Profile of Underground Natural Gas Storage Facilities and Market Hubs

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Preface

The INGAA Foundation is an organization of gas pipelines and suppliers to the natural gas industry. The INGAA Foundation commissioned Foster Associates, Inc. to prepare this profile of the business and structure of gas storage and market hubs in the United States and Canada.

This is the third in the Foundation's series of reports on the structural market characteristics of the natural gas industry. The first in the series, *Profile of Intrastate Gas Pipelines*, was published in 1993. The second report, *Profile of Natural Gas Gathering in the U.S.*, was published in 1994. Through these reports, the INGAA Foundation hopes to promote greater understanding of the natural gas industry.

EXECUTIVE SUMMARY

Introduction

New underground natural gas storage and market center hubs have been among the most dynamic aspects of the evolving North American natural gas markets. These developments stem from the impacts of FERC Order No. 636, which potentially increased the service value offered from these facilities. In particular, the Order shifted the responsibility of supply arrangements to end-use markets and mandated the change to straight fixed-variable rate design.

This report, prepared by Foster Associates on behalf of the INGAA Foundation, examines underground storage and market hub characteristics. We present an inventory of storage projects, including location, ownership and capacity of existing facilities as well as new and proposed projects, and discuss the underlying uses and relative benefits and costs. Market hubs are also discussed, with special attention given to developers, location, services offered, and how these services relate to other products offered in the market. Two appendices to this report describe many of the storage projects and market hub projects that are in various stages of development. Information in these descriptions is based on marketing information provided by developers, supplemented by publicly available data.

Underground Storage

- About 400 underground storage facilities are currently in operation across the U.S., offering 3.5 Tcf of working gas capacity and 70 Bcf per day of deliverability. In addition, 10 underground storage facilities are operating in Canada, with working capacity of 440 Bcf and deliverability of 7 Bcf per day.

- Market share of U.S. storage by type of owner is summarized on the following table.

STORAGE OWNERSHIP BY COMPANY TYPE (Percent)		
	Working Gas Capacity	Maximum Deliverability
Interstate Pipelines	61.2%	51.4%
LDC	29.6%	36.1%
Intrastate Pipelines	6.5%	7.3%
Other a/	2.7%	5.2%
TOTAL	100.0%	100.0%

a/ Principally independent storage developers and producers.

- While interstate pipelines own 61 percent of the U.S. working gas storage capability, they have contracted the vast majority of storage capacity to their customers, primarily local distribution companies (LDCs), retaining an average of 13 percent of the 61 percent of U.S. working gas capacity for operational needs and to provide no-notice service.

- LDCs own 30 percent of the U.S. storage capacity, with the largest concentration of ownership in the East North Central area and in California. Total LDC control of working gas storage capacity is 83 percent, including their ownership and storage contracted from interstate pipelines.

- Traditionally, LDCs have invested in and contracted for storage capacity primarily to meet their seasonal and peak day requirements. However, the recent unbundling of services at the LDC level has resulted in LDCs offering storage on a contract basis to third parties, both onsystem and offsystem customers. A survey of the largest LDC storage owners found that those controlling 80 percent of the working gas capacity do offer storage service to third parties.

- Gas storage capacity ownership in Canada differs from that in the U.S. In total, Canadian producers own 31 percent, distribution companies own 55 percent and pipelines own 14 percent of the total working gas storage capability.

- About 60 new storage facilities in the U.S. are proposed or are in various stages of development. If all of these facilities were to be constructed (which is unlikely), they would add almost 500 Bcf of working gas capacity and about 19 Bcf per day of withdrawal capability, or 14 and 26 percent, respectively, to existing storage capacity and capability.

- In Canada, LDCs and producers are the primary developers of new and expanded storage, with a proposed total of 62 Bcf of working gas or an increase of 14 percent.

- Several reasons exist for the current interest in gas storage: (1) improved competitive positioning of storage services (e.g., impact of shifting to a straight fixed-variable cost allocation and rate design methodology and unbundling of pipeline services); (2) new services offered by storage (e.g., market hub services); (3) new market demand potential (e.g., power generation); (4) potential for market-based rates; (5) development of multi-use storage facilities; and (6) desire to take advantage of short-term price fluctuations in gas supply costs.

- New gas storage facilities differ in many important respects from traditional storage: (1) storage developers are now a diverse group, and many are developing storage capacity on a stand-alone basis, with success based upon its relative economics, rather than as a means of meeting bundled service requirements; (2) many storage projects are being developed as joint ventures; (3) several storage projects have requested and obtained FERC's permission to offer services at market-based rates; (4) storage providers are advertising much greater flexibility of services and in many instances these services are "custom-tailored" to customer specifications; and (5) over 60 percent of new storage deliverability is being developed in salt dome facilities rather than depleted fields and reservoirs.

- Important and desirable storage facility characteristics include the following: (1) relatively high withdrawal/injection capability and fast turnaround capability; (2) relatively high volume of working gas as a percentage of total gas (e.g., low cushion gas requirements); (3) ability to increase reservoir pressure without leaking gas into adjoining formations; (4)

potential of native gas to be used as cushion gas; and (5) location in shallower reservoirs, thereby reducing drilling costs.

- One important consideration of storage is location, i.e., market area or production area. Storage location relates closely to how it is used, its ownership and its relative economics. Production area storage can be used by suppliers to improve operational efficiency by leveling wellhead production rates and pipeline throughput volumes. Market area storage is traditionally used to improve market efficiency by meeting peak and seasonal requirements, resulting in higher load factors for long-haul transmission capacity.

  Underground storage capability is spread throughout the U.S., with heavier concentrations of market area storage in the North Central (West and East) and Middle Atlantic regions, and production area storage in the West South Central region.

- The three types of underground storage facilities are depleted oil and gas fields, aquifers, and salt caverns. The table below presents several statistical characteristics of the different storage reservoirs.

