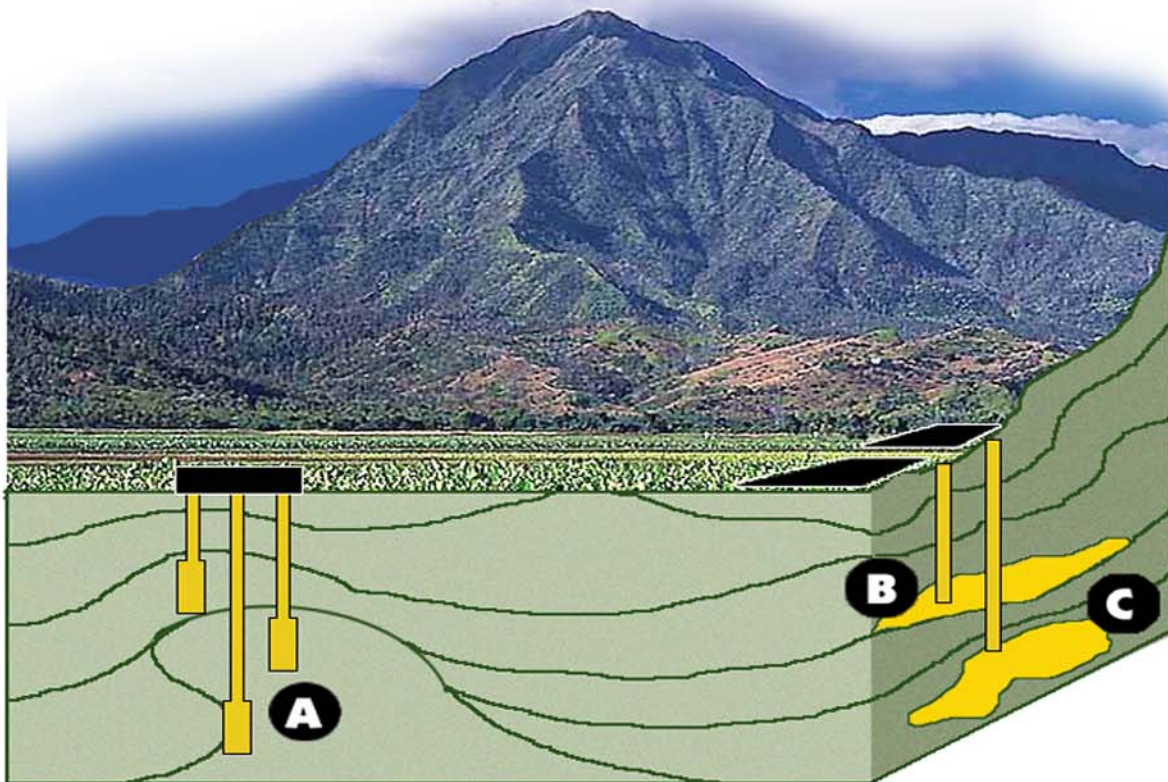


CURRENT STATE OF AND ISSUES CONCERNING Underground Natural Gas Storage

Docket No. ADo4-11-000



A – Salt Caverns

B – Aquifers

C – Depleted Reservoirs



Federal Energy Regulatory Commission

Staff Report • September 30, 2004

Current State of and Issues Concerning Underground Natural Gas Storage

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KEY FINDINGS:

- Under average conditions and from a nationwide perspective, storage appears to be adequate to meet seasonal demand; however, continued commodity price volatility indicates that more storage may be appropriate.
- Storage may be the best way of managing gas commodity price, so the long-term adequacy of storage investment depends on how much price volatility customers consider “acceptable.”
- A study performed by the National Petroleum Council indicates that there may be a need in North America for 700 Bcf of new storage between now and 2025. Another study, by The INGAA Foundation, concludes that 651 Bcf of new storage may be needed in the United States and Canada by 2020. In addition, there may be certain region-specific (e.g., Southwest, New England) needs for new storage.
- Geology, economics and environmental impacts may stall development and could jeopardize achieving forecasted capacity needs.
- Reengineering of existing storage fields is underway in order to improve working gas capability – application of new engineering techniques can help to ensure that development of new fields stays on track.
- Four key methods that market participants use to value storage (e.g., cost of service; least-cost planning; seasonal valuation, or intrinsic; and, option-based valuation, or extrinsic) do not always reach the same result because they are based on differing views of the need and reasons for storage.
- Storage projects in certain geographic areas (e.g., Southwest) often fail the Commission’s market-based rates tests.
- Creative ratemaking approaches may encourage storage development.
- Creative certificate and policy choices may also encourage storage development by reducing costs and permitting additional opportunities to generate revenues.

This report addresses three aspects of the state of and issues concerning the underground storage of natural gas: the history of storage development and its physical characteristics and the need for storage; the economics of underground storage; and, ratemaking options for future storage development.

The underground storage of natural gas has historically been critical in assuring that overall demands and use-specific requirements of natural gas customers are met. The Natural Petroleum Council's (NPC) September 2003 report¹ noted that the demand for storage is expected to increase in the foreseeable future. Specifically, the NPC foresees the need for an additional 700 Bcf of new storage in the United States and Canada over the next 20 years, which translates to an average of 35 Bcf of new storage being added each year.

Presently, from a national perspective and assuming average weather, storage appears to be adequate. However, simply considering average demand and national balances does not tell the complete story. For some market areas, particularly those that are distant from supply sources, the development of new storage infrastructure could cost-effectively help customers maintain service reliability and manage commodity price volatility.

In addition, gas prices have increased with the decline in gas production. During the "gas bubble" of the 1980s-1990s, production increased in response to short-term spikes in demand. Production increases coupled with demand decreases in this same period allowed supply to meet demand, even during peak periods, without significant price spikes. As production declined or flattened over the past few years, production spikes can no longer be relied upon to meet demand spikes. As a result, commodity price swings manage demand fluctuations.²

Building new storage may be an effective way to reduce commodity price volatility. Demand for storage services to manage price volatility will depend on customer tolerance for price risk, how that price risk is valued, and

the cost of service. Accordingly, there may be a public policy interest in encouraging storage development.

While the desire of project sponsors to build new storage in the Southwest and Northeast has been demonstrated by the various applications seeking to develop projects, the development has not occurred for economic, environmental, geological and political reasons.

Specifically, in the Southwest there have been three recent storage projects that, for various reasons, have not been developed. The Desert Crossing storage project, although initiated, has not been further pursued; while no formal reason for not pursuing development was provided, market (contractual) support did not materialize and environmental concerns associated with certain aspects of the proposal were raised.³ The Copper Eagle storage project, located on the outskirts of Luke Air Force Base, became the subject of security and safety concerns; plans for its development have been delayed following expressions of concern by the State of Arizona legislature.⁴ The sponsor of the Red Lake storage project did not pursue development owing to Red Lake's unwillingness to go forward without authorization for market-based rates. Its inability to demonstrate a significant lack of market power resulted in the Commission's decision to deny market-

¹ *Balancing Natural Gas Policy - Fueling the Demands of a Growing Economy*, National Petroleum Council (2003).

² *See Report on the Natural Gas Price Spike of February 2003*, Staff Investigating Team, July 23, 2003.

³ *Desert Crossing Gas Storage and Transportation System LLC*, 98 FERC ¶ 61,277 (2002).

⁴ *Copper Eagle Gas Storage L.L.C.*, 97 FERC ¶ 62,193 (2001); *Copper Eagle Gas Storage, L.L.C.*, 99 FERC ¶ 61,270 (2002).

based rate authority.⁵ Evidence of the desire for storage in the Southwest was demonstrated in the *Southwestern Gas Storage Conference* held on August 23, 2003, in Phoenix, Arizona.⁶ There, participants, including the Chairman of the Arizona Corporation Commission, expressed unanimous support for the proposition that development of new storage in the region was needed.

In the Northeast, two major projects, the NE Hub storage project and the Avoca storage project, similarly never came into service, and the Wyckoff/Greyhawk storage project has been delayed, although they all were certificated by the Commission, but encountered various technical and economic problems.⁷ While these projects were located in New York state in areas where the geology is conducive to the development of underground storage, the geology in other parts of the Northeast is not practical for the development of underground storage.

As discussed in more detail in this report, there are other approaches to achieving the development of new storage using both new and existing fields. For example, reengineering of existing storage fields is an ongoing exercise to improve working gas capability. In addition, the application of new engineering techniques can prove useful in achieving greater deliverability from existing fields. These techniques also help to ensure the efficient development of new fields in areas geologically conducive to storage, stays on track.

Through new design approaches and the application of advanced engineering techniques, certain physical barriers to the development of new storage can potentially be overcome. However, as discussed later in this report, long-term market price signals appear to be weak for new storage development. Further, the four key methods that market participants use to value storage (cost of service;

and, least-cost planning seasonal arbitrage, or intrinsic; and option-based or extrinsic) do not always reach the same result because they are based on differing views of the need and reasons for storage.

But regulatory requirements may prove to be a financial barrier inhibiting development in some regions. Storage developers have claimed a preference for market-based rates. And, in the markets where new storage developers cannot assert market power, market-based rates have been allowed.

Current Commission rate policy provides considerable flexibility to design cost-based rates, negotiated rates and market-based rates. Additional cost-based rates and market-based rate alternatives could be explored to encourage additional storage development. Further, revised storage project certification requirements and procedures could potentially reduce costs and offer the potential to generate additional revenues

This report sets out some of these approaches and also describes some non-cost-based approaches that may be useful in addressing financial obstacles to new storage development.

⁵ *Red Lake Gas Storage, L.P.*, 103 FERC ¶ 61,277 (2003); *Red Lake Gas Storage, L.P.*, 102 FERC ¶ 61,077 (2003).

⁶ *Southwestern Gas Storage Technical Conference*, Docket No. AD03-11-000, Notice of Technical Conference (2003).

⁷ *NE Hub Partners, L.P.*, 105 FERC ¶ 61,334 (2003); *Avoca Natural Gas Storage*, 88 FERC ¶ 62,245 (1999); *Wyckoff Gas Storage Company, LLC*, 105 FERC ¶ 61,027 (2003).

Natural gas storage facilities are used to meet gas demand peaks which exceed production and long-haul pipeline throughput. Increasingly, storage also plays a variety of roles helping market participants manage pipeline imbalance charges and daily and seasonal price volatility. When cold weather or other market conditions create more demand for gas than domestic production or imports can satisfy, gas that has been put in storage can be withdrawn to make up the difference. While natural gas is also stored for peak daily and hourly uses mainly by distribution companies and liquefied natural gas (LNG) is stored briefly at import terminals, this report will focus on what is known as traditional underground gas storage, as well as, the new, nontraditional usage of storage developed by the unbundling of storage and the new market conditions.

Traditional Underground Storage

Geology is a key issue for determining the location of new traditional underground storage projects and the expansion of existing projects. There are areas that have the geological characteristics to construct storage fields; other areas do not. Selection of any new underground gas storage location depends on geological and engineering properties of the storage reservoir, its size and its cushion, or base, gas requirements. It also depends on the site's access to transportation pipeline infrastructure, gas production sources, and to markets.

The use of underground gas storage facilities in the natural gas industry is almost as old as the development of long distance transmission lines. The first high pressure transmission lines began operations in 1891 with successful construction of two parallel 120-mile, 8-inch diameter lines from fields in northern Indiana to Chicago. The first successful gas storage project was completed in 1915 in Welland County, Ontario. The following year, operations began in the Zoar field near Buffalo, New York.

Underground storage field operations include a host of component and interdependent facilities. There are injection/withdrawal wells, observation wells, water disposal wells, gathering lines, dehydration facilities, gas

measuring facilities, compressors, etc. Underground storage fields come in three basic types: depleted gas/oil reservoirs, salt caverns, and aquifers. Access to at least one major transportation pipeline to receive gas or deliver gas is, of course, a complementary requirement.

The Nontraditional Usage of Underground Storage

In addition to meeting the traditional seasonal load variations, the hourly swings, and emergency situations, storage is now being used to meet services created by both the unbundling of storage and by the new market conditions. Specifically, storage is being used to:

1. Meet the regulatory obligation to ensure supply reliability at the lowest cost to the ratepayer by maintaining specific levels of storage inventory.
2. Avoid imbalance penalties and facilitate daily nomination changes, parking and lending services, and simultaneous injections and withdrawals.
3. Ensure liquidity at market centers to help contain price volatility and maintain orderly gas markets.
4. Offset the reduction in traditional supplies that were relied upon to meet winter demand.
5. Increase the comfort inventory level of working gas or top gas.
6. Offset, through the injection of more gas during the shoulder months, the growing summer peak impacts from electric generation.
7. Support other electric generation loads.

Three Types of Underground Gas Storage Facilities

Salt Cavern

Some storage facilities use caverns that are leached or mined out of underground salt deposits (salt domes or salt formations). Salt cavern capacity typically is 20 percent to 30 percent cushion gas and the remaining capacity is working gas. Working gas can generally be recycled 10-12 times a year in this type of storage facility. These facilities

are characterized by high deliverability and injection capabilities and are mainly used for short peak-day deliverability purposes (i.e., for fueling electric power plants).

