Natural Gas Storage - End User Interaction Task 6

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EXECUTIVE SUMMARY

New opportunities have been created for underground gas storage as a result of recent regulatory developments in the energy industry. The Federal Energy Regulatory Commission (FERC) Order 636 directly changed the economics of gas storage nationwide. Pipelines have been required to "unbundle" their various services so that pipeline users can select only what they need from among the transportation, storage, balancing and the other traditional pipeline services. At the same time, the shift from Modified Fixed Variable (MFV) rate design to Straight Fixed Variable (SFV) rate design has increased the costs of pipeline capacity relative to underground storage and other supply options. Finally, the ability of parties that have contracted for pipeline and storage services to resell their surplus capacities created by Order 636 gives potential gas users more flexibility in assembling combinations of gas delivery services to create reliable gas deliverability. In response to Order 636, the last two years have seen an explosion in proposals for gas storage projects.

Another major development affecting the demand for storage is the restructuring of the electric power industry. The trend began with the passage of the Public Utilities Regulatory Policies Act (PURPA), which allowed non-utility electric generators, or qualifying facilities, to provide electric power to electric utilities. Since 1978, substantial amounts of cogeneration and independent power capacity have come on line. Repeal of the Fuel Use Act enabled this capacity to be built with efficient gas-fired turbine technologies. The Energy Policy Act of 1992 and newly proposed FERC regulations will further facilitate the break-up of the electric power industry into independent generators, transmission companies, and distribution utilities. The fuel of choice for most cogeneration and independent power has been, and probably will continue to be, natural gas. Since many of these units are not the lowest cost generation sources available to a utility, they may not be operated full time. Thus, they use gas intermittently over time and could eventually decrease the need for storage.

A. Project Purpose

The primary purpose of this project is to develop an understanding of the market for natural gas storage that will provide for rigorous evaluation of federal R&D opportunities in gas storage technologies, operating practices, and approaches for information management. The purpose of Tasks 5 and 6 is to analyze and report on the impact that aggressive advancements in technology can have on the use, cost and performance of gas storage.

B. Project Objectives

The primary objectives of the overall project are:

1. To identify market areas and end-use sectors where new natural gas underground storage capacity can be economically employed;
2. To develop a storage evaluation system that will provide an analytical tool to evaluate storage requirements under alternative future economic, technology, and market conditions; and
3. To analyze the economic and technical feasibility of alternatives to conventional underground gas storage.

C. Project Analytical Approach

To meet the aforementioned objectives, an analytical approach was developed to simulate the decision-making process used by storage developers in deciding where, how much, when, and what type of storage facility would be economic. Initially, it was thought that these decisions could be made based on the concept that gas demands of various types of end users within a given region could be satisfied by storage capacities within that region. As described below, this initial approach had to be modified to examine storage needs and economics on a total North American gas system basis, and to recognize that in today's gas market, storage is of interest to many more parties than just the end-users.

Both the initial and final approaches to determining the need for storage in a region recognize that there are two primary conditions that must exist to make storage economic. The first condition is that there must be seasonal or shorter-term changes in gas demands of end-users each year. If all consumers used constant amounts of gas all year long, there would be no economic justification for storage. This occurs because pipeline transportation rates are less expensive than storage rates, if the pipeline capacity is well utilized. Secondly, there must be differences in the cost of gas and/or the cost of gas delivery during the year. If the price of gas and its transportation costs did not vary over the course of a year, storage would simply be an additional cost to add to the total cost of delivered gas.

The overall project has been divided into six tasks. Tasks 1,3, and 5 are the analytical assignments that respond to the three primary objectives listed above. Tasks 2, 4, and 6 are the written reports for the three analytical tasks. Task 1 defines the storage market, including identification of existing and proposed storage facilities and their costs, development of an analytical basis for comparing the economics of gas storage with its competitors, and preliminary identification of where additional storage may be required. Task 3 involves development of a data base and screening criteria for existing and potential storage reservoirs, and modification of DOE's Gas Systems Analysis Model (GSAM) to evaluate the effects of technology changes on storage reservoirs in much the same way as on production reservoirs. Task 5 involves the evaluation of alternative storage technologies under varying market conditions.

The primary work items involved in completion of Task 5 of this gas storage analysis project are:

- testing the effects of aggressive reservoir development technology application on the need for storage;
- testing the effects of aggressive reservoir development technology application on the cost and performance of potential new storage reservoirs;
- testing the effects that the addition of the gas storage model has on the gas supply, demand, and price projections of GSAM under various economic and technology assumptions;
- summarizing the lessons learned from both Task 3 and Task 5, regarding the demand for storage in the consuming regions under various economic and technology scenarios; and
- describing the recommended additional tasks that are needed to improve the quantitative results of model tests on the demand for storage under various economic and technology scenarios.

These work items have been completed and a brief summary of the Task 5 findings is provided in the following section.

D. Major Findings of Task 5

The gas storage module for GSAM was used to test two comparison cases involving four supply/demand and technology scenarios that provided insights on how economic and technological changes will affect the demand, cost and performance of gas storage capacity. In other words, an attempt was made to examine potential future requirements for gas storage that account for several possible futures in the North American gas market.

In the first comparison, aggressive technology advancement assumptions were added to a Base Case, creating a Technology Case. The Base Case represents essentially the status quo in gas markets and evolutionary technology advancement. In this comparison, the Technology Case resulted in more use of storage, lower cost storage, and improved storage performance. In the second comparison, the same aggressive technology advancement assumptions were added to a High Demand Case, creating a High Demand Technology Case. The High Demand Case differs from the Base Case in the amount of gas demand growth it experiences, primarily for fueling electric power generation. In the High Demand Case, gas wins the future competition with coal for increasing shares of power generation fuel. As in the first comparison, the addition of improved technology results in more use of storage, lower cost storage, and improved storage performance. In both of the higher technology cases, aggressive advancements are assumed in technology for both exploration and production and for storage reservoirs. The major findings from testing these four scenarios are listed below.

1. Among the four scenarios tested, the greatest use of storage as measured by annual gas extraction rates occurs in the Technology Case, wherein total U.S. gas extraction declines from 1,185 Bcf in the year 2000 to 854 Bcf in 2010. The Base Case uses the least amount of storage at 1,077 to 765 Bcf between the years 2000 and 2010. In both of the case comparisons, the addition of aggressive technology increases the need for storage, as shown in the following table.

Extraction Rates for Storage Gas, Bcf

Comparison Cases	<u>2000</u>	<u>2005</u>	<u>2010</u>
Base Case	1,077	905	765
Technology Case	1,185	1,050	854
High Demand Case	1,098	931	776
High Demand/Tech Case	1,173	1,021	831

In all four cases, the use of storage declines by 28 to 29 percent between 2000 and 2010. There are two reasons for this decline in storage utilization: 1) Most of the growth in gas demand is for power generation rather than for the temperature-sensitive residential and commercial loads that improve the economics for gas storage, and 2) gas deliverability from storage reservoirs is assumed to decline at five percent per year.

2. The number of new gas storage reservoirs developed varies from four in the Base Case to 11 in the Technology Case. Only four demand regions are projected to add new storage capacity in any of the cases analyzed, the East North Central, West South Central, Mountain South, and California. As in the case of total storage capacity utilized, the two higher technology cases resulted in more demand for new storage capacity. The following table summarizes the numbers of new storage facilities selected for the two comparisons.

Summary Of New Storage Facilities

Region	Base Case	Technology	High Demand Case	High Demand Tech Case
East North Central	1	2	1	1
West South Central	1	2	3	2
Mountain South	0	5	0	3
California	<u>2</u>	<u>2</u>	<u>2</u>	<u>2</u>
Totals	4	11	6	8

