Natural Gas Storage in the United States in 2001: A Current Assessment and Near-Term Outlook

by James Tobin and James Thompson

This report examines the large decline of underground natural gas storage inventories during the 2000-2001 heating season and the concern that the nation might run out of working gas in storage prior to the close of the heating season on March 31, 2001. This analysis also looks at the current profile and capabilities of the U.S. natural gas underground storage sector.

Since the start of the 2000-2001 heating season,[1] the drawdown of underground storage inventories has been significantly greater than in any season since 1995-1996 when large withdrawals led to an end-of-season record-low working gas inventory of 758 billion cubic feet (Bcf). On February 23, 2001, storage inventories were estimated to be about 937 Bcf. If monthly withdrawals continue at the average rate of the past 5 heating seasons, storage stocks would drop to 624 Bcf by March 31, 2001 (Table 1).[2] If instead, withdrawals match the highest regional draws in February and March of the past 5 years, storage stocks could drop to 461 Bcf (see box "Storage Measures," p. 3).[3]

Even with higher-than-average withdrawal rates through the rest of the heating season, storage stocks are expected to be adequate to meet demand. Furthermore, demand for storage supplies from February 23 through the end of March may not be as high as during the previous 3 months. Weather forecasts for the remaining weeks of the heating season call for more moderate temperatures which would reduce seasonal demand and lessen withdrawal activities. According to American Gas Association (AGA) weekly estimates, cumulative withdrawals in 2001 have slowed somewhat as milder weather patterns have developed in many areas of the United States.[4]

Regionally, if withdrawals continue at the 5-year average rate through the rest of the heating season, working gas inventories in the 280 underground storage sites located in the East Consuming Region (Figure 1)[5] would fall to about 351 Bcf. This is 225 Bcf less than the region's 5-year average stock levels on March 31. The West Consuming Region (37 sites) would end the season with about 76 Bcf remaining, 126 Bcf below the 5-year average. The 98 underground storage facilities located in the Producing Region would end the season with 197 Bcf remaining, 164 Bcf below its 5-year average. It is estimated that remaining inventories will be near the record low levels reached at the end of the 1995-96 heating season in the East and Producing Region (Table 1). Levels in the West are already below the record low of 151 Bcf.

While end-of-season storage inventories this year likely will be lower than average, there is little likelihood that working gas levels for the regions will be completely drawn down. Nevertheless, working gas inventories at some sites could drop so far that operators (see box "Owners and Operators of Storage," p. 5) would need to dip into base gas inventories to maintain operations.[6] It is more likely, however, that operators would minimize operations at these sites and/or increase operations at other facilities where possible.

Natural gas requirements to refill storage for the next heating season will probably near 10 Bcf per day (for 214 days) compared with an average injection level during April-through-October 2000 of 7.6 Bcf per day. This increase in demand, especially when natural gas prices are high, will likely have an impact upon the market over the next several months.

Background

Several factors have contributed to today's relatively low storage levels: some market related, some weather related. For instance:

[1]The gas industry heating season refers to the 5-month period from November 1 through March 31.

[2]The estimates of working gas levels presented in this analysis are sceanario results based on historical withdrawal data. These simple sceanrios are for illustrative purposes. The official Energy Information Administration (EIA) outlook for storage levels are presented in the *Short-Term Energy Outlook*.

[3]Historical data used in the scenario analyses are from: •Monthly data from Form EIA-191, " Underground Natural Gas Storage Report" through November 30, 2000; • Weekly estimates by the American Gas Association (AGA) for the period December 1, 2000, through February 23, 2001; and •5-year (1995-1999) lowest, highest, and average net withdrawals by region for the months February and March (Form EIA-191).

[4]National Oceanic and Atmospheric Administration (NOAA) forecasts.

[5] As defined by the American Gas Association.

[6]At most underground storage sites, base gas inventories can be, within operational tolerances (specific to each site), tapped if needed. However, this is not true for aquifer-based storage sites, where dipping into base gas at any level can ruin the water drives associated with such sites.

Table 1. Underground Natural Gas Storage Estimates for 2000-2001 End-of-Season Inventories
(Billion Cubic Feet)

Region	Working Gas in Storage as of:		Projected Working Gas on 3/31/2001 Based on Site-by-Site Withdrawals During 1995-1999			Actual End-of-Heating Season Working Gas Inventories (1995-1999)	
	11/01/2000	2/23/2001	Average	Lowest	Highest	Average	Lowest [1]
East	1,826	603	351	251	411	576	341
West	312	99	76	63	89	202	151
Producing	636	234	197	148	282	361	195
Total	2,774	937	624	461	781	1,139	758

[1] The regional remaining inventories do not sum to the U.S. level because the year in which the lowest inventory occurs varies per region.

