

Estimating Natural Gas Salt Cavern Storage Costs

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Abstract

Peak load natural gas storage demand is primarily served from salt caverns as they offer high deliverability, with both injection and withdrawal rates easy to vary on short notice. Many short term traders use salt cavern storage to maximize profits by arbitraging differences in price from unpredictable and occasionally unanticipated demand surges. It is generally acknowledged that higher storage levels increase injection costs and reduce withdrawal costs. Recently, there has been a dearth of investment in new gas storage capacity. Forecasts, however, predict that demand for storage capacity in the Gulf Region will increase in the next few years, mainly in response to US LNG exports and the use of natural gas in power generation. LNG exports, in particular, will likely increase seasonality in demand for U.S. natural gas since the primary importers of U.S. natural gas, Europe and Asia, have less storage themselves. This demand will put pressure on existing storage capacity. Comprehension as to how storage, injection and withdrawal costs respond to increased demand for storage is essential to understanding natural gas pricing.

1 Introduction

Natural gas is an important fuel source used for residential heating, industrial manufacturing, and power generation in the U.S. and many other countries. It is the cleanest fossil fuel and provides significant additional advantages for power generation due to its widespread availability, dispatchability and affordability. A significant challenge for the natural gas sector, however, is the seasonal and volatile nature of demand paired with the steady and constant nature of its supply. In months with extreme temperatures, demand for natural gas skyrockets, while in temperate months demand decreases significantly. This leads to unattractive price volatility for purchasers of natural gas and potential profits for owners if natural gas storage facilities, who can take advantage of spatial and intertemporal arbitrage opportunities. Storing natural gas during times of low demand and prices and increasing supply by drawing down inventories during times of high demand and prices also assists consumers by decreasing price variation. Storage of natural gas also helps transmission companies manage sudden load variations and maintain system stability. More widespread use of natural gas storage depends on its cost. In this paper, I use a GMM estimation technique on first order conditions from a structural model of a representative agent to investigate the operating costs of salt cavern storage facilities.

Prior to 1992, gas storage facilities were almost exclusively owned and controlled by interstate and intrastate pipeline companies. They sold natural gas to consumers as a bundled service including production, transmission and storage services. In April 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636, which essentially unbundled these services to help foster the structural changes necessary to create a competitive market for the American natural gas industry (American Gas Association, 2017). Order 636 instructed owners of storage facilities to open access to storage to third parties and only

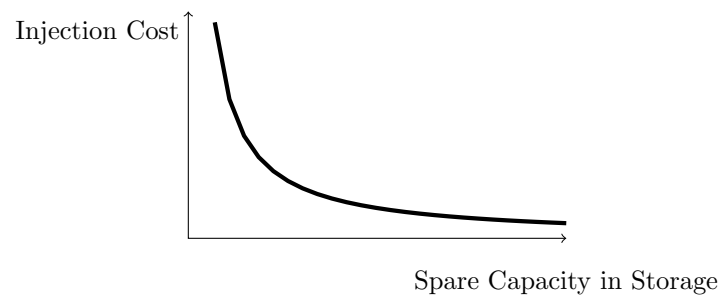
allowed the former to reserve space for their own use to balance system supply. The newly deregulated market presented new arbitrage opportunities. Previously, storage could be used only as a physical hedge to market conditions. After liberalization, it could also be used a financial tool to profit from price differentials for short term gas traders (Schoppe, 2010). Order 636, along with high price volatility, led to an impressive expansion of high deliverability storage facilities during the late nineteen nineties (Fang et al., 2016). High deliverability facilities allow for rapid injection and withdrawal of gas from storage, but generally tend to have lower storage capacity. They are especially important for supplying unexpected demand surges in the electricity generation sector.

In 2016, as in the three preceding years, no new underground facilities were developed in the U.S. and the only expansion of capacity has been represented by brownfield investment in the South Central (Gulf) region, concentrated mostly in high deliverability salt cavern storage facilities (EIA, 2017b).

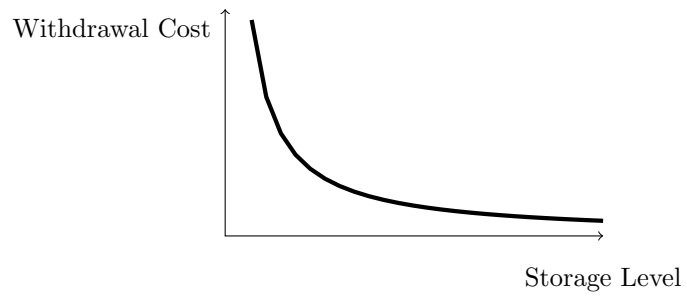
The nature of natural gas demand also has been changing and will continue to do so. Overall, demand changes can be attributed to three main causes. First, natural gas use for power generation has grown substantially in recent years and is expected to grow further not only because of the relatively high energy efficiency and low cost of combined cycle natural gas plants. Single cycle natural gas turbines are also a good complement to intermittent renewable generation sources. Second, industrial demand for natural gas has been growing in recent years, although this demand growth contributes to base load demand. Third, LNG exports are expected to strengthen the demand for U.S. gas with the U.S. expected to become a net gas exporter in 2017 (EIA, 2017c). The importance of these sources of natural gas demand will put a premium on gas storage facilities that can meet sudden demand surges. Understanding the effects these changes will have on natural gas storage facilities is then of great importance.

