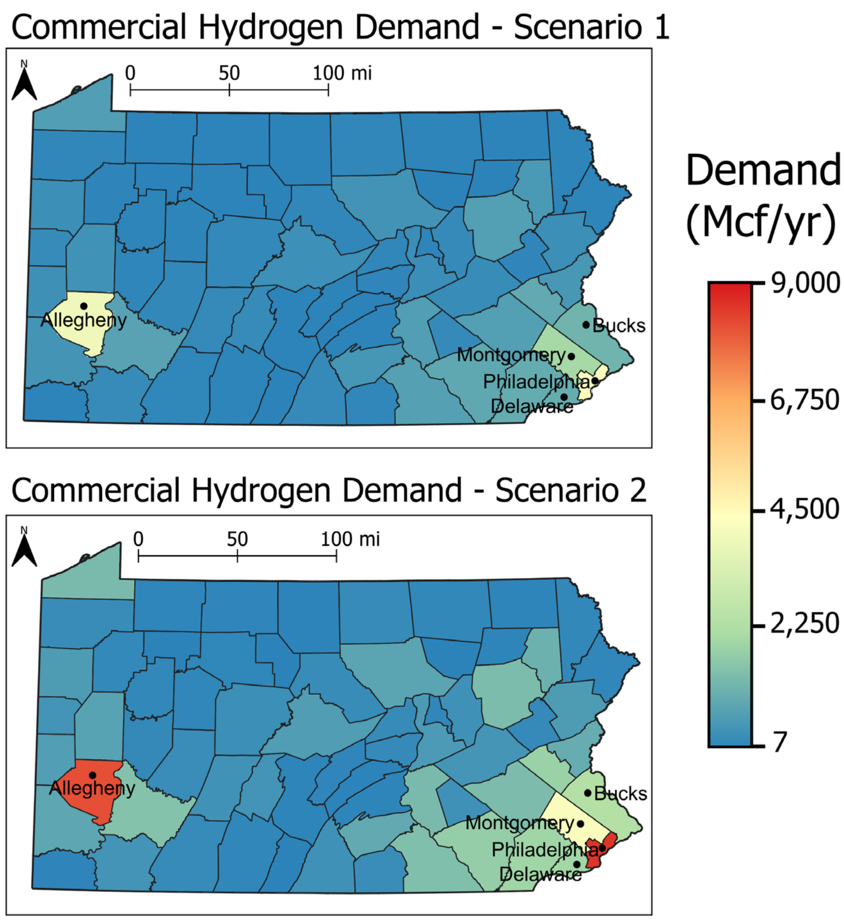

Figure 10. 2050 commercial H_2 demand by county and H_2-NG blend scenario (top-1:1, bottom-2:1). Top five counties are labeled with their names.

Table 5. Estimates of Pennsylvania's total commercial H_2 demand in 2050 and the amount of buffering that may be required by UHS based on current operational data from UGS. Current buffering is approximated as in Table 4.

Scenario	1:1 H_2-NG blend		2:1 H_2-NG blend	
	Bcf/yr	MMkg/yr	Bcf/yr	MMkg/yr
Estimated total commercial H_2 demand	0.028	0.022	0.057	0.045
11% commercial H_2 demand buffering	0.003	0.002	0.006	0.005
16% commercial H_2 demand buffering	0.004	0.003	0.009	0.007

3.3 Industrial Sector Demand Projections

Figure 11 shows county-level H_2 demand for key H_2 industrial sector businesses. Table 6 presents an estimate of Pennsylvania's total industrial H_2 demand under two alternative scenarios of demand buffering by UHS: 11% and 16% of total annual demand for the sector.

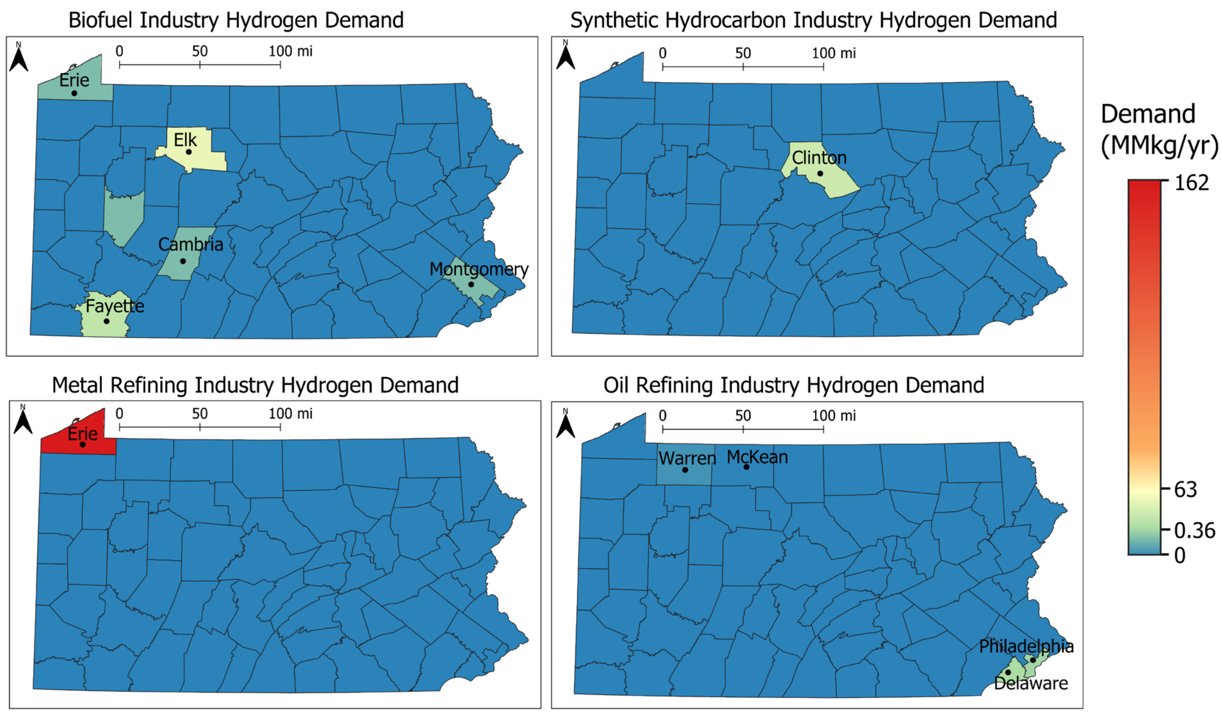

Figure 11. 2050 industrial H_2 demands by major H_2-consuming business types and county (Ruth et al., 2020). Top five counties are labeled with their names.