Note: Regions are those established by the American Gas Association. Totals may not sum because of independent rounding.

Source: Energy Information Administration, Form EIA-191, "Underground Gas Storage Report"; and American Gas Association Weekly Storage Survey.

- On November 1, 2000, working gas storage levels (2,774 Bcf) were the lowest for the start of a heating season since 1976 and 208 Bcf below the 5-year average. The previous low was 2,810 Bcf on November 1, 1996. The volume of net injections (1,624 Bcf) between March 31 and October 31, 2000, was also the lowest for a refill season in at least 10 years.

- High natural gas prices during the first several months of the 2000 refill season caused some storage users to defer injections. Spot prices at the Henry Hub increased from $2.40 to $5.02 per million Btu (MMBtu) between January and November 1, 2000 (Figure 2). Despite the surging prices, injection activity grew substantially during the last 2 months of the refill season (September and October), with net injections exceeding the 5-year average for those months.

- Net withdrawals during November 2000 were the highest for the month of November (293 Bcf) in over a decade,[7] as much colder-than-normal temperatures in many areas increased demand for space heating. Preliminary figures for December indicate a similar occurrence, with net withdrawals nearing the 758 Bcf level, a record for that month as well.

- Underground storage facilities in California and New Mexico were called upon to supplement regional supplies lost because of the El Paso pipeline disruption in New Mexico in August 2000.[8] The high level of withdrawals drew down storage inventories in the region just as unseasonable weather and the electricity market difficulties in the region developed.

Shifts in Storage Use Impact Inventories and Storage Activities

The natural gas industry is also experiencing low storage inventories this heating season because of changes in inventory management practices and storage utilization over the past decade as a result of market restructuring. During that time, the operational practices of many U.S. underground storage sites became much more market-oriented. Many storage gas owners (marketers and other third parties) are minimizing inventories in an attempt to synchronize their buying and selling activities more effectively with market needs while minimizing their business costs.

Reflecting the change in focus within the natural gas storage industry during recent years, the largest growth in daily withdrawal capability has been from high-deliverability storage sites, which are mainly salt cavern storage reservoirs.

[7] Energy Information Administration, *Natural Gas Monthly*, January 2001, DOE/EIA-0130(2001/01) (Washington, DC, February 2001), Table 9.

[8] The incident occurred at the El Paso Natural Gas Company's Pecos River crossing in the southeast corner of New Mexico where three lines (two 30-inch and one 26-inch pipeline) cross the river. While only one 30-inch line blew, the other two lines were also shut down. As a result, 1.2 Bcf per day, out of a normal 2.0 Bcf per day, of natural gas flowing along El Paso's southern route to its Arizona and California markets was affected for several months. In fact, 5 months after the incident the blown pipeline segment, although repaired, has yet to be placed back in service. The company reports, however, that with adjustments to pressure in the other two lines, flows through the repaired portion at the site approximate 90 to 95 percent of previous levels for all three lines and customer service has not been impaired.

Storage Measures

Total capacity is the maximum volume of gas that can be stored in an underground storage facility and is determined by the physical characteristics of the reservoir.

Base gas (or **cushion gas**) is the volume of gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season.

Working gas capacity is, by definition, total capacity minus base gas.

Working gas is the volume of gas in the reservoir above the designed level of the base gas. Working gas is that which is available to the marketplace.

Deliverability is a measure of the amount of gas that can be delivered (withdrawn) from a storage facility on a daily basis. Also referred to as the deliverability rate, withdrawal rate, or withdrawal capacity, deliverability is most often measured in terms of million cubic feet or dekatherms per day. The deliverability of a given storage facility is variable, and depends on factors such as the amount of gas in the reservoir at any particular time, the pressure within the reservoir, compression capability available to the reservoir, the configuration and capabilities of surface facilities associated with the reservoir, and other factors. In general, a facility's deliverability rate varies directly with the amount of base and working gas in the reservoir: it is at its highest when the reservoir is most full and declines as working gas is withdrawn.

These facilities can cycle their inventories more rapidly than can other types of storage (see box "Types of Natural Gas Storage Facilities," p. 7),[9] a feature more suitable to the flexible operational needs of today's storage users. Since 1993, when access to interstate underground natural gas storage became completely open, daily withdrawal capability from high-deliverability storage facilities has grown by 62 percent and the number of sites has increased from 21 to 27. During this same period, the average cycling rate at these sites increased from 1.66 in 1993 to 2.10 in 2000, as marketers, electric generation, and other variable-load customers have made increasing use of the unique service features of this type of storage. Interestingly, although five new (greenfield) storage facilities were developed in the United States between 1996 and 2000, the bulk of new working gas capacity and growth in daily (withdrawal) deliverability (about 4 percent in each category) during that time came from expansions to all types of existing storage sites.