3. The High Demand Technology Case shows the combined effects of the High Demand and Technology Cases. The number of new storage facilities added in the High Demand Technology Case is lower than in the Technology Case because of the increased power generation load that goes with the High Demand assumptions. This added load takes the place of storage because gas use for generation is typically a summer load that reduces the seasonality of demand, making better year-round use of pipeline capacity. However, two more new storage facilities are added in the High Demand Technology Case compared to the High Demand Case.
4. Typically, the impact on a potential storage reservoir from adding aggressive technology advancement to a given scenario: 1) raises the volume of working gas available in the reservoir, 2) increases reservoir deliverability, 3) raises the levelized investment cost, and 4) lowers the total fixed costs. These changes are observed in both of the comparisons made wherein improved technology assumptions were added to the Base and High Demand Cases.
5. Substantial pipeline capacity is added to transport gas from the Mountain North to Mid-Continent, Gulf of Mexico West to Texas Gulf Coast, and from the Mountain North to San Juan regions in all four scenarios. Other significant pipeline capacity additions are projected from Alberta to Canada East and on into the U.S. Northeast in all four scenarios and from the San Juan to the Permian in the two higher technology cases. Significantly, the two higher technology cases projected less demand for additional capacity on TransCanada Pipelines than the Base and High Demand Cases, as increased gas supply at lower prices reduced U.S. dependence on Canadian imports. The regions receiving gas through these pipeline expansions are not included in regions projected to need gas storage because in these instances pipeline capacity was determined to be more economic than storage.
6. Prices for the gas storage service used in the four scenarios vary widely within each storage region and among the four scenarios tested. Prices, based on company tariff rates for existing facilities and reservoir development cost estimates for new storage facilities, vary from as little as \$0.11 to as much as \$1.63 per Mcf stored. The lower prices are typically for older facilities that had lower investments for facility development and for the cushion gas.
7. Because GSAM is structured to recognize only two seasons and the winter season is 151 days long, the economic advantage of gas storage is very likely understated in this study. Since there is no recognition of the higher winter loads that typically occur for shorter periods, the full advantage of both peak shaving and shorter-cycle storage cannot be determined. As structured now, gas pipeline capacity is justified over 151 days of constant demand despite the fact that peak gas demands can be several times the average 151-day demand. Since pipeline capacity rarely can be justified for the gas demands of the coldest ten to 30 days of winter, the model's use of this average winter load is unrealistic. Shorter winter seasons are required to more realistically simulate the economics of storage and peakshaving.

I. INTRODUCTION

The Task 2 report for this project, completed in January 1996, focused primarily on describing the types, capacities, and costs of natural gas storage facilities that are available and the markets that gas storage is required to serve. The Task 4 report, completed in February 1997, described the modifications that have been made to the Gas Systems Analysis Model (GSAM) for evaluating prospective storage projects under varying technical, economic, and regulatory conditions. Initial tests of the modified model selected regional lists of existing storage facilities that are forecast to be utilized and of potential new storage reservoirs, including their costs of service. This Task 6 report provides the results of additional model tests under varying scenarios and additional analysis of Task 4 model runs -- emphasizing the effects that improved technology will have on comparison cases with similar economic parameters.

A. *Industry Developments*

New opportunities have been created for underground gas storage as a result of recent regulatory developments in the energy industry. The Federal Energy Regulatory Commission (FERC) Order 636 directly changed the economics of gas storage nationwide. Pipelines have been required to "unbundle" their various services so that pipeline users can select only what they need from among the transportation, storage, balancing and the other traditional pipeline services. At the same time, the shift from Modified Fixed Variable (MFV) rate design to Straight Fixed Variable (SFV) rate design has increased the costs of pipeline capacity relative to underground storage and peak shaving¹ options. Finally, the secondary market² in pipeline and storage services created by Order 636 gives potential gas users more flexibility in assembling combinations of gas delivery services to create reliable gas deliverability. In response to Order 636, the last two years have seen an explosion in proposals for gas storage projects.

Another major development affecting the demand for storage is the restructuring of the electric power industry. This trend began with the passage of the Public Utilities Regulatory Policies Act (PURPA), which allowed non-utility electric generators, or qualifying facilities, to provide electric power to electric utilities. Since 1978, substantial amounts of cogeneration and independent power capacity have come on line. Repeal of the Fuel Use Act enabled this capacity to be built with efficient gas-fired turbine technologies. The Energy Policy Act of 1992 and newly proposed FERC regulations will further facilitate the break-up of the electric power industry into independent generators, transmission companies, and distribution utilities. The fuel of choice for most cogeneration and independent power has been, and probably will continue to be, natural gas. Since many of these units are not the lowest cost generation sources available to a utility, they may not be operated full time. Thus, they use gas only intermittently over time.

B. *Project Objective and Analytic Approach*

The primary objectives of this project are: 1) to identify U.S. market areas and end use sectors where new natural gas underground storage capacity can be economically employed, 2) to provide the

¹ The two primary peak shaving options are liquefied natural gas (LNG) and propane and air mixtures. LNG supplies can be from imports and by liquefaction of pipeline gas during warmer months. Peak shaving operations are typically performed by local gas distribution companies (LDCs).

² Secondary markets for pipeline and storage services were created when Order 636 allowed the parties that have contracted for those services to resell their surplus capacity.

Federal Energy Technology Center (FETC) with a storage evaluation system that will provide the analytical tools necessary for FETC to evaluate storage requirements under alternate economic, technology, and market conditions, and 3) to analyze the feasibility of alternatives to conventional gas storage methods.

In order to meet these objectives, an analytic approach was developed to determine the critical decision parameters used by new storage field developers in deciding to develop a new storage project. These decisions focused on two areas:

- Technical Issues: What is the technical capability of the site including, working gas capacity, deliverability and injection rates, investment and operating costs, and location?
- Market Issues: Is there a market for the storage, considering the alternatives available in energy markets, including potential advancements in underground storage technology?

C. *The Uses of Underground Gas Storage and Its Operational Aspects*

In general, the operation of an underground gas storage facility typically involves: 1) injecting the desired volume of pipeline gas into the reservoir using pipeline pressure and onsite compressors to augment the pipeline pressure, if necessary, as reservoir pressure builds up during injection, 2) monitoring storage pressure during static periods to determine leakage rates, 3) withdrawing gas from the reservoir when it is needed, using reservoir pressure initially, 4) processing the stored gas to remove water, liquid hydrocarbons, and any other impurities, and 5) compressing the stored gas to pipeline pressure whenever the reservoir pressure is inadequate.

In the past, when most gas storage was used to supplement pipeline gas supply during the winter season when gas demand was highest, the operations described above were essentially a seasonal task (one cycle per year). Gas was withdrawn during cold weather and reinjected during the warmer months — with some injection during winter months, if temperatures moderated. With the restructuring of the gas industry under FERC Order 636 and rapid increases in high deliverability, salt cavern storage, new forces are at work shaping the way storage is used. The pipelines no longer control how most of the storage capacity is used. The downstream gas shippers, LDCs, and large consumers that have contracted for the storage make the decisions on when and how much to inject and withdraw. The pipelines have retained just enough storage capacity to manage their own operations. Pipeline company use of storage now is very like a surge drum to handle short-term differences in the amount of gas being placed into and taken from the line.

Although most shippers still use much of their storage capacity in the traditional way, to augment pipeline capacity in times of heavy seasonal demands, the following newer uses have gained importance in recent years.

1. *Balancing Supply with Demand*

Because a typical gas shipper cannot accurately estimate the amount of gas it will need every day, there will be daily imbalances between the gas the shipper places into the pipeline and takes from the pipeline. Some will take more gas than they placed into the pipeline and others will leave gas in the line. The pipeline can usually manage the net daily imbalance with its load management storage. If individual shippers have a substantial daily imbalance they can be charged a penalty amount for causing pipeline load management problems. More typically, the daily imbalances are acceptable and a monthly imbalance penalty is of more concern. Because monthly imbalance penalties charged by pipelines can be sizable, shippers frequently use storage to balance their gas supplies and demands.

2. Emergency Supply

In the past, when the gas pipelines were fully responsible for serving the contracted demands of their customers, problems with gas supply at the producer level were typically solved by the pipeline. The pipeline customers might have peak shaving supplies that would serve as emergency supplies for a few hours or days. When a pipeline had a supply problem, it used gas from its storage or obtained gas from other suppliers and/or pipelines. As common carriers, pipelines no longer have this supply responsibility, except for small portions of their throughput that is sold to very small consumers that cannot find and purchase their own gas and contract for transportation. Thus, shippers now need to have their own methods of handling supply emergencies. For supply problems that affect major percentages of their total supply or last for several days, gas storage is an obvious solution for shippers.

3. No-Notice Service

A relatively new service offered by gas pipelines that can provide shippers a substitute for having their own storage is no-notice service. If a shipper (that has contracted with a pipeline for no-notice service) experiences gas demand in excess of the pipeline transportation volume nominated for a day, the shipper can call on its pipeline to transport the deficit up to the maximum daily quantity of the no-notice contract. The pipeline has no obligation to provide the gas transported under no-notice service, however. The storage that the pipeline may need to supply this no-notice service can be a part of the operational storage capacity that FERC Order 636 allows interstate gas pipelines to retain.

4. Gas Marketer Operations

The unbundling of gas service by interstate gas pipelines, as required by FERC Order 636, combined with the desire of many past pipeline customers to retain a bundled supply and delivery service, has prompted gas marketers to offer this comprehensive service. To help balance their supply and delivery volumes and meet emergencies, many of the marketers have contracted for or purchased storage capacity.