To understand the demand for storage facilities, a comprehensive analysis that considers regional responses to demand and supply changes is needed. A recent study by Fang et al. (2016) uses a proprietary nonlinear programming system to model the U.S. natural gas market. They examine how gas storage utilization will be affected under two different scenarios. In a base case scenario, wide availability of natural gas lead to increases in power sector demand and LNG exports. In a contrasting “Low Oil and Gas Resource” case, renewable energy becomes more prominent in the power sector and natural gas generation is used only to stabilize the system. At an aggregate level, the study finds there will be very little additional storage needed under either case. The study also predicts, however, that higher LNG exports and increased demand for natural gas in the power sector will increase utilization of high deliverability storage in the Gulf region, which mainly takes the form of salt cavern storage facilities. Nevertheless, the study does not find that storage expansion will be warranted, implying that existing salt cavern storage facilities will be stressed. The costs of injecting and withdrawing natural gas from salt caverns, and responses and reactions to increased utilization of such facilities, will therefore likely have an increasing impact on natural gas prices and stability of the natural gas delivery system.

Industry experts suggested, anecdotally, that the cost of injecting/withdrawing natural gas from storage depends on both the level of gas stored in the facility and the rate of injection/withdrawal. In particular, costs of injecting natural gas appear relatively stable and constant when inventory levels are below 85%-90% of total storage capacity, but increase at an increasing rate when storage levels exceed this threshold. Similarly, withdrawal costs escalate when storage levels near the minimum (cushion gas) level. Figure 1 illustrates these effects of storage levels on injection and withdrawal costs.



(a) Injection Costs as Storage Levels Change



(b) Withdrawal Costs as Storage Levels Change

Figure 1: Injection and Withdrawal Costs

It has been observed that as utilization in salt cavern storage facilities increase, a higher inventory level (or cushion gas) is required to maintain the integrity of the facility (FERC, 2004). Increased utilization in the Gulf region will therefore most likely increase the injection costs into storage for salt cavern storage facilities.

The main contribution of this paper will be to examine what would happen to injection costs if storage utilization in the Gulf region increased due to LNG exports and enhanced demand from the power sector. Specifically, the primary goal will be to develop and estimate a model that quantifies the degree to which injection costs increase when storage levels near capacity. There are a number of benefits of estimating such a cost function: it will aid in valuation of gas storage methodologies; it will provide more clarity on the pricing of natural gas; and it will give some insight into the behavior of short term gas traders.

To facilitate the understanding of this problem, the next section will present a brief introduction on the different types of demand for natural gas storage, the physical properties and types of underground storage, and the nature of gas storage contracts. The paper will then provide a literature review of the relevant research in this area, which will be followed by the theoretical model and model estimation, and finally an analysis of future expected storage costs.

2 Types of Demand for Natural Gas Storage

Due to its gaseous state, natural gas needs to be stored in an environment that pressure low enough to limit leakage and resulting losses of the fuel. On the other hand, pressure in the storage facility assists the extraction of gas from storage. Naturally occurring underground formations, such as depleted oil and gas reservoirs, aquifers and salt caverns provide the most effective means to store

gas in its natural form. Alternatively, natural gas can be stored in pipelines (when spare capacity is available) or as LNG¹ in LNG storage tanks. The latter requires liquefaction of the fuel prior to storage and regasification before it can be injected back into a pipeline system. Each type of storage facility has its own set of physical properties, which in turn determine the cost of storing natural gas as well as the type of storage that the facility is best suited for.

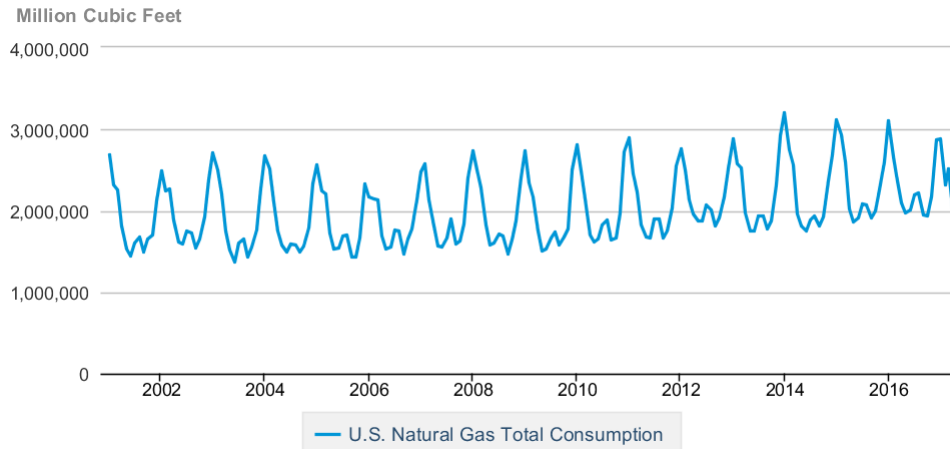
In principal, there are two different purposes for storing natural gas. The first is to meet predictable seasonal variations in natural gas demand. Storage operators purchase natural gas during times of low demand, or the “shoulder months”,² and sell the gas during periods of high demand, in order to arbitrage profitable seasonal price differences. Typically, natural gas demand is highest during the winter months when it is used to heat houses, commercial and industrial interiors. Increasingly, natural gas is also used during the summer months to provide air conditioning, as natural gas open cycle turbines provide most of the peaking power generation in the United States. In 2016, natural gas accounted for approximately 33.8% of electric generation in utility scale facilities (EIA, 2017), although an increasing number of these would be combined cycle plants used to provide base or intermediate load, which tend to be less seasonal in nature. It is the predictable, seasonal nature of demand for natural gas that has provided the need and incentive to develop storage facilities. Figure 2 illustrates the seasonal demand for natural gas. Natural gas stored to meet predictable seasonal variations in demand tends to be held in storage for longer periods to account for changing seasons and weather patterns.