Table 6. Estimates of the total Pennsylvania industrial H_2 demand in 2050 and the amount of buffering that may be required by UHS based on current operational data from UGS.

Scenario	H2@Scale
Total industrial H_2 demand (MMkg/yr)	460
11% industrial H_2 demand buffering (MMkg/yr)	51
16% industrial H_2 demand buffering (MMkg/yr)	74

3.4 Transportation Sector Demand Projections

Figure 12 shows Pennsylvania's county-level H_2 demand for LDVs, MDVs, and HDVs. Table 7 presents an estimate of Pennsylvania's total transportation H_2 storage demand under two alternative buffering scenarios: 11% and 16% of total sector demand buffering, respectively.

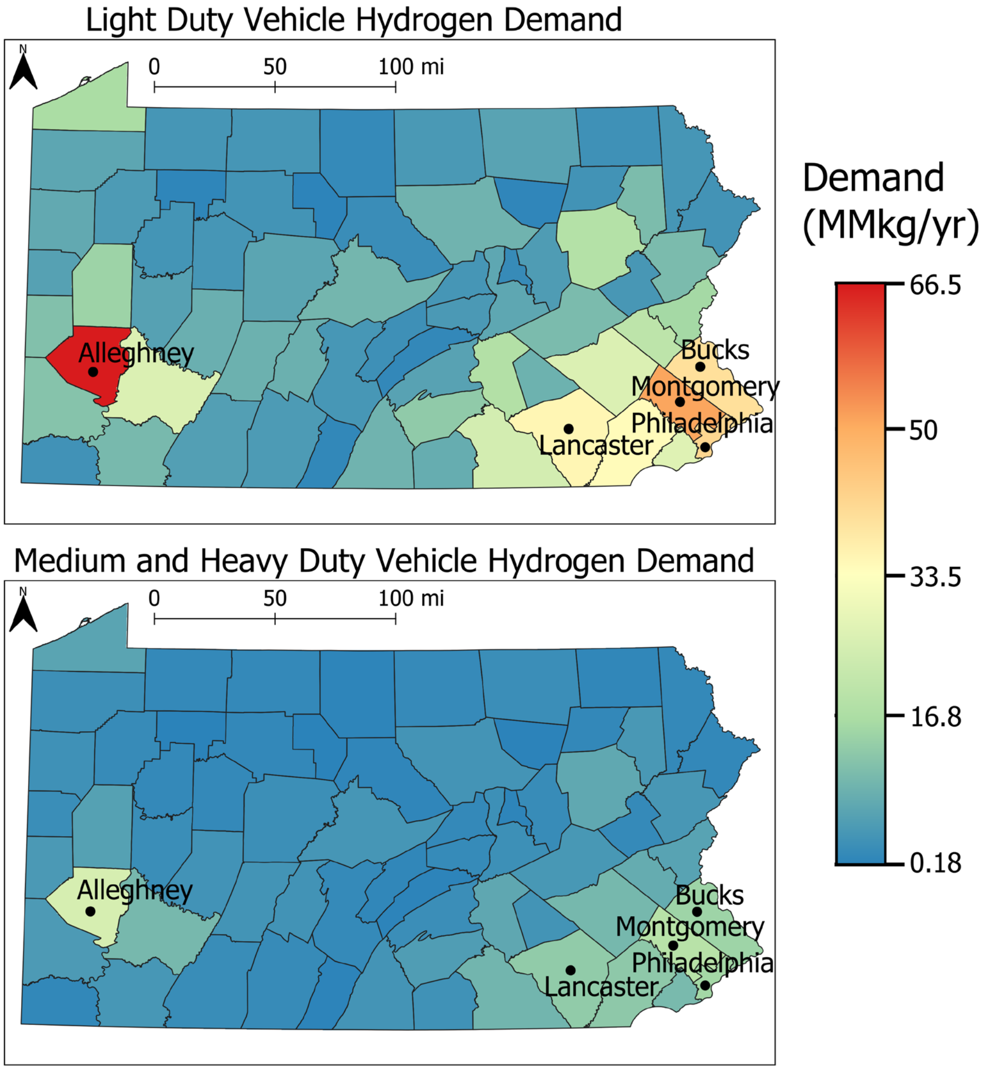

Figure 12. 2050 H_2 demand by light-duty and medium- and heavy-duty vehicles. Top five counties are labeled with their names.

Table 7. Estimates of the total Pennsylvania transportation H_2 demand in 2050 and the amount of buffering that may be required by UHS based on current operational data from UGS.

Scenario	Estimate
Total transportation H_2 demand (MMkg/yr)	1050
11% transportation H_2 demand buffering (MMkg/yr)	110
16% transportation H_2 demand buffering (MMkg/yr)	170

3.5 Total Projected Hydrogen Demand by County

Pennsylvania's projected H_2 demand for 2050 was totaled across all sectors, and two annual demand buffering scenarios based on current NG UGS operations (11% and 16% of total) were assumed to compute UHS storage demand for the state and for each county. The total projected 2050 demand across residential, commercial, industrial, and transportation sectors for Pennsylvania is slightly more than 1,500 MMkg/yr. In 2021, Pennsylvania consumed 1,801 Bcf of NG (U.S. Energy Information Administration, 2023c). Assuming standard conditions, 1,500 MMkg of annual H_2 demand represents approximately 635 million cubic feet (MMcf) (0.63 Bcf), less than 1% of the total volume of NG that flowed through pipelines in the state in 2021 to serve end users. Future work could explore how concentrations of H_2 might be different across parts of the system (based on demand and other factors) to inform where blending and separation stations might be placed.

The total H_2 demand for Pennsylvania equates to a storage demand of 161 MMkg/yr at 11% buffering or 244 MMkg/yr at 16% buffering. Figure 13 shows total storage demand projections for 2050 assuming 1:1 H_2-NG blends by volume for residential and commercial sector demands.