GENERAL STATISTICAL CHARACTERISTICS
OF U.S. UNDERGROUND STORAGE

Characteristics	Depleted Fields	Aquifers	Salt Caverns
Number	332	46	20
Capacity			
Working (Bcf)	3,081.2	329.0	90.8
Maximum Deliverability (Bcf/d)	54.4	7.8	8.1
Maximum Injection (Bcf/d)	23.7	3.5	2.5
Maximum Days to Withdraw a/	57	42	11
Maximum Days to Inject a/	130	94	36
Percentage of Cushion Gas a/	52%	72%	33%

a/ Based on average of all facilities. Major variation exists among facilities. Also, in many instances, maximum days to withdraw working gas from storage is overstated because most storage facilities cannot maintain maximum deliverability rates at low inventory levels.

- The relative economics of storage are complicated by the variety of benefits offered by storage on the one hand and the array of rates and associated costs on the other. To an important extent, the benefits relate to the type of business of the user, as well as the storage location. Producers/marketers derive benefits from greater field production efficiency, contractual advantages, and the use of storage as a risk management tool. The economic value of storage to interstate pipelines is lower today than under a bundled sales environment; pipelines' need for storage has been reduced to quantities that support no-notice service and pipeline operations. Local distribution companies (and end users) derive the greatest value from storage. Benefits of storage to LDCs include the following: (1) assistance in meeting seasonal and peak day demands, thereby minimizing firm transportation and/or no-notice service requirements; (2) enabling levelized or off-season gas purchases; and (3) a risk management tool.

- The storage user must weigh the aggregation of the components of storage costs against the benefits in order to decide if storage is economical. Total storage costs include the cost of storage itself, fuel costs, costs associated with transportation capacity to and from storage, and the inventory cost of holding gas in storage. Because of fixed reservation (deliverability) charges for firm service, the average cost level for high deliverability storage can be significantly reduced with multiple cycling capability that spreads the demand charge over greater volumes. In addition, storage costs to meet needle peak demand (e.g., 10-day service) are higher than the cost of meeting seasonal requirements (e.g., 100-day service), because the former requires a higher daily contract demand level for which a monthly reservation charge applies.

Market Hubs

- About 35 major market centers and hubs have sprung up across the U.S. and in Canada. Few of these existed prior to the implementation of FERC Order No. 636. Those that did exist were primarily market centers or locations of multiple buyers and sellers in the producing areas.

- Market centers become hubs by offering a greater menu of services, including parking, loaning, wheeling and title transfer, as well as electronic trading at the hub and between hubs. While these services are now advertised, they are defined less specifically than other gas industry services and are evolving as dictated and/or requested by customers.

- Hubs are being developed and promoted by various industry participants -- pipelines, distributors, producers, marketers and independent operators. The services they provide depend on the hub location and available facilities.

- Many hub services are being provided alongside other services being offered by LDCs and pipelines. To some extent, therefore, these services can be considered as by-products of the main services offered by these companies. As a result, certain issues have evolved -- firm versus interruptible service obligations, regulatory jurisdiction and revenue sharing.

- Two of the more important hub characteristics are the number of pipeline interconnections (along with associated capacity) and the availability of storage capacity. Hub promoters generally advertise the number of interconnecting pipelines, directional flow and capacity, proximity to more important centers (e.g., the Henry Hub) and access to storage. Many hubs have onsite storage capacity that permits parking or loaning of gas volumes for various durations of supply or market disruptions. In fact, many traditional and new storage developers are advertising themselves as hubs, rather than just providers of storage.

- Hubs post rates for the services they perform; however, competition and the uncertainty of the value added by hub services have resulted in sharp discounting of these rates at most hubs. Many industry participants feel that the number of hubs and the services they offer will be reduced by competitive forces.

I. INTRODUCTION

Under contract with the INGAA Foundation, Foster Associates,[1] Inc., has prepared this report pertaining to underground gas storage and market hub characteristics. With respect to underground storage, we first present an inventory of storage projects, including location, ownership, and capacity of existing storage facilities, and then identify new or proposed storage facilities, followed by a discussion of uses and relative benefits and costs. With respect to market hubs, the report focuses on the developers, hub location and service offerings, and how these products relate to other products offered in the industry.

There are three appendices to this report. Appendix A-1 presents information about numerous individual storage projects, Appendix A-2 presents selected storage project maps, Appendix B-1 describes several market hubs, Appendix B-2 presents selected market hub maps, and Appendix C is a statistical appendix.

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1 William G. Foster directed the research, assisted by Rebecca Reddick, Eric Smith, David Neal, and Patricia Bradley.

II. UNDERGROUND STORAGE

The use of underground gas storage facilities is almost as old as the development of long distance transmission lines. Long distance, high pressure transmission lines began operations in 1891 with the successful construction of two parallel 120-mile, 8-inch diameter lines from fields in northern Indiana to Chicago.[1] The first successful gas storage project was completed in 1915 in Welland County, Ontario. The following year, operations began in the Zoar field near Buffalo, New York. Today, nearly 400 underground storage facilities are located in the U.S., with working gas capacity of 3.5 Tcf and maximum daily deliverability capability of 70 Bcf.[2] In addition, ten underground gas storage facilities operate in Canada, with working capacity of 440 Bcf and maximum daily deliverability of 7 Bcf.

The ability to store gas and use these supplies when needed improves market efficiency with respect to both production and transmission, as illustrated by Figures 1 and 2. Figure 1 depicts the uneven U.S. gas load pattern throughout the year created by the residential/commercial winter heating load swings. Certain northern markets have seasonal swings that are much more severe.[3]

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1 See Economics of Natural Gas in Texas - Stockton, Henshaw and Groves - 1952.

2 Total storage capacity consists of working gas and cushion gas. Working gas is the gas that can be withdrawn, while cushion gas is base gas, sometimes called native gas, that cannot be withdrawn because it is used to maintain pressure and deliverability rates.