Natural gas storage can also be used to meet unpredictable peak load de-

¹Liquefied Natural Gas (LNG) is obtained by cooling natural gas (in a liquefaction plant) to -260 degrees Fahrenheit, (-162.2 degrees Celsius), after the extraction of oxygen, water and carbon dioxide, as well as most sulfates (Office of Fossil Energy, 2016). This reduces the volume by a factor of 600 and permits cost-effective transport by way of specially constructed tanker ships. A regasification plant turns the LNG back into natural gas after delivery.

²These are generally the months of May-June and September-October.

Figure 2: Seasonality of U.S. Gas Demand



Source: U.S. Energy Information Administration

mand. Facilities that serve such demand generally do so on short notice and profit from the resulting price spikes. Peak load storage facilities may hold gas for as little as a few days to as much as a few weeks before withdrawing it for sale (Natural Gas Supply Association, 2014). The unforeseen demand spikes can come from local distribution companies (LDC) or power generators. Power generators and LNG exporters may also produce unexpected declines in demand, and hence injection opportunities, when power plants or liquefaction operations are interrupted (Fang et al., 2016). Due to their high deliverability, salt cavern storage facilities, to be described below, are the best suited underground storage facilities to serve peak load demand. When considering above ground facilities, LNG peak shaving plants ³ can be used for the same purpose. Due to the existing infrastructure in salt cavern storage in the Gulf region, as well as the expected growth in demand for high deliverability storage in the Gulf region, this paper will focus on estimating the costs of injection of natural gas

³LNG storage is used in Asia for this purpose and being increasingly used in Europe too.

into salt caverns in the Gulf region.

3 Physical Properties and Types of Underground Storage

Depleted oil and gas reservoirs, aquifers, and salt caverns are the most common formations used for underground storage. The particular desirability of these three types of underground storage is based on their geological and geographical traits. Each differs in terms of its working gas capacity, base (cushion) gas, shrinkage factor, deliverability and geographical location. A storage facility's working gas capacity refers to the amount of gas that can be injected into and withdrawn from storage for use. Since storage reservoirs must maintain a certain amount of pressure for extraction purposes, there is a minimum amount of gas required, called the base or cushion gas level, below which no gas can be extracted from storage. Essentially, a storage operator must inject a certain amount of gas into the reservoir that is extremely difficult to recover. It is more profitable to have a lower base gas level. The working gas capacity and the base gas make up the total capacity of storage.

The shrinkage factor of a storage facility refers to the amount of leakage of gas that occurs from the reservoir. All underground facilities lose some natural gas through leakage, with the amount lost depending on the permeability of the enclosing rock and pressure. Deliverability reflects the rate at which gas can be withdrawn from and injected into storage. Higher deliverability indicates that natural gas can be cycled through the storage site more quickly. Finally, the proximity of the storage site to end users and market centers affects the price of the stored gas and the value of the facility for meeting peak demand changes. Brief descriptions of the aforementioned types of storage facilities are presented

below.

3.1 Depleted Oil and Gas Reservoirs

Depleted oil and gas reservoirs consist of underground formations that have increased pore space as a result of prior oil and gas extraction. These formations provide natural cost advantages as the geological characteristics of the site are already known from previous activity. Further, depleted reservoirs normally have existing infrastructure to extract and transport natural gas, which lowers investment costs. The surrounding rock is also often non-porous (the reason the hydrocarbons were trapped in the first place), which reduces leakage. Consequently, depleted reservoirs are generally the cheapest storage sites to develop and are the most abundant type of storage in the United States. They are primarily located in producing regions of the U.S. and require about 50% base gas (Natural Gas Supply Association, 2014). Depleted reservoirs are typically used to satisfy base load demand as they have lower deliverability.

3.2 Aquifers

Natural aquifers can also be converted for use as a natural gas storage site. They have geological characteristics similar to depleted reservoirs (EIA, 2015b), yet they are less well known. Essentially, the natural gas displaces water instead of hydrocarbons from the pore spaces in the rock. Aquifers are generally more expensive to develop than depleted reservoirs and require the highest base gas of all 3 storage facility types. They are generally used for base load demand, although they are occasionally employed to serve peak load demand as well (Natural Gas Supply Association, 2014). Aquifers are the least desirable form of storage and are generally commissioned when there are no depleted fields or salt caverns nearby.

3.3 Salt Caverns

Salt caverns are primarily located in the Gulf region and are created by a process called “salt mining” where water is injected into salt formations underground to dissolve the salt and create a cavern (Fairway Energy, 2017). While salt caverns require the highest initial investments for development, they provide the lowest per unit costs for gas storage. This is due to the high deliverability of salt caverns, which is higher than both depleted reservoirs and aquifers. Salt caverns only require about 33% of cushion gas (Fang et al., 2016) but have much lower storage capacity. Since this makes them less viable to serve base load demand, they are primarily employed to serve peak load demand. They account for approximately 10% of working storage capacity in the U.S.⁴ and 28% of daily deliverability (EIA, 2015a).

4 Storage Technology and Contracts

When the owners of natural gas decide to inject or withdraw gas from storage, they are motivated primarily by anticipated price differences compared to their variable costs, which in turn equal the sum of the injection and withdrawal prices charged by storage operators. Understanding the nature of storage contracts is then vital to modeling the decision of natural gas owners to inject and withdraw gas from storage. We will later use these decisions to help uncover their respective cost functions.

The majority of underground natural gas storage facilities are owned by interstate and intrastate pipeline transmission companies, although a significant number are owned by LDCs and independent storage operators as well (Natural Gas Supply Association, 2014). Owners of storage facilities generally lease out storage space to third party clients according to detailed contracts that specify

⁴Specifically, in the lower 48 States.

a monthly, fixed payment based on the leased storage space, as well as variable payments. The monthly leasing rate depends on the type of service required by the customer. A renter can either choose to purchase uninterruptible service, which guarantees access to the allocated storage space, or interruptible service, where the rented space is accessible only when the storage provider is capable of providing the space. Predictably, uninterruptible space is more expensive than interruptible storage space.