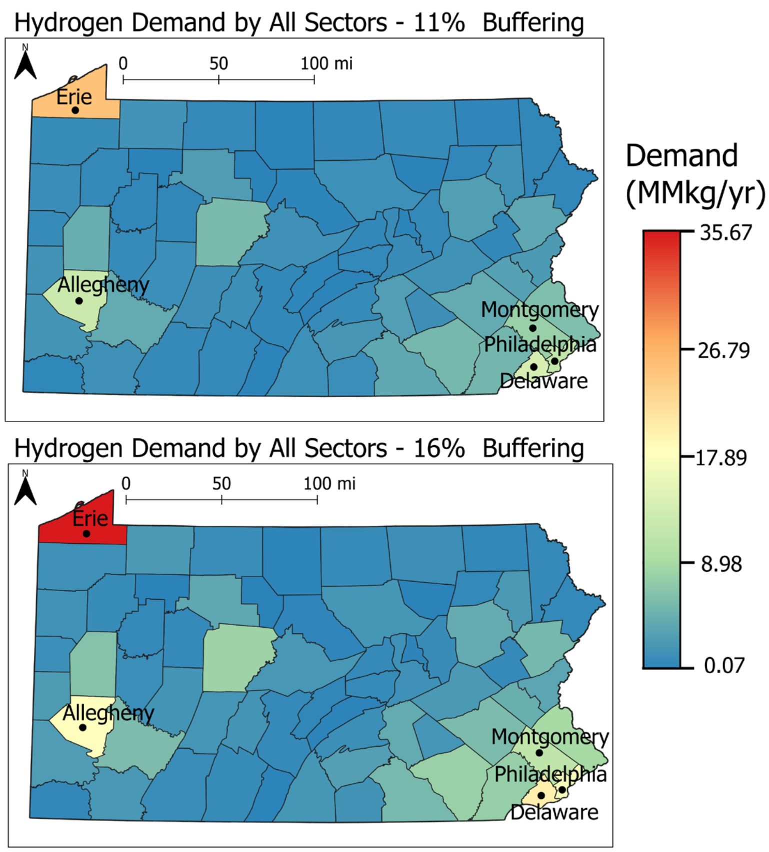

Figure 13. 2050 H_2 storage demand total for all sectors by county and annual demand buffering scenario. Top five counties are labeled with their names.

Erie County shows the highest projection of total storage demand under both buffering scenarios. The allocation of H_2 demand for metals refining to Erie County (160 MMkg/yr in total before buffering) is larger than for any other sectoral demand aggregate across all other counties. This is an approximation based on the assumption of the location of metal-refining demand within Pennsylvania (on the shores of

Lake Erie). This demand is likely allocated throughout western Pennsylvania, which would affect the ranking of counties by total H_2 storage demand. With more specific point location data for metal refining facilities, this framework could create a more targeted result. Given this caveat, the top four and bottom four counties for H_2 storage demand (based on all sector totals) are shown in Table 8.

Table 8. Top four and bottom four counties in Pennsylvania in terms of total projected H_2 storage demand for 2050

County	Totals Scenario 1, 1:1 Blend, 11% (MMkg/yr)	Totals Scenario 2, 1:1 Blend, 16% (MMkg/yr)
Erie	24.50	35.60
Delaware	13.60	19.70
Allegheny	12.10	17.60
Philadelphia	11.50	16.80
Fulton	0.178	0.259
Sullivan	0.132	0.193
Forest	0.119	0.173
Cameron	0.073	0.106

3.6 Underground Hydrogen Storage Costs

Initially, we bounded our evaluation of the LCHS to four scenarios to create low and high estimates of the costs to convert existing UGS sites or to build new UHS sites. We then conducted sensitivity analyses to understand the major cost drivers and potential for cost minimization. To calibrate our approach, we compared the costs of storage of a single depleted hydrocarbon reservoir well and a single salt cavern well with the same volumetric storage capacity (20 MMcf) and depth (3,360 ft). We then applied our TEA framework to calculate the storage costs for the depleted hydrocarbon reservoir sites identified and studied by Lackey et al. (2023) within Pennsylvania. Sensitivity analyses allowed us to understand how the calculated storage cost responds to changes in cushion gas price, amount of cushion gas required, and the price of electricity used to operate the facility.

The initial capital costs required for building a new site were calculated. These costs included site characterization, well drilling and completion, preparing caverns (solution mining the cavern and brine disposal, leaching, and mechanical integrity test), setting up compressors and aboveground well operation equipment, procurement and injection of cushion gas, and building pipelines from the compressor to the well injection site. Lord et al. (2014) estimated the well construction cost for both salt caverns and saline aquifers at $1.15 million per well, and for depleted hydrocarbon reservoirs at $0.26 million per well to repurpose existing wells. Their costs are expressed in 2007 U.S. dollars. We inflated those costs to 2022 dollars for our work using the Consumer Price Index. For an example comparison between two facilities with equal storage volumes of 20 MMcf, the capital costs for a salt cavern storage facility that can store 8,800 tons of H_2 and a hydrocarbon reservoir that can store 4,481 tons are given in Table 9 and the breakdown of those costs is summarized in Figure 14.

Table 9. UHS site capital and development costs for a 20-MMcf single-well facility with no additional pipeline construction required

Characteristic/Cost	Salt Cavern	Depleted Hydrocarbon Reservoir
H2 Storage Mass	8800 tons	4481 tons
Permitting	\$1.2M	\$0.71M
Site Characterization	\$0.115M	\$0.115M
Cavern Costs (Mining + Leaching costs)	\$41M	-
Mining	\$13M	-
Leaching	\$28M	-
Cushion Gas Capital Cost	\$6.6M – \$13M	\$11M – \$22M
Compressor	\$25M – \$38M	\$23M – \$34M
Wells	\$1.88M	\$0.382M
Cleaning Equipment	\$10M – \$15M	\$10M – \$15M
Separator	\$3.66M – \$5.48M	\$3.66M – \$5.48M
Monitoring System	\$0.88M	\$0.88M
Metering	\$0.015M	\$0.015M
Odorizer (if needed)	\$0.02M – \$0.06M	\$0.02M – \$0.06M
Total Site Capital Costs	**\$90M – \$117M**	**\$50M – \$79M**

Surface facilities constitute 44-51% of the TCC for salt cavern storage while underground facilities make up 37-47%. For depleted hydrocarbon reservoirs, surface equipment accounts for 71-75% of TCCs, of which 43-46% is compressor costs. Cushion gas costs are 7-11% of total CAPEX for salt caverns and 22-26% for depleted hydrocarbon reservoirs. Our resulting total CAPEX estimates for salt caverns (\$90M to \$117M) and depleted hydrocarbon reservoirs (\$50M to \$79M) align with literature findings that developing a UHS facility at an existing depleted hydrocarbon reservoir will reduce capital costs by 40-70% (Coyle, 2022). Compressor costs comprise 28-33% of the TCC of salt cavern storage, which is close to the 18% estimated by Papadias & Ahluwalia (2021). The same authors found that for salt-cavern storage, brine disposal is the largest cost, accounting for 25% of the TCC (including 12% for transportation, 12% for disposal, and 1% for interim brine storage). Here we have grouped brine disposal cost into the leaching cost, which represents 24-31% of TCCs. Salt thickness and depth drive the major storage SDCs for cavern-based storage. At a thickness above 80 m, a cavern with larger volume can be created, reducing the number of caverns required to achieve a desired storage capacity for the facility, all else being equal (Coyle, 2022). As a result, the high-cost burden of creating caverns, creation of wells, and well maintenance (e.g., mechanical integrity tests) can be reduced.