The increasing influence of high-deliverability storage may change the meaning of the inventory levels. For instance, because gas can be rapidly injected/withdrawn from these sites,[10] how full they are on November 1 has less significance than inventory levels for depleted reservoir or aquifer storage, which are designed to cycle (deplete) their inventories once a heating season. Whereas the high-deliverability sites in the Producing Region make up only 11 percent of the total working gas capacity, the capacity has different potentials than other sites. For example, a high-deliverability facility with a working gas capacity of 1 Bcf theoretically could cycle 12 Bcf during a calendar year. A site that is only 50-percent full at the end of a given month could be 100-percent full or heavily depleted sometime during the month. The storage operations of such a site are not dictated by the seasonal need to store gas as a backup, but rather are a function of customer needs as they occur.

Effect of High Natural Gas Prices

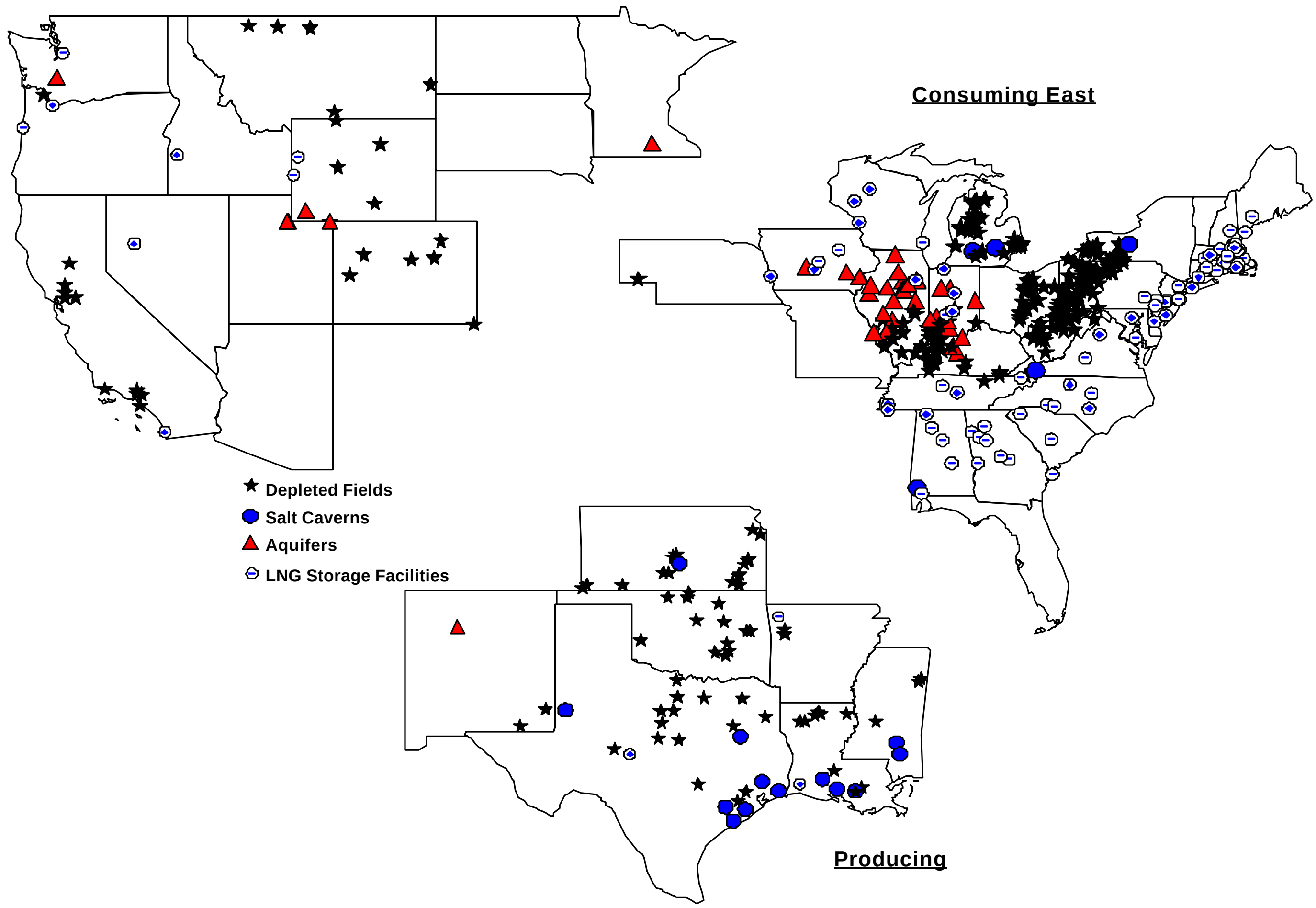
High natural gas prices during the first half of 2000, and the rapid jump in prices after August 2000, had a two-fold effect. First, some storage users sold storage gas to take advantage of the higher prices and increase their income significantly, while second, the high prices lessened the amount of natural gas flowing into storage. Between January and August 2000, natural gas spot prices at the Henry Hub increased from a monthly average of $2.40 per million Btu (MMBtu) to $4.42, a rise of 81 percent (Figure 2).[11] But that rise was less than the 98-percent increase that occurred between August and December 2000. Spot prices at the Henry Hub rose to