The storage operator also charges for injecting natural gas into, and withdrawing natural gas out of, storage, including associated fuel costs. The operator may also impose daily withdrawal and injection limits. Since extraction and injection use different technologies, the injection and extraction costs typically, but not always, are not identical. In fact, the Spindletop storage facility in Beaumont, Texas, operated by Centana Intrastate, which will be examined in this paper, charges the same rate⁵ to inject and extract natural gas, within daily maximum injection and withdrawal bounds.

To inject natural gas into storage, the incoming gas needs to be filtered and then compressed by a gas motor or turbine, which requires fuel (DEA, 2017). Most natural gas contracts, according to postings by the Texas Railroad Commission, charge approximately 2% of injected gas volume to cover fuel costs, in addition to the injection charge.

To extract natural gas from storage, the gas first needs to be sufficiently pressurized. Compressors may be required to compress the gas before it is injected into the pipeline network. While in storage, gas absorbs water which can be corrosive and damaging to pipelines. Storage operators must thus remove all hydrates from the gas, usually through a process called glycol dehydration (DEA, 2017).

⁵Based on the most recent rate postings by the Texas Railroad Commission.

5 Literature Review

There appears to be no, or a negligible amount, of research on estimating storage injection/withdrawal costs. This may be because data on costs and storage levels are needed and are either not readily available or are available only at the aggregate level. Most research analyzing underground natural gas storage has focused on valuing underground storage fields. Most of the literature uses either intrinsic valuation methods, which essentially value storage facilities using seasonal price spreads, or extrinsic valuation techniques, which focus on financial hedging and trading. All of the papers described in this section use calibration techniques to place a value on storage. As far as we know, this is the first paper to estimate a model of the natural gas and storage problem.

Boogert and De Jong (2008) develop a Monte Carlo valuation method where they employ a Least Squares Monte Carlo methodology using an American options framework to model the investment decisions of storage and ultimately value storage. Cortes (2010) expands this methodology by introducing multi-factor processes into the Least Squares Monte Carlo algorithm. Chen and Forsyth (2007), on the other hand, develop a valuation method using a semi-Lagrangian technique to solve the storage problem that is modeled as a Hamilton-Jacobi-Bellman equation. Thompson et al. (2009) derive a valuation method using nonlinear partial-integro-differential equations. Finally, Henaff et al. (2013) and Li (2007) both present valuation methods that effectively combine extrinsic and intrinsic valuation principals to represent a more realistic setting.

These papers do not focus on the cost of injecting and withdrawing natural gas into and from storage respectively, nor how these costs change with storage levels. These costs will ultimately affect profitability and should be expected to influence the final calibrated valuations of underground natural gas storage. The results from this paper should be helpful in increasing the reliability of the

valuation methodologies described above.

The storage decision problem can also be viewed as an inventory problem, and many papers have examined the decision to invest in inventories. This paper uses an empirical approach very similar to the Euler-equation estimation technique, first introduced by Hansen and Singleton (1982). In the context of this paper, the most important research on the inventory problem was performed by Cooper et al. (2010). While looking at the decision to invest in capital, Cooper et al. (2010) use Euler equations to recover capital investment costs in a discrete choice setting with periods of inactivity. The methodology employed in Cooper et al. (2010) is very similar to the estimation technique proposed in this paper to estimate natural gas injection costs.

6 Data

Proprietary data on the injection and withdrawal rates of gas into the Spindletop Storage Facility, operated by Centana Intrastate, was generously provided by Genscape, Incorporated. The Spindletop storage facility is a salt cavern storage field located in Jefferson County, Texas with a storage capacity of 21,100 million cubic feet (Mmcf) and cushion gas of 6929.8 Mmcf. It has similar characteristics to most other salt cavern storage facilities in the Gulf region. Genscape, Inc. monitors gas flows into and out of storage using infrared technology and electro-magnetic field monitors. Daily storage levels and rates are measured in Mmcf and are observed from June 1, 2015 to January 31, 2017. Of note is that the data set has observations of storage levels that exceed 85% of storage capacity whereas it has no observations that are near cushion gas levels. This will make identifying the asymptotic nature of withdrawal costs, when inventories approach cushion gas levels, impossible. The rest of the paper will therefore focus on estimating the injection cost function.

The gas trading hub located nearest the Spindletop storage cavern is the NGPL Texas Oklahoma (TexOk) Gas Trading Hub. Daily TexOk spot prices were obtained from Bloomberg. Since the futures prices at TexOk were not readily available, I constructed the TexOk futures prices by determining the differential between the TexOk and Henry Hub spot prices and adjusting the Henry Hub futures prices with the differential between the TexOk and Henry Hub spot prices. Prices on the weekends were filled with Friday’s prices since injection and withdrawal activity were observed on the weekends.

The operating characteristics of the Spindletop Facility, such as working gas capacity and base gas, measured in Mmcf, were obtained from the Texas Railroad Commission. Since prices are reported in \$/Mmbtu and the operating characteristics as well as the injection/withdrawal rates were given in Mmcf, the gas quantities in the dataset were converted to Mmbtu by multiplying these values by a factor of 1037 (EIA, 2017d) to provide consistent units.