Depleted Oil/Gas Reservoir

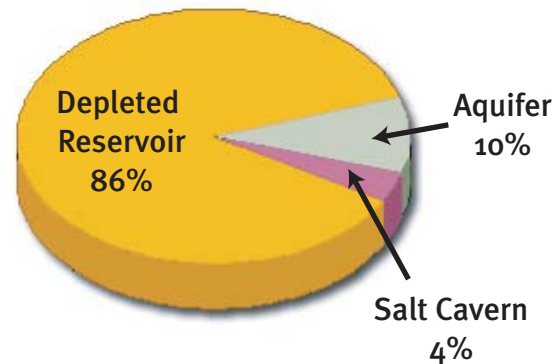
The most common underground gas storage facilities are those that use deep underground natural gas or oil reservoirs that have been depleted through earlier production. These reservoirs are naturally occurring, and their potential as secure containers has been proven over the millennia that the reservoirs held their original deposits of oil and gas. An underground gas storage field or reservoir is a permeable underground rock formation (average of 1,000 to 5,000 feet thick) that is confined by impermeable rock and/or water barriers and is identified by a single natural formation pressure. The working gas capacity is typically 50 percent, with the rest of the capacity maintained to ensure adequate deliverability. Gas is typically withdrawn in the winter season and injected during the summer season. This type of storage facility could be used for seasonal system supply or for peak-day demands.

Aquifer

A large number of reservoirs are bound partly or completely by water-bearing rocks called “aquifers.” The nature of the water in the aquifer may vary from fresh to nearly saturated brines. Aquifer storage facilities typically have high cushion gas requirements, ranging between 50 percent to 80 percent. However, they achieve high deliverability rates, with gas injected in the summer season and withdrawn in the winter.

The following chart, based on the Department of Energy’s Energy Information Administration (EIA) final 2001 data, shows that depleted reservoirs are the dominant type of underground storage based on total capacity. These percentages have slightly changed using 2002 EIA data, which are not yet final.⁸

Types of Underground Storage Capacity



Source: Energy Information Administration

Summary of Physical Characteristics of Traditional Natural Gas Storage

(The following descriptions are from the Natural Gas Supply Association)⁹

The most common form of underground storage consists of depleted gas/oil reservoirs. Depleted reservoirs are those formations that have already been tapped of all their recoverable hydrocarbons. This leaves an underground formation geologically capable of holding natural gas. In addition, using an already developed reservoir for storage purposes allows the use of the extraction and distribution equipment left over from when the field was productive. Having this network in place reduces the cost of converting a depleted reservoir into a storage facility. Depleted reservoirs are also attractive because their geological characteristics are already well known. Of the three types of underground storage, depleted reservoirs, on average, are the cheapest and easiest to develop, operate and maintain.

⁸ Form EIA-191, Monthly Underground Gas Storage Report.

⁹ See NGSAs Web site at <http://www.naturalgas.org/naturalgas/storage.asp>

Aquifers are underground permeable rock formations that act as natural water reservoirs. However, in certain situations, these water-containing formations may be reconditioned and used as natural gas storage facilities. Because they are more expensive to develop than depleted reservoirs, these types of storage facilities are usually used only in areas where there are no nearby depleted reservoirs. Traditionally, these facilities are operated with a single winter withdrawal period, although they may be used to meet peak load requirements as well. Aquifers are the least desirable and most expensive type of natural gas storage facility for a number of reasons. First, the geological characteristics of aquifer formations are not as thoroughly known as are depleted reservoirs. A significant amount of time and money goes into discovering the geological characteristics of an aquifer and determining its suitability as a natural gas storage facility. Also, the cushion gas requirement for aquifers is higher than for depleted oil/gas reservoirs.

Underground salt formations offer another option for natural gas storage. These formations are well suited to natural gas storage because salt caverns, once formed, allow little injected natural gas to escape from the formation unless specifically extracted. The walls of a salt cavern also have the structural strength of steel, which makes it resilient to reservoir degradation over the life of the storage facility. Salt caverns are formed out of existing salt deposits. These underground salt deposits may exist in two possible forms: salt domes and salt beds. Salt domes are thick formations created from natural salt deposits that, over time, move up through overlying sedimentary layers to form large dome-like structures. Salt beds are shallower, thinner formations. Because salt beds are wide and thin, salt caverns in them are more prone to deterioration and may also be more expensive to develop than salt domes.

Operating Characteristics of the Types of Underground Storage

The pressure range in a depleted reservoir for the storage operating cycle depends upon (1) the safe upper limit of the reservoir pressure (bottom hole or surface pressure),

(2) the flow capacity of the wells, and (3) compression requirements when injecting gas into the reservoir or delivering to market. Normally gas and oil fields have pressures at discovery in the range of 0.43 to 0.52 pounds per square inch per foot of depth. The highest pressure level possible normally will provide the maximum storage capacity and the wells will have the highest flow capacity.

Peak-day or seasonal deliverability is directly related to storage volume vs. storage pressure. Required storage deliverability services (daily or seasonal volumes) require maximum storage pressure and gas-in-place volumes prior to the withdrawal season.

Therefore, the main issues are how much gas can be carried over from year to year, how long the gas can remain in the reservoir prior to being turned over and how soon can the capacity be refilled. These problems are not based on some theoretical behavior, but instead are based on experience under a variety of turnover and injection conditions.

It is operationally improper to simply let the gas sit in any storage field. If working gas is not recycled properly, it will move from higher pressure areas of the storage field to lower pressure areas, move into tighter formations or migrate to a point that will result in an increase in cushion gas requirements or gas loss.

The following table summarizes our understanding of how the three types of storage fields are generally operated. Less cushion gas is needed for salt caverns and they can be filled and emptied much more frequently than aquifers or depleted reservoirs. For aquifers or depleted reservoirs, the injection period usually corresponds with the months of April through October (214 days), while the withdrawal period is usually the months of November through March (151 days). Storage operators must use their best geologic and engineering judgment to vary from this schedule. Early season cold weather can reduce storage gas in place and deliverability, while late season cold weather can reduce the next season's required injections in terms of volumes and days.

Gas Storage Facility Operations

Type	Cushion to Working Gas Ratio	Injection Period (Days)	Withdrawal Period (Days)
Aquifer	Cushion 50% to 80%	200 to 250	100 to 150
Depleted Oil/Gas Reservoirs	Cushion 50%	200 to 250	100 to 150
Salt Cavern	Cushion 20% to 30%	20 to 40	10 to 20

Source: Analysis of FERC filings

Nationwide Storage Capacity

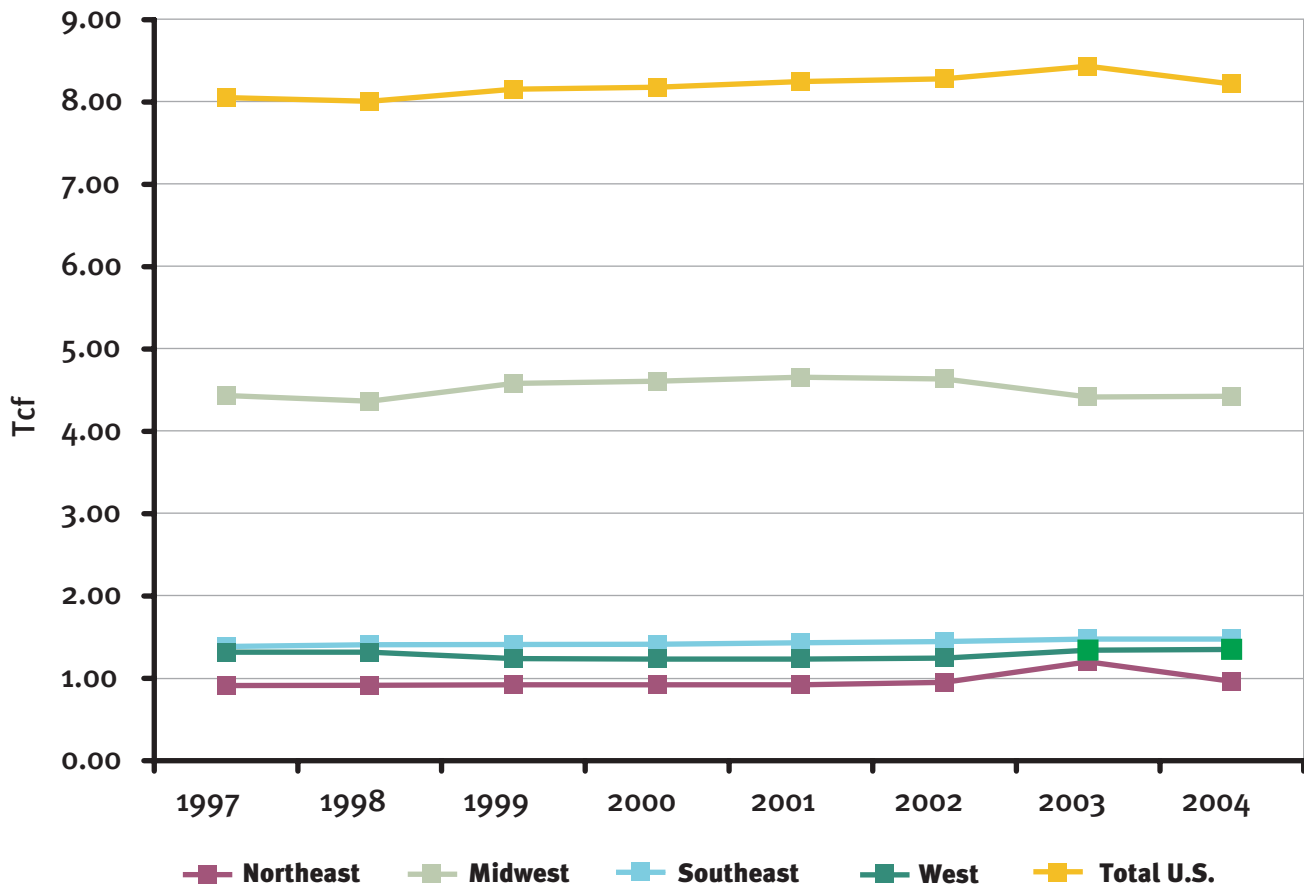
Because not all storage is under the Commission's jurisdiction, we have to look to other sources of information to get nationwide totals of storage capacity. The EIA reports that as of 2002 (the latest data available), interstate pipelines operated nearly 55 percent of the nation's gas storage capacity¹⁰ but had contractual rights to use only 8 percent of the working gas capacity for their own purposes. Local distribution companies (LDCs) and intrastate pipeline companies operated about 35 percent of working gas capacity and independent operators operated about 10 percent of working gas capacity. However, most of the pipeline's storage capacity, about 73 percent, is contractually committed to LDCs. Marketers also hold a significant share of storage capacity under contract, about 15 percent. The total maximum U.S. natural gas storage capacity (cushion, or base, gas plus working gas) reported to the EIA fluctuated slightly above

the 8 Tcf level for the past eight years (8 to 8.4 Tcf), while for the same period, the EIA reports that working gas storage capacity has varied between 4.4 and 4.7 Tcf.

Using a different survey, the Office of Fossil Energy – which, like EIA, also is in the Department of Energy – reported that as of 2003 there were 110 underground gas storage operators that maintain and operate 415 underground gas storage facilities with a working gas capacity of 3.9 Tcf in this country. Of this total number of facilities, 201 are FERC-jurisdictional, controlled by 43 operators. The total FERC-jurisdictional working gas capacity is 2.5 Tcf. Close to half of all the storage capacity is located in the Midwest. The graph on the following page shows the relatively stable amount of storage capacity from 1997 to present, based on EIA's data.

¹⁰ Form EIA-191, Monthly Underground Gas Storage Report.

Volumes of Underground Natural Gas Storage



Source: U.S. Department of Energy, Office of Fossil Energy

However, total reported storage capacity has never really been tested with operating experience. Thus, the value that defines “full” when determining the total working gas capacity is not known exactly. Even the EIA’s “Basics of Underground Natural Gas Storage” discusses three different approaches to measuring “percent full” of U.S. natural gas storage. Based on our interpretation of historical data, staff believes there is a total practical storage operating capacity of 7.6 Tcf, of which 3.5 Tcf¹¹ is working gas capacity and the remaining 4.1 Tcf is cushion gas. The American Gas Association (AGA) reported that the largest working gas capacity held in storage during a given time period was 3,294 Bcf. Therefore, based on EIA data of total storage capacity being at least 8.2 Tcf for several recent

years, the staff estimates that there is as much as 600 Bcf of potential working gas capacity available within existing storage fields for future use. Thus, staff estimates the total U.S. potential working gas capacity to be 3.6 to 3.8 Tcf. Based on these estimations, there is 200 Bcf to 500 Bcf of potential working gas capacity beyond the presently proven 3.5 Tcf of working gas that could be reengineered and used.