5. Gas Producer Storage

Gas producers are using field area storage to help maintain a constant flow of gas from their wells and to back up their production commitments in case of field equipment problems. Both conventional depleted reservoir and salt cavern storage are used for these purposes.

6. Gas Market Hubs

FERC Order 636 encourages the development of market centers or hubs at locations where several interconnected gas pipelines can facilitate physical gas trades among multiple sellers and buyers. The need for storage to balance these physical trades on a day-to-day basis has led to many hubs being located where storage is available or is being developed.

7. Price Hedging and Speculation

Because of the fairly regular seasonal cycles in gas prices and the more general price volatility that exists since gas prices were decontrolled, there are opportunities for those who have storage capacity to buy gas when prices are at the lower end of the seasonal swings. LDCs and marketers that have storage capacity try to take advantage of these opportunities to minimize their gas costs. The challenge in this practice is to find a combination of a lower gas price plus a storage cost that is lower than the higher price of gas in the season of higher demand. These hedging operations use conventional gas storage.

Operators and users of high deliverability storage, which is several times as costly as conventional storage, can speculate on the rise and fall of gas prices -- cycling their capacity several times each year in some cases. The ability to cycle several times per year can offset the additional costs of high deliverability storage, if the speculator anticipates price swings accurately most of the time.

8. Injection/Withdrawal Patterns

An informative measure of average operations for gas storage facilities is their pattern of gas injections and withdrawals over a period of time. The DOE/EIA publishes monthly data on gas storage injections and withdrawals by states which show general patterns of gas flows in and out of storage.

In late 1993, the American Gas Association (AGA) began publishing weekly reports of estimates of the working gas storage, regionally and nationally. These reports for the first time give weekly data on net storage injection and withdrawal volumes. Since the AGA data do not show separate volumes for injections and withdrawals, the total in and out movements are missed. This omission is most critical in locations such as California, where high deliverability reservoirs and the lack of a severe winter season allow substantial short-term cycling of storage all year.

AGA collects the statistical information on underground storage from more than 35 companies which account for about 85 percent of total working gas capacity in the U.S. The report covers three regions (the producing area, the east consuming region, and the west consuming region) as well as national totals. The AGA regions are depicted in Figure I-1. AGA calculates the percent of the total working gas remaining in storage for the reporting companies and extrapolates this percentage to all of the U.S. storage facilities. So far, there appears to be a reasonable correlation between these reports and those of the DOE/EIA. The DOE/EIA monthly data are reported from a larger sample of storage operators.

Figure I-2 provides a summary of AGA weekly working gas volumes in storage for the three AGA regions and the U.S. total. Although the working gas volumes did not bottom out and peak in exactly the same weeks during 1994, the regional patterns are very similar. Storage gas reaches a minimum volume in March or early April when withdrawals are ending and peaks in November before the winter season withdrawal begins.

Figure I-1
AGA Underground Gas Storage Regions

Figure I-2
Estimated Working Gas in Storage, 1994

D. Modeling of Peak Shaving Gas Supplies

1. Regional Economics of Peak Shaving

As described in Chapter VI of the January 1996 Final Report for Task 2 of this project, peak shaving gas supplies are not the economic choice for incremental capacity to meet peak day gas demand in most regions of the U.S., when compared to underground gas storage. Only the New England, Florida, California, and the Pacific Northwest regions currently show an economic advantage for peak shaving over underground storage. However, peak shaving is used and is being expanded in some regions for reasons that are apparently outside of simple economic comparisons. Several definitions of terms should be clarified before proceeding with this discussion of peak shaving.

2. Definition of Peak Shaving

A common definition of peak shaving supplies is a supply of gas that an LDC or an end-user can access without depending on a delivery system outside of its own facilities. Thus, a major liquefied natural gas (LNG) storage and regasification facility used to enhance a gas pipeline's delivery capability does not qualify as peak shaving. The only peak shaving supplies of significance in the U.S. are LNG and mixtures of propane and air. Peak shaving supplies are usually expected to last for only three to ten days as supplements to other larger supply sources during periods of peak demand.

In recent years LNG has been the favored peak shaving gas supply as its costs have declined with improved refrigeration processes and equipment efficiencies. Propane/air mixtures have been in declining use for peak shaving and some facilities were being abandoned until the frigid eastern U.S. weather of January 1994 caused some rethinking of the value of these plants. One of the reasons for the decreasing popularity of propane/air is the incompatibility of propane in some uses of natural gas. For example, any significant propane contamination of compressed natural gas (CNG) used for vehicle fuel can result in gradual loss of tank capacity as propane condenses in the tank. In addition, propane/air must be diluted with large amounts of natural gas to be suitable for most gas burners, while LNG can be used undiluted. Despite this trend toward LNG in the selection of peak shaving supplies, those LDCs that have

major propane/air facilities are expected to continue using them. A major advantage of propane/air peak shaving is the potential for resupply of propane during the winter, while only the LNG storage supplied by LNG imports can be recharged in winter.

3. Justification of Peak Shaving Investments

Despite the fact that current comparisons show peak shaving to be economically inferior to underground storage in all but four regions of the U.S., existing peak shaving facilities continue to be used each winter and additional capacity is being constructed in the eastern U.S. A very large part of the justification of peak shaving for LDCs has to be the added confidence obtained by having what amounts to an emergency supply of gas within their own control. Peak shaving supplies represent an insurance policy for the coldest winter nights. This policy is important because interruption of supply to residential and commercial customers is taken as a very serious failure of a gas utility's obligation to serve, by their public service commissions, as well as the affected customers. The public relations costs and renewal of service costs for interrupted customers are not included in the economic comparisons made here for peak shaving vs. underground storage.

4. Model Assumptions for Peak Shaving Supplies

Peak shaving supplies are not modeled as variables in the gas storage module of GSAM for two reasons. First, GSAM is currently not structured to include a peak period of three to ten days duration (a third season) that is necessary to perform the economic evaluation of peaking versus other supply alternatives. This short season is necessary for evaluation of peak shaving economics because the relatively low investment cost and higher operating costs of peak shaving typically provide lower cost gas than storage does for only a few days of each winter. The second reason is that, in most consuming regions, peak shaving does not appear to be economically superior to storage, even for short time periods.

To account for the fact that both LNG and propane/air peak shaving is practiced for small volumes of gas supply in several consuming regions, the integrating module of GSAM has been designed to include the use of peak shaving gas volumes each winter. Only those regions that currently have peak shaving facilities are forecast to have peaking capacity in the future, and the only regions that are forecast to have peaking growth are those with announced projects. Since the use of peak shaving capacity can vary from zero to 100 percent from year to year, the annual use of peak shaving gas in each region is assumed to be 50 percent of the peaking capacity in the region. The Middle Atlantic region, which has the greatest peak shaving capacity of the 15 consuming regions, can store only 1.3 percent of its current gas demand for residential, commercial, and industrial customers. The highest percentage of supply represented by peaking capacity is in New England, at 1.8 percent of gas demand, for these same three consuming sectors. Thus, peaking supplies are not a large part of total North American gas supply and should not be expected to have much influence on the use of underground gas storage. A summary of the peaking volumes used in the model is provided in Table I-1.

The forecast costs of peak shaving supplies used by LDCs in all consuming regions that have these facilities are provided in Table I- 2.

Table I-1
Peak Shaving Gas Use Assumptions
(MMcf per Year)

LNG WINTER USE				
REGION	1995	2000	2005	2010
New England	4,050	5,050	5,050	5,050
Middle Atlantic	13,811	13,811	15,811	15,811
South Atlantic	6,558	8,558	8,558	8,558
Florida	-	-	-	-
East South Central	2,566	2,566	2,566	2,566
East North Central	4,975	4,975	4,975	4,975
West South Central	-	-	-	-
West North Central	4,312	4,312	4,312	4,312
Mountain 1	-	-	-	-
Mountain 2	913	913	913	913
California	-	-	-	-
Pacific Northwest	1,349	1,349	1,349	1,349
Canada-East	1,142	1,142	1,142	1,142
Canada-West	300	300	300	300
Northern Mexico	-	-	-	-
PROPANE/AIR WINTER USE				
REGION	1995	2000	2005	2010
New England	664	664	664	664
Middle Atlantic	453	453	453	453
South Atlantic	2,368	2,368	2,368	2,368
Florida	38	38	38	38
East South Central	547	547	547	547
East North Central	1,873	1,873	1,873	1,873
West South Central	-	-	-	-
West North Central	2,229	2,229	2,229	2,229
Mountain 1	11	11	11	11
Mountain 2	56	56	56	56
California	60	60	60	60
Pacific Northwest	56	56	56	56
Canada-East	-	-	-	-
Canada-West	-	-	-	-
Northern Mexico	-	-	-	-

Table I-2
Peak Shaving Gas Cost Assumptions
(\$/Mcf)

	1995	2000	2005	2010
LNG	5.84	6.67	6.53	6.40
Propane/Air	6.93	7.91	7.75	7.59

E. Regulatory Issues

1. Regulatory Jurisdiction

Most storage facilities have to comply with both FERC and state regulations. In those cases where the stored gas is involved in interstate commerce, FERC certification of the project prior to this development and FERC approval of the tariff is mandatory. In these cases, state and local authority will be limited to such items as approval of the site, environmental controls, safety requirements, and public health considerations. In those cases where gas storage will not be involved in interstate commerce, the state and local authorities would have complete jurisdiction at the level they deem necessary.