The estimated capital cost of cushion gas is \$6.6M to \$22M depending on the source of H_2 and cushion gas percentage required (30-50% depending on the storage type, as presented in Table 10). Considering the price difference between fossil-derived and renewable H_2 sources, we used a price range of \$2.5 to \$5.0/kg-H_2. We have not conducted a technical sensitivity analysis on the reservoir effects of using CO_2 or other gases as cushion gas in this report.

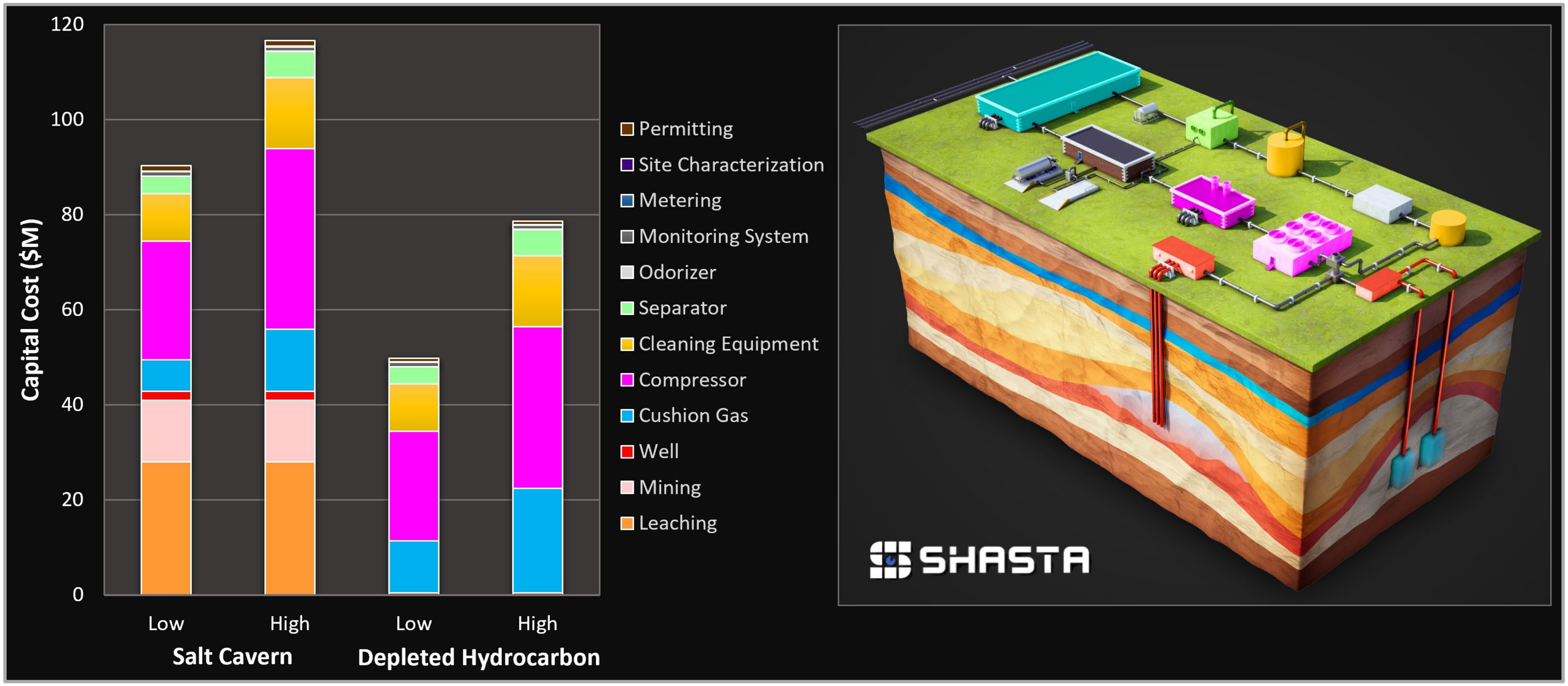

Figure 14. Share of capital costs for site development, well, cavern, and equipment for a 20-MMcf single-well UHS facility with no additional pipeline construction required. Capital costs are connected to surface and subsurface system components roughly by color coding.

Our LCHS analysis framework estimates that the cost of a single-well storage facility ranges from \$1.21 to \$3.28/kg of H_2 for a 4,400- to 8,800-ton salt cavern storage facility, while the cost for a similarly-sized depleted hydrocarbon reservoir ranges from \$1.25 to \$2.74 (Figure 15). Singh (2022) estimated storage cost per kg of H_2 for various storage systems (in 2021 U.S. dollars), and their estimate for salt caverns was \$1.65/kg (CAPEX \$1.51/kg, OPEX \$0.14/kg), which is within the range of our estimates.

Our sensitivity variables for results included three different total gas (mass) storage cases, 8,800 tons, 6,600 tons, and 4,400 tons (Figure 16) while also varying different parameters in the model as presented in Table 10. For each case, we calculated CAPEX, OPEX, and LCHS under different cushion gas percentages, working gas capacities, and prices for cushion gas within the ranges shown in Table 10 and for varying compression rates (2,000 to 3,000 kg/hr), numbers of compressors (single compressor versus added backup compressor), and injection well depths (2,000 to 6,700 ft). Figure 16 shows the minimum, first quartile, median, third quartile, and maximum LCHS (\$/kg) for all 528 sensitivity calculations we completed.