Another technical point is that storage working gas capacity is directly related to the availability of supply. If there is sufficient gas supply available during the early injection season when storage pressures are lowest, the storage operators could inject at the highest rates and re-

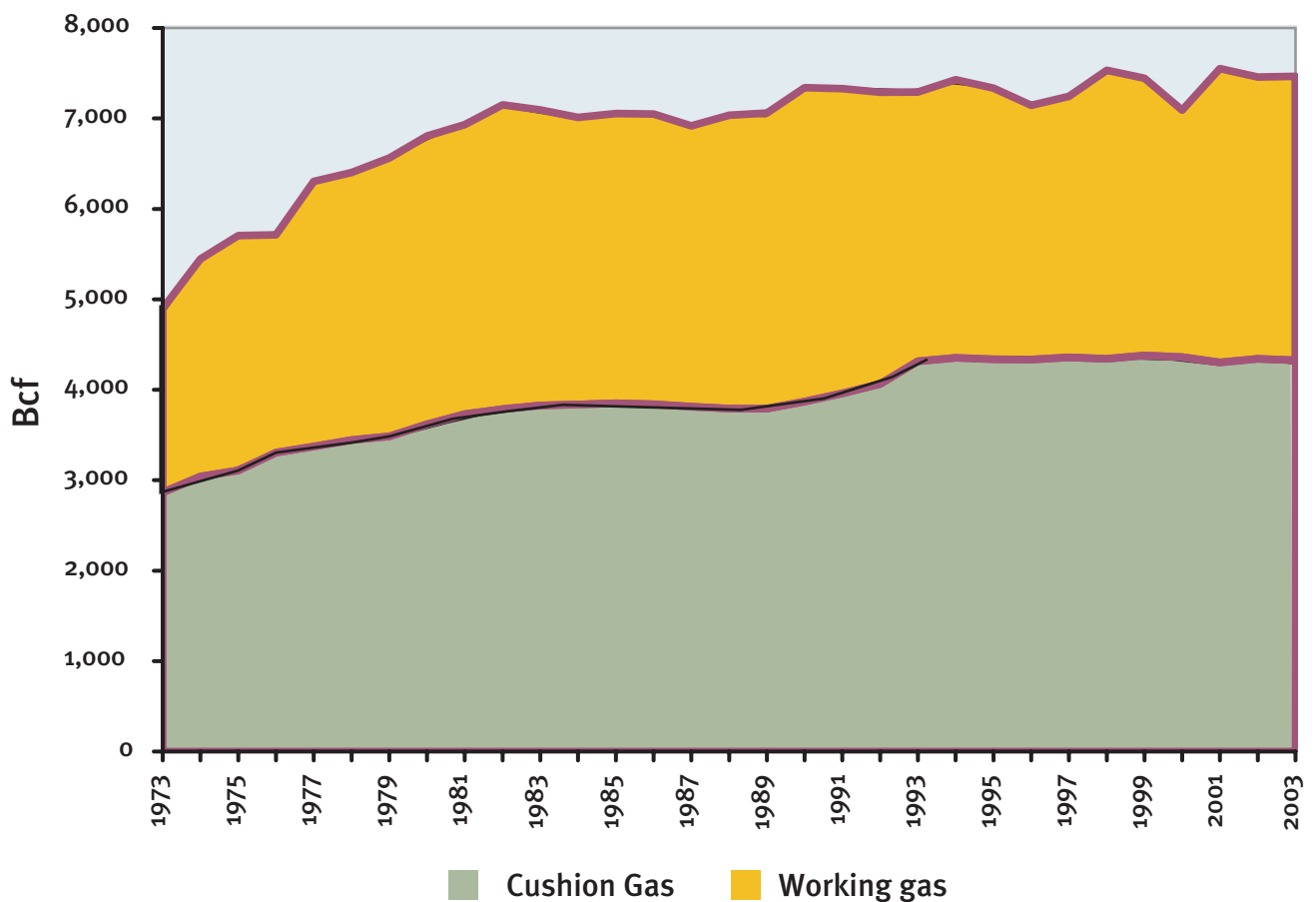
¹¹ Actual total operating capacity reported by EIA monthly (2001-02 withdrawal season). However, the total potential working gas capacity is estimated by EIA to be 3.9 Tcf, thus we would accept that working gas could be 3.5 Tcf to 3.9 Tcf.

pressurize their storage reservoirs to be ready for withdrawal season, which usually begins November 1 each year. As storage reservoir pressures increase, gas-in-place volume also increases and the injection rate declines gradually in late injection season. Therefore, the injection rate is higher at the beginning of injection season and lower at the end of injection season. The withdrawal rate is highest at the end of injection season, when storage reservoir pressure is highest. Storage operators estimate the volume of supply needed for each season and they try to refill their storage fields' working gas capacities based on historical performance levels and match their storage capacities with their customers' requirements. Many storage fields are designed to have some excess working gas capacities and operational flexibility to withdraw some cushion gas, as needed, within the late withdrawal season.

Actual Storage Operating Capacities

As shown below, based on historic EIA data, cushion gas averaged about 54 percent of the total operating capacity from 1975 through 1991. In 1992, cushion gas began to increase, reaching 61 percent of the total operating capacity in 2000. While cushion gas has been increasing, working gas capacity has been decreasing. This increase/decrease of cushion and working gas capacity could represent the reclassification of working gas to cushion gas as a result of open access, as well as maintaining higher storage pressures to support higher withdrawal rates. Also, this supports the need for realignment or re-engineering of existing storage fields to improve the cycling capability of the storage fields and reduce cushion gas requirements if and when higher storage services are needed.

Relative Volumes of Working and Cushion Gas



Source: Graph generated by FERC staff from EIA data

Storage Capacity Summary

Total U.S., storage operating capacity (EIA data) =
7.6 Tcf (actual)
Total U.S., working gas capacity (potential) =
3.9 Tcf (estimated by EIA)¹²
Total U.S., actual operating working gas =
3.5 (1990-1991 withdrawal season)

Total Jurisdictional operating capacities
(staff estimation) = 5.2 Tcf
Total Jurisdictional working gas capacities
(staff estimation) = 2.5 Tcf

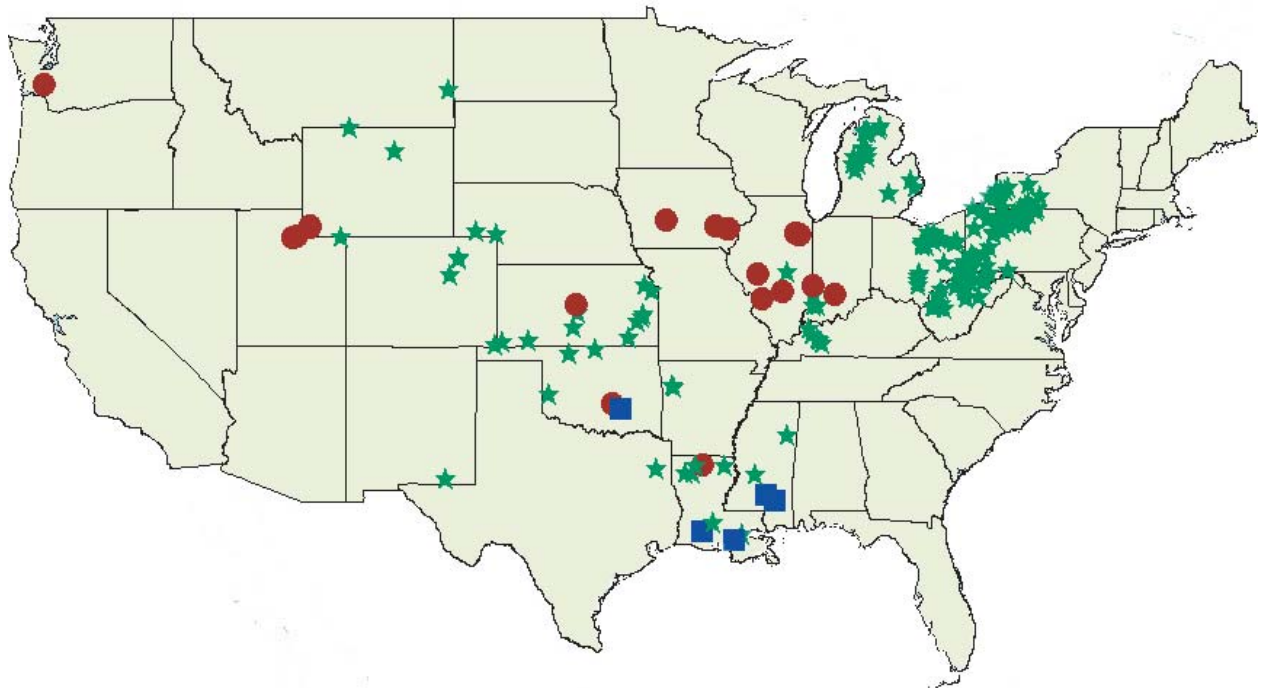
Regional Distribution of Underground Storage

The maps below illustrate the regional distribution of underground storage, which is concentrated in upper Ohio Valley, Michigan, Illinois, Gulf Coast and south central locations. This regional distribution is based on convenient geology, historic natural gas usage patterns and location of depleted oil/gas reservoirs. There are locations in the northeastern United States where there are no depleted oil/gas field, salt domes/formations or natural geological confinements for the development of underground storage fields. While an alternative is the importation and storage of LNG (surface or subsurface), this alternative faces land use and local siting barriers.¹³

¹² EIA, Natural Gas Monthly, 1973-2003, shows estimated working gas capacity of 3.2 to 3.5 Tcf.

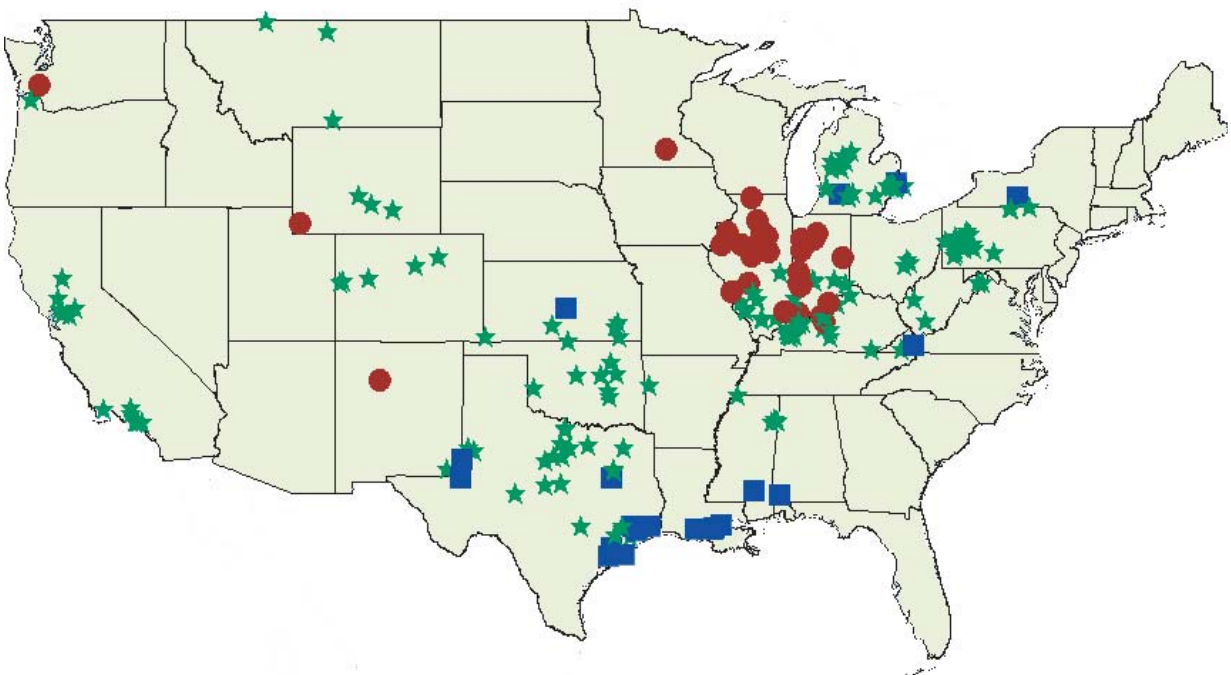
¹³ In addition to the LNG import terminal at Everett, Mass., which has a storage capacity of 3.4 Bcf, there are 46 liquefaction and satellite storage tanks located in Connecticut, Maine, Massachusetts, New Hampshire and Rhode Island owned and operated by LDCs. The total combined storage of peak shaving and satellite storage is 15 Bcf. Cumulative vaporization capacity of these storage tanks, plus that from the Everett facility, is approximately 2.3 Bcf/d, which can supply as much as 50 percent of the region's peak day needs. In addition to the LNG storage, LDCs have 260 propane tanks in New England with a total storage capacity of 1 Bcf of liquefied petroleum gas (LPG). Vaporization from LPG can meet 5 percent of New England's peak day needs. *See also* New England Natural Gas Infrastructure, Docket No. PL04-1-000, December 2003.

FERC Jurisdictional U.S. Storage by Type and Location



★ Depleted Gas Reservoir ● Aquifer Storage Field ■ Salt Cavern Storage

Non-jurisdictional U.S. Storage by Type and Location



★ Depleted Gas Reservoir ● Aquifer Storage Field ■ Salt Cavern Storage

Source: Developed using Platts PowerMap and GasData

The Commission's Role in Underground Storage

Commission Certificates

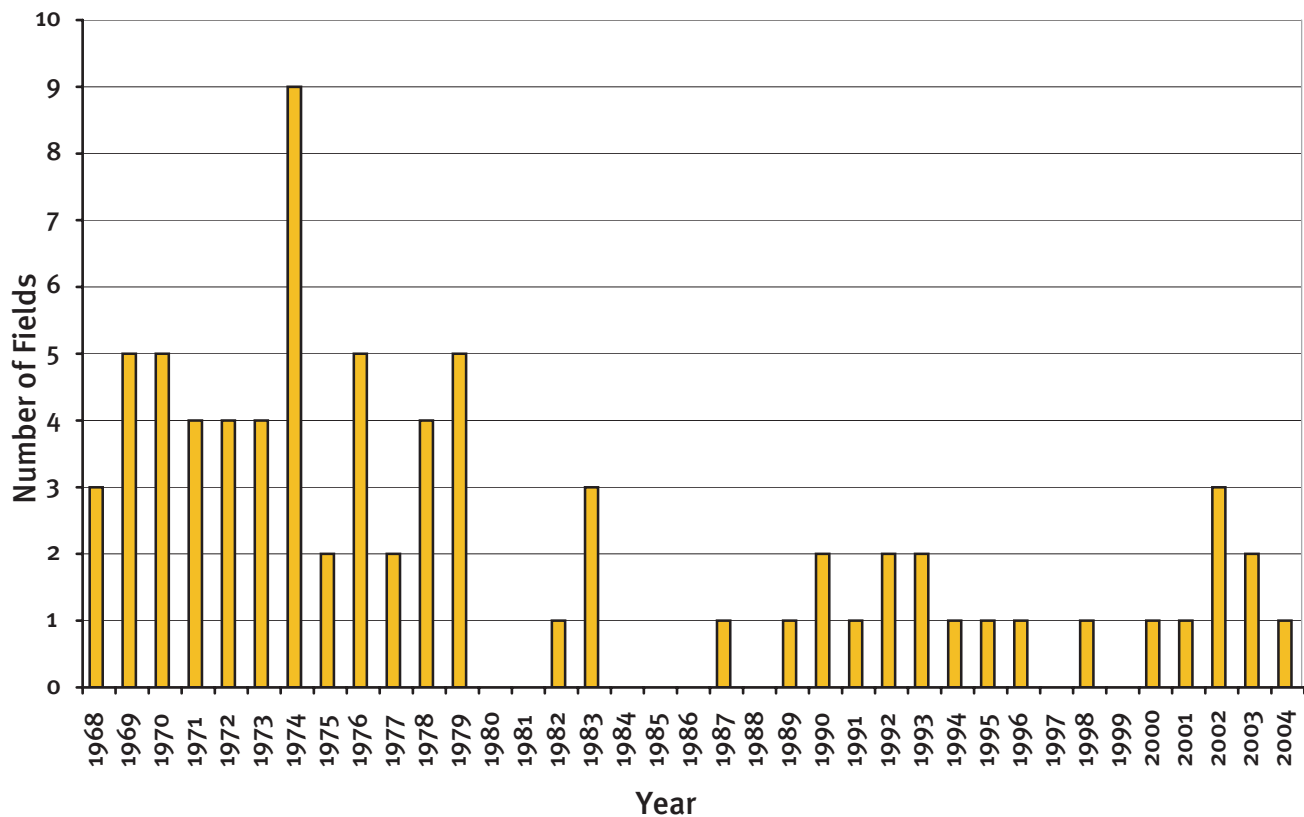
The Commission has jurisdiction over any underground storage project that is owned by an interstate pipeline and integrated into its system. Also, independently operated storage projects that offer storage services in interstate commerce are under the Commission's jurisdiction. The chart below is based on staff's compilation of Commission orders and it shows that the annual number of new storage fields certificated by the Commission has decreased since the 1970s and early 1980s. Beginning in 2002, the new certificated storage fields mostly involved the development of small depleted gas fields and salt cavern storage fields.