[9]Currently, on average, high-deliverability storage facilities cycle their inventories 2.1 times per year, compared with .78 for depleted reservoirs and .60 for aquifers.

[10]Most high-deliverability sites are designed to cycle their inventory as rapidly as once a month although none currently operate at such a high rate.

[11]Daily spot prices are from Financial Times Inc., *Gas Daily*. Monthly averages are derived by the Energy Information Administration, Office of Oil and Gas.

Figure 1. The Largest Number of Underground and LNG Storage Sites Are Located in the Consuming East Region



Summary of Underground and LNG Storage, by AGA Region and Reservoir Type, 2000

Region	Depleted Gas/Oil			Aquifer Storage			Salt Cavern Storage			Total			LNG Facilities		
	Sites	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Sites	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Sites	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Sites	Working Gas Capacity (Bcf)	Daily Deliver-ability (MMcf/d)	Sites	Site Capacity (Bcf)	Daily Deliver-ability (MMcf/d)
East	243	1,690	31,888	33	351	7,457	4	4	298	280	2,045	39,643	83	73	10,135
West	31	590	8,620	6	39	1,175	0	0	0	37	628	9,795	13	12	1,186
Producing	74	1,089	17,166	1	1	12	23	135	11,118	98	1,226	28,296	3	7	312
Total	**348**	**3,368**	**57,674**	**40**	**392**	**8,644**	**27**	**139**	**11,416**	**415**	**3,899**	**77,734**	**99**	**92**	**11,633**

Bcf = Billion cubic feet. MMcf/d = Million cubic feet per day. LNG = Liquefied natural gas.
Note: Regions are those established by the American Gas Association.
Source: Energy Information Administration, Form EIA-191, "Underground Gas Storage Report."

Owners and Operators of Storage

The principal owner/operators of these underground storage facilities are (1) interstate pipeline companies, (2) local distribution companies (LDCs) and intrastate pipeline companies, and (3) independent storage service providers. If the facility serves the interstate market it is subject to Federal Energy Regulatory Commission (FERC) regulations; otherwise, it is State regulated. Owners and operators of storage facilities are not necessarily the owners of the gas held in storage. Some gas is held in storage facilities in custody or under lease with shippers, LDCs, or end users who own the gas.

Interstate pipeline companies operate about 60 percent of all working gas capacity in the United States. Underground storage is particularly important to interstate pipeline companies because they depend heavily on storage inventories to facilitate load balancing and system supply management on their long-haul transmission lines.

LDCs and intrastate pipeline companies account for about 33 percent of working gas capacity. LDCs generally use gas from storage sites to serve customer needs directly, whereas intrastate pipeline companies use underground storage for operational balancing and system supply as well as the energy needs of end-use customers.

Independent operators own or operate about 7 percent of current working gas capacity. Many of the salt formation and high-deliverability sites currently being developed have been initiated by independent storage service operators.

Since 1994, almost all of the underground storage facilities that serve the interstate market, and are subject to the jurisdiction of the FERC, operate on an open-access basis; that is, the major portion of working gas capacity (beyond what may be reserved by the pipeline/operator to maintain system integrity and for load balancing) at each site must be made available for lease to third-parties on a nondiscriminatory basis. Prior to 1994, the use and control of capacity at an interstate storage facility was the purview of the pipeline owner.

Today, in addition to the interstate storage sites, many storage facilities owned/operated by large LDCs, intrastate pipelines, and independent operators, operate on an open-access basis, especially those sites affiliated with natural gas market centers. At these facilities, the use of working gas capacity has become market-oriented in addition to serving as a backup or supplemental seasonal supply source. For instance, marketers and other third-parties have the opportunity to move gas into and out of storage (subject to the operational capabilities of the site or the tariff limitations) as changes in price levels present arbitrage opportunities. Seasonal factors no longer are the only component governing the use of underground storage inventory – supply, demand, and prices are playing a larger role.