Table 10. Summary of the range of key properties, cost categories, and resulting levelized costs of UHS by storage type

	Salt Cavern	**Depleted Hydrocarbon Reservoir**
Storage Capacity (MMcf)	10 – 20	20 – 40
Mass (ton)	4400 – 8800	4400 – 8900
Cushion Gas (%)	20 – 30	50
Working-Gas Capacity (ton)	2000 – 6800	2000 – 4000
Cushion-Gas Cost (\$/kg)	2.5 – 5.0	2.5 – 5.0
LTCC (\$)	1.08 – 2.37	1.12 – 2.48
WOMC (\$)	0.02 – 0.19	0.01 – 0.03
COMC (\$)	0.11 – 0.72	0.12 – 0.23
LCHS (\$/kg)	1.21 – 3.28	1.25 – 2.74

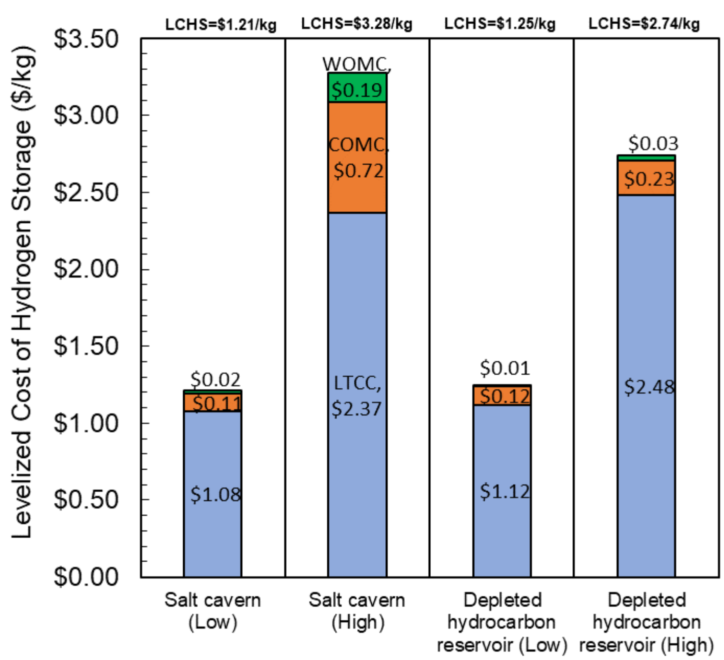

Figure 15. Levelized costs of hydrogen storage for salt cavern and depleted hydrocarbon storage types

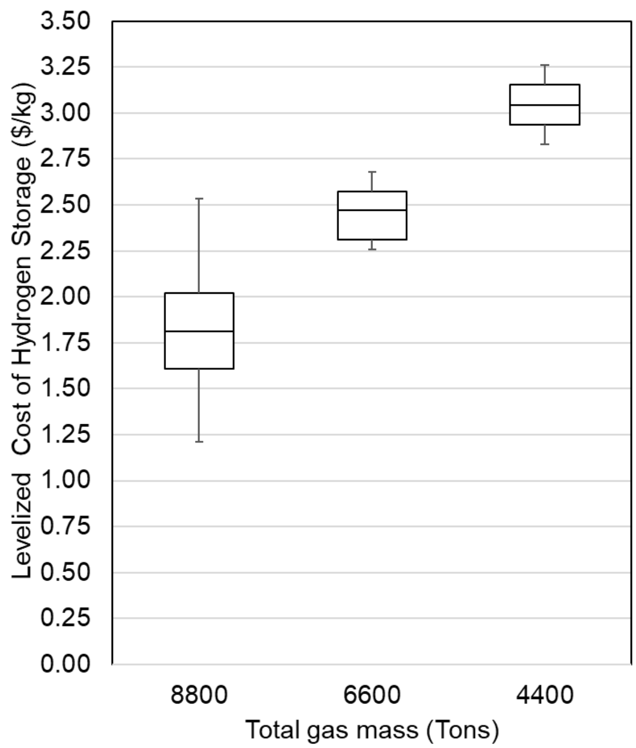

Figure 16. Case-by-case comparison of LCHS for all sensitivity analysis variations for a single-well salt cavern storage facility highlighting the effect of varying total H_2 storage mass

We observed an increase in the levelized capital cost per kg H_2 with a decrease in total storage volume (note the descending horizontal axis in Figure 16). Similarly, Papadias & Ahluwalia (2021) found that the installed capital cost of UHS in salt caverns decreases appreciably, from ~$95/kg-$H_2$ at 100 tonnes-H_2 stored to <$19/kg-$H_2$ at 3,000 tonnes-H_2 stored. Over the same scale, the authors found a decrease in annual storage cost from ~$17/kg-$H_2$ at 100 tonnes-H_2 stored to ~$3/kg-$H_2$ at 3,000 tonnes-H_2 stored. When the storage volume was reduced by 50%, our estimate of LCHS increased by 22-57%. Our estimates further show an increase in LCHS by a factor of seven (from $2.8 to $22.14/kg) when the volume is reduced by a factor of 10 (from 4,412 tons to 441 tons). While in smaller UHS facilities a change in electricity price from $0.05/kWh to $0.10/kWh did not change the LCHS significantly, we observed an 8% increase in LCHS in an 8,800-ton facility under the same change in electricity price. We explored the impact of compressor power efficiency (kWh/kg) on LCHS and found a minimal impact. Increases in the point value selected within our assumed range for cushion-gas price leads to its capital cost share driving the LTCC from $1.97 to $2.39/kg of H_2, which translates into a 22% increase in the LCHS.

3.7 Techno-economic Site Screening and Selection

In our cost analysis of Pennsylvania's existing depleted hydrocarbon storage sites, we found that the costs varied significantly across sites (Figure 17) because of their wide range of physical characteristics (e.g. NG storage capacities varied from <1 to 72 Bcf; see Section 2.2).

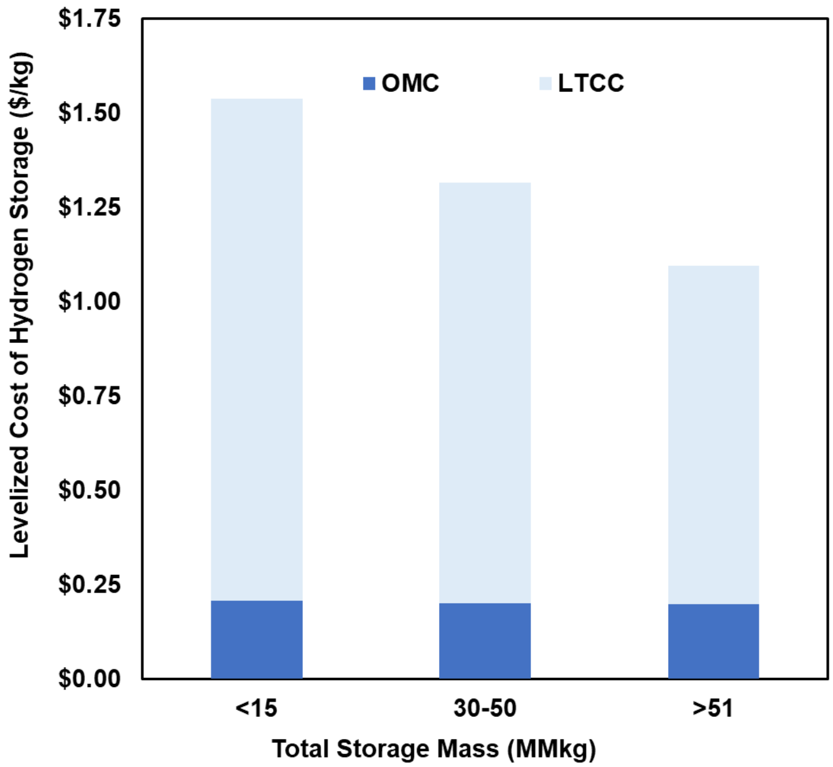

Figure 17. Levelized total capital costs (LTCC), and operation and maintenance costs (OMC) for UGS sites studied in Pennsylvania.