7 Model and Results

7.1 Theoretical Model

We build a model where a representative agent in a competitive natural gas market maximizes expected profits by making a series of investment decisions based on storage volumes, spot prices and futures prices. Let $p_{t,T}^s$ represent the spot price of natural gas on day t in month T and $F_{t,T}(n)$ denote the futures price on day t in month T for delivery in month $T+n$ at the trading hub. Contracts expire at the TexOk Trading Hub on the last business day of the month. Define $i_{t,T}$ as the amount of gas injected into, ($i_{t,T} > 0$), or withdrawn from, ($i_{t,T} < 0$), storage at time t and month T . Allow S_{Max} to be the maximum storage capacity, and S_{Min} the base gas (cushion gas), of the storage facility. Let $S_{t,T}$

represent the level of gas in storage on day t in month T . $C^I(S_{t-1,T}, i_{t,T}, S_{Max})$ is the cost of injecting $i_{t,T}$ gas into storage, which is a function of the previous end of day storage level, $S_{t-1,T}$, and the maximum storage capacity, S_{Max} , as well as the injection rate, $i_{t,T}$. The domain of $C^I(S_{t-1,T}, i_{t,T}, S_{Max})$ is $(S_{t-1,T}, i_{t,T}, S_{Max}) \in [S_{min}, S_{Max}] \times [0, S_{Max} - S_{t-1,T}] \times \mathbb{R}_{++}$. The cost of withdrawing gas, $C^W(i_{t,T})$, is only a function of the amount of gas withdrawn, $i_{t,T}$, for $i_{t,T}$ negative. Specifically, the domain of $C^W(i_{t,T})$ is $[S_{Min} - S_{t-1,T}, 0]$. The withdrawal cost function is not modeled to be dependent on inventory levels because, as discussed in the following section, such a function cannot be identified in the data set. Let $C^{Fuel}(i_{t,T})$ represent the variable fuel cost incurred during injection. The function $C^{Fuel}(i_{t,T})$ is defined to be 0 when $i_{t,T}$ is negative and some increasing function of $i_{t,T}$ when $i_{t,T}$ is positive. Let N_T be the number of days in month T . Finally, define the agent's information set on day t in month T as $I_{t,T}$ and β as the daily discount factor.

The profit maximizing agent then solves the following problem:

$$\begin{aligned}
\max_{i_{t,T} \in \Gamma_{t,T}} E \left[\sum_T \left[\sum_t^{N_T-1} \beta^{t+\sum_{i=0}^{T-1} N_i} \left((F_{t,T}(1) - p_{t,T}^S) i_{t,T} \right. \right. \right. \\
\left. \left. \left. - 1\{i_{t,T} > 0\} [C^I(S_{t-1,T}, i_{t,T}, S_{Max}) + C^{Fuel}(i_{t,T})] \right. \right. \right. \\
\left. \left. \left. - 1\{i_{t,T} < 0\} C^W(i_{t,T}) \right) \right. \right. \\
\left. \left. + \beta^{N_T+\sum_{i=0}^{T-1} N_i} \left((p_{N_T,T}^S - F_{N_T,T}(1)) S_{N_T,T} + (F_{N_T,T}(2) - p_{N_T,T}^S) S_{N_T,T} \right. \right. \right. \\
\left. \left. \left. - \{i_{N_T,T} > 0\} [C^I(S_{N_T-1,T}, i_{N_T,T}, S_{Max}) + C^{Fuel}(i_{N_T,T}) - (F_{N_T,T}(1) - p_{N_T,T}^S) i_{N_T,T}] \right. \right. \right. \\
\left. \left. \left. - \{i_{N_T,T} < 0\} [C^W(i_{N_T,T}) - (p_{N_T,T}^S - F_{N_T,T}(1)) i_{N_T,T}] \right) \right] \right] \quad (1)
\end{aligned}$$

such that:

$$\Gamma_{t,T} = [S_{Min} - S_{t-1,T}, S_{Max} - S_{t-1,T}] \quad (2)$$

$$S_{t,T} = S_{t-1,T} + i_{t,T} \quad \text{for } t > 1 \quad (3)$$

$$S_{1,T} = S_{N_{T-1},T-1} + i_{1,T} \quad \text{for } t = 1 \quad (4)$$

where:

$$\frac{\partial C^I(S_{t-1,T}, i_{t,T}, S_{Max})}{\partial i_{t,T}} > 0 \quad (5)$$

$$\frac{\partial^2 C^I(S_{t-1,T}, i_{t,T}, S_{Max})}{\partial i_{t,T}^2} > 0 \quad (6)$$

$$\frac{\partial C^W(i_{t,T})}{\partial i_{t,T}} < 0 \quad (7)$$

$$\frac{\partial^2 C^W(i_{t,T})}{\partial i_{t,T}^2} \leq 0 \quad (8)$$

Reflecting behavior observed in practice, futures contracts are used as a financial hedge. On day t in month T , the agent makes injection and storage decisions after observing last period's end of day storage level, the current spot price, $p_{t,T}^s$ and the prompt month futures price, $F_{t,T}(1)$. Every time the agent purchases gas to inject into storage, it secures a prompt month futures contract to lock in a profit. When it withdraws gas to sell at price $p_{t,T}^s$, the agent closes out the corresponding futures position. On the contract's expiration date, the agent decides whether to roll over its position based on the futures price two months out. Specifically, at the end of the month, the agent closes out its futures positions with a cash settlement and then rolls over its position into the next month. The agent thus uses the futures market to respond to and profit from unanticipated price surges. Notice that the daily profit at time (N_T, T) in Equation (1) converges to 0 since the spot price converges to the prompt month

futures price on the contract's expiration date.

Equation (2) restricts injection/withdrawal rates to prevent inventory levels exceeding the physical constraints of the storage facility. Equation (3) describes the transition equation of gas inventories in storage, where $S_{t,T}$ is the end of day storage level at time (t, T) . Equations (5)-(8) impose the assumptions (illustrated in Figure 1) that the cost functions for injection and withdrawal of natural gas are strictly convex and convex functions in injections and withdrawals, respectively. Notice that the first two derivatives of $C^W(i_{t,T})$ are negative because withdrawals are defined as negative numbers.