Maximum deliverability is the highest achievable one-day withdrawal rate. This maximum is generally not sustainable during withdrawal of all working gas because most fields lose deliverability as the level of working gas inventory is reduced. Maximum deliverability can be maintained only if year-round injections/withdrawals are possible. Because of this limitation and market demand for sustainable service, new projects are being designed with year-round injections and withdrawals, and existing storage providers are implementing such services (e.g., Panhandle Eastern's Flexible Storage Service).

3 For example, 62 percent of the East North Central gas market is residential/commercial heating load, compared to 40 percent of the U.S. as a whole. This results in a regional market load factor of only 33 percent in this market, compared to 41 percent nationally.

U.S. NATURAL GAS CONSUMPTION (1/92 - 12/94)

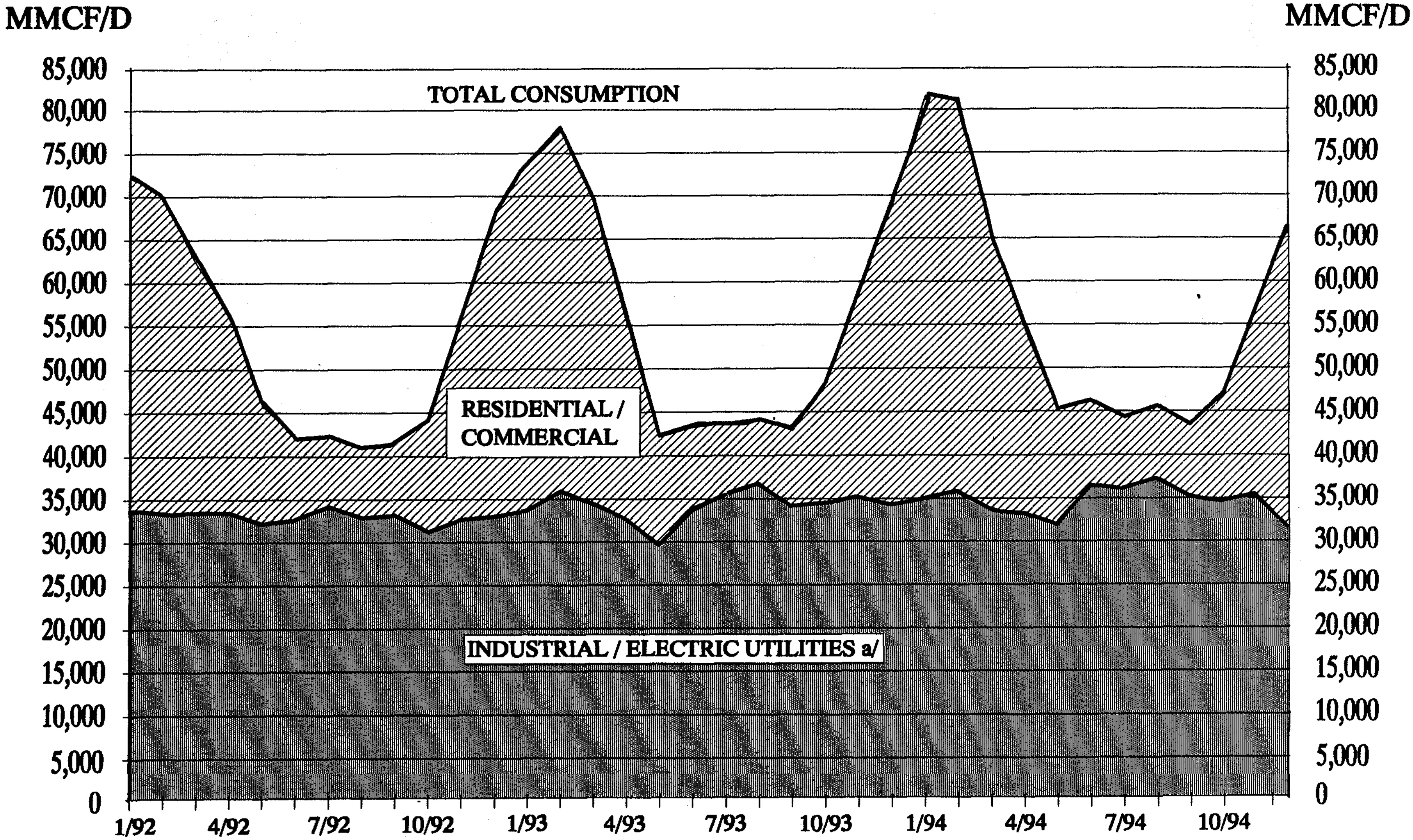

FIGURE 1

a/ Includes Lease and Plant Fuel and Pipeline Fuel.

Note: Total consumption levels depicted here will not equate to total supply levels shown on Figure 2 due to "losses and unaccounted for".

Substantial regional market differences in total gas requirements are depicted on the following table.

Table 1

MARKET REQUIREMENTS
(MMcf/d)

Region	Annual (1993)	Peak Day a/ 1993 (Actual)	Peak Day a/ Normal	Peak Day a/ Design	Estimated Market Load Factor (Percent)
New England	1,409	3,048	3,200	3,840	37%
Middle Atlantic	6,049	13,833	14,800	16,472	37%
East North Central	10,000	23,001	26,500	30,210	33%
West North Central	3,884	9,716	11,200	12,768	30%
South Atlantic	4,554	8,854	10,300	11,495	40%
East South Central	2,706	5,937	6,115	6,715	40%
West South Central	16,737	25,557	28,800	29,952	56%
Rocky Mountain	2,883	5,655	6,956	7,985	36%
Pacific Northwest	1,089	2,441	2,618	2,901	38%
Pacific Southwest	5,304	8,997	8,648	9,513	56%
Lower 48 States*	54,614	107,039	119,137	131,851	41%

* May not compute due to independent rounding.

a/ Non-coincidental.

Source: Foster Associates, Inc.