Likewise, based on our compilation of applications at the Commission, the number of applications to construct and modify storage facilities has fluctuated from the 1970s through 2004. We attribute the large number of applications during the late 1970s and early 1980s to the industry's reaction to colder-than-normal winters. The current increase in the number of storage applications reflects modifications of existing storage fields (increasing capacity and efficiency) as well as applications by independent storage operators entering the natural gas market as a result of Order No. 636.

Current Commission Cases

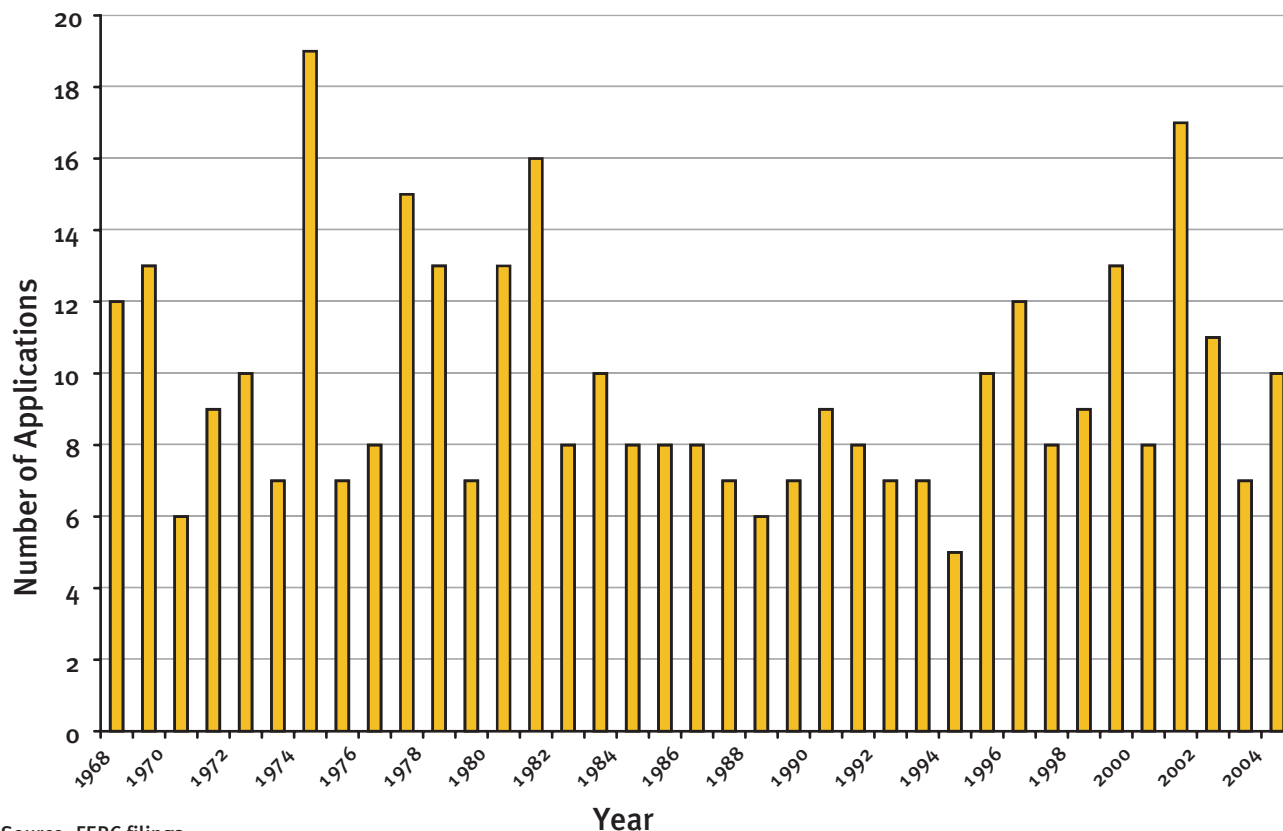
Eleven major interstate storage projects (adding six new storage fields) were certificated since 2002, authorizing

FERC Certification of New Storage Fields by Year



Source: FERC filings

Certificate Applications for Realignment of Storage



Source: FERC filings

the development of 74.7 Bcf of new interstate working storage capacity for the U.S. Of the 74.7 Bcf of new storage capacity, 17.9 Bcf has been delayed or put on hold when compared to the applicant’s originally projected in-service date. Of the 11 storage projects, four projects would add 12.2 Bcf of new storage capacity into the Northeast region, but it is these projects that have been delayed. Two projects have added 12.1 Bcf of new storage capacity in the Midwest and five projects added 50.4 Bcf of new storage capacity in the Gulf Coast/Southeast.

Four storage projects are pending before the Commission; they have a projected capacity of 54 Bcf for the Northeast,

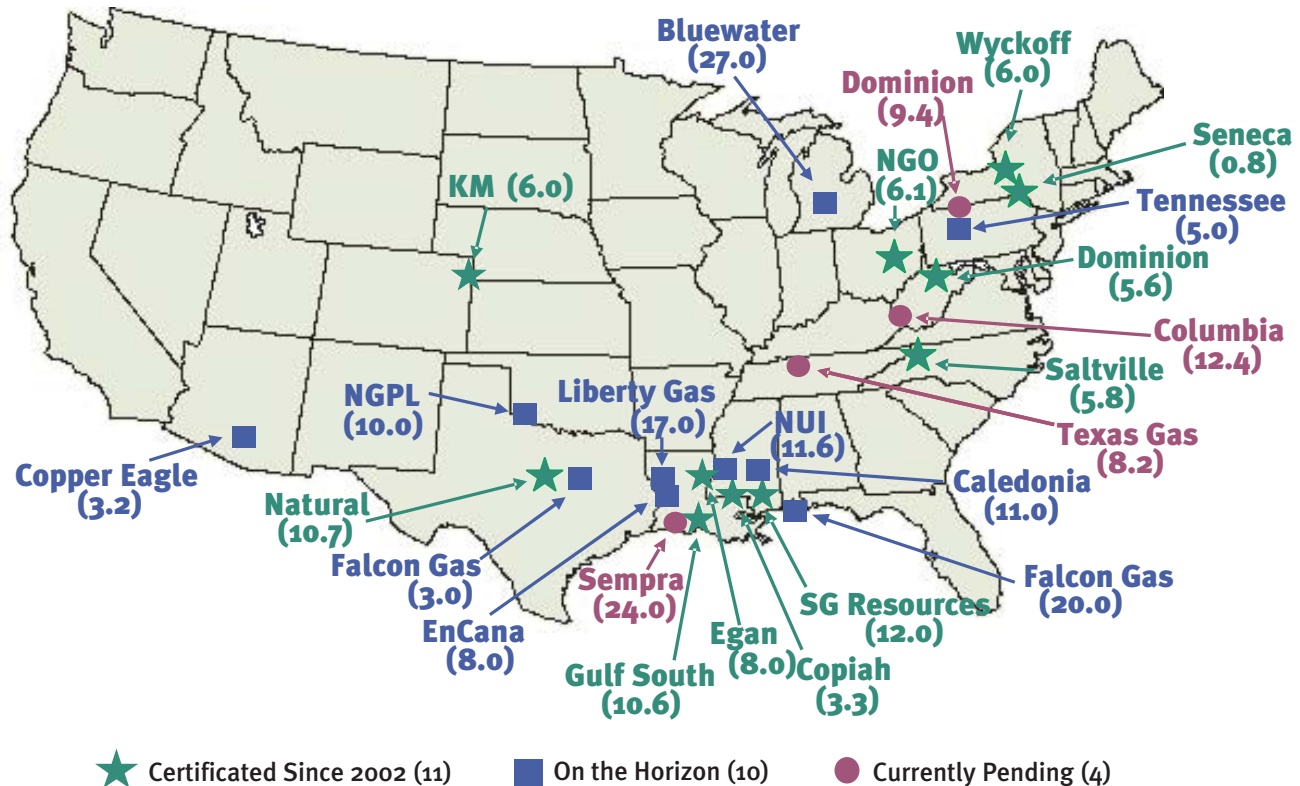
Midwest and Gulf Coast/Southeast regions. The present pending and anticipated storage projects will be required to meet the increasing seasonal peak-day requirements.

Ten publicly announced storage projects are on the horizon with potential storage capacity totaling 115.8 Bcf. Of this amount, 5 Bcf would be in the Northeast, 27 Bcf would be in the Midwest, 53.6 Bcf would be in the Gulf Coast/Southeast and 3.2 would be in the West.

The regional distribution of these approved, pending and on-the-horizon projects is shown on the map below.

Recent Gas Storage Projects

Capacity in Bcf; August 2004



Source: FERC filings and price industry reports

Current Developments Regarding Underground Storage

New Technologies

Current methods of improving storage field efficiency, such as mechanically removing debris, washing, injecting acids and creating new perforations in the well pipe often provide only limited and temporary improvements. New technologies are now being used to improve storage field efficiency:

- To unclog storage wells, a low-frequency/high frequency sound wave device is being used that vibrates the scale off the well pipe.
- There are innovative fracturing technologies, such as injecting high pressure liquid carbon dioxide instead of water or other liquids, to keep clays from sticking and sealing off parts of the reservoir.

- In salt cavern development, operators can chill the natural gas and condense its volume to reduce the size of the storage field and the amount of brine that needs disposing.
- Operators can use “lined rock caverns” in storage facilities, in which a steel tank has been installed in a cavern that has been blasted into the rock of a hill.
- Freezing natural gas in the presence of water creates hydrates, thus allowing for large quantities to be stored in same volumes.
- Operators can use the Bishop Process (TM by Conversion Gas Imports) in which LNG is unloaded offshore, warmed to 40 degrees Fahrenheit and then stored as natural gas vapor in underground salt caverns either onshore or offshore.

More on LNG and Underground Storage

Quantities of LNG imports into the United States have increased almost six-fold from 85 Bcf in 1998 to 507 Bcf in 2003. Should LNG imports grow in the future as projected, more storage facilities (LNG tanks, salt cavern storage and depleted offshore oil/gas reservoirs) will be needed. The DOE is studying a novel method of unloading and regassifying LNG directly from ocean tankers for storage in underground salt caverns. Under the Bishop Process, LNG would be received directly from an offshore tanker, regasified, pressurized and warmed to 40 degrees F, then injected into underground salt caverns. A DOE study identified more than two dozen potential sites that had suitable salt formations, sufficiently close proximity to existing pipelines and navigable water.¹⁴ This process would eliminate the need to build expensive aboveground cryogenic storage tanks. A combination of the Bishop Process with the construction or conversion of existing offshore depleted gas fields, platforms and lines could also be a means to import, store and transport LNG. There are many offshore depleted gas fields that could be used for this purpose.

Problems with Underground Storage Projects

A few storage projects have been canceled, delayed or placed on hold due to market concerns, environmental

issues and rate issues. Specifically, storage projects have been placed on hold until the market improves or have been cancelled due to a lack of market interests. Environmental concerns such as brine disposal used in the development of salt caverns and land use have been raised. Storage projects have incurred funding problems and cost concerns, and some projects have been cancelled or delayed due to pipeline infrastructure problems. With the denial of market based rates for storage projects by the Commission, certain storage proponents believe cost-based rates may not provide adequate incentives to attract the investment necessary to develop the proposed storage facilities.