2. Tariff Rates

Typical rates for gas storage will include both fixed and variable charges that are based on costs of constructing, operating, and maintaining the facility. The fixed monthly charges are normally applied to the total volume of gas storage space reserved and the delivery rate required for gas withdrawals. The variable charges are applied to the volumes of gas injected and withdrawn. Recently, the FERC has approved "market-based" rates for a few storage facilities that are considered to be subject to sufficient competition from other storage facilities. Although tariff rates for storage are being discounted now by operators in areas where surplus capacity exists, the tariffs remain the best data source for existing storage service costs.

3. FERC Order 636

In April 1992, the Federal Energy Regulatory Commission (FERC) issued Order 636, "Pipeline Service Obligations and Revisions to Regulations Governing Self-Implementing Transportation Under Part 184 of the Commission's Regulations." This order marked the culmination of the restructuring of the natural gas industry.

To summarize the impact of the order, FERC determined that the traditional role of pipelines as gas merchants, purchasing gas at the wellhead and selling it to LDCs at the city-gate, was a hindrance to the development of a competitive gas market. FERC intended to make comparable the transportation of gas sold by pipelines and non-pipelines while maintaining the reliability of service.

Within this initiative, FERC unbundled storage from the sales and transportation functions of the pipeline. Pipelines with downstream storage could keep it "only to fulfill their obligations with respect to system storage management (load balancing) and 'no-notice' transportation." The rule intended for access to facilities to be on an "even, nondiscriminatory basis among all shippers." DOE/EIA has estimated that 80 to 90 percent of interstate working gas capacity will become available to previous pipeline customers under Order 636.³

In addition, the FERC encouraged the development of market centers as meeting places for gas purchasers and sellers. As a consequence, pipeline storage took on a new role within the industry. Without storage, the seller needs to find a buyer to receive his supply or else there is no sale. Storage allows market centers to provide intertemporal transportation between buyers and sellers. Some storage was transferred or leased to LDCs, some was leased to end-users who wished to insure an uninterrupted gas supply, and some was purchased by brokers, marketers or others with the intention to capitalize on the changes in market prices.

Under Order 636, pipelines were allowed significant latitude in penalizing shippers whose accounts were out of balance. In many cases, shippers experiencing fluctuating demand can use short-term storage to maintain balance, and thus avoid penalty.

Order 636 also raised the cost of pipeline transportation for consumers and resellers that do not have a steady demand for gas by mandating the straight fixed-variable (SFV) rate design. SFV shifts essentially all the fixed costs of gas transmission to the monthly demand charge for the pipeline capacity reserved. Now the only significant variable cost of transmission service is the compressor fuel used by the pipeline. This cost is typically a small fraction of the total transmission cost. Since the demand charge must be paid every month, regardless of the gas volume transported, shippers with low load factors (with wide variations in gas use) now pay more for gas delivery than when part of the fixed costs were

³ EIA. "The Expanding Role of Underground Storage," Natural Gas Monthly, October 1993.

included in the charges for gas actually delivered. This change to SFV rates for pipeline capacity has increased the economic attractiveness of storage use for some shippers — compared to paying the higher demand charges of pipelines. Thus, some shippers have increased their storage capacity to offset reductions in pipeline capacity reservations.

F. Organization of the Report

Following this introductory section, the report next presents descriptions of the effects that aggressive technology advancements for E&P and storage gas reservoirs can have on gas supply, demand, and prices and on the development and costs of gas and gas storage. These descriptions are followed by a section that summarizes the lessons learned in performing the Task 5 analysis. The section concludes with a discussion of the GSAM modifications that are recommended to provide a more robust tool for evaluating the need for gas storage and the impacts that the application of technology advancements can have on storage performance.

II. EFFECTS OF TECHNOLOGY ON DEMAND FOR GAS STORAGE

Two comparisons of test cases have been made to observe the effects of improved technology on the demand for natural gas storage. These two scenarios were designed to: 1) analyze the effects of improved technology for both E&P and storage reservoirs compared to a Base Case and 2) analyze the effects of improved technology on a High Demand Case for both E&P and storage reservoirs compared to a High Demand Case without improved technology. This chapter describes the results of these tests.

A. Test Case Scenarios

Four model run cases were tested to determine the effects on storage demand that result from changes in technology scenarios. A Base Case, using essentially the status quo for supply, demand, and price parameters, provides a scenario against which the Technology Case is tested. The Technology Case, assumes that E&P technology advances aggressively for both E&P and storage reservoirs. This reduces the cost of finding and producing gas, primarily through improved well completion designs and practices. Changes from the Base Case include the use of both advanced well stimulation techniques and horizontal wells in reservoirs where these completions are appropriate. The Base Case assumes that technology advancements are evolutionary for E&P and storage reservoirs.

The High Demand Case differs from the Base Case in assuming that gas wins in the competition with coal for power generation markets. Gas wins because it is assumed to be less expensive than coal and because gas-fired generation technology retains its efficiency lead over coal-fired technology. The High Demand Case assumes that technology advancements are evolutionary for E&P and storage reservoirs. The High Demand/Technology Case differs from the High Demand Case in that it assumes that E&P technology advances aggressively for both E&P and storage reservoirs.

Scenario Summary

Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Current electric mkt. for gas	Current electric mkt. for gas	Gas wins electric market	Gas wins electric market
Evolutionary E&P technology	Aggressive E&P technology	Evolutionary E&P technology	Aggressive E&P technology
Current environmental rules	Current environmental rules	Current environmental rules	Current environmental rules
Expand No.Border pipeline	Expand No.Border pipeline	Expand No.Border pipeline	Expand No.Border pipeline
Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline	Add Sable Island pipeline
Export gas to Mexico	Export gas to Mexico	Export gas to Mexico	Export gas to Mexico

All of the cases assume that only 50 percent of the working gas capacity for each active gas storage reservoir is utilized in a year. This assumption was made for several reasons. First, it is unreasonable to assume that all working gas is withdrawn from each active storage reservoir every year, because of the difference in severity of winter weather. Although the future average annual capacity utilization of gas storage reservoirs is unknown, an initial assumption of 70 percent utilization resulted in essentially no new storage capacity being developed. Even at the 50 percent level for storage capacity utilization, many existing storage reservoirs are not chosen for operation by the storage module. The operation of the integrating linear program of GSAM for finding optimal solutions to balancing supply and demand and the seasonal construction of GSAM both contribute to the low level of storage demand found in the four cases investigated. These modeling issues are described below.

The GSAM supply/demand integrating model optimizes the use of gas storage in balancing gas supplies and demand. In effect, it finds the least costly storage reservoir in a demand region and selects it for use, if its use results in lower gas costs than using additional gas pipeline capacity. The module uses

all of the capacity available in that reservoir before looking for the next more expensive storage reservoir and comparing its costs to those of pipeline capacity. If allowed to use 100 percent of each storage reservoir's working capacity, far fewer existing storage reservoirs would be selected for operation each year. The storage optimization process looks at current economics for using either storage or more pipeline capacity and develops an efficient solution based on the fixed and variable costs of deliverability. Through this process the storage module has indicated that many existing storage reservoirs are uneconomic. This is reasonable to some extent, because there are probably numerous existing storage reservoirs that would not be developed today in competition with new storage or other supply alternatives.

The fact that GSAM is structured to recognize two seasons in a year is a major improvement over many energy models in widespread use today. Two seasons, for example, allows for gas storage injection and withdrawal periods, and provides a basis for comparing the economics of using gas pipeline capacity vs. storage capacity. However, a winter season of 151 days adds bias against storage demand. Because the model assumes an average winter demand over 151 days rather than a shorter peak demand period and that any new pipeline capacity will be used for 151 days, pipeline capacity can be justified unrealistically. Substantially more storage capacity would be justified if it were to be compared with the costs of providing pipeline capacity for a few peak demand days each winter. Until GSAM is modified to handle a shorter winter period, the benefits of gas storage will not be fully recognized.