Figure 2 illustrates that storage withdrawals are the means by which seasonal peak requirements are met, as opposed to fluctuations in production and/or imports. Production occurs at a relatively even pace, either directly meeting market requirements or providing storage injection gas for future use. Thus, the availability of storage allows producers to satisfy needs with fewer (drilled) wells.

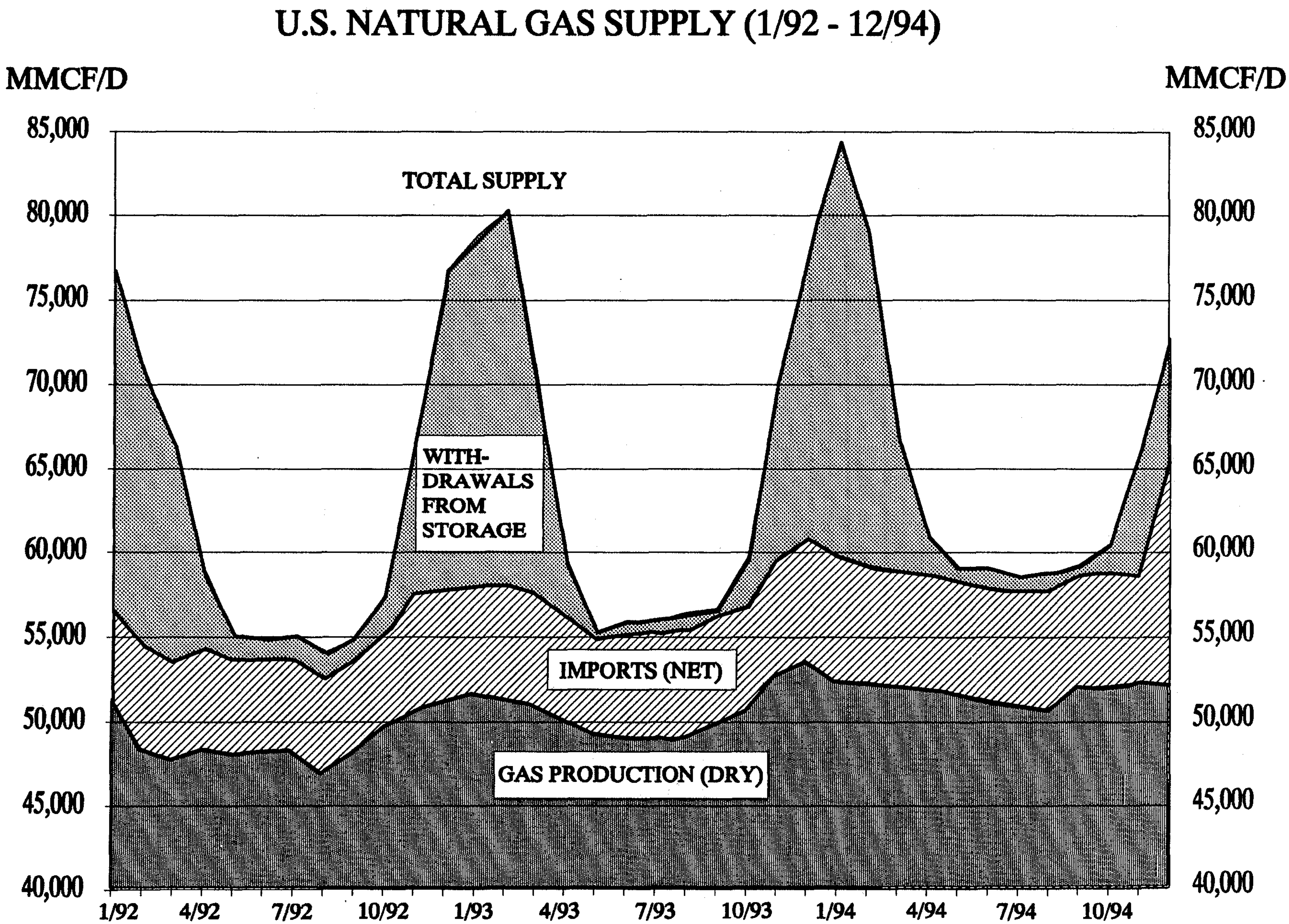
U.S. NATURAL GAS SUPPLY (1/92 - 12/94)
MMCF/D
MMCF/D
85,000
80,000
75,000
70,000
65,000
60,000
55,000
50,000
45,000
40,000
TOTAL SUPPLY
WITH-
DRAWALS
FROM
STORAGE
IMPORTS (NET)
GAS PRODUCTION (DRY)
1/92
4/92
7/92
10/92
1/93
4/93
7/93
10/93
1/94
4/94
7/94
10/94

FIGURE 2

Factors that affect whether or not gas reservoirs will make good storage reservoirs are both geographic and geological. The greater the porosity of the rock, the faster the rate of injection and withdrawal. The size of the reservoir, the thickness of the gas-bearing rock stratum and the extent to which the stratum is covered by cap rock are also important factors.

Specifically, important storage reservoir characteristics include the following:

(1) Withdrawal/injection capability as a percentage of working gas. From the perspective of the storage customer, the higher this percentage, the better. The maximum withdrawal or injection capability depends on the porosity and permeability of the reservoir. Some other determinants of withdrawal/injection capability include the quality of the surface and downhole facility, such as compression horsepower and pipe diameter.[1]

(2) Working gas as a percentage of total gas. Total gas in storage is comprised of working gas and cushion gas. Only working gas is withdrawn from storage. Cushion gas represents an investment cost, and cushion gas as a lower percentage of total gas is preferable. Depleted gas fields may have natural gas already present (i.e., native gas), thereby reducing or eliminating the need for additional cushion gas supplies. Aquifer pools and salt domes require the purchase of cushion gas, which adds to cost, although the proportion of cushion gas for salt dome storage is generally less than for aquifers.