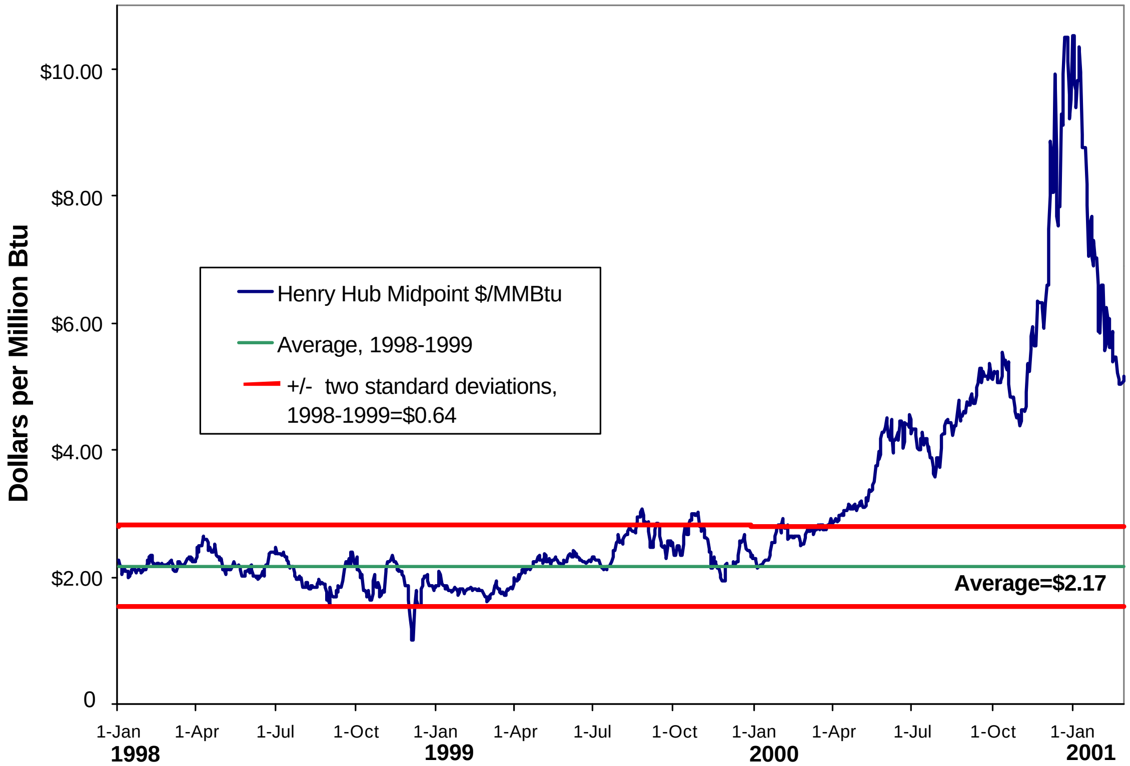
record levels, reaching an average of $8.75 per MMBtu in December and $10.53 on December 29. On the West Coast, spot prices for natural gas flowing into California from the Southwest rose to $58.50 per MMBtu on December 29.

The price increases during the early months of the refill season caused many storage users to limit their rate of injections, in part in anticipation that prices would drop later in the season. However, natural gas prices continued to rise rather than receding. As prices increased, storage operators who had adopted a wait-and-see attitude found that they had no alternative but to acquire needed storage reserves on the spot market at the higher prices. Storage users that had access to supplies under long-term contracts faced less of a dilemma since the contracted prices, even where indexed, were lower than on the spot market. Overall, however, storage injections during October 2000 were more than in October 1999, reflecting a move to fill storage reserves regardless of price levels.

The high prices late in the refill season also affected overall storage stock levels. Local distribution company (LDC) storage operators and users who are very dependent on storage gas for their seasonal backup supplies always attempt to refill available working gas capacity before the heating season begins.[12] However, other storage users, especially those whose operations are more market-focused and use storage as either a price-hedging mechanism or a short-term marketing tool, tended to place less gas in storage through October. As a result, working gas levels at the beginning of the 2000-2001 heating season reached only 2,774 Bcf, compared with the 5-year average of 2,982 Bcf, an 8-percent difference. It also was 1 percent below working gas levels at the beginning of the 1996-1997 heating season, previously the record low for beginning-of-season storage inventories.

[12]Over the past 5 years LDC owned and operated storage sites, on average, showed a 85-90 percent fill rate on November 1, compared with a 70-75 percent level for Independents and 78-85 percent for Interstate pipeline operators.