The total CAPEX for storage site development ranged from $57M to $64M for facilities smaller than 15 MMkg, $119M to $159M for facilities with capacities of 30 to 50 MMkg, and $238M to $279M for 51 to 100 MMkg facilities. The Pennsylvania UGS sample includes several facilities of capacities on the Bcf scale that may require significantly more CAPEX to convert, contributing to a long right tail on the CAPEX distribution. The median CAPEX for compressors is calculated at $35.9 million. Well drilling costs ranged from $0.18M to $7.9M. When levelized, the estimated costs for the existing Pennsylvania sites are significantly lower than the costs for the 20 MMcf example sites described in Section 3.6. The baseline LCHS calculated for developing a new UHS facility at a depleted hydrocarbon reservoir site ranged from $0.76 to $1.7/kg, while the cost to convert an existing site within Pennsylvania's size range was 61% of the cost for a new facility and ranged from $0.33 to $0.76/kg H_2. The highest LCHSs are for the Pennsylvania UHS facilities with the smallest capacities, but costs decrease with an increase in storage capacity only up to 1 Bcf. If cushion gas could be procured from a cheaper source, the median LCHS could be reduced by 36% ($0.56 to $0.84/kg). Leveraging the existing underground cushion gas while mixing to the desired H_2-NG ratio over time could further reduce the cost; however, we have not incorporated that analysis in this case study. If an onsite electricity generation source, like solar or wind, is available to supplement electricity required and the overall price of electricity could be reduced by 50%, the LCHS could be reduced to $0.75 (a 12% decrease) for a new site and 29% at an existing site. With a lower cushion-gas price and electricity price, the median LCHS could be reduced by 49%.

The total working-gas mass for depleted hydrocarbon reservoirs in Pennsylvania (assuming 100% H_2) is 836 MMkg (Lackey et al., 2023). Figure 18 shows the locations of the storage sites along with their working gas mass and aggregated county-level total H_2 working gas mass.

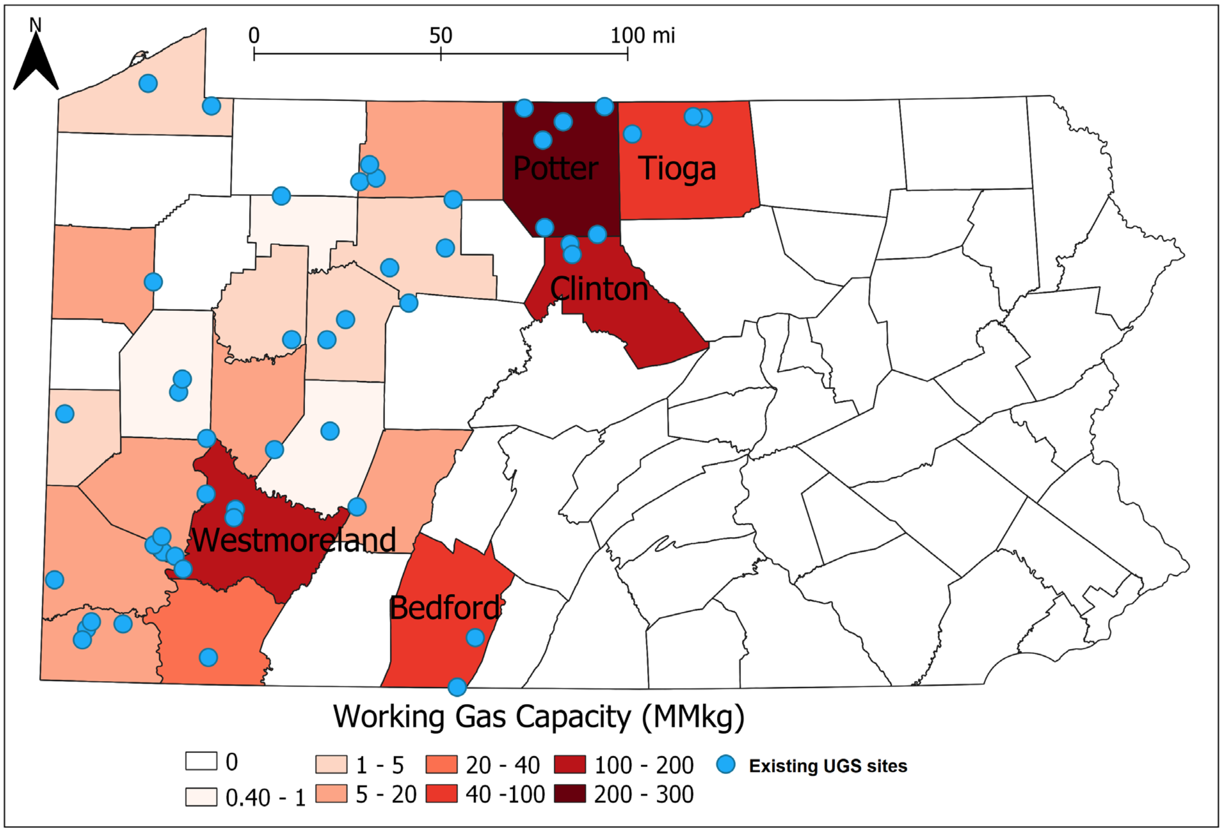

Figure 18. H_2 working gas mass of existing Pennsylvania UGS storage facilities (Lackey et al., 2023) aggregated to county level, and locations of existing UGS facilities. Top five counties are labeled with their names.

The total annual demand for H_2 storage in Pennsylvania ranges from 161 to 244 MMkg/yr depending on the amount of annual demand buffering required for the H_2 economy. In Pennsylvania, 22 out of 68 counties have potential UHS storage sites in depleted hydrocarbon reservoirs, mostly in the western and northern-central parts of the state. Based on our demand analysis, the pure H_2 working gas mass of these storage sites (836 MMkg) exceeds the estimated demand in 2050 for the entire state of Pennsylvania. However, the spatial disparity between the largest working gas mass sites and highest H_2 demand counties creates a geospatial surplus or deficit of potential existing storage capacity at the county level.