(3) Pressure integrity of the reservoir. The ability to increase storage reservoir pressure without leaking gas into adjoining formations is a desirable characteristic so that greater quantities of gas can be stored. If the reservoir is totally surrounded by impermeable rock, overpressuring the reservoir may be possible without gas breaking out and escaping. Usually, salt caverns can be overpressured without problems. In contrast, overpressurizing an aquifer reservoir or depleted gas field with an underlying water column can result in pushing the gas down to the water zone and permitting escape from the storage pool.

(4) Composition of native gas. Pipeline quality cushion gas is preferable so that working gas injected into the reservoir will not be contaminated. If contamination occurs, then impurities must be removed.

[1] Horizontal wells rather than vertical wells can improve injection/withdrawal capability.

(5) Depth of reservoir. Generally, shallow reservoir depths are preferable because deeper storage reservoirs require higher drilling costs.

Storage Location

Storage location is a very important consideration. For example, if the reservoir is not close to existing transmission lines or market areas, the developer may incur greater expenses to establish connections with pipelines.

Storage location affects how the facility is used, its ownership and its relative economics (each of which is discussed below). Storage can generally be classified as either market area or production area storage.

Production area storage is generally utilized to improve efficiency of delivery capability by leveling wellhead production rates and pipeline throughput volumes. More recently, production area storage has also been used as a marketing tool, and in conjunction with market center hubs (see Section III).

Market area storage is traditionally used to improve market efficiency by meeting peak and seasonal requirements, resulting in higher load factor usage of long-haul transmission capacity. In addition, market area storage offers other advantages, such as risk management options.

Underground storage capability is spread throughout the U.S., with heavier concentrations in the North Central, West South Central and Middle Atlantic regions. The following table and two maps (Figures 3 and 4) depict the concentration of storage facilities and capacity across U.S. census regions.

Table 2

UNDERGROUND GAS STORAGE CAPACITY

Region	Working Gas Capacity (Bcf)	Maximum Deliverability (Bcfd)
New England	0	0
Middle Atlantic	477	8.2
East North Central	1,167	23.4
West North Central	173	3.9
South Atlantic	185	3.4
East South Central	161	4.6
West South Central	764	16.7
Rocky Mountain	340	2.6
Pacific Northwest	22	0.6
Pacific Southwest	212	7.1
TOTAL*	3,501	70.3

* May not compute due to independent rounding.

Schedule 1 of the Statistical Appendix (Appendix C) presents the inventory of total U.S. underground storage: the name of the project, state location, operator, type of storage, and size of storage, including working gas, total capacity, injection and maximum daily withdrawal capability. Schedule 2 of Appendix C shows similar information for Canadian storage projects.

REGIONAL WORKING GAS STORAGE CAPACITY (BCF)

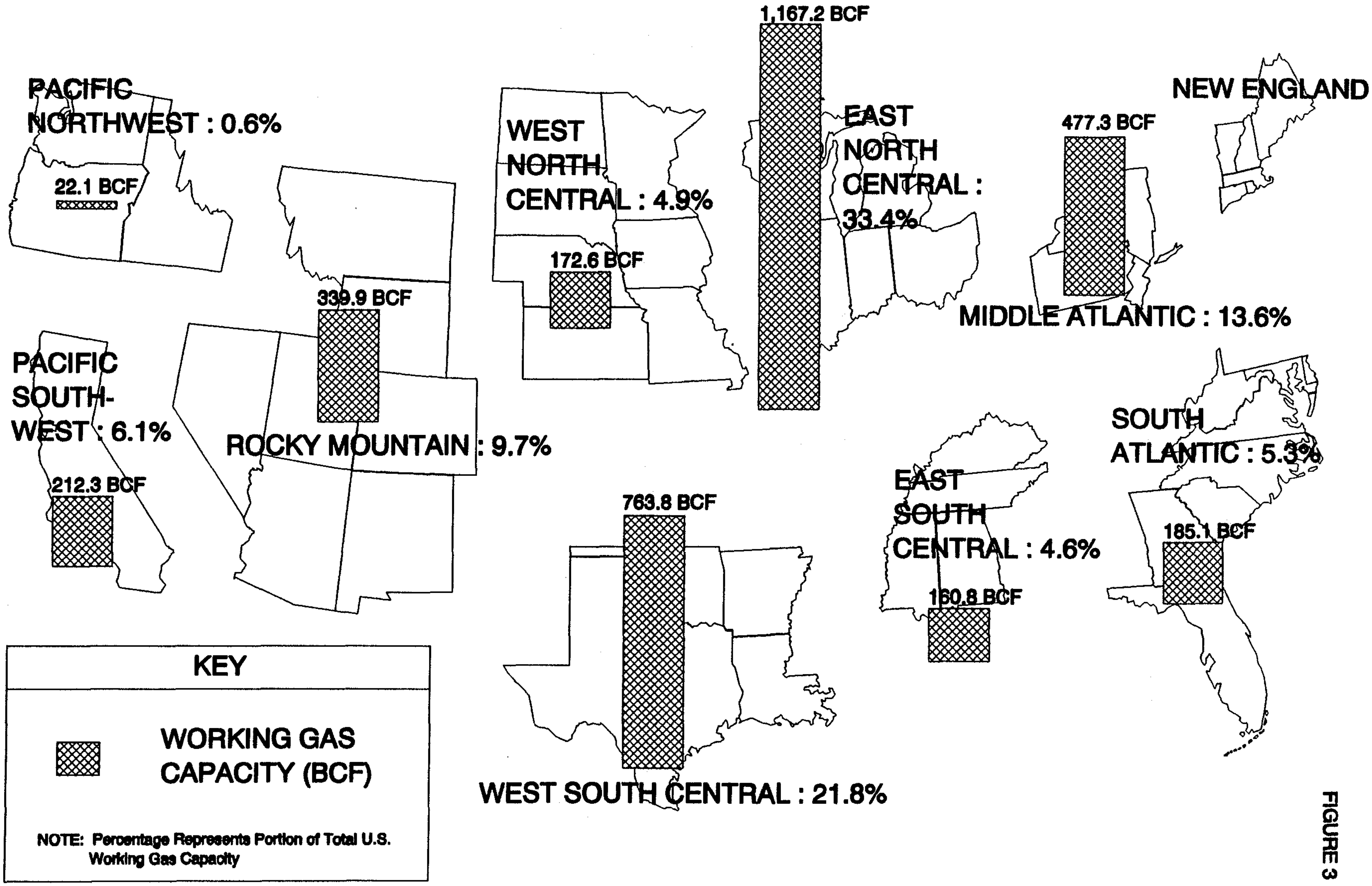

FIGURE 3

REGIONAL MAXIMUM DELIVERABILITY (BCF/D)