7.2 Cost Function Specifications and Identification

As previously mentioned, the cost of injecting/withdrawing gas into/from storage depends on the level of gas in storage at the time of injection/withdrawal as well as the rate of injection/withdrawal. As the level of gas in storage increases, it becomes increasingly more expensive to inject gas. Anecdotal evidence suggests costs start increasing at increasing rates when the inventory level nears 85% of the maximum capacity of the facility. Conversely, as storage levels are depleted, it becomes increasingly more expensive to withdraw gas from storage since there is less pressure to expel the gas from storage. In fact, there is a floor of natural gas storage below which no further gas can be extracted from the facility (Natural Gas Supply Association, 2014).

To capture this behavior we must specify an injection cost function that increases with injection rates and asymptotes to $+\infty$ as storage increases to S_{Max} . Similarly, the cost of withdrawing natural gas must increase with the rate of withdrawal and asymptote to $+\infty$ as storage decreases to S_{Min} . To identify and estimate costs when inventories near capacity or base gas, sufficient observations are needed where storage levels are above 85% of the maximum

storage capacity level or within 15% of the base gas level. Our data satisfies this condition for S_{Max} but not for S_{Min} . We therefore postulate a cost of withdrawal that increases with the volume of withdrawals but does not depend on inventory levels.

The cost of injection is modeled as:

$$C^I(S_{t-1,T}, i_{t,T}, S_{Max}) = \frac{\alpha i_{t,T}}{(S_{Max} - S_{t-1,T})^\delta} \quad (10)$$

This specification is useful because it captures the effect of increasing storage levels on injection costs. However, the parameters are not invariant to the units that $S_{t,T}$ and $i_{t,T}$ are measured in. Specifically, if we rescale $S_{t,T}$ and S_{Max} by the same proportion k and maintain $\alpha k^{1-\delta}$ constant we get identical costs.

The cost of withdrawal is modeled as:

$$C^W(i_{t,T}) = \gamma i_{t,T} \quad (11)$$

At the time of injection, the agent also has to pay a fuel cost. According to the most recent Spindletop contracts, obtained from the Texas Railroad Commission, a fuel cost of 2% of the value of injected volumes is charged. In particular, the fuel cost is modeled as:

$$C^F(i_{t,T}) = 0.02 p_{t,T}^s i_{t,T} \quad (9)$$

7.3 Empirical Model

Using the cost functions defined above, and the fact that $p_{N_T}^S$ converges to $F_{N_T,T}(1)$, we now model the agent's constrained maximization problem in the following manner:

$$\begin{aligned}
L(i_{t,T}, \lambda_{t,T}, \mu_{t,T}) = & \max E \left[\sum_T \left[\sum_{t=1}^{N_T} \beta^{t+\sum_{i=0}^{T-1} N_i} \left(1\{i_{t,T} > 0\} [(F_{t,T}(1) - p_{t,T}^S) i_{t,T} \right. \right. \right. \\
& - \frac{i_{t,T}}{(S_{Max} - S_{t-2,T} - i_{t-1,T})^\delta} - 0.02 p_{t,T}^S i_{t,T}] \\
& + 1\{i_{t,T} < 0\} [(p_{t,T}^S - F_{t,T}(1)) i_{t,T} - \gamma i_{t,T}] \\
& \left. \left. \left. + \mu_{t,T}(i_{t,T} - S_{Min} + S_{t-1,T}) + \lambda_{t,T}(S_{Max} - S_{t-1,T} - i_{t,T}) \right) \right] \right] \\
& + \beta^{N_T + \sum_{i=0}^{T-1} N_i} \left((F_{N_T,T}(2) - F_{N_T,T}(1)) (S_{N_T-1,T} + i_{N_T,T} \right. \\
& \left. \left. \left. + \mu_{N_T,T}(i_{N_T,T} - S_{Min} + S_{N_T-1,T}) + \lambda_{N_T,T}(S_{Max} - S_{N_T-1,T} - i_{N_T,T}) \right) \right) \Big] | I \Big]
\end{aligned} \tag{10}$$

Differentiating Equation (10) with respect to $i_{t,T}$, we obtain the first order condition:

$$\frac{\partial L}{\partial i_{t,T}} = \begin{cases} E \left(\beta^{t+\sum_{i=0}^{T-1} N_i} \left(\{i_{t,T} > 0\} [F_{t,T}(1) - p_{t,T}^S - \frac{\alpha}{(S_{Max} - S_{t-2,T} - i_{t-1,T})^\delta} - 0.02 p_{t,T}^S] \right. \right. \\
+ 1\{i_{t,T} < 0\} [p_{t,T}^S - F_{t,T}(1) - \gamma] \\
\left. \left. - \{i_{t+1,T} > 0\} \beta \frac{\alpha \delta i_{t+1,T}}{(S_{Max} - S_{t-1,T} - i_{t,T})^{\delta+1}} | I_{t,T} \right) \right) = 0 & t \in \{1, \dots, N_T - 1\} \\
E \left(\beta^{N_T + \sum_{i=0}^{T-1} N_i} \left(F_{N_T,T}(2) - F_{N_T,T}(1) \right. \right. \\
- 1\{i_{N_T,T} > 0\} \left[\frac{\alpha}{(S_{Max} - S_{N_T-2,T} - i_{N_T-1,T})^\delta} + 0.02 p_{N_T,T}^S \right] \\
- 1\{i_{N_T,T} < 0\} [\gamma] \\
\left. \left. - 1\{i_{N_T+1,T} > 0\} \beta \frac{\alpha \delta i_{N_T+1,T}}{(S_{Max} - S_{N_T-1,T} - i_{N_T,T})^{\delta+1}} | I_{N_T,T} \right) \right) = 0 & t = N_T \end{cases}$$

Notice that the constraints on $i_{t,T}$ are not binding. In particular, the functional form of the injection cost function guarantees that it is never profit maximizing for an agent to set $i_{t,T} = S_{Max} - S_{t-1,T}$. When $i_{t,T}$ is negative, we

can assume an interior solution since inventory levels never approach the lower bounds in the data set. Thus, both $\mu_{t,T}$ and $\lambda_{t,T}$ from Equation (10) are set to zero.