Our analysis of potential UHS working gas mass aggregated to the county level and projected demand for the counties shows that between 16 and 18 of Pennsylvania's 67 counties will have surplus H_2 storage potential based on annual demand buffering after meeting the county's needs (Figure 19). Only three counties (Butler, Clearfield, and Erie) that have existing UGS sites will not be able to meet demand in their own county. One way to meet the storage demand of UHS deficit counties without constructing new facilities would be to transport H_2 to (for storage) and from (for withdrawal) adjacent counties with storage surpluses. With the total potential storage exceeding the state's estimated demand, all the counties' demand could be met, and any surplus capacity could be used to support H_2 demand buffering for adjacent states if the supporting offtake infrastructure is developed. For a quick approximation, assuming a 100-km (62-mile) straight-line transportation distance, we determined that 43 of Pennsylvania's 67 counties might be served from stored H_2 in existing depleted hydrocarbon reservoirs in the state if offtake and transportation infrastructure for that distance were obtainable by customers.

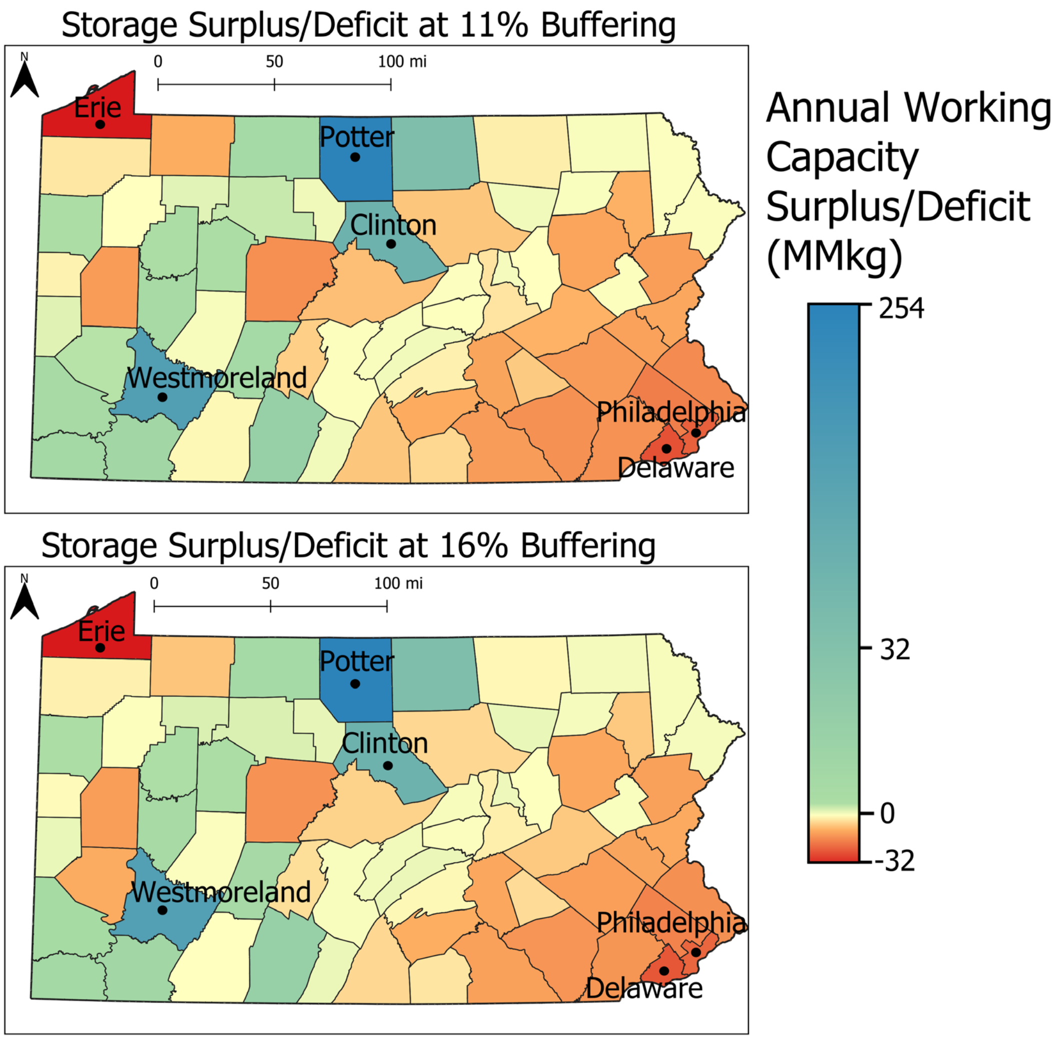

Figure 19. Full distribution of storage surplus/deficit by county. Positive values are surpluses and negatives are deficits. Top five counties are labeled with their names.

Based on the quantity of working-gas mass in each depleted hydrocarbon reservoir, county-level storage demand, and the cost of storage, an initial screening based on TEA approaches shows that the six sites highlighted in Figure 20 might be early candidates for UHS conversion. Future expansions of this framework will develop and consider a full set of planning criteria for developing UHS sites based on TEA insights.