Need for More Storage

Estimations of the need for more storage first require projections of national and regional natural gas supply and demand. Then one must estimate the future expansion of natural gas transmission and distribution to gauge how much more storage might be needed to meet seasonal and peak deliverability demands. The price of natural gas and the price volatility also affect the need for storage and such factors also need to be estimated. The NPC gas study and other sources have estimated a need for additional storage in the United States and Canada of up to 700 Bcf by 2025. This has been projected on a regional basis by work sponsored by The INGAA Foundation, as follows below:

New North American Gas Storage Requirements

Incremental Working Gas Capacity in EEA Base Case	2004-2008			2009-2020			Total		
Western Canada	30 Bcf			40 Bcf			70 Bcf		
Eastern Canada/Michigan	36 Bcf			74 Bcf			110 Bcf		
Midwest	–			60 Bcf			60 Bcf		
New York	10 Bcf			56 Bcf			66 Bcf		
Pennsylvania / West Virginia	33 Bcf			90 Bcf			123 Bcf		
Gulf Coast	72 Bcf			5 Bcf			77 Bcf		
West Coast	21 Bcf			78 Bcf			99 Bcf		
Other	10 Bcf			37 Bcf			47 Bcf		
Total	212 Bcf			439 Bcf			651 Bcf		

Source: Energy and Environmental Analysis Inc, *At the Crossroads: Crisis or Opportunity for Natural Gas*

¹⁴ See <http://www.fe.doe.gov/programs/oilgas/storage/index.html>.

Staff Observations on the Current State of Underground Storage

Natural gas storage is in better shape this year than last. From a national perspective, we have adequate storage volumes in place in the United States at this time to cover normal conditions. The EIA's "Weekly Natural Gas Storage Report" divides U.S. underground gas storage into three regions: East, West and Producing. As of September 9, the United States had 257 Bcf more in storage than at this time last year and 183 Bcf more than the five-year average for this time of year. If storage injection continues at its current pace, there should not be any problem in refilling working gas storage to the previous year's level (3,155 Bcf on October 31, 2003) and the storage fields should be full and pressurized to their designed levels.

In recent years, however, relatively few new storage fields have been built. Also, there has been an abandonment of a number of old, inefficient, and uneconomically operated underground gas storage fields. Traditionally, underground storage fields were designed to meet peak seasonal demands. Today, especially with the proliferation of gas-fired electric plants, storage facilities are increasingly expected to meet rather dramatic daily or even hourly swings. Thus, storage operations are changing with changing market characteristics. The load profile has changed for natural gas customers over the past few years, and gas supply now is required – sometimes quickly – throughout the year rather than merely meeting peak seasonal demands. Therefore, storage fields with high injection and withdrawal capabilities are becoming the main choice for many storage operators. The traditional marketplace now values highly diversified types of storage services and has increasingly sought storage that rewards flexibility, safety and reliability. This is the main reason why storage operators are re-engineering and conducting detailed studies of their storage fields to see how they can improve the performance

of existing storage facilities. Storage field re-alignments are being implemented to increase working gas capacity within existing fields and to reduce cushion gas requirements, which results in increases in deliverability.

Since 1968, there have been many applications for the realignment of old storage fields. Storage operators have modified old storage designs, incorporated new design procedures and constructed surface and subsurface facilities. These modifications include drilling large-diameter wells, relocating wells within reservoirs, incorporating coil tubing drilling (CTD)¹⁵ and horizontal well drilling and completing larger diameter wells. Additionally, storage operators are adding compression, dehydration facilities, and new gathering lines. Operators are also using new technical procedures to better understand reservoir geology, confinement and reservoir flow behaviors, abandoning uneconomical facilities and incorporating new storage operational procedures.

Storage field modifications have generally provided new operational capability for storage operators to recycle more working gas efficiently. By cycling working gas during both injection and withdrawal seasons, the storage operator is able to confine the storage gas, better define geological parameters, reduce gas migration/loss, increase efficiency and reduce operational cost. Finally, a few storage fields' working gas volume has increased and cushion gas volume of those same fields were reduced.

On balance, through realignments or re-engineering procedures, injection/withdrawal capability has increased without any significant increase in total storage operating capacity. In fact, data indicate that the total U.S. storage operating capacity (jurisdictional and nonjurisdictional) has remained about the same over the past few years. Thus, the recent trend in storage field construction activity has predominantly been the modification and realignment of existing storage fields to meet changing market demands rather than a dramatic increase in

¹⁵ CTD is used in existing storage reservoir when the conventional well enhancing techniques (hydraulic fracturing, acidizing and/or re-perforating) for enhancing well performance have not proved to be effective.

construction of new storage fields. During the past 10 years, there has been a significant increase in the ability to move gas in and out of storage.

It is the staff's technical opinion that prudent operational procedures and realignment of storage facilities within the past few years by storage operators have resulted in better use of storage capacity. Storage operators have modified their storage facilities and improved storage capabilities with different types of storage operations and services than offered in previous years. In staff's view, in the future, storage operators will construct a limited number of storage facilities on an as-needed basis. However, these projects will tend to be highly selective, taking advantage of particularly advantageous locations or highly favorable geological characteristics.

Historical storage engineering and operational data indicate that not all working gas has been recycled in many storage fields. There are many old storage fields that could and should be redesigned and realigned by incorporating new technology, reducing cushion gas volume, increasing working gas volume and increasing efficiency of storage operation by recycling more working gas. All these new designs and modifications will improve operational capability and reduce operational costs without necessarily increasing the total certificated storage capacity. It is advantageous environmentally and also more cost effective to improve the cyclic capability of existing underground field than to construct a new depleted oil/gas field. It is important to recognize that steadily increasing storage demands will not necessarily be met with large investment in new storage fields in the United States.

The level of total gas storage capacity has been relatively flat for a number of years. During the past few years we have seen an average of only one or two new underground gas storage certificated per year. However, the National Petroleum Council's projected need of up to 700 Bcf of

new working storage capacity by 2025 discussed above can be met by the construction of only 35 Bcf of working capacity per year over the next 20 years. The industry appears to be close to meeting or surpassing this goal based on the storage projects that we have approved, have pending before us or are expecting to be filed in the near future. While several old storage fields have been abandoned, others have been sold for less-active local uses. However, over the past 10 years the Commission has authorized many storage realignment applications to improve injection/withdrawal and operational capability of existing storage fields.

Storage Economics

Successful storage infrastructure investments, as with all private sector capital expenditures, must provide attractive financial characteristics. Many investment measures are used by industry to evaluate the commercial viability of projects including, although not limited to, net present value and internal rate of return. These techniques provide different indicators of a project’s merit but fundamentally each is a measure of cash flow benefits relative to capital expenditures and operating expenses. Independent, unregulated storage projects will generally be expected to have returns on equity exceeding 20 percent while jurisdictional storage projects will typically have equity returns between 12 percent and 15 percent. The higher return for unregulated projects, often salt-cavern based, is due to the perceived market, geologic and development risks.

Capital costs and cash flow, and hence, the economic attractiveness of storage, depends upon the physical characteristics and capabilities of a particular storage field, the services to be provided and to a lesser extent, regulatory regimes. Development costs vary greatly by the type of storage and its performance characteristics. The projected revenue and cash flow benefits differ for facilities designed to ensure seasonal supply reliability and meet daily or intra-day demand swings as compared to capturing commodity arbitrage opportunities. Further, regulators can restrict the ability of storage projects to realize profits or, conversely, guarantee profits.

Consistent with the physical perspective that storage amounts nationally are generally adequate and the requirement for new storage is more of a chronic versus acute need, the economics for new storage development are not robust, with the exception of expansions of existing fields. In particular, high-deliverability storage projects that could serve to mitigate price levels and volatilities as seen during the price spikes of 2003 and 2004 have particular challenges in matching value to capital costs.

Storage Development Costs

Among the three types of storage fields (salt cavern, depleted reservoir and aquifer), salt caverns are generally the most expensive to develop on a capacity basis. However, because salt cavern storage can be cycled many times (up to 12 times for some facilities), on a deliverability basis it can be less costly than other types of storage facilities.

A typical 6-12 cycle Gulf Coast salt cavern can cost upwards of \$10 million/Bcf of working gas capacity and is higher in other regions, with Midwestern facilities the next most expensive, followed by the Rockies, the Northeast and finally California and the Pacific Northwest. A typical 2-cycle depleted reservoir field can cost between \$5 million and \$6 million/Bcf.¹⁶ The following table summarizes broad ranges of development costs.

Development Cost of Working Gas Storage

Type	Development Costs Per Bcf of Working Gas Capacity
2-Cycle Reservoir	\$5 - \$6 million
6-to-12 Cycle Salt Cavern	\$10 - \$12 million As much as \$25 million
Gulf Coast Northeast and West	

Source: Industry sources

¹⁶ Industry sources

Generalizations aside, costs are site-specific based on:

- the quality and variability of the geologic structure of the proposed site;
- the amount of compressive horsepower required;
- the type of surface facilities needed;
- the proximity to pipeline infrastructure; and
- permitting and environmental issues.

Significant project development effort must be done before a storage site is located and planned, increasing the risk of project delays and cost overruns.

The cost of base gas is one of the most expensive elements of a storage project. As a rule of thumb, the total capacity of depleted reservoirs normally consists of 50 percent base gas. Expansions of existing reservoir storage, however, can significantly reduce the need for base gas. Total aquifer storage field capacity is made up of between 50 percent and 80 percent base gas. A salt cavern storage field typically requires 25 percent base gas. However, leaching and brine disposal costs for salt caverns are high. This is due to the large amounts of water needed to leach a salt cavern and the environmental problems associated with disposing of the brine during the leaching process.

The majority of recent storage projects involve re-working and expanding older high-quality depleted reservoirs to generate higher deliverability using new technologies such as horizontal drilling. These projects minimize development costs by leveraging the existing infrastructure and avoiding many environmental issues.¹⁷ In addition, field performance is easier to judge because the characteristics are already known.

The table in the next column summarizes recent examples of storage development costs.¹⁸

Gas Storage Development Costs

	Gulf Coast Salt Cavern	Northeast Reservoir Storage
Capacity (BCF)	5	9.4
Deliverability (MMcfd)	500 (est.)	147
Base Gas Cost (\$ Millions)	12	3.2
Total Development Costs (\$ Millions)	65	39.5

Source: Dominion Resources, Inc, CBI Storage Conference, Feb. 23-24, 2004

The Value of Storage

The value of storage will depend on what function storage provides with different purposes, for instance, for reliability of supply, imbalance management, seasonal arbitrage and trading. Storage operators and customers have developed sophisticated techniques for valuing storage based on option theory. Consistent with the variety of storage uses are a range of valuation approaches that include:

- Cost of Service Valuation;
- Least Cost Planning;
- Seasonal Valuation (Intrinsic); and
- Option-Based Valuation (Extrinsic).

Cost of Service Valuation

Cost-of-service is used to value services offered by regulated storage providers such as interstate pipeline

¹⁷ CBI Storage Conference, Houston, Texas, February 23-24, 2004.

¹⁸ Dominion Application, CBI Storage Conference, February 23-24, 2004.

companies. It allows for recovery of costs and a return on capital. Published rates and tariffs are maintained. Services priced in this manner include firm storage service, no-notice storage service, interruptible storage and parking and lending services. Based on a review of 20 storage operator tariffs, the median cost-of-service rate per Dth of annual working gas capacity for firm storage service is \$0.64.¹⁹ A summary of the tariff rates is provided in Appendix A.

Most cost-of-service regulated storage is reservoir storage. A cost-of-service rate for high-deliverability salt cavern storage would be much higher than traditional storage. As a hypothetical example:

- Capital cost = \$60 million for a 5-Bcf Gulf Coast cavern
- Annual Cost of service = \$14.63 million²⁰
- Unit storage cost = \$2.93 per Mcf per year

Seasonal Valuation

The seasonal valuation of storage is called the intrinsic value. It is the difference between the two prices in a pair of forward prices and does not include trading benefits. This strategy, based on locking-in forward spreads, is simple to execute, both financially and physically. The seasonal spread for next winter is demonstrated in the following table.²¹

Monthly Contract Values for Natural Gas Futures

Delivery Month	Forward Price
Jul-05	5.933
Aug-05	5.955
Sep-05	5.950
Oct-05	5.985
Nov-05	6.225
Dec-05	6.438
Jan-06	6.578
Feb-06	6.538
Mar-06	6.380

Source: Derived from New York Mercantile Exchange data

The differential for July 2005 to January 2006 is $(\$6.578 - \$5.933)/(1.05) = 62¢$ as of September 3, 2004, and assuming one year of discounting at 5 percent (thus, the denominator of 1.05). More conservatively, the seasonal spread assuming average values over the entire injection and withdrawal periods would be approximately 47¢. The more conservative estimate uses average prices for the seven-month injection and five-month withdrawal season as compared with using the highest and lowest values.

While the spread is 47¢-62¢, for the 2005-05 winter the spread going into the current winter widened to \$1.84 for October 2004 to January 2005. This differential was high by historical standards and was largely the result of falling October prices rather than increasing January prices; January prices remained relatively stable during this period. This appeared to reflect an adequate supply of gas in the market due to a mild summer with reduced cooling demand. In terms of ability to store excess production, if more storage capacity were available at these prices, it's likely that gas would have been injected into it and prices wouldn't have fallen so much. Eventually, this would have resulted in a reduction in January prices under "normal" weather expectations, or increased reliability to handle extreme demand situations. However, with regard to the planning horizon for storage development, developers would look to next year's prices and beyond to economically justify projects as compared to a short-term spread of three to four months.