Despite these weaknesses in the GSAM analysis of demand levels for storage capacity, many valuable results have been developed through use of the storage module. The more efficient storage reservoirs in each region have been identified. Large differences in regional storage needs and excess storage capacities have been found. Major differences in the cost of using storage have been discovered. And lastly, the regional effects on storage demand from changing economic conditions and improvements in E&P technologies have been computed. These results are discussed in the following section.

B. Data Issues

Several problems exist in the data available for both the existing storage reservoirs and the depleted reservoirs that are available for development as gas storage facilities. The most comprehensive data available for existing storage reservoirs is the American Gas Association (AGA) 1993 Report, *Survey of Underground Gas Storage Facilities in the United States and Canada*. This source does not provide any porosity or permeability values and many reporting companies have not provided data for all of the facility parameters listed. These missing data prevented precise physical characterizations of the reservoirs involved. These problems were overcome by estimating the missing properties based on the properties that are provided, from conversations with storage operators, the knowledge ICF Resources has regarding reservoirs in similar plays, and use of the U.S. Geological Survey play data.

The major problem for potential storage reservoirs is the lack of a data base for depleted reservoirs in the Appalachian region. Because this region is so highly dependent on gas storage, this omission had to be overcome. The solution was to generate representative data for a set of potential storage reservoirs using play characterizations based on data for existing storage reservoirs in the region and U.S. Geological Survey play data for the reservoirs that may be future candidates for storage facilities. A second problem with the depleted reservoir data was that some very large multi-reservoir fields are reported by NRG Associates, Inc. as single reservoirs, thereby overstating all of the capacity data. This problem was handled by deletion from the data base used in the study all of the "reservoirs" that were judged to be so large that re-pressuring costs would be prohibitive.

C. Study Results

Although the results of the four test scenarios are not considered to be precise regarding the demand for storage, for the reasons described above, they do support the conventional wisdom that storage capacity is in surplus in some parts of the U.S. The following paragraphs summarize the study findings for storage demand, storage costs, gas supply and demand, gas prices, and pipeline capacity additions. The demand regions used are illustrated in Figure II-1.

Figure II-1
GSAM Demand Regions

1. Storage Demand

The total regional gas storage demand (including both existing storage facilities and reservoirs selected for development of new storage facilities) selected by the GSAM demand and integrating module for the four scenarios analyzed are summarized in Table II-1. These storage demand volumes represent annual gas extraction from storage.

It is obvious from Table II-1 that the total U.S. storage usage is greater in the two scenarios with aggressive technology than in the two comparative scenarios with evolutionary technology advancement. As will be shown later in this report chapter, the technology cases provide greater total gas supply and demand at lower prices than the two comparative cases, thereby increasing the market for gas and for storage. Table II-1 also shows that the High Demand/Technical Case uses less storage than the Technical Case. As explained later, any case that includes the High Demand Case parameter of increased electric power generation demand for gas reduces the demand for storage.

In all four scenarios, the demands for gas storage shown in Table II-1 decline over the forecast period. There are two reasons for this decline. First, there is the model assumption that storage reservoir deliverability declines by five percent each year. For those reservoirs that have lower deliverabilities, this deliverability decline sometimes means that the working gas available for withdrawal cannot all be extracted in the 151-day winter period. Thus, depending on their maximum gas extraction rates, the volume that can be withdrawn from individual reservoirs tends to decline unevenly during the 1995 to 2010 forecast period. The demand for new storage facility development is inadequate to make up for

these annual losses in withdrawal capacity. As explained earlier, the demand for new storage would likely be much larger if the GSAM winter season were structured to deal with peak demands rather than just a winter season demand.

Table II-1
Extraction Rates for Storage Gas, Bcf

Region	Base Case			Technology Case		
	2000	2005	2010	2000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	350	308	260	372	341	280
West South Central	208	169	137	227	188	148
West North Central	58	47	36	58	47	36
Mountain South	2	1	1	57	56	51
Mountain North	39	11	34	35	33	31
California	<u>62</u>	<u>56</u>	<u>48</u>	<u>78</u>	<u>72</u>	<u>59</u>
U.S.	1,077	905	765	1,185	1,050	854
Region	High Demand Case			High Demand/Tech Case		
	2000	2005	2010	2000	2005	2010
Mid Atlantic	203	182	144	203	182	144
South Atlantic	90	79	64	90	79	64
East South Central	65	52	41	65	52	41
East North Central	359	313	261	383	336	276
West South Central	227	189	156	231	192	155
West North Central	59	47	36	59	47	36
Mountain South	2	1	1	43	42	36
Mountain North	26	7	21	25	23	20
California	<u>67</u>	<u>61</u>	<u>52</u>	<u>74</u>	<u>68</u>	<u>59</u>
U.S.	1,098	931	776	1,173	1,021	831

The second reason for the declines in storage use is that most of the gas demand increases forecast are for electric power generation, rather than for temperature sensitive residential and commercial loads. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. The following table shows how the share of total gas demand used for electric generation grows in the four cases tested.

Shares of U.S. Gas Demand Used for Power Generation

CASES	2000	2005	2010
Base	20.0%	24.5%	25.5%
Technology	21.3%	26.8%	27.3%
High Demand	20.3%	26.1%	28.7%
High Demand/Tech	22.2%	27.3%	29.8%

2. New Storage Facilities Added

The number of new gas storage facilities selected by the demand and integrating modules for use between 2000 and 2010 varies from four for the Base Case to 11 for the Technology Case. All of the new storage facilities are forecast to start up in the year 2000. The regions where these new facilities are forecast to be added are summarized in the following table.

Summary Of New Storage Facilities

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
East North Central	1	2	1	1
West South Central	1	2	3	2
Mountain South	0	5	0	3
California	<u>2</u>	<u>2</u>	<u>2</u>	<u>2</u>
Totals	4	11	6	8

The demand and integrating modules select new reservoirs in only four regions for the four scenarios compared. Thus, of the 12 U.S. demand regions in GSAM, eight require no new storage capacity under any of the scenarios analyzed. All of the four regions that require new storage facilities, except the Mountain South add new storage in each of the four cases. The two cases with aggressive technology require the most new storage facilities at 11 and 8 reservoirs, respectively. The requirement for new storage capacity is lower in the High Demand/Technical Case than for the Technical Case for the same reasons described earlier for storage utilization and as further described below.

When comparing the Technology and High Demand/Technology Cases, all of the increase in gas demand that the High Demand/Technology Case sees is for fueling more electric power generation. Because gas demand for power generation is highest in warmer months in most regions, this added summer load takes the place of some gas storage by helping keep pipelines full year round. On the other hand, in the Technology Case, gas fuels a smaller share of power generation and the loss of this gas load causes gas demand to be more seasonal. Lower summer use of gas pipelines means that more new gas storage can be economically justified.

The differences in U.S. gas demand for power generation fuel and total demand for gas are summarized for each scenario in the following two tables.

Summary Of U.S. Gas Demand for Power Generation, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	3,322	3,424	3,354	3,440
2000	4,450	4,899	4,554	5,221
2005	5,924	6,936	6,387	7,074
2010	6,330	6,995	7,259	7,781

Summary of Total U.S. Gas Demand, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	20,108	20,304	20,152	20,324
2000	22,188	22,951	22,465	23,505
2005	24,216	25,890	24,511	25,912
2010	24,815	25,600	25,326	26,122

3. Use of Existing Gas Storage Facilities

Across the four cases studied, the projected utilization of existing working gas capacity in the ten regions that have underground storage facilities varies from zero to 100 percent. As an example, neither of the two storage facilities in the Pacific Northwest region are selected for use in any of the cases. In each of the four cases, gas demand growth in the Pacific Northwest is projected to be handled by additional pipeline capacity from the Rockies Foreland supply area. At the other extreme, the only storage reservoir in the Mountain South states of New Mexico and Arizona is always used. Similarly, in the Middle Atlantic and South Atlantic regions, storage capacity utilization varies from 97 to 100 percent in the four cases studied. In the other six regions storage capacity utilization ranges from 28 to 91 percent. The following table summarizes these storage utilization percentages in the year 2010 for the ten storage regions.

Summary of Capacity Utilization Rates for Existing Gas Storage in 2010

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Mid Atlantic	100%	100%	100%	100%
South Atlantic	97%	97%	97%	97%
East So. Central	91%	91%	91%	91%
East No. Central	60%	63%	61%	63%
West So. Central	83%	83%	83%	94%
West No. Central	49%	49%	49%	49%
Mountain South	100%	100%	100%	100%
Mountain North	74%	74%	74%	28%
Pacific NW	0%	0%	0%	0%
California	90%	90%	90%	90%
U.S.	74%	75%	75%	73%

Although we believe that these capacity utilization values do not show the true economic use of existing gas storage facilities, they do indicate the variation in storage needs among the regions. These values tend to support the general belief that storage is over-built in the East North Central, West North Central, and Mountain North regions. The high storage utilization rates in the Mid Atlantic, South Atlantic, and East South Central regions should be expected as these regions are directly involved in the gas flow to New England, where no underground storage is available and seasonal swings in gas demand are large.