Essentially the first order condition stipulates that the expected marginal value of injecting gas for time (t, T) and $(t + 1, T)$ must equal the expected marginal cost of doing so. Notice that the agent considers the effect of increasing storage levels on injection costs when making injection decisions.

Without solving the entire system, we can estimate the injection cost parameter using the first order condition as a moment condition in a GMM setting. Any vector that includes elements from the agent's information set at time (t, T) , such as past prices and storage levels, should be orthogonal to the first order condition (7.3) since such a vector would contain no new information when the agent makes its decision. These past observations can then provide instruments to be used in a GMM framework. Define the matrix of instruments orthogonal to the moment condition as z_t , where z_t is an $m \times q$ matrix, such that $q \geq 3$ and m is the dimension of the sample size. We then have the following set of moment equations, M :

$$M = \begin{cases} E \left(z' (\beta^{t+\sum_{i=0}^{T-1} N_i} \left(\{i_{t,T} > 0\} [F_{t,T}(1) - p_{t,T}^S - \frac{\alpha}{(S_{Max} - S_{t-2,T} - i_{t-1,T})^\delta} - 0.02p_{t,T}^s] \right. \right. \\ \quad \left. \left. + 1\{i_{t,T} < 0\} [p_{t,T}^s - F_{t,T}(1) - \gamma] \right. \right. \\ \quad \left. \left. - \{i_{t+1,T} > 0\} \beta \frac{\alpha \delta i_{t+1,T}}{(S_{Max} - S_{t-1,T} - i_{t,T})^{\delta+1}} | I_{t,T} \right) \right) = 0 & t \in \{1, \dots, N_T - 1\} \\ E \left(z' (\beta^{N_T + \sum_{i=0}^{T-1} N_i} \left(F_{N_T,T}(2) - F_{N_T,T}(1) \right. \right. \\ \quad \left. \left. - 1\{i_{N_T,T} > 0\} \left[\frac{\alpha}{(S_{Max} - S_{N_T-2,T} - i_{N_T-1,T})^\delta} + 0.02p_{N_T,T}^s \right] \right. \right. \\ \quad \left. \left. - 1\{i_{N_T,T} < 0\} [\gamma] \right. \right. \\ \quad \left. \left. - 1\{i_{N_T+1,T} > 0\} \beta \frac{\alpha \delta i_{N_T+1,T}}{(S_{Max} - S_{N_T-1,T} - i_{N_T,T})^{\delta+1}} | I_{N_T,T} \right) \right) = 0 & t = N_T \end{cases}$$

7.4 GMM Estimation

To estimate the model using GMM, z_t was constructed to contain the first 40 lags of the spread between the NGPL TexOk daily futures and spot prices as well as the first differenced daily Henry Hub spot prices. We look at the spreads and differenced data, as opposed to the levels of the data, to exclude non-stationary instruments.⁶ The discount factor, β , was set to 0.9998 to reflect the short duration of transactions and the low interest rate environment. The heteroskedastic and autocorrelation consistent errors were calculated using a Quadratic Spectral Kernel with the lag selection set to 22, which was determined as the optimal lag structure using the Newey and West (1994) optimal lag selection method.

The difference in the scale of the injection units and the inventory units caused the gradient, with respect to α , to become very flat. In particular,

$$\nabla_{\alpha} = -\beta^{t+\sum_{i=0}^{T-1} N_i} \left(\{i_{t,T} > 0\} \frac{1}{(S_{Max} - S_{t-2,T} - i_{t-1,T})^{\delta}} + \{i_{t+1,T} > 0\} \frac{\beta \delta i_{t+1,T}}{(S_{Max} - S_{t-1,T} - i_{t,T})^{\delta+1}} \right)$$

is very near to 0 and this created convergence issues. To obviate this problem, the inventory units were rescaled by 1000 so that the denominator is now measured in MBtu. While this normalization will change the estimates, as previously discusses in the identification section, the predictions and counterfactuals will remain unaltered. The estimates are presented in Table 1.

A post estimation Hansen test was performed to confirm the validity of the instruments. Having obtained a p-value of 1, we can safely assume the instruments are exogenous to the error terms.

Tariffs charged by the Spindletop Facility, operated by Centana Intrastate,

⁶Both the NGPL Texok futures/spot price spread and the first differenced Henry Hub spot prices had p-values of 0 in a Dickey-Fuller test for a unit-root.

Table 1: Results

Cost Parameters	
α	.4178537 **** (35.76)
δ	.4702111 **** (119.27)
γ	.0331166**** (399.82)
N	560

t statistics in parentheses

* $p < 0.1$ ** $p < 0.05$, *** $p < 0.01$, **** $p < 0.001$

are posted by the Texas Railroad Commission, its state regulator. These rates are subject to maximum injection and withdrawal rates. The estimated injection cost function should provide some insight into rates that would be charged if storage levels increased. In terms of the validity of the model, it accurately predicts current prices given observed storage levels. The most recently posted injection tariffs for the Spindletop Storage Facility are 0.01\$/Mmbtu. The model predicts the cost to inject one Mmbtu of gas, at the median level of storage observed in the dataset, to be 0.009\$ with a bootstrapped standard error of 0.0028. Of course, we only have one observation point for comparison, but the predictions for current costs are quite accurate given the information we have. We can then more confidently examine some implications of these estimates in the next section.