Historical seasonal spreads for a variety of locations are shown in the following chart.²²

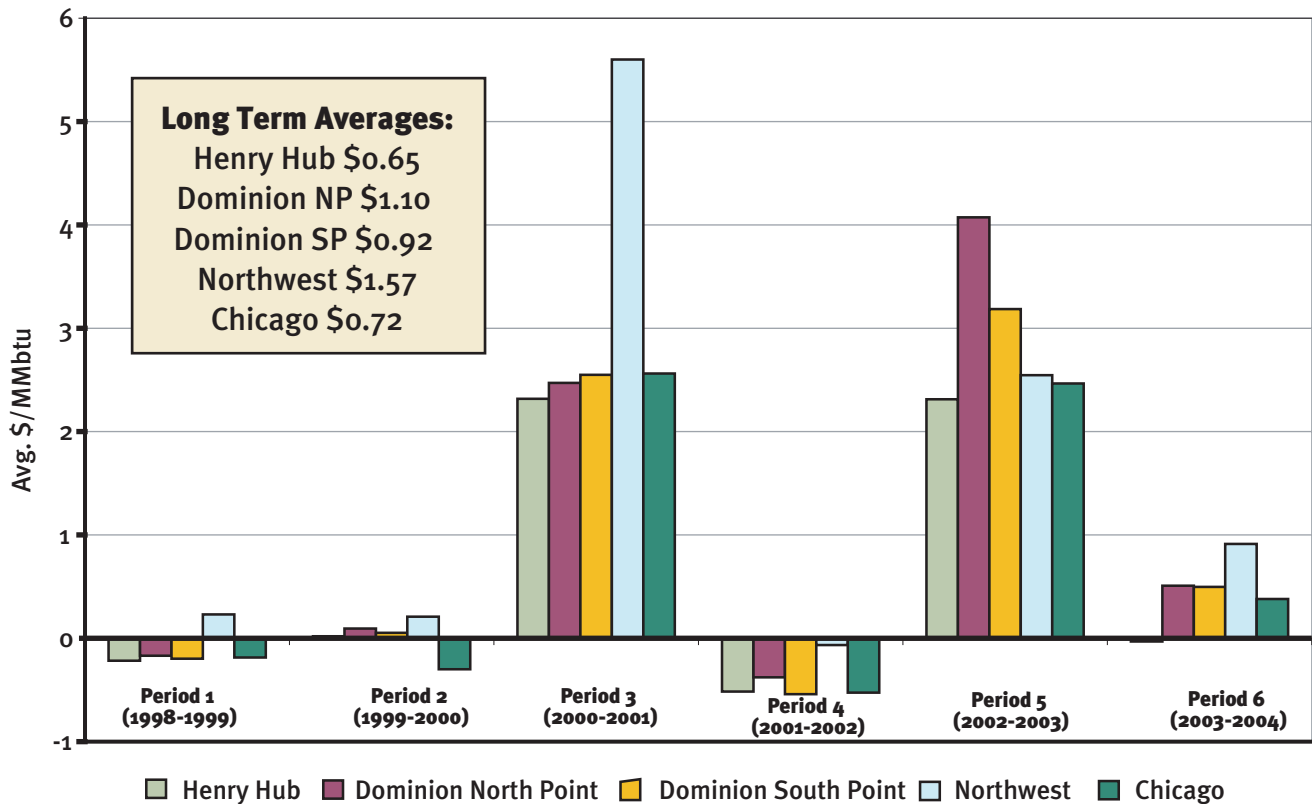
¹⁹ Staff review of rates and tariffs as maintained on informational postings.

²⁰ Staff calculation assuming: return on equity of 13 percent, debt cost of 8 percent, 50/50 debt/equity ratio, 34 percent federal tax rate, 3 percent state ad valorem tax, 20-year book life and 10-year tax life.

²¹ Staff analysis of September 3, 2004, settlements on the New York Mercantile Exchange (Nymex).

²² Staff analysis of *Gas Daily* data, nominal values.

Average Gas Price Differentials Between Summer and Winter Seasons



Source: Derived from Platts Gas Daily data

Option-Based Valuation for High-Delivery Storage

High-deliverability storage provides trading benefits that increase with the number of turns, or cycles, per year. This is often referred to as the extrinsic value of the storage and is in addition to the intrinsic value.

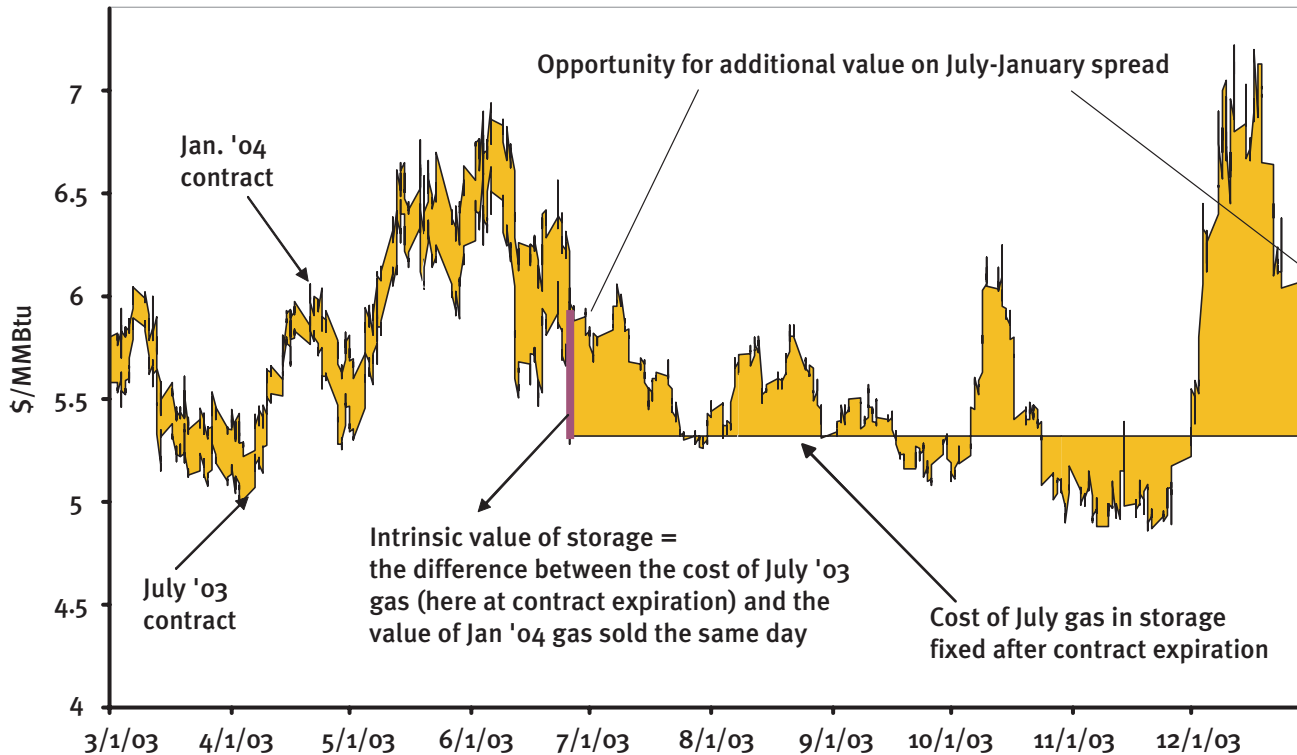
The premium of extrinsic value is similar to a call option on a time spread, increasingly so for a high delivery facility.

This gives storage holders the opportunity, although not the obligation, to inject at one time and withdraw at another time. Similar to any option, the value is proportional to forward prices, price volatility, strike price and time to expiration.

The chart on the following page illustrates the difference between extrinsic and intrinsic values.

Difference Between Intrinsic and Extrinsic Value of Natural Gas Storage

Nymex Gas Contracts, July 2003 and January 2004



Source: Based on New York Mercantile Exchange data

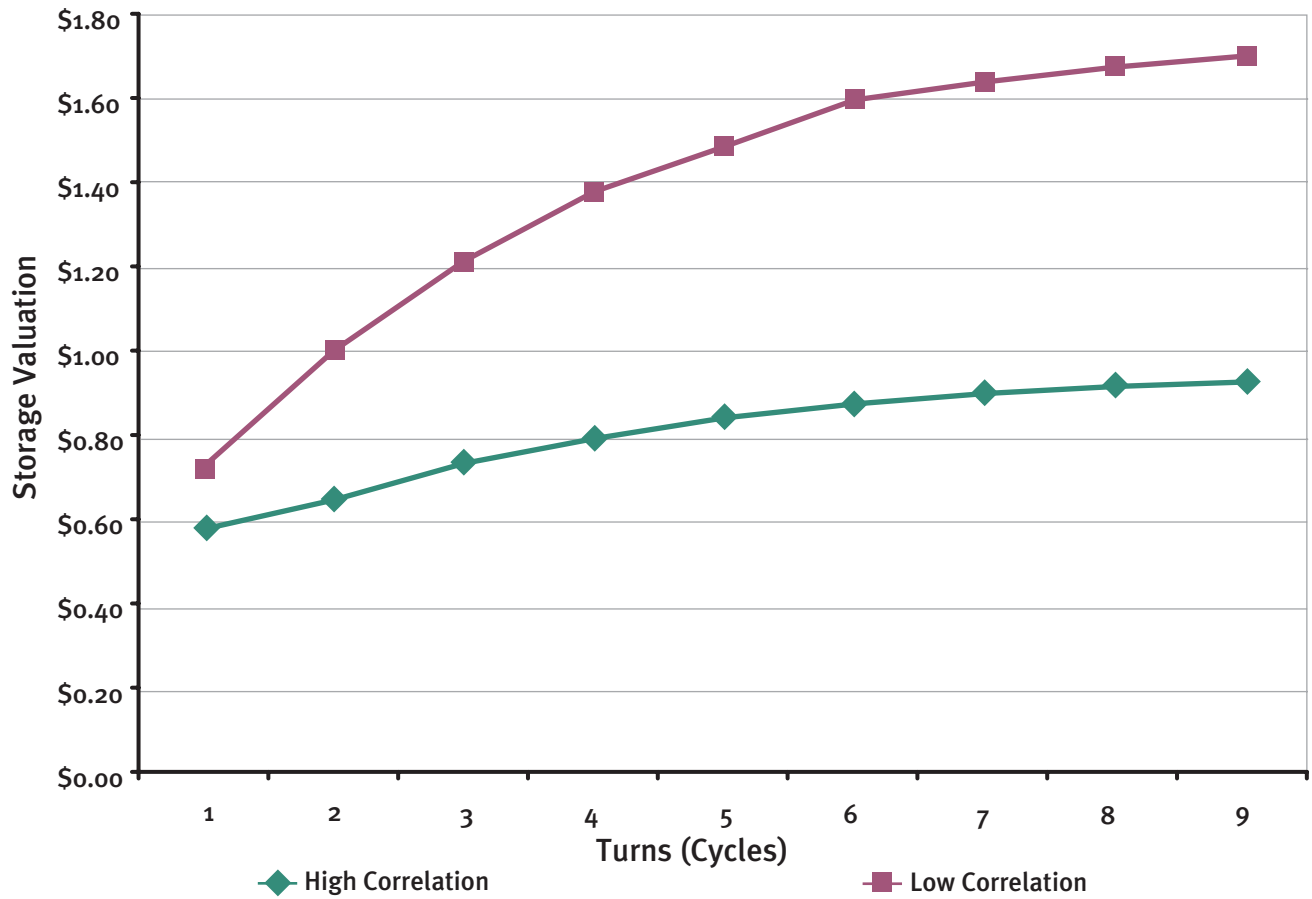
If all opportunities for injection and withdrawal are successfully exploited, the value of the multiple-turn facility will be several times the value of a single-turn facility with no opportunities to take advantage of market prices. Current, average estimates of extrinsic values in the Gulf Coast range from \$1.00 for a three-turn facility to \$1.30 for a nine-turn facility, resulting in total storage

valuation, including both seasonal arbitrage and extrinsic trading benefits, of approximately \$1.60 to \$1.90 for the three-turn and nine-turn facilities, respectively.

The chart on the next page demonstrates the extrinsic value as compared to storage cycles.²³

²³ The extrinsic value is determined by not only the spread between future prices for injection periods and future prices for withdrawal periods, but also by the volatility of prices along the natural gas futures curves curve and the degree to which the individual months move together as measured by correlation. The more volatile and less correlated the prices for individual months are, the greater the probability that the spread between prices for an injection month and a withdrawal month will widen. This in turn increases a storage facility's potential profitability.

Extrinsic Value of Natural Gas Storage



Source: Analysis of New York Mercantile Exchange forward prices and Bloomberg data

Least-Cost Planning

Least cost planning is storage valuation as typically performed by local distribution companies and other large-volume gas customers. Storage is valued by considering the savings resulting from not having to use a more expensive option. There is a wide range of valuations that are highly dependent upon a gas consumers' load profile. The following hypothetical load duration curve illustrates least cost planning.