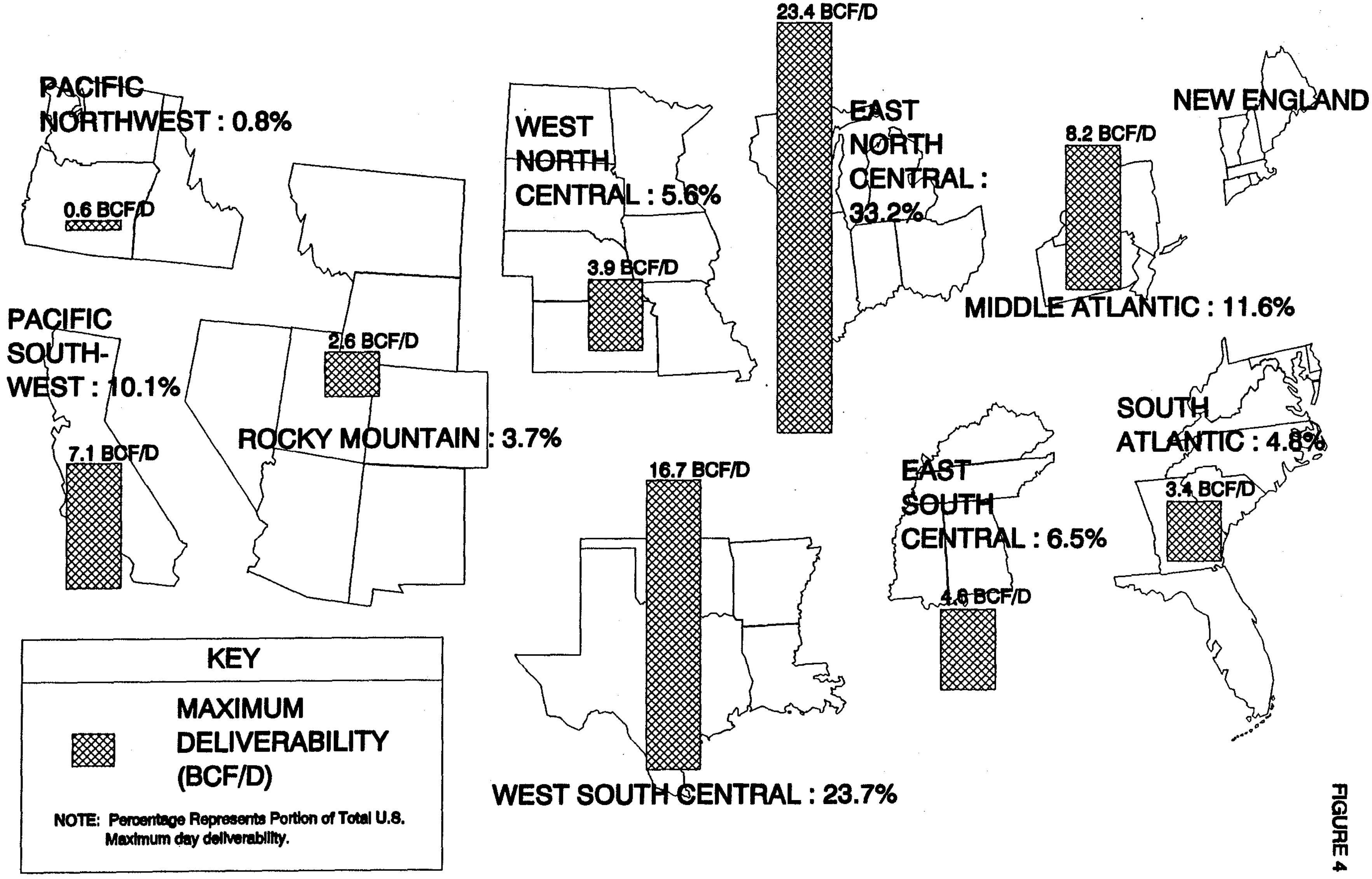

FIGURE 4

Market area storage is used in various ways, although the primary purpose is to meet seasonal and peak day requirements. The following table shows the extent to which peak day requirements are met by storage, pipeline capacity and other means in nine U.S. regions.[1]

Table 3

PEAK DAY SUPPLY/DEMAND (MMcf/d)

Region	Net Pipeline a/ Capacity	Storage	Peak Shaving b/	Local Production	Total
New England	2,457	--	2,007 c/	--	4,464
Middle Atlantic	7,026	8,197	2,656	500	18,379
East North Central	16,806	23,356	1,873	718	42,753
West North Central	7,778	4,104	1,802	878	14,562
South Atlantic	6,022	3,400	2,560	231	12,213
East South Central	3,864	4,607	1,140	502	10,113
Rocky Mountain	4,862	2,571	126	2,032	9,591
Pacific Northwest	2,096	550	601	--	3,247
Pacific Southwest	7,295	7,086	42	862	15,285

a/ Net pipeline capacity is gross capacity into a region minus capacity out used to serve other regions.
b/ LNG and propane air.
c/ Includes Distrigas LNG.

Source: Foster Associates, Inc.