Figure 2. Natural Gas Spot Prices at the Henry Hub Market Center, January 1998–February 2001



Source: Financial Times Energy, *Gas Daily.*

Record Withdrawals in November and December

The U.S. underground natural gas storage sector began the 2000-2001 heating season prepared for a winter similar to the preceding two heating seasons but encountered a winter more like 1995-1996, which had resulted in record-low storage stocks by the end of the season. Unlike the start of the 1995-96 heating season, however, when beginning inventories were relatively high and November temperatures were normal, storage stocks at the start of the 2000-2001 heating season were at the lowest level in at least 20 years and November temperatures were colder than usual.

Adding to this situation, net withdrawals from storage during November 2000 reached an unusually high 293 Bcf because of much colder-than-normal weather. This represented a more than 10-percent depletion of an already low total working gas inventory level in the first month of the heating season.

Compared with November 1998 and 1999, when net withdrawals amounted to only 36 Bcf and 35 Bcf, respectively, November 2000 reflected the highest first month withdrawal rate in 10 years. December withdrawals also were at unusually high levels, with an estimated drawdown of 758 Bcf, or 59 percent more than the average for the previous 5 years of 477 Bcf.

Regional Aspects and Assessments

Each regional market in the United States has widely varying patterns of energy use and natural gas requirements. The **East Consuming Region**, particularly those states in the northern tier, relies extensively on storage gas to meet peak demand during the winter months. The region has the highest level of working gas storage capacity of the regions and the largest number of storage sites (Figure 1), mainly in depleted reservoirs. In addition, above-ground liquefied natural gas (LNG) storage facilities provide supplemental backup and/or

Types of Natural Gas Storage Facilities

The three principal types of underground storage sites used in the United States today are: (1) depleted reservoirs in oil and/or gas fields, (2) aquifers, and (3) salt cavern formations. (Several reconditioned **mines** are also in use as gas storage facilities). Each type has its own physical characteristics (porosity, permeability, retention capability) and economics (site preparation costs, deliverability rates, cycling capability), which govern its suitability to particular applications. Two of the most important characteristics of an underground storage reservoir are its capability to hold natural gas for future use and the rate at which gas inventory can be withdrawn, its deliverability rate.

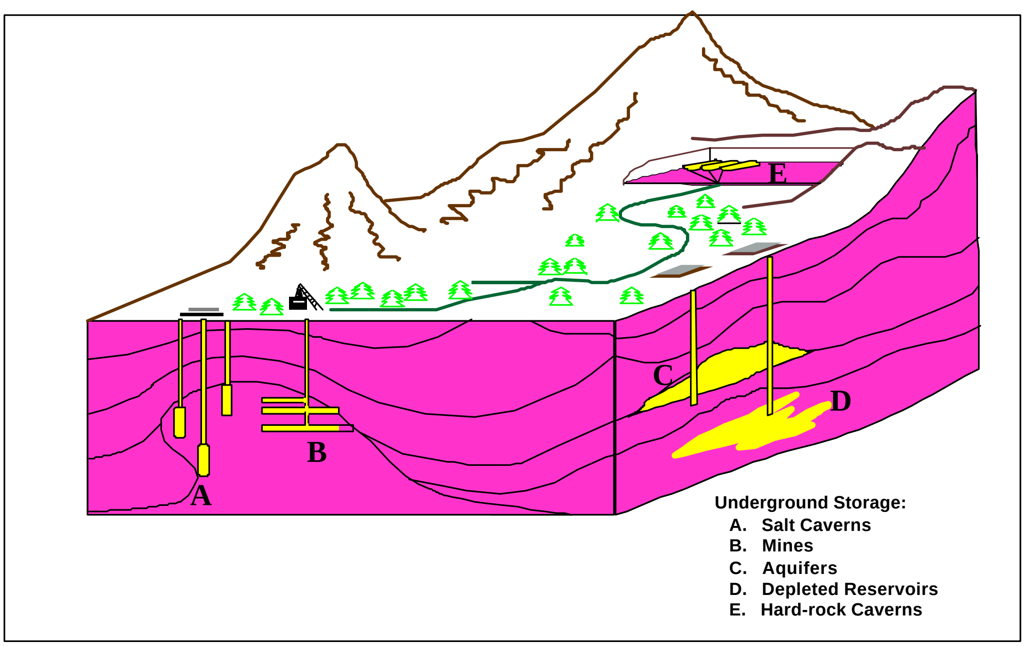
Most existing gas storage in the United States is in **depleted natural gas or oil fields** that are close to consumption centers. Conversion of a field from production to storage duty takes advantage of existing wells, gathering systems, and pipeline connections. Depleted oil and gas reservoirs are the most commonly used underground storage sites because of their wide availability.