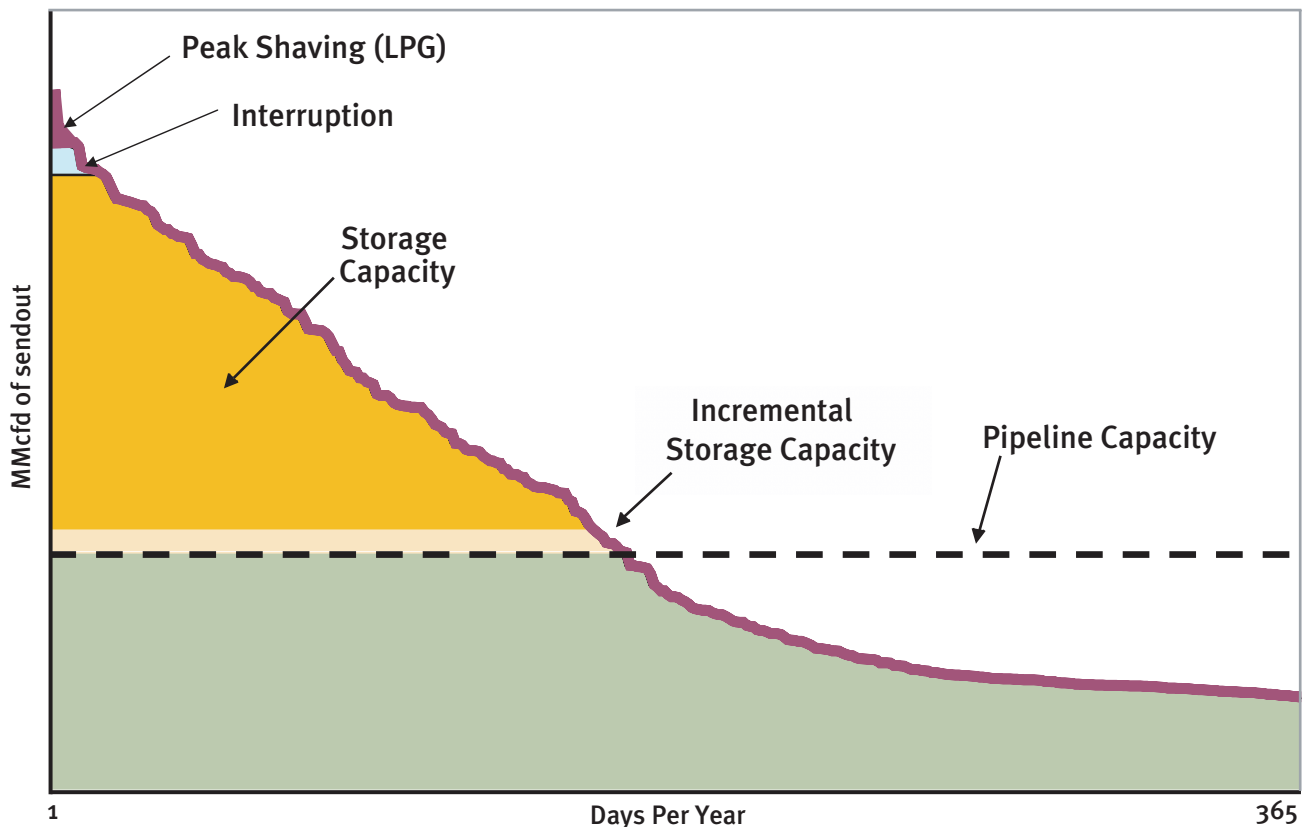
Using this evaluation technique and assuming the incremental storage capacity is priced relative to long haul

pipeline capacity, the unit value for market area storage given a 50 percent load factor is 70¢ to \$1.10.²⁴

Economic Summary and Conclusions

A summary of current, alternative valuations, depending on use of the facilities, and based on the proceeding analyses, is shown below. These approaches are not mutually exclusive, all of them are currently in use, and most prudent customers will use some combination in quantifying value.

Least Cost Planning for Gas Storage



Source: Based on representative industry data

²⁴Does not take into account additional transportation capacity to make storage comparable to pipeline delivery. Chart is an illustrative load duration curve.

Varying Costs of Gas Storage

Type	\$/Mcf of Working Gas
Storage Median Cost-of-Service	\$0.64
Storage Seasonal Spread (Intrinsic) for Winter 05/06 as of August 2004	\$0.47 to \$0.62
Least-Cost Planning (Generally Applies to Reservoir Storage)	\$0.70 to \$1.10
Salt Cavern Hypothetical Cost-of-Service (Gulf Coast)	\$2.93
Salt Cavern Market Value (Intrinsic plus Extrinsic Gulf Coast)	\$1.60 to \$1.90

Source: Summary of industry and financial data cited in this report

Seasonal spreads, ranging from 47¢ to almost 62¢ for the winter of 2005-06 as of September 2004, are comparable to the cost expansions of reservoir storage, and indicate storage supply and demand are reasonably in balance on a national level. However, storage may be the best way of managing gas commodity price volatility under more extreme weather conditions, so the long-term adequacy of storage investment depends on how much price volatility is considered “acceptable”. The public policy interest in volatility mitigation may be different than wholesale market valuations.

Although storage costing less than or near its intrinsic or seasonal arbitrage value will always be fully subscribed, the market value of storage relative to its costs currently does not provide incentives for most independent storage development. Project economics are a challenge for salt cavern storage. At a market value of approximately \$1.60 to \$1.90/Dth/year, it is difficult to justify developing salt caverns outside of the low-cost Gulf Coast. Project developers are not likely to achieve a cost-of-service comparable returns that would require a rate approaching \$3 in the Gulf Coast and much higher elsewhere where development is more expensive.

The financial and regulatory circumstances of storage customers can hinder storage development. Even if a proposed new storage facility is economic, state regulatory policies may inhibit its development. Because state regulators exercise prudence reviews for cost recovery of

new storage facilities, it may be easier for local distribution companies to simply purchase gas at index rather than invest in facilities to mitigate volatility. Thus, many local distribution companies do not see the value of entering into storage contracts that reflect extrinsic value. The Arizona Corporation Commission (ACC) recently released a policy statement embracing the need for new storage capacity and may be amenable to addressing this problem by altering the incentives to contract for storage service.

The loss of a vibrant trading sector means fewer customers will pay for the trading benefits of storage. For instance, one developer said he would be lucky to get \$1 for storage valued intrinsically and \$1.60 extrinsically. The market will often only pay for 50 percent of the extrinsic value to account for the likelihood of not being able to realize the full value.

Electric generators can use inexpensive pipeline imbalance management that makes third party storage less attractive as an alternative. Park and loan rates are typically less than 20¢ per day and more palatable to independent electric generators, especially given their weak credit and inability to make long-term commitments to storage. Finally, at high gas prices, base gas becomes a barrier to entry for reservoir storage development and also provides incentives to abandon existing fields to sell the base gas.

POSSIBLE OPTIONS FOR STIMULATING UNDERGROUND STORAGE DEVELOPMENT

In prior sections we discussed how underground natural gas storage is a valuable resource that can ensure service reliability, serve as a substitute for gas transmission and thereby reduce overall delivery costs, and through hedging help moderate gas commodity price volatility. By all accounts, demand for the natural gas resource will continue to grow over the next 20 years, particularly with respect to gas-fired electric generation. Gas storage development is an essential element of the infrastructure that will be necessary to reliably and efficiently serve these new demands.

While current and projected storage development is keeping pace with aggregate storage demands, underground storage development in some market areas, such as the Southwest and New England, has been virtually non-existent. Few new projects in the Southwest have been proposed and several have failed or face significant opposition.²⁵ The geology in these areas is also not favorable to large scale underground storage development, and competition from pipeline expansions and LNG development may be dampening demand for new underground gas storage. Further, state unbundling initiatives limit the ability of LDCs, the traditional purchasers of storage services, to renew or enter into new contracts for long-term storage service, primarily due to uncertainty over cost recovery at the local level and to stranded cost considerations. Additionally, in the Southwest, until the Commission reformed services on the El Paso Natural Company system to put in place firm contract demand levels for all of its customers,²⁶ market signals for new storage services were virtually non-existent. Almost all gas service in the East-of-California market was provided on a full requirements basis and El

Paso had no daily penalties for service imbalances. As a result, El Paso's customers had no need to individually contract for storage services to meet peak demand or pipeline balancing requirements.

Some independent storage developers, such as Red Lake, assert that storage development is considerably more risky than pipeline construction primarily because of the inability to secure similar long-term contractual commitments. They assert that in contrast with new pipeline construction, where contract commitments are typically in the 10 to 20 year range, contract commitments for storage service exceeding a 1 to 5 year range are rare. They contend that traditional cost-based storage rate design will not encourage further development of storage due to the evolving and risky nature of storage services, the fact that the primary users of these new services (e.g., daily and intraday balancing, and commodity arbitrage) are often not the traditional creditworthy LDCs, and that traditional cost-based rates do not reflect the value of service on peak, and do not reflect rates of return that adequately account for the risky nature of these investments. Additionally, they imply that affiliated storage development has subtle, and in some instances, tariff advantages over storage provided by independent third parties, which may lead to increased costs and service inefficiency for all customers. According to Red Lake, the best and preferred way to permit them to fairly compete and recover their costs is through the flexibility of market-based rates. Pricing schemes short of market-based rates may provide too little flexibility and shift too much risk to independent storage providers to encourage storage development.

²⁵ The Red Lake storage project failed after being denied market-based rate authority for failing the Commission's market power test. The Desert Crossing storage and transportation project failed due to environmental issues and the contract support that did not materialize. The developers of the Copper Eagle storage project failed to secure contractual support and have sold development rights to the project to El Paso Natural Gas Company (El Paso). El Paso has yet to overcome local opposition to the project, secure contractual commitments and file for certificate authorization. Additionally, no LDCs in these areas have pursued development of storage projects, which could be another indicator of demand for new storage.

²⁶ See *El Paso Natural Gas Co.*, 99 FERC ¶ 61,244 (2002); *El Paso Natural Gas Co.*, 100 FERC ¶ 61,285 (2002); *El Paso Natural Gas Co.*, 104 FERC ¶ 61,045 (2003).

It is not entirely clear as to why, but the paucity of underground storage project development in some areas of the country may simply be attributable to market forces and alternative service options. Whether regulatory policies act as unnecessary barriers to further storage development is a question that merits further inquiry. Traditional cost-based storage service rate design, which prices service on an average basis, may not accurately reflect the value of service in peak periods; and rates of return on equity may not reflect today's risk and shareholder expectations, or may no longer be appropriate for new storage services at all. The Commission's test for authorizing market-based rates may not accurately capture or measure the market power of storage providers generally, or more narrowly of independent storage providers. Also, pipeline services and tariff requirements, as well as certificate applications filing requirements and procedures, may be seen as a barrier to entry and development.

Discussed below are various rate, service, tariff and policy approaches the Commission could take to encourage the development of additional underground storage projects. These include: (1) options to traditionally developed cost-based rates and incentive rates, as well as options for periodic cost and revenue review; (2) market-based rates for all new entrants; and (3) Commission policies to increase service options or reduce costs.

Cost-Based Rate Options for Storage Development

Peak/Off-Peak Rates and Term Differentiated Rates

The current storage rate design policy was developed for storage service with a single yearly cycle of injection and

withdrawal. This rate design policy is known as the Equitable method. Under this policy, 50 percent of a project's fixed costs are collected based on storage deliverability and fifty percent are collected based on storage capacity; no return on equity and related taxes are permitted in the variable rate component (injection and withdrawal charges). Furthermore, injection and withdrawal charges are designed to recover only variable costs. Potential storage providers fear that under this rate design, capital costs will not be recovered,²⁷ i.e., uniform monthly rates do not adequately reflect variations of service value, and may result in underrecovery of costs in periods of low demand.

In Order No. 637²⁸ the Commission recognized that traditionally-designed rates with uniform maximum prices permit short-term service customers to purchase capacity at prices that may be lower than the market value of the capacity, while off-peak capacity may go unused without discounting. The Commission found that flexible peak/off-peak or seasonal rates based on value of service concepts (rather than specific costs), promotes allocative efficiency by providing more efficient pricing signals. Under this approach, customers that value capacity more highly should be expected to pay higher prices when capacity is scarce. Conceptually, peak/off-peak or flexible rates may be designed in any number of ways. For example, the value of service between peak/off-peak may be determined using price differentials between specified points. Alternatively, load factors or other measures for attributing value may be used. However, under this approach, any increase in rates at peak must be offset by decreases in off-peak rates, such that the annual revenue requirement is not exceeded. This ensures that the rates remain cost based.

²⁷ See *supra* note 5.

²⁸ *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs., Regulations Preambles, 1996- 2000 ¶ 31,091 (2000), *order on reh'g*, Order No. 637-A, FERC Stats. & Regs., Regulations Preambles, 1996- 2000 ¶ 31,099 (2000), *order denying reh'g*, Order No. 637-B, 92 FERC ¶ 61,062 (2000), *aff'd in part and remanded in part*, *Interstate Natural Gas Association of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002).

While an annual revenue cap would limit the rates the storage service provider may charge, it should allow storage providers considerable flexibility to develop rates that would allow full recovery of costs and encourage entry into the market. Additionally, these flexible rates would serve as the recourse/backstop rates in any negotiated rate program.²⁹ Rates could be negotiated between customers and the storage provider which are mutually efficient and beneficial. Further, increased revenues from peak short-term services reduces the level of costs that need to be recovered from long-term customers, and reduces the need for rate discounts in off-peak periods and the associated cost shifting that occurs through rate discount adjustments.

Similarly, storage providers could develop term-differentiated rates, as contemplated in Order No. 637. Term-differentiated rates do not differentiate between seasons, as in the above discussion, but instead differentiate based on the length of contract term. Rates designed to reflect differences in contract terms recognize that shorter term contracts subject the service provider to more risk, and higher rates may be appropriate to compensate the service provider for the additional risk. Conversely, long-term contracts would reflect lower rates for service on a comparable basis.

An alternative approach to flexibly marketing storage services for storage operators would be through the use of voluntary auctions. Auctions can be used in both the cost (e.g., with an annual revenue cap) and market-based rate regimes. As discussed in Order No. 637, properly designed auctions can provide for efficient allocation of services, reduce transactions costs and provide for more accurate dissemination of relative pricing information to the marketplace.³⁰ Auctions also can be used as methods of

mitigating the effects of market power by limiting the ability of sellers to withhold capacity, to price discriminate, or to show favoritism.

Cost of Service Adjustments

An additional cost-based rate option for encouraging investment in underground storage could be accomplished through adjustments to the cost of service, *i.e.*, the annual revenue requirement of the project. For example, an equity return premium to reflect higher risks associated with storage development, or accelerated depreciation could induce entry by allowing higher maximum rates. In this example higher rates would occur because (1) the normal cost of equity would be increased by a premium to reflect higher risk or simply to incent development, and (2) the depreciable life of the storage project's assets would be shortened. Accelerated depreciation allows the full cost of capital to be recovered more quickly.³¹ It may seem counter-intuitive to grant cost adjustments that would increase costs when storage developers argue they cannot recover costs under traditionally designed cost-based rates. However, the higher maximum rates allow more revenue collection during periods of peak demand. Further, these cost adjustments could be coupled with flexible peak/off-peak, seasonal or other rate design methods that reflect periodic differences in the value of service.