The fact that the East North Central region is shown to need only about 60 percent of its storage capacity and yet adds one or two new facilities in each case occurs because many of the existing reservoirs have low deliverability rates per unit of their cost of service. Because of this poor economic efficiency many of the East North Central region storage facilities are not chosen for use in any of the

cases studied. The new storage reservoirs chosen for the East North Central have substantially higher gas deliverability rates per unit of cost than the existing facilities that are not selected.

In addition to the 11 new storage facilities developed in the Technology Case, as described earlier, the projected need for more storage capacity caused an additional six existing storage reservoirs to be used that were not used in the Base Case. Similarly, in the High Demand/Technology Case, an additional eight existing storage reservoirs are used that were unused in the Base Case along with the eight new reservoirs selected for storage development. A different trend occurs in the High Demand Case where only one additional existing storage reservoir is selected for addition to the six new storage facilities chosen and three existing storage facilities are shut down. All of the existing storage facilities that are shut down are in the East North Central region, except for one in the Mountain North region in the High Demand/Technology Case. This change in selection of which existing storage reservoirs to use is caused primarily by the more costly deliverability of many East North Central storage facilities. The following table shows the regions in which these changes in the use of existing storage facilities occur.

**Summary Of Changes In Existing Storage Facility Use
Compared To The Base Case**

Region	Technology Case	High Demand Case	High Demand/Tech Case
Middle Atlantic	No change	No change	No change
East South Central	No change	No change	No change
East North Central	4 Facilities Added & 1 Facility Dropped	1 Facility Added & 3 Facilities Dropped	4 Facilities Added & 1 Facility Dropped
West South Central	1 Facility Added	No change	3 Facilities Added
Mountain North	1 Facility Added	No change	1 Facility Dropped

4. Technology Effects on Storage Characteristics

At present, the GSAM model and storage modules cannot be used to accurately test existing storage reservoirs for the effects of technology advancements, because data for a large part of the existing storage reservoir capacity is not available and the storage module has been designed to work around this data problem. However, potential new storage reservoirs that are evaluated by the model for use as new storage reservoirs have been tested for the effects of improved technology. This report section describes the effects observed from four model runs that comprise two comparisons. A Technology Case is compared with a Base Case and a High Demand/Technology Case is compared with a High Demand Case.

Typically, the impact on a potential new storage reservoir from adding aggressive technology advancement to a given scenario: 1) raises the volume of working gas available in the reservoir, 2) increases reservoir deliverability, 3) raises the levelized investment cost, and 4) lowers the total fixed costs per Mcf. Since the technology advancements applied to gas storage reservoirs typically involve improvements in well completions, it is logical that less cushion gas is needed in a given reservoir, hence more working gas is available. Improved well completions can also enhance the deliverability of some reservoirs, unless, for example, the net pay is too thick to benefit from horizontal wells or fracturing is ineffective. In all cases observed, the cost of improved well completion technology raises the storage facility levelized investment when the cost of cushion gas is excluded. Total fixed costs, including the cost of cushion gas required for the reservoir, are typically lower with advanced technology involvement because less cushion gas is required and the price of cushion gas is usually lower in the technology cases.

Table II-2 provides six regional examples of how advanced technology affects the performance and costs of candidate reservoirs for storage service. Three of the sample reservoirs, located in areas where new storage reservoirs were more often chosen in competition with additional pipeline capacity, were selected for storage use by GSAM. The other three candidate reservoirs were not chosen for storage use. As should be expected, the levelized investment costs and total fixed costs for the reservoirs selected for storage service are substantially lower than the reservoirs not selected.

When comprehensive Appalachian reservoir data are available and the storage module is modified to allow application of technology advancements to existing gas storage reservoirs, the same types of effects on existing storage reservoir performance and costs as found for new storage reservoirs can be analyzed by GSAM. Results are expected to be similar to those in Table II-2 for new storage reservoirs.

Initially, the storage module was designed to analyze the effects of technology advancements on existing storage reservoirs despite inadequate reservoir data for the eastern United States. Poor history matching for costs and performance resulted in modification of the storage module to work around this data problem. This modification does not allow testing of existing storage reservoirs for the effects of new technologies.

5. Gas Pipeline Capacity Additions

In the process of optimizing gas supply to meet growing demand, the demand and integrating modules found that the efficient approach to increased gas deliveries was a mixture of adding gas storage capacity and more gas pipeline capacity. Table II-3 shows where pipeline expansions occur, when the expansions began, and how much pipeline capacity was demanded by the year 2010, for the four cases analyzed. The larger expansions were needed from the Mountain North to Mid-Continent, the Mountain North to San Juan, and Gulf of Mexico West to the Texas Gulf Coast regions. There also were major expansions on TransCanada Pipelines from Alberta to Canada East for all four cases and from the San Juan to Permian in the Technology and High Demand Technology cases.

It is significant that the two aggressive technology cases need less pipeline capacity from Alberta to the east on TransCanada Pipelines. The increased U.S. supply at lower prices made available by the E&P technology advancements reduces U.S. dependence on Canadian supply.

6. Storage Prices

Tariff rates for gas storage service are typically comprised of two monthly fixed charges, one for storage capacity and the other for withdrawal deliverability. Variable volumetric rates are charged for the amounts of gas injected and withdrawn and sometimes a separate fuel charge based on storage use. Typical variable rates would be one or two cents per Mcf injected and another one or two cents for volumes withdrawn. The fixed charges are many times the size of the variable costs, bringing the tariff rates of storage up to a range of from \$0.30 to \$1.40 per Mcf, depending on the age of the facility. Older facilities are typically much less expensive than newer ones. A major cause of this difference is the cost of the capitalized base gas in the reservoir. Today's base gas value can be ten times that of 25 years ago.

Table II-2
Examples of Technology Effects on Storage Reservoir Candidates

Storage Characteristic Region	Base Case	Technology Case	Change	High Demand Case	High Demand/ Tech Case	Change
<i>Mountain South (Selected)</i>						
Working gas, MMcf	18,083	18,644	561	18,083	18,644	561
Deliverability, MMcfd	52	65	13	52	65	13
Investment, \$/Mcf	\$ 0.10	\$ 0.11	\$ 0.01	\$ 0.10	\$ 0.11	\$ 0.01
Total fixed cost, \$/Mcf	\$ 0.47	\$ 0.31	\$ (0.16)	0.43	0.371	\$ (0.06)
<i>California (Selected)</i>						
Working gas, MMcf	54,913	57,575	2,662	54,913	57,575	2,662
Deliverability, MMcfd	176	178	3	176	178	3
Investment, \$/Mcf	\$ 0.10	\$ 0.11	\$ 0.01	\$ 0.10	\$ 0.11	\$ 0.01
Total fixed cost, \$/Mcf	\$ 0.50	\$ 0.40	\$ (0.10)	\$ 0.46	\$ 0.48	\$ 0.02
<i>West South Central (Selected)</i>						
Working gas, MMcf	55,288	57,366	2,078	55,288	57,366	2,078
Deliverability, MMcfd	155	178	23	155	178	23
Investment, \$/Mcf	\$ 0.10	\$ 0.11	\$ 0.01	\$ 0.10	\$ 0.11	\$ 0.01
Total fixed cost, \$/Mcf	\$ 0.50	\$ 0.38	\$ (0.12)	\$ 0.47	\$ 0.43	\$ (0.04)
<i>East N. Central (Not selected)</i>						
Working gas, MMcf	32,135	32,456	321	32,135	32,456	321
Deliverability, MMcfd	67	114	46	67	114	46
Investment, \$/Mcf	\$ 0.96	\$ 0.99	\$ 0.03	\$ 0.96	\$ 0.99	\$ 0.03
Total fixed cost, \$/Mcf	\$ 1.92	\$ 1.54	\$ (0.38)	\$ 1.89	\$ 1.57	\$ (0.32)
<i>Middle Atlantic (Not selected)</i>						
Working gas, MMcf	6,891	8,064	1,173	6,891	8,064	1,173
Deliverability, MMcfd	27	35	8	27	35	8
Investment, \$/Mcf	\$ 0.60	\$ 0.71	\$ 0.11	\$ 0.60	\$ 0.71	\$ 0.11
Total fixed cost, \$/Mcf	\$ 1.16	\$ 1.08	\$ (0.08)	\$ 1.13	\$ 1.11	\$ (0.02)
<i>West N. Central (Not selected)</i>						
Working gas, MMcf	40,938	41,570	632	40,938	41,570	632
Deliverability, MMcfd	94	133	39	94	133	39
Investment, \$/Mcf	\$ 0.37	\$ 0.39	\$ 0.03	\$ 0.37	\$ 0.39	\$ 0.03
Total fixed cost, \$/Mcf	\$ 0.96	\$ 0.72	\$ (0.24)	\$ 0.93	\$ 0.76	\$ (0.17)

Notes:

1. All reservoirs shown are gas reservoirs not currently in storage service.
2. Regions labeled (Selected) were selected by GSAM to be new storage reservoirs.
3. Investment costs exclude cushion gas purchases and are levelized over a 20-year life for the volume of gas withdrawn.
4. Total fixed costs include the cost of cushion gas.
5. All examples are from year 2010 projections.