In some areas, most notably the Midwestern United States, natural **aquifers** have been converted to gas storage reservoirs. An aquifer is suitable for gas storage if the water-bearing sedimentary rock formation is overlaid with an impermeable cap rock. While the geology of aquifers is similar to depleted production fields, their use in gas storage usually requires more base (cushion) gas and greater monitoring of withdrawal and injection performance. Deliverability rates may be enhanced by the presence of an active water drive.

Salt caverns provide very high withdrawal and injection rates compared with their working gas capacity. Base gas requirements are relatively low. The large majority of salt cavern storage facilities have been developed in salt dome formations located in the Gulf Coast States. Salt caverns leached from bedded salt formations in Northeastern, Midwestern, and Western States are also being developed to take advantage of the high volume and flexible operations possible with a cavern facility. Cavern construction is more costly than depleted field conversions when measured on the basis of dollars per thousand cubic feet of working gas capacity, but the ability to perform several withdrawal and injection cycles each year reduces the per-unit cost of each thousand cubic feet of gas injected and withdrawn.

The potential use of **Hard-rock cavern** storage is currently undergoing testing in the United States. None are operational as natural gas storage sites at the present time.

Types of Underground Storage



Source: PB-KBB Inc. Recreated by Energy Information Administration, Office of Oil and Gas.

Peaking Supplies: Liquefied Natural Gas

Underground natural gas storage inventories provide suppliers the means to meet peak customer requirements up to a point. Beyond that point the distribution system still must be capable of meeting customer short-term peaks and swings that occur on a daily and even hourly basis. During periods of extreme usage, peaking facilities, as well as other sources of temporary storage, are relied upon to supplement system and underground storage supplies.

Peaking needs are met in several ways. Some underground storage sites are designed to provide peaking service, but most often LNG and liquefied petroleum gas such as propane are vaporized and injected into the gas distribution system to meet instant requirements. Short-term linepacking is also used to meet anticipated surge requirements.

The use of peaking facilities, as well as underground storage, is essentially a risk-management calculation, known as peak-shaving. The cost of installing these facilities is such that the incremental cost per unit is expensive, perhaps as high as $10 per thousand cubic feet. However, the cost of a service interruption, as well as the cost to an industrial customer in lost production, may be much higher. In the case of underground storage, a suitable site may not be locally available. The only other alternative might be to build or reserve the needed additional capacity on the pipeline network.

A local gas distribution company (LDC) installs supplemental supply sources (underground storage, LNG/propane) and uses linepacking to "shave" as much of the difference between the total maximum user requirements (on a peak day or shorter period) and the baseload customer requirements (the normal or average) daily usage. Each unit "shaved" represents less demand charges (for reserving pipeline capacity on the trunklines between supply and market areas) that the LDC must pay. The objective is to maintain sufficient local underground storage capacity to minimize capacity reservation costs on the supplying pipeline by using conventional storage and also having in place additional supply sources such as LNG and propane air to meet large shifts in daily demand. In these instances, the tradeoff is between high-deliverability storage such as salt dome facilities and propane-air plants.

Although peaking facilities are often used only a few days a year, their availability is critical. For instance, if it were not for these facilities more long-haul pipeline capacity, and in many cases local pipeline deliverability, would have to be built to serve end-use customers. In addition, much more underground storage would have to be developed (if suitable sites were available) to meet peak and surge requirements in addition to seasonal supply while more large industrial and electric generation users of natural gas would have to have the capability to fuel-switch during peak periods.

peaking services to a number of local natural gas distribution companies on a short-term basis. Though a relatively small supply source compared to underground natural gas storage (regional LNG working gas capacity is only 4 percent that of underground storage sites), LNG facilities in the region are capable of delivering 10.1 Bcf per day to the network on a temporary basis (see box above, “Peaking Supplies: Liquefied Natural Gas”).

At the start of the current heating season, eastern underground storage stocks were at 1,826 Bcf, just 2 percent below the 5-year average. By the end of December, however, regional storage stocks were about 20 percent below the 5-year average. The warmer temperatures in January in the region gave storage operators the opportunity to reduce net withdrawals. From January through mid-February, net withdrawals were nearly 13 percent less than the 5-year average for the period, with a daily drawdown of almost 10 Bcf. This development ended the steep decline of the previous 2 months, which had it continued might have seen end-of-season working gas inventories reaching as low as 158 Bcf. Nevertheless, the East Consuming Region can be expected to end the season with low working gas inventories, substantially below the 5-year average, and perhaps matching the record low levels reached in March 1996.