Additional rate policy options could be considered to address storage developer cost recovery concerns. One such option would be to permit storage developers to use unit of throughput depreciation. Under this approach, accounting would follow revenues and storage developers might avoid losses in the early years of a project. Alternatively, regulatory asset treatment could be

²⁹ Under the Commission's negotiated rate policy, rates can be negotiated as long as customers can always choose service under an approved cost-of-service recourse rate, also known as the recourse rate. *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076 (1996), *reh'g and clarification denied*, 75 FERC ¶ 61,024 (1996) (Policy Statement).

³⁰ Minimum bid criteria could be established to ensure full cost recovery.

³¹ Accelerated depreciation may require the Commission to waive its tax normalization policy regarding adjustments to the rate base.

conditioned for unrecovered costs in the short term. These unrecovered costs would be reflected in future rates. While such an option would deviate from traditional Commission cost-based ratemaking policy, it would better ensure full recovery of storage development costs over the long term and thereby incent development.

Modification of the Requirement for a Three-Year Revenue Review

Another approach for incenting development of underground storage would be to modify the Commission's current certificate policy of requiring cost and revenue studies to be filed within three years of certification of new projects. Elimination or modification of this requirement would, at a minimum, delay or lengthen the maximum time for a review of a project's costs and revenues. Under such an approach, storage providers will be afforded greater certainty with respect to the initial rates, which could translate into additional incentives to construct and operate storage projects. As above, this option maintains the Commission's ability to use Section 5 of the Natural Gas Act to ensure that the cost-based recourse rate remains just and reasonable.

Market-Based Rates

The Commission's authority to authorize market-based rates is premised on the theory that the just and reasonable standard of the Natural Gas Act, the Federal Power Act and the Interstate Commerce Act does not limit the Commission to any particular ratemaking methodology; rather, the Commission has flexibility in selecting rate making methods. The Commission has developed tests of competitiveness for the purpose of determining if market-based rate authority should be granted. These tests are based on the market competitiveness analysis in the U.S. Department of Justice and the Federal Trade Commission, *Horizontal Merger Guidelines* (1997).

In 1996, the Commission issued *Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines* (Policy Statement)³² which established a framework for analyzing market-based rate proposals in gas pipelines (which includes gas storage). The Policy Statement's framework addresses whether the applicant has market power; that is, can the applicant: (1) withhold or restrict services to increase price a significant amount for a significant period of time, or (2) discriminate unduly in terms of price or conditions. Before the Commission can conclude that a seller cannot exercise market power it must either (1) find that there is a lack of market power because customers have sufficient "good alternatives" or (2) mitigate the market power (*i.e.*, permit market-based pricing only if specified conditions are met that prevent the exercise of market power).

In Order No. 572, the Commission amended its regulations to adopt filing requirements with respect to applications for market-based rates by oil pipelines.³³ The framework created by these required filings is essentially the same as described above for the competitive analysis of gas pipelines.

With respect to granting a public utility the authority to make market-based sales of electric power, the Commission must determine that the applicant does not have the ability to exercise market power in generation.³⁴ The Commission determined in *Kansas City Power & Light Company*³⁵ that it is no longer necessary to examine generation market power when considering market-based rate applications for sales from new generation units. This was codified in Order No. 888, section 35.27³⁶ of the Commission's regulations, providing, in relevant part, the following:

Notwithstanding any other requirements, any public utility seeking authorization to engage in sales for resale

³²74 FERC & 61,076 (1996), *reh'g and clarification denied*, 75 FERC & 61,024 (1996); *see supra* note 27.

³³ *Market-Based Ratemaking for Oil Pipelines*, FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 31,007 (1994) ; 18 C.F.R. § 348.

³⁴ The other considerations are whether the applicant has transmission market power, whether the applicant can erect barriers to entry, and whether there is potential for affiliate abuse and reciprocal dealing. *See Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy*, 107 FERC ¶ 61,018 (2004).

³⁵ 67 FERC ¶ 61,183 (1994).

³⁶ 18 C.F.R. § 35.27 (2003).

of electric energy at market-based rates shall not be required to demonstrate any lack of market power in generation with respect to sales from capacity for which construction has commenced on or after July 9, 1996.³⁷

However, as the Commission stated in Order No. 888, it will consider whether an applicant, properly citing section 35.27, nevertheless possesses generation market power if specific evidence is presented by an intervenor.³⁸

As noted above, independent storage developers assert that pricing schemes short of market-based rates may provide too little flexibility and shift too much risk therefore discouraging storage development. But, under the Commission's traditional tests for market competitiveness, demonstrating lack of market power may not be possible in all areas of the country. For example, conditions in western storage markets, particularly market concentration and entry conditions, make it impossible for significantly-sized storage projects to demonstrate that they lack market power under tests the Commission has developed to evaluate market competitiveness.³⁹

However, to the extent that it is desirable to encourage further storage development, the following options or alternatives for granting market based rate treatment could be considered.

Market-Based Rates for New Independent Storage Projects

In this first approach, Commission policy would be modified to allow market-based rates for new independent storage providers, subject to possible mitigation measures, on the grounds that new storage projects add incremental capacity to existing markets, thereby giving customers new choices for services, and with the provision that all

market risks lie with the projects' owners (i.e., no captive customers). The Commission could determine market-based rates for new independent storage projects to be just and reasonable because customers are better off than they would be if the project was not built, and customers will face additional service options because of the new infrastructure provided by the new storage project.

Since the new project's owners assume all market risk and have no captive customers to pass costs on to, they must successfully sell storage in order to cover fixed costs and try to make a profit. Under this theory, customers can always choose to not use the new project and act as they would if the project had not been built.⁴⁰ As a result, project sponsors must price their services at rates that are low enough to attract customers. That is, customers are better off paying the market-based rates than they would have been if the project had not been built.

The rate flexibility provided by this option allows an unlimited upside for rates in periods when storage has high demand⁴¹ to compensate for the periods when storage has low demand and investment costs are not recouped. Further, to the extent the Commission is concerned with the potential for high market-based storage service prices in times of great scarcity, it could consider mitigation measures, such as requiring that capacity be sold through open and transparent auctions. While this requirement may not mitigate prices under all supply and demand scenarios, it would ensure that the storage service provider did not withhold capacity to drive up prices. Alternatively, the Commission could require periodic review of market-based rate storage services. Again, this approach may not directly mitigate high prices in all situations, but it would provide the Commission an opportunity to review rates and services.

³⁷ See 18 C.F.R. § 35.27 (2003).

³⁸ See *Promoting Wholesale Competition Through Open-Access Non-Discrimination Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities*, Order No. 888, FERC Stats. & Regs., Regulations Preambles 1991-1996 ¶ 31,036 (1996) .

³⁹ See *supra* note 5.

⁴⁰ The California Public Utility Commission largely authorized the construction and operation of the Wild Goose Storage Inc. project on this basis (see Appendix B for full description).

⁴¹ This is, in part, what happened in California electricity and gas markets in 2000-2001.

Finally, the Commission might consider removing the rate cap on capacity release transactions and other short-term and interruptible services. The theory behind this alternative is that service providers and customers with existing cost-based storage or transmission capacity would have an incentive to compete with the storage provider, and thereby keeping storage prices down.

Reviewing the Market Power Test for Adequacy in Storage Markets

An alternative to granting market-based rates to all new independent storage projects, would be to find that the current test for market power does not accurately measure it. Some storage developers assert that they are unable to secure long-term service agreements as pipelines do in construction applications. Accordingly, to the extent a storage provider could demonstrate an inability to secure firm service contracts for the entire capacity of its storage field, for terms exceeding some specified time, such as 1, 2 or 5 years, the Commission could find it lacked market power, and grant market-based rate authority. The Commission would likely want to establish guidelines, in advance, for such capacity offerings to ensure they were conducted on an open and transparent basis, and barriers to longer term contracts were not established.

The mitigation measures discussed in the previous section could be applicable to these alternative approaches, as well.

Revise or Waive Commission Policies

It has been suggested in informal discussions with companies that are considering storage projects, that entry

into storage would be assisted by waivers or exemptions of certain environmental and certificate analyses, affiliate rules, open access requirements for offering firm and interruptible service, and prohibitions against making bundled sales. The Commission could consider initiating an industry dialogue to explore possible improvements to the current process for environmental review and certificate authorization. For instance, the current blanket certificate program is not available for storage related activities except for initial testing and development. However, since the existing regulations have long indicated that certain types of storage projects are usually not major federal actions, and because the issues that are unique to the development of storage fields are very limited, the Commission could consider revising its regulations to add certification of storage projects to the blanket program. In addition, the industry is only beginning to avail itself of existing Commission programs such as the Pre-Filing Process for storage fields. Either or both of these possible avenues may assist in allowing storage projects to be approved more quickly.

Further, storage providers have asserted that waivers of various open-access requirements and limitations on operators to engage in commodity arbitrage for their own account limit their ability to maximize or capture the value of their investment. To the extent the Commission believes development of storage assets is essential for ensuring service reliability in all markets, it could consider revising open-access requirements to encourage storage development. The Commission could protect against potential market abuses by requiring the storage providers to file periodic reports on their activities and revoke any waivers after considering complaints by customers or potential customers.

APPENDIX A

[Revised October 15, 2004]

Gas Storage Tariff Rates

Pipeline Company	Max Daily Deliverability	Max Seasonal Capacity	Injection/Withdrawal Commodity Rate	Annual 100% Load Factor (60 storage days)	Working Capacity (Bcf)	Total Capacity (Bcf)	Facility State	Facility Type
ANR	\$2.3999	\$0.2449	\$0.0084	\$0.74	181.3	333.5	TX	Depleted Reservoir
BLUE LAKE GAS STORAGE	\$1.8027	\$0.0258	\$0.0990	\$0.58	42.0	49.0	MI	Depleted Reservoir
COLUMBIA GAS TRANSMISSION	\$1.5080	\$0.0290	\$0.0153	\$0.69	243.1	669.6	WV	Depleted Reservoir
DOMINION	\$1.7984	\$0.0145	\$0.0154	\$0.56	382.2	755.8	WV	Depleted Reservoir
MICHIGAN GAS STORAGE	\$0.8357	\$0.0136	\$0.0190	\$0.21	34.0	109.5	MI	Depleted Reservoir
MIDWEST GAS STORAGE	\$4.5272	\$0.0463	\$0.0056	\$0.96	0.9	4.5	IL	Aquifer
NATIONAL FUEL	\$2.1556	\$0.0432	\$0.0139	\$0.47	149.3	317.9	NY	Depleted Reservoir
NATURAL GAS PIPELINE CO	\$1.2900	\$0.2881	\$0.0197	\$0.59	205.3	603.3	TX	Depleted Reservoir and Aquifer
NGO TRANSMISSION	\$1.6373	\$0.0320	\$0.0726	\$0.36	1.5	5.1	OH	Depleted Reservoir
NORTHERN NATURAL GAS CO	\$1.5874	\$0.3854	\$0.0225	\$0.75	55.3	206.0	TX	Depleted Reservoir and Aquifer
PANHANDLE	\$2.9700	\$0.4246	\$0.0385	\$0.71	74.0		TX	
QUESTAR	\$2.8533	\$0.0238	\$0.0105	\$0.63	53.0	139.5	UT	Aquifer
SOUTHWEST GAS STORAGE	\$2.8496	\$0.3419	\$0.0015	\$0.91	57.1	165.5	TX	Depleted Reservoir and Aquifer
TEXAS GAS TRANSMISSION	\$1.4318	\$0.0304	\$0.0166	\$0.68	86.2	176.2	KY	Depleted Reservoir and Aquifer
TRANSCO	\$2.7208	\$0.0152	\$0.0322	\$0.78	182.7	312.9	TX	Depleted Reservoir and Salt Cavern
TRUNKLINE GAS COMPANY	\$3.5985	\$0.5767	\$0.0005	\$0.77	12.9	42.8	TX	Depleted Reservoir
YOUNG GAS STORAGE	\$1.5620	\$0.0590	\$0.0200	\$0.41	5.3	9.9	CO	Depleted Reservoir

Sources: Capacity data from Platts GASdat; tariff information from company filings with FERC.

Example of State Regulatory Approach

In late June 1997, Wild Goose Storage Inc. became California's newest gas utility and the state's first independent storage provider. The Wild Goose storage field is located in the southwest corner of Butte County in California at the site of the depleted Wild Goose natural gas field. It has a working gas volume capacity of 24 Bcf, a maximum injection rate of 450 MMcf/d, and a maximum withdrawal rate of 480 MMcf/d. The field is connected to the PG&E transmission system and can be used to manage imbalances and OFOs on the PG&E system.

The California PUC set out rules for independent natural gas storage facilities which exempt independent gas storage providers from traditional cost-of-service ratemaking, but subjected them to the regulatory jurisdiction of the PUC. The developers of the project must take the risks for its commercial performance without any direct recourse to the customer of the utility system. Finding that as a new entrant without market share Wild Goose will lack market power, the CPUC authorized Wild Goose to offer its storage services at market-based rates under tariffs that set rates within a rate window.

In order to prevent predatory pricing, the floor rate could not be set below Wild Goose's short-run marginal cost, but Wild Goose had substantial freedom to set the ceiling rate, under the theory that its potential customers would not be captive but may choose other storage providers. The CPUC was unable to determine that Wild Goose could not exercise market power. Neither could the CPUC determine that the potential for Wild Goose to exercise market power was fully mitigated by its lack of control of the transportation system or by other factors.

The CPUC revoked the relaxed reporting requirements approved in prior decisions. The CPUC placed reporting requirements such as interactions between a utility and its affiliates, changes in status that would reflect a departure from the characteristics the Commission relied upon in approving market-based rates, and providing service agreements for short-term transactions (one year or less).