Table II-3
Pipeline Capacity Additions, MMcfd Gas

Pipeline Route	Base Case			Technology Case			High Demand Case			High Demand/Tech Case		
	1995 Capacity	2010	Added	Years	2010	Added	Years	2010	Added	Years	2010	Added
	All Cases	Capacity	Capacity	Expanded	Capacity	Capacity	Expanded	Capacity	Capacity	Expanded	Capacity	Capacity
Alberta to Canada East	4,053	6,982	2,929	2005-2010	5,596	1,543	2000-2010	7,204	3,151	2005	8,653	2,800
South Louisiana to Florida	1,957	1,957	0	None	2,492	535	2000	1,957	0	None	2,492	535
Gulf of Mex.W. to Tex.Gulf Coast	2,662	6,606	3,944	2000-2005	6,869	4,237	2000-2010	6,903	4,241	2000-2010	6,663	4,021
Mountain North to Mid Cont.	385	8,580	8,195	2005-2010	9,437	9,052	2005-2010	8,832	8,447	2005-2010	9,519	9,134
Mountain North to San Juan	246	2,235	1,989	2000-2005	4,551	4,305	2000-2010	2,387	2,141	2000-2010	4,374	4,128
Mid Atlantic to New England	2,210	2,210	0	None	2,257	47	2010	2,210	0	None	2,257	47
Sable Is. to New England	0	400	400	2005	400	400	2005-2010	400	400	2005	400	400
Rockies to Pacific Northwest	254	415	161	2005	456	202	2005	810	556	2005-2010	793	539
San Juan to Permian	987	987	0	None	4,071	3,084	2010	987	0	None	3,708	2,721
Alberta to West N. Central	1,568	2,268	700	2000-2005	2,268	700	2000	2,268	700	2000-2005	2,268	700
Rockies to West N. Central	547	1,147	600	2000	1,147	600	2005	1,147	600	2000	1,147	600

The ranges of storage tariff rates for the facilities used in each region are summarized in the following table. Rates for the facilities not chosen by the storage module were in some cases substantially higher than the rates shown here.

Price Ranges For Gas Storage Facilities Used, \$/Mcf

Region	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Middle Atlantic	\$0.17 to \$0.92	\$0.16 to \$0.92	\$0.17 to \$0.93	\$0.19 to \$0.93
South Atlantic	\$0.26 to \$0.62	\$0.28 to \$0.62	\$0.26 to \$0.63	\$0.28 to \$0.63
Florida	None used	None used	None used	None used
East South Central	\$0.16 to \$1.13	\$0.16 to \$1.13	\$0.16 to \$1.13	\$0.17 to \$1.13
East North Central	\$0.15 to \$1.63	\$0.15 to \$1.38	\$0.21 to \$1.38	\$0.16 to \$1.38
West South Central	\$0.11 to \$0.90	\$0.11 to \$0.90	\$0.11 to \$0.91	\$0.13 to \$1.14
West North Central	\$0.30 to \$0.97	\$0.30 to \$0.97	\$0.30 to \$0.97	\$0.32 to \$0.97
Mountain South	\$0.22	\$0.22	\$0.22	\$0.22 to \$0.71
Mountain North	\$0.17 to \$0.78	\$0.17 to \$0.78	\$0.17 to \$0.78	\$0.20 to \$0.71
California	\$0.29 to \$1.04	\$0.29 to \$1.04	\$0.29 to \$1.04	\$0.31 to \$1.04
Pacific Northwest	None used	None used	None used	None used

These gas storage prices were developed in two ways. Prices for existing gas storage facilities were based on cost of service tariff rates filed by the owners or operators. Prices for new storage facilities were calculated, based on reservoir properties, the investments required to develop them, and estimated operating and maintenance costs. The procedure for calculating storage costs for the individual reservoirs in existing storage facilities and new facilities was described in Chapter IV of the Final Report for Task 4 under this contract.

7. Gas Supply

The GSAM net U.S. gas supply forecasts that support the storage demand results of this study vary from a low of 19,278 Bcf in the Low Demand Case for the year 1995 to a high of 25,708 Bcf for the year 2010 in the High Demand Case. These supply figures include U.S. gas production and peak shaving volumes, but exclude imports. The following table summarizes total supplies for each of the four scenarios.

Summary of Total U.S. Gas Supply, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	19,357	19,637	19,397	19,613
2000	22,027	22,559	22,253	23,028
2005	24,054	26,232	24,463	26,115
2010	24,222	25,708	24,728	25,902

Between 1995 and 2010 gas imports from Canada continue to grow as they have in recent years. By 2010 Canadian gas supply to the U.S. in the Base Case grows by another 15 percent, reaching 3,245 Bcf. In the Technology Case the 2010 total is 2,827 Bcf, an increase from 1995 of a little over one percent. This shows that improved technology can make the U.S. less dependent on Canadian gas. The same result is evident when comparing the High Demand and High Demand/Tech Cases. Canadian gas imports grow by 17 percent in the High Demand Case and only 11 percent when aggressive technology advancement is added to that case. A summary of Canadian gas imports for the four scenarios is provided in the following table.

Summary Of Canadian Gas Imports, Bcf

Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
1995	2,829	2,790	2,817	2,828
2000	2,522	2,768	2,600	2,935
2005	2,804	2,598	2,772	2,701
2015	3,245	2,827	3,296	3,140

8. Gas Prices

Improving E&P technology and an accessible resource base provide the foregoing supply volumes at relatively small price increases until the year 2010, when average U.S. prices for the preceding five years climb by 32 to 72 percent, among the four scenarios tested. The lowest average U.S. price projections are for the Technology Case, reaching only \$2.00 per Mcf by the year 2010. The highest 2010 price is found in the High Demand Case at \$2.35 per Mcf. Table II-4 summarizes gas supply prices for the total U.S. and several supply areas for the four scenarios analyzed

By the year 2010, the highest gas prices among all of the regions shown occur in the High Demand Case and the lowest prices are in the Technology Case. Consistent with history, the highest price seen in 2010 is in the Appalachian region at \$2.85 per Mcf in the High Demand Case. The lowest price in the year 2010 among all regions occurs in the Williston Basin at \$1.48 per Mcf in the Technology Case.

Table II-4
Summary Of Gas Supply Prices, 1993\$/Mcf

Location	Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
U.S. Average	1995	1.23	1.32	1.38	1.32
	2000	1.38	1.21	1.27	1.12
	2005	1.64	1.16	1.74	1.16
	2010	2.17	2.00	2.35	2.16
Rockies	1995	1.04	0.95	0.99	0.95
	2000	1.01	0.87	0.88	0.75
	2005	1.19	0.74	1.27	0.81
	2010	1.69	1.52	1.85	1.69
Alberta	1995	0.90	0.89	1.05	0.91
	2000	1.18	0.67	1.09	0.54
	2005	1.25	0.97	1.36	0.80
	2010	1.69	1.69	1.87	1.76
Gulf of Mex. West	1995	0.94	1.30	1.37	1.31
	2000	1.25	1.06	1.15	0.97
	2005	1.49	1.11	1.68	1.19
	2010	2.32	2.06	2.39	2.24
Appalachia	1995	1.63	1.55	1.62	1.55
	2000	1.67	1.46	1.57	1.38
	2005	2.02	1.52	2.12	1.59
	2010	2.63	2.54	2.85	2.73

The Technology Case, which has the lowest priced supply, predictably has the largest demand for gas. Under this scenario, the technology advancements are so robust that, even at the lower prices, gas reserves and production are able to support the increases in demand. These higher demands occur in each of the four major consuming sectors.

Examples of consumer prices in several demand regions that these gas supply prices translate to after adding delivery charges are summarized in Table II-5. The range of consumer prices is illustrated by the electric power generation and residential sectors. The five demand regions shown are the largest in the U.S. in gas consumption.