As shown on Table 3, the proportion of maximum day storage withdrawal to total peak supply varies across markets, from a high of 55 percent in the East North Central region to no storage withdrawals in New England. While areas like New England have no local storage, companies within these areas rely on storage in other areas. However, in doing so, they have to have pipeline capacity from the storage to the market.

1 The Southwest region is not shown because the majority of its storage is classified as production area storage.

Ownership

U.S. storage market share by type of owner is presented on the following table.

Table 4

STORAGE OWNERSHIP BY COMPANY TYPE
(Percent)

	Working Gas Capacity	Maximum Deliverability
Interstate Pipelines	61.2%	51.4%
LDCs	29.6%	36.1%
Intrastate Pipelines	6.5%	7.3%
Other a/	2.7%	5.2%
TOTAL	100.0%	100.0%

a/ Principally independent storage developers and producers.

Interstate pipelines own 61 percent of the total working capacity and 51 percent of maximum deliverability from storage. The largest pipeline owners are CNG, ANR Pipeline, Columbia and Natural (via working capacity, see Schedule 1 of Appendix C). Interstate pipelines' storage operations and rates are regulated by the FERC. As pipelines have unbundled their services pursuant to Order No. 636, they have contracted the vast majority of the storage capacity to their customers, primarily LDCs. In turn, LDCs use this storage to meet system requirements or release or resell such capacity.[1] Interstate pipelines have only retained a portion of their storage capacity for operational needs, including system balancing requirements and the ability to offer no-notice service to customers. In total, pipelines have retained only 13 percent of their storage capacity for operational purposes. This percentage is based on a weighted average of retained storage versus pipeline working

[1] Thus far, there has been only limited capacity release activity in storage capacity, largely because the concept and practice of unbundled storage is new to the industry. In addition, LDCs are the largest contractors of storage and they can readily pass through storage capacity costs to their customers and/or use storage for bundled services (e.g., the direct sales market). To date most releases of firm transportation capacity have been short-term (e.g., one month). One month of released storage capacity would have very little value, if any.

capacity. (Source: Pipeline restructuring orders re FERC Order No. 636 and Schedule 1 of Appendix C.)

Distribution companies comprise the second largest group of storage owners, controlling about one-third of the U.S. capacity. The largest LDC owners of storage are Michigan Consolidated Gas, Northern Illinois Gas, Southern California Gas, Consumers Power and Pacific Gas & Electric (see Schedule 1 of Appendix C). The largest concentrations of ownership are in the East North Central region and in California. These percentages, of course, do not include the storage capacity contracted by the LDCs from interstate pipelines; thus, the total LDC control over U.S. storage capacity is 83 percent including their own share (30 percent), plus any storage contracted from interstate pipelines (53 percent).

Traditionally, LDCs invest in and contract for storage capacity primarily to meet system seasonal and peak day requirements. However, the unbundling of services at the LDC level has resulted in LDCs also providing contract storage services for third parties -- both onsystem and offsystem customers. Foster Associates surveyed the largest LDCs owning storage, as part of this study, to determine which offer storage service to onsystem and/or offsystem customers. The results of this survey are summarized in Table 5.

The surveyed LDCs own about 85 percent of the LDC-owned storage capacity in the U.S. Of the companies surveyed, those controlling over 80 percent of working gas capacity offer storage service on a contract basis to third parties, and most of these companies (again by capacity) offer such service to onsystem and offsystem customers. Most of the LDCs that offer storage service do so on both a firm and interruptible basis.

Intrastate pipelines also own storage, primarily in the producing states of Texas and Oklahoma. In certain instances, these companies are affiliated with electric and gas utilities operating within the state and regulated by state public service commissions. For example, if a Texas intrastate pipeline provides sales service to LDCs, then the company is regulated by the Texas Railroad Commission. In Oklahoma, intrastate pipelines are generally regulated by the Oklahoma Corporation Commission.

Table 5

RESULTS OF SURVEY
OF LDCs OFFERING STORAGE SERVICES
TO THIRD PARTIES
(as of April 1995)

LDCs	Yes	No
Arkansas Western		None offered
Citizens Gas & Coke Utility		None offered
Consumers Power	Existing contracts *	
East Ohio Gas		None offered
Illinois Power		None offered
Indiana Gas		None offered
Lone Star	On-system	
Louisville Gas & Electric		None offered
Michigan Consolidated Gas	On-&-Off System*	
Montana Power	On-&-Off System*	
Northern Illinois Gas	On-&-Off System **	
ONG		None offered ***
Peoples Gas Light & Coke	On-System*	
Peoples Natural Gas	On-System*	
Pacific Gas & Electric	On-&-Off System*	
Public Service of Colorado		Program on hold
Southern California Gas	On-&-Off System*	

* Company provides firm service.
** Company provides firm service for on-system customers.
*** ONG has offered such services in the past.

In addition to pipeline and LDC owners, other parties own storage, primarily producers and independent storage developers. Producer-owned storage, generally located in the Southwest, is used to enhance delivery capability and as a marketing tool.

Independent storage companies have grown and continue to develop gas storage projects as an attractive investment opportunity.

Gas storage ownership in Canada is different than in the U.S. The gas pipelines generally do not own a large share of the storage. Rather, producers (e.g., AEC and Amoco) own the majority of the storage capacity in producing areas and distribution companies (particularly Union and Consumers) own the storage in market areas. In total, Canadian producers own 31 percent, distribution companies own 55 percent, and pipelines own 14 percent of total working capacity (see Schedule 2 of Appendix C).

<u>New Storage Development</u>

About 60 new storage facilities are proposed or are in various stages of development. These projects are listed in Schedule 3 of Appendix C, together with location, type of storage and announced capacity or additions. (These projects are not listed in Schedule 1 of Appendix C unless they are currently operational.) If all of these facilities were to be constructed, they would add almost 500 Bcf of working gas capacity, and about 19 Bcf per day of withdrawal capability. These additions would raise existing working capacity and withdrawal capability by 14 percent and 26 percent, respectively. Total investment in the projects would be in the order of $2 billion.