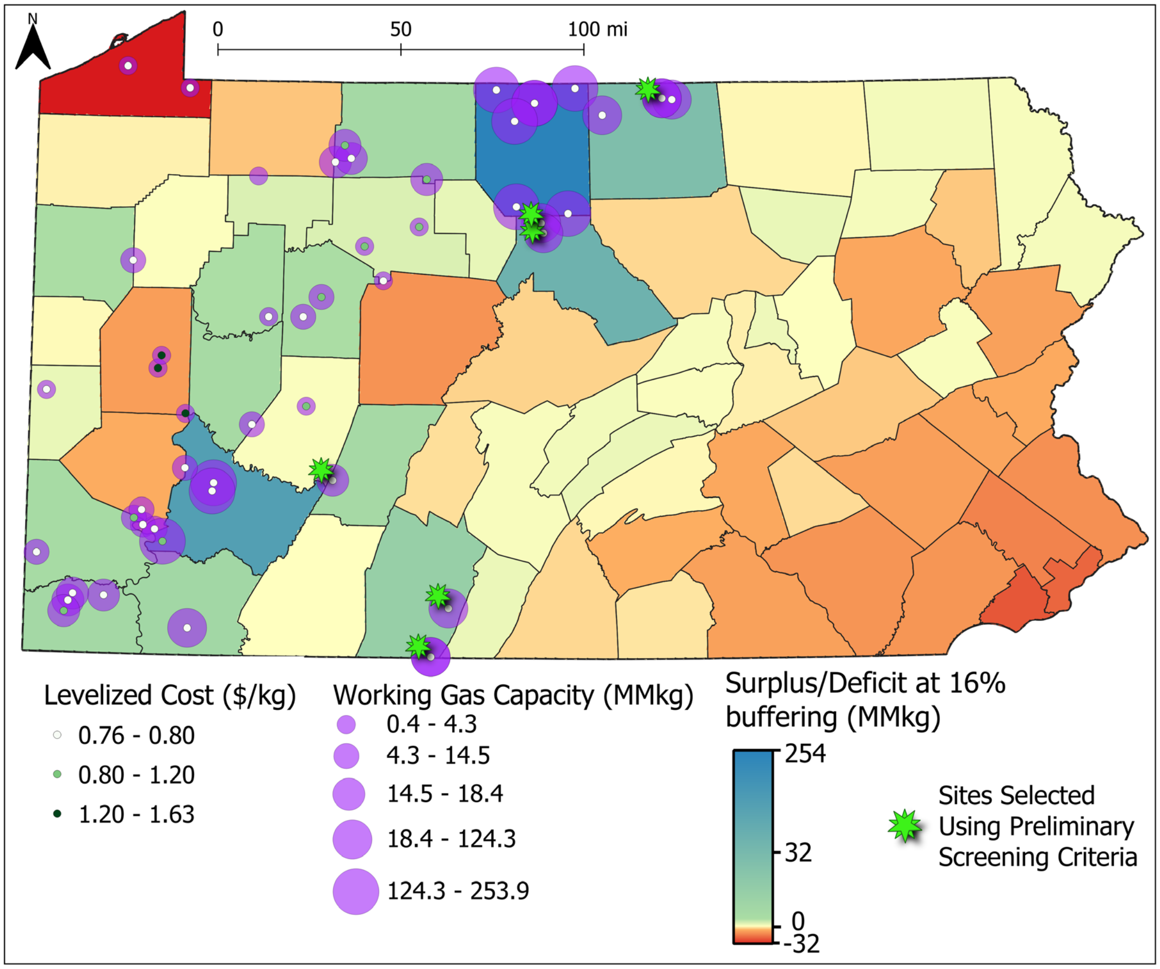

Figure 20. Preliminary screening of optimal hydrogen storage site development in Pennsylvania

4.0 Conclusions

An H_2 future, enabled by UHS, will depend on the United States' existing and future H_2 storage potential and the trajectory of both H_2 supply and demand in the coming years. While storing large quantities of H_2 in the subsurface is technically feasible and likely necessary for scaling up the H_2 economy across different sectors, the economics of UHS need to be better understood. To that end, we developed a site-specific TEA framework for UHS that builds on previous work and adds more granularity to the key factors that need to be considered for conversion of existing UGS sites or the creation of new UHS sites. We implemented the framework to evaluate costs, understand the cost drivers, and identify sensitivities of LCHS to various factors of UHS systems using example characteristics for one model salt cavern storage facility and one model depleted hydrocarbon reservoir storage system. We then evaluated levelized costs of UHS for facilities with a range of storage capacities using data from existing UGS facilities in Pennsylvania.

We found that the LCHS was higher for salt-cavern facilities ($1.2 to $3.3/kg) than for depleted hydrocarbon reservoirs ($1.2 to $2.7/kg). We also found that the storage costs could be reduced by procuring less expensive electricity to operate the facility and cushion gas at lower prices. A 50% reduction in the price of electricity could reduce the LCHS by 12-29%, and the use of H_2 produced by fossil fuels with or without carbon capture (or another, less-expensive cushion gas alternative to H_2 produced by renewable energy sources, such as nitrogen) could decrease the LCHS by 17-36%.

In our Pennsylvania case study, we screened potential UHS sites using the working-gas capacity for existing depleted hydrocarbon reservoirs that are used for UGS, estimated county-level demand, and the estimated cost of storage as the initial set of inputs. The six sites identified for conversion potential based on the criteria in this example (Figure 20) have an estimated total of 210 MMkg of working gas mass (using 100% H_2) and could supply the state's full need assuming 11% demand buffering or fulfill 88% of the state's demand buffering at 16% at a storage cost of $0.76 to $0.80/kg or even lower if some of the existing facilities could be retrofitted at lower costs than the literature-derived estimates used in our study.

As H_2 interacts with surface materials, causing corrosion and embrittlement of surface and subsurface facilities that lead to mechanical and physicochemical failure due to cracking (Ugarte & Salehi, 2022), the costs of resistant materials to mitigate embrittlement needs to be considered in future work. Major component replacement (e.g., compressor replacement cost) is not included in our framework. According to previous studies by Demir and Dincer (2018), compressors used to store H_2 in underground caverns may have a reduced lifespan of approximately 15 years. Including impacts to typical compressor and major component lifespans due to the introduction of H_2 in the process is an area for future refinement of this framework.

Our analysis is based on a set of engineering assumptions, secondary data, and information on various components collected from several literature sources. This approach introduces several uncertainties in our estimate results, but the framework we developed can be applied with updated data as industry partners provide information and as science advances. For cost estimation approaches presented here, a future step of this work is to socialize our assumptions with industry partners to address some of the uncertainties and ultimately to build a tool where users can adjust their input variables on demand. A refinement of the cost technique informed by simulation and experimental research related to leaks and losses related to aboveground and belowground equipment is another logical next step for this work. For the demand analysis, the work can be refined by considering additional assumptions for each of the sectoral projections or by applying more robust econometric methods to accommodate complex dynamics related to policy or technology breakthrough that might accelerate demand for H_2. For the residential sector, an analysis that considers more factors of human behavior that drive adoption of environmentally friendly technology might be integrated into the framework. For the commercial sector, accounting for the development or evolution of new building codes and appliance standards would help to arrive at more accurate projections. For the transportation sector, future work might include factors such as fleet trends and charging infrastructure projections. Further, based on additional parameters and multi-criteria decision analysis methods, the framework presented here may be integrated into a tool that allows users to demarcate “suitable” areas for technology adoption based on their preferences. Existing and potential offtake infrastructure locations, including NG pipelines and major highways, might be integrated into TEA screening approaches using extensions of this framework. This type of approach and framework could also enable a user to analyze the effects on the LCHS and economic screening outputs based on factors that vary significantly from site to site and different decision contexts.

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