8 Examining the Impact of Increased Utilization

We now explore how prices would change for different utilization rates of storage in salt caverns. The base case cost, in other words the cost that is currently

observed at the Spindletop storage facility, is 0.01\$/Mmbtu. The median utilization level of the Spindletop facility in the dataset is 85%; increasing storage levels to 90% or beyond is thus not unrealistic. Table 4 presents the predicted injection costs of 1 Mmbtu of gas for storage levels beyond 90% of capacity, with the associated standard errors, estimated using a bootstrapping method with 10000 simulations. The predicted costs for all spare capacity levels are plotted in Figure 4.

Figure 3: Predicted Injection Costs for High Storage Levels

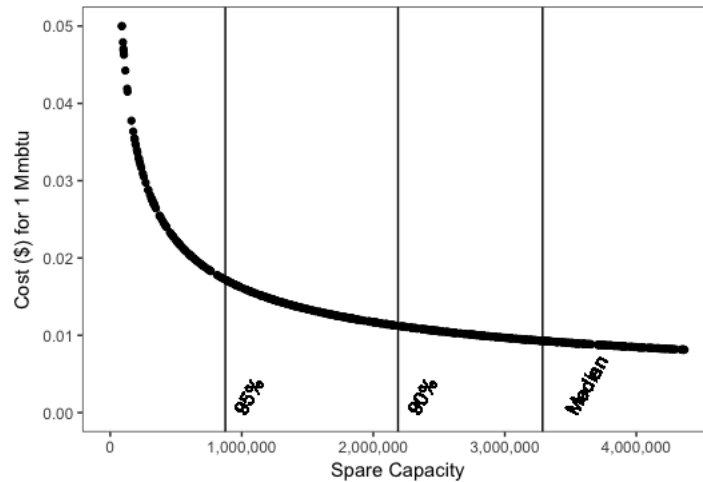
Utilization Level	Cost (\$/Mmbtu)	Standard Error	% Increase from \$0.01/Mmbtu
90%	0.0112	0.000005	12
91%	0.0118	0.000005	18
92%	0.0125	0.000005	25
93%	0.0133	0.000005	33
94%	0.0143	0.000006	43
95%	0.0156	0.000006	56
96%	0.0173	0.000007	73
97%	0.0198	0.000007	98
98%	0.0239	0.000009	139
99%	0.0332	0.000016	232

As aforementioned, the LNG export and power generation industries are the most likely candidates to use salt cavern storage facilities. The following will discuss some potential consequences of increased use of storage on these industries.

Cheniere Energy, currently the most prominent exporter of LNG to European and Asian markets, has signed several 20 year contracts where the company receives some fixed payment per Mmbtu of gas, which has been formulated to cover liquefaction and transportation costs, and 115% of the NYMEX Henry Hub price. The average 2017 Henry Hub spot price ⁷ was \$2.49 (EIA,

⁷As of October 2017.

Figure 4: Predicted Costs given Spare Capacity



2017a). This gives Cheniere an average margin of \$0.37/Mmbtu. Figure 4 exhibits the predicted costs for various storage levels. The maximum injection cost should most likely not exceed 0.033\$/Mmbtu. The maximum predicted cost, 0.033\$/Mmbtu, accounts for 1.3% of the current average Henry Hub price. Given Cheniere’s margins and assuming prices remain stable, we should expect Cheniere to see a decrease in their profits. This increase in costs should not, however, alter their decision to use salt cavern storage and export LNG. Given the likelihood that LNG exporters will still find it profitable to use salt caverns to store their natural gas, despite cost increases, it is more probable that these cost increases will occur. Increased demand from LNG exporters and the resulting price increases will likely affect the decision to use natural gas in the power generation sector for peak demand.

In the past year, the price of gas at the Henry Hub, adjusted to energy conversion heat rates to reflect the different energy efficiency of different power plants, has consistently outpriced Powder River Basin coal. In the summer of 2017, the Henry Hub price has been nearly identical to Central Appalachian

coal EIA (2017). Increased utilization of salt caverns in the Gulf region, which as described above is likely, would put additional upward pressure on the cost to generate power with natural gas. Given spare capacity rates of 90%-99%, storage injection costs could be anywhere from 0.45% to 1.3% of the current average yearly Henry Hub price. While these costs may not seem significant, they can cause natural gas to lose favor to coal on the margin. Of course, demand for coal and gas in power generation is a multifaceted problem and depends on more than just spot prices, but higher gas prices, spurred by increased injection costs into storage and heightened demand for gas exports, would certainly not encourage demand for gas.

9 Conclusions and Policy Implications

There will most likely be a greater use of salt cavern storage in the Gulf region in future years. Increased LNG exports from the area, as well as the electric sector's growing reliance on natural gas, will put increasing pressure on the existing underground storage capacity.

Since injection and withdrawal costs are sensitive to the amount of pressure in the storage facility, they are likely to change in the coming years with increased use of the facilities. This paper has provided estimates on how injection costs will change as storage is used more extensively, using a GMM estimation technique that recovers the unknown parameters from profit maximization assumptions and observed injection/withdrawal rates. The estimated results imply that as storage levels approach capacity, injection costs increase at an increasing rate.

The quantification of an injection cost function into salt cavern storage is an important finding for determining natural gas pricing and understanding the behavior of short term natural gas traders, who have a considerable influence

on the market. At the theoretical level, it should also aid in building models that seek to determine the value of natural gas storage facilities. The landscape of the U.S. natural gas market has greatly changed in the past few years and continues to do so, mainly in response to the Shale Revolution and the beginning of U.S. LNG exports. The natural gas storage industry is due to change with it.

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