Many of the underground storage facilities in the **West Consuming Region**, especially in California, are used as market area reservoirs to allow domestic and Canadian gas supplies entering the region to flow at a rather constant rate. Storage facilities in the West Consuming Region began the winter with 312 Bcf of working gas (50 percent of working gas capacity) compared with 366 Bcf (58 percent) in the previous heating season, lower than the regional 5-year average of 372 Bcf. In part, this low level reflects the major withdrawals from storage following the disruption of supplies into the region brought on by the El Paso pipeline rupture in New Mexico in August 2000. Storage supplies in the region, especially in California, were used extensively to support high gas demand, owing to unseasonable weather between August and October. High natural gas prices in the region also induced third-party storage users to market some of their stored natural gas rather than maintain it in storage. Consequently, underground storage facilities in the region were understocked when colder weather occurred in November 2000. California operators alone saw a further decrease of 35 percent in their working gas inventories (27.3 Bcf net withdrawals) during that month as a result.[13] During January 2001, there were reports that some storage facilities in California were already dipping into base gas inventory to maintain service to customers.

Many of the underground storage facilities in the **Producing Region** are linked to market centers and play a vital role in the efficient export and transmission of natural gas to other areas. Although the storage sites in the region had only 636 Bcf of working gas inventory (52 percent of working gas capacity) at the beginning of the 2000-2001 heating season (Figure 1), many of these sites are high-deliverability salt-cavern facilities[14] whose rapid inventory turnover capabilities serve swing gas and/or variable-load customers within and without the region.[15] Because of the nature of these facilities, especially those associated with market centers, their operations are designed to provide storage customers with specialized services such as parking and loaning[16] and rapid access to supplies to respond quickly to market and price fluctuations.

The low level of working gas inventories in the producing area also reflects the high market demand for natural gas. Much of the storage in the producing areas of the country is used for the storage of natural gas that is not immediately marketable,[17] but because the recent and current demand for natural gas has been unusually high, more gas is going directly to end users and less is reaching storage. This has implications for markets in the East Consuming Region as well, as producing area storage gas serves as a load-balancing tool for the long-haul interstate pipelines serving the East.

[13]Energy Information Administration, *Natural Gas Monthly*, January 2001, Table 14.

[14]While 23 of the region's 98 sites are salt caverns accounting for 11 percent of working gas capacity, the daily deliverability from these sites represents over 39 percent of all storage deliverability within the region.

[15]Because of the nature of their operations, natural gas-fired electric power generation plants, and industrial feedstock users of natural gas, tend to vary their needs on a daily, if not hourly basis. High-deliverability storage is well suited to meeting these types of needs.

[16] Natural gas shippers or marketers often need temporary storage at or near natural gas pipeline transfer points (hubs) to meet short-term needs to accommodate their pipeline transporter's receipt/delivery balancing requirements.

[17]Often this is natural gas that is produced in association with oil production, whose production may not coincide with natural gas demand.

Near-Term Outlook

Regardless of how the rest of the 2000-2001 heating season plays out, remaining working gas inventories on March 31, 2001, are likely to approach record lows and remain at low levels through the first several months of the refill season. Given the current high price levels for natural gas and a growing overall demand for baseload supplies, the efforts to replace storage gas will contribute to upward price pressure in the markets. The situation could be difficult depending on whether new natural gas production supplies enter the markets and higher prices cause end users to conserve. While gas prices probably will drop—EIA has predicted that prices will fall to the low $4.00 range during the summer months[18]—end-use demand could remain high, perhaps owing to greater need by the electric power generation sector. This could affect storage refilling.

The upcoming refill period could resemble that of last year's. Several favorable factors, however, could help improve the situation during the upcoming refill season. They are:

- Increases in U.S. natural gas production because of high price levels
- More gas imports flowing from Canada
- Prices declining somewhat from peak levels in early 2001
- Decreased demand by industrial natural gas users owing to continued high prices and a slowing economy.

While these possibilities could increase supplies available for storage or lower the cost of acquiring storage supplies, there are cautionary notes. Many operators and storage users dependent on backup storage supplies likely will increase their refill activity to levels well above those of previous years to compensate for the high drawdowns of the 2000-2001 heating season. The heavy demand for natural gas to refill depleted storage inventories between April and October 2001 will vie with baseload requirements to a greater degree than in previous years. Hot weather and renewed economic strength would both add to demand. This heightened competition for supplies should place some upward pressure on price levels. Prices, though dropping, are still expected to exceed the average price level of the 2000 refill season, which could dampen refill activity.

[18]Energy Information Administration, *Short-Term Energy Outlook – February 2001* (February 6, 2001 release), http://www.eaid.doe.gov.