As should be expected, gas prices for power generation are lowest in the West South Central region where gas is plentiful and alternative fuel prices are relatively low. By contrast, residential gas prices for the regions shown here are highest in the Middle Atlantic states where gas transmission distances are greater and alternate fuel prices are relatively high. The higher gas prices for electric generation appear in the South Atlantic region. Residential prices are lowest in the East North Central region for all scenarios.

Table II-5
Examples of Regional Gas Prices for Electric and Residential Sectors, 1995\$/Mcf

Region	Sector	Year	Base Case	Technology Case	High Demand Case	High Demand/Tech Case
Mid Atlantic	Electric	1995	1.58	1.55	1.57	1.55
		2010	2.44	2.54	2.96	2.84
	Residential	1995	6.96	6.83	6.94	6.83
		2010	8.10	7.92	8.25	8.12
S. Atlantic	Electric	1995	1.56	1.55	1.55	1.55
		2010	2.74	2.73	2.66	2.95
	Residential	1995	6.47	6.34	6.45	6.34
		2010	7.68	7.48	7.82	7.68
E.N.Central	Electric	1995	1.50	1.47	1.48	1.46
		2010	2.31	2.31	2.86	2.75
	Residential	1995	4.99	4.87	4.98	4.87
		2010	6.07	5.89	6.23	6.08
W.S.Central	Electric	1995	1.36	1.33	1.35	1.34
		2010	2.21	2.18	2.54	2.40
	Residential	1995	5.14	5.02	5.12	5.03
		2010	6.17	6.00	6.34	6.18
California	Electric	1995	1.70	1.61	1.63	1.61
		2010	2.33	2.24	2.65	2.48
	Residential	1995	5.98	5.85	5.92	5.85
		2010	6.60	6.47	6.82	6.66

Following the same pattern seen in supply prices, the two cases with improved technology result in lower consumer prices than their comparison cases without the aggressive technology advancements. Thus, the cost reductions provided by advanced technology for E&P and storage reservoirs are passed on to consumers.

III. MAJOR FINDINGS FROM TASK 3 AND TASK 5 ANALYSES

Separately from the specific conclusions reached for each of the analytical tasks of this project, there are a number of more general findings that are summarized in this chapter.

A. *Demand for Storage Capacity*

As currently designed with only two seasons, GSAM is incapable of applying appropriate economic measures of the value of storage. Consequently, GSAM is biased toward adding pipeline capacity instead of storage. Evidence of this bias against storage appears in forecasts of storage usage. Some regions that have operating storage reservoirs today are shown as not needing any storage capacity. In some scenarios, existing storage reservoirs are dropped from active use while other existing storage reservoirs are added to the active list. Even though these model test runs have assumed that the maximum withdrawal of gas from each active storage reservoir is only 50 percent of the working gas capacity, the forecast average U.S. capacity utilization is only 75 percent of this restricted availability. Despite its severe winters, the East North Central region is projected to use only about 60 percent of its huge storage capacity.

Three of the regions that are projected to use nearly all of their available working gas capacity are ones that move gas toward New England that has no storage facilities and experiences large seasonal swings in gas consumption. Despite this full use of existing capacity, these three regions (East South Central, South Atlantic, and Mid Atlantic) add no new storage capacity in any of the scenarios tested.

B. *Demand for Pipeline Capacity*

Significant amounts of new pipeline capacity are projected by GSAM, but it is primarily for moving gas out of regions where large production increases are anticipated. The largest of these pipeline expansions are for moving gas out of the Rocky Mountains, to the Midwest and southward to the San Juan for redirection to the east and west. Other major pipeline expansions are out of the Gulf of Mexico West and western Canada. The only new pipeline capacity projected for New England is from Sable Island, beginning in 2005.

C. *Effect of Electric Industry Reorganization on Storage Demand*

If coal should become the favored fuel for power generation in the future, GSAM predicts that more storage capacity will be needed. This somewhat counter-intuitive projection is logical because gas demand is forecast to continue to grow in the other consuming sectors. The residential and commercial growth will increase the amount of winter demand relative to summer demand, thereby worsening the load factors of pipelines and making storage more economically attractive.

If gas should become favored over coal for power generation, the seasonal differences in gas demand will be reduced because electricity use is greater in summer for air conditioning in most regions. The less difference there is between summer and winter gas demand in a region, the more pipeline capacity can be economically justified to serve the region.

D. *Effects of Improved Technology on Storage Costs*

In the comparisons made, the application of improved technology typically increases the investment for new storage facilities because horizontal wells, fracturing, and other improved well completion techniques cost more than more conventional completions. However, the typical increase in working gas capacity in a reservoir results in purchasing less cushion gas. This reduced need for cushion gas, plus the lower price of gas in the higher technology scenarios, results in substantially lower projections for total fixed costs for new storage capacity. The range of total fixed cost decreases observed in a sample of new storage reservoir candidates using advanced technology varied from two to 18 percent.

E. *Effects of Improved Technology on Storage Deliverability*

The projected effects of improved well completion technologies on storage deliverability vary markedly, depending on the physical characteristics of the gas producing formation. The range of deliverability increases observed in a sample of new storage reservoir candidates using improved technology varied from 2 to 69 percent.

F. *Effects of Improved Technology on Natural Gas Supply, Demand, and Price*

GSAM model runs project the application of aggressive advanced technology for E&P and storage reservoirs will raise U.S. gas supply and demand and lower gas prices compared to scenarios with the same economic assumptions but only evolutionary technology changes. For the scenarios tested in Tasks 3 and 5 for this study, U.S. gas supply and demand increases created by technology vary from 2 to 9 percent between the years 2000 and 2010. U.S. average gas supply prices during this time period are projected to be from 8 to 33 percent lower when advanced technology is used.

G. *Effects of Improved Technology on Canadian Gas Imports*

The effects on Canadian gas imports from applying advanced technology on comparable GSAM test scenarios is an initial imports increase in the year 2000, then reductions through 2010. The range of reduced imports observed was from 3 to 13 percent.

IV. RECOMMENDED IMPROVEMENTS TO GSAM MODULES

In the course of analyzing model results for Tasks 3 and 5 of this project, the need for several improvements to three GSAM modules have become apparent. These three modules are the demand module, the storage module, and the integrating module. The importance of these improvements varies from some that are minor to others that are imperative for obtaining more precision in determining: 1) the level of storage capacity that is economic now and in the future, and 2) the impact of applying aggressive technologies to E&P and storage reservoirs. The recommended improvements are described below in approximate order of priority.

1. The demand module must be expanded to incorporate more than two seasons. Without shorter winter seasons to properly evaluate the economic benefits of underground storage and peak shaving supplies, the model will continue to be biased toward increasing pipeline capacity. Without this improvement, any model runs made can provide only indications of the effects of changes in economic and technology assumptions, not the quantitative effects needed for decisions on technology R&D projects.
2. Another major impediment to obtaining better quantitative results of storage demand and costs is the lack of comprehensive reservoir data in the Appalachian region. The lack of adequate data for reservoirs in the Appalachian region seriously constrained the ability to perform reasonable history matching on storage performance and costs in the eastern U.S. This severely restricts any analyses of the impact of aggressive technology advancements applied to existing storage reservoirs. Appalachian reservoir data are critical to the storage module because this region has 32% of the U.S. storage capacity.
3. When more comprehensive Appalachian reservoir data become available, the storage module needs to be modified to allow for testing the effects of technology advancements on existing storage reservoirs. Since deliverability improvement of existing reservoirs appears to be an industry trend, this module improvement should be given high priority.
4. The integrating module logic should be modified to balance supply and demand at one-year or five-year periods at time to avoid the unrealistic "perfect foresight" used now. Currently GSAM balances all future years simultaneously, limiting the number of bad decisions made in the near term because future supply, demand, and prices are foreseen.
5. The storage module assumption for storage reservoir deliverability decline should be changed from five percent per year to three percent per year.
6. The storage module assumption for storage reservoir well workover cycle should be changed from every two years to every five years.
7. The demand module needs to be modified to account for interfuel competition (including electricity) in the residential and commercial sectors. Without this change, GSAM will not be an adequate tool for evaluating the impacts of the competition gas will face from coal and electricity as the electric industry deregulates and reorganizes.
8. The integrating module should be modified to use individual supply curves for each production region, rather than use a national supply curve.

Numerous additional but lower priority recommendations for model improvements have been documented in the memorandum, "Recommendations from the GSAM Workshop February 5-6, 1997." These seven model improvements have been highlighted because they are considered to be more critical for enhancing the results of gas storage analyses.