Proposed storage capacity expansions in Canada total 62 Bcf of working gas, representing an increase of 14 percent (see Schedule 4).[1] LDCs (e.g., Canadian Western and Union) and producers (e.g., AEC and Amoco) are the primary developers of new or expanded storage. There has been a large increase in producer developer storage since 1992 due to increasing demand for Canadian gas in both the United States and in Canada and the increase in export capacity from Canada to the United States.

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[1] Similar to the U.S., the proposed increase in deliverability (32 percent) in Canada is higher than the increase in working gas capacity.

Reasons for this current interest in storage include the following:

- Improved competitive positioning of storage service, resulting from pipelines shifting to a straight fixed-variable cost allocation and rate design methodology;

- Required unbundling of pipeline services, allowing creation of competitive stand-alone storage services;

- New services facilitated by storage, particularly market hub and market center services;

- Greater demand for supply reliability, stems (in part) from the shift in supply responsibility to LDCs and end users;

- New market demand potential (e.g., power generation via combined cycle units), requiring quicker capacity response;

- Potential for market-based rates;

- Development of multi-use storage facilities;

- Need to resolve receipt/delivery imbalances more quickly to avoid penalties; and

- Desire to take advantage of short-term price swings.

Many new services facilitated by storage can be characterized as short-term services.[1] These include (1) system balancing -- daily and/or monthly reconciliation of nominations and deliveries between buyers and sellers; (2) emergency backup -- use of storage gas as backup source of supply in case of production failure or non-delivery, (3) no-notice service -- to ensure delivery of the difference between customer's daily nominations and the actual requirements on that day, and (4) price hedging -- the use of storage to hedge seasonal or short-term price period differentials. These services require substantially more operational

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1 Storage facilities may be classified as seasonal reservoirs and/or high deliverability sites. Seasonal sites are designed to be filled over most of non-heating season (April - October), with withdrawal during most of the winter heating season (November - March). High deliverability sites are situated to provide rapid withdrawal rates or rebuilding of inventory in response to peak demands, emergency backup and/or system load balancing. High deliverability sites can be drawn down in 10-20 days and generally refilled in 30-40 days or less.

flexibilities than traditional seasonal storage programs, such as the ability to inject and withdraw gas on a continuing basis throughout the year and the ability to withdraw large quantities of gas quickly to respond to surges in demand or to replace lost production.

To provide a more detailed picture of new storage development, Appendix A-1 to this report includes descriptions of 32 geographically dispersed storage facilities. Some of the projects are in operation while others are in various stages of development. Maps depicting facility locations and accessible transmission lines are provided (see Appendix A-2) for many of these projects. Wherever possible, the report has used actual marketing information provided by the storage developers for project summaries.[1]

The new storage facilities differ in many important respects from traditional storage:

- Storage developers are a diverse group, and most are developing storage capacity on a stand-alone basis with success based upon the capacity's own relative economics, rather than as a means of meeting a bundled service requirement. Developers of new projects includes LDCs, pipelines, producers, marketers, and independent companies.[2] Most developers of U.S. projects are generally U.S. companies; however, Canadian companies (e.g., Union and TransCanada) are also investing in U.S. storage projects. In some instances, producers' interest in storage stems from their ownership of depleted resources. Others are interested in storage in order to provide market hub services. For example, Tejas Power recently formed Market Hub

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[1] The information on storage projects (and market hubs) was collected over the first half of 1995. The dynamics of these projects are such that ownership, regulatory status, rates, proposed services and other characteristics are likely to change beyond the mid-1995 period.

[2] Examples of each type of owner include:

LDCs:	MichCon, CMS, NYSEG, Union
Pipelines:	Enron, Panhandle Eastern/TETCO, CNG, Williams, CIG, NFGS, Questar, ANR Pipeline
Producers/Marketers:	Chevron, Entre, Natural Gas Clearinghouse, Hamilton, Equitable Resources
Others:	Tejas Power, HNG Storage, McFarland, Makowski, Midwest Gas Storage

Partners (other partners are New Jersey Resources, Miami Valley Leasing, NIPSCO, and Public Service Electric & Gas) to develop storage and market hubs jointly. This joint development includes current several projects already involving affiliates of Tejas: Moss Bluff, Egan, MS-1, NE-1, and the Grands Lacs market center. In addition to high deliverability storage services, these projects will offer cash market trading, title transfers, and other hub services.

- Many storage projects are being developed as joint ventures, in which partners generally seek a stand-alone investment opportunity or usage to supplement natural gas businesses (e.g., meeting system requirements and/or as a marketing tool). Examples of joint ventures are Avoca and Cayuta, Washington 10, MS-1, NE-1, Egan, Moss Bluff, Riverside, and Thomas Corners.

- Several storage projects that are under FERC jurisdiction either as interstate pipelines or subject to Section 311 regulations have requested and obtained FERC permission for market-based rates. These include Richfield (Kansas), Transok (Oklahoma), Petal (Mississippi), Bay Gas (Alabama), Ouachita River (Louisiana) and Avoca (New York).[1]

- Storage providers are advertising much greater flexibility in services, and in many instances these services are "custom-tailored" to customer specifications. Services include year-round injection and withdrawal capability, greater response time (e.g., less than one-hour notice), much greater withdrawal capability (e.g., 10-day withdrawal), multiple-cycling (up to 10 to 12 times per year), and a menu of hub services (e.g., parking, loaning, title transfer and wheeling).

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1 Other storage projects with pending requests for market-based rates include Thomas Corners, Enron (Napoleonville, Louisiana), Entre Energy (Offshore LA), Llano (New Mexico), and Northern Natural (Kansas and Iowa). FERC has denied requests by ANR Pipeline (Michigan) and MichCon (Michigan).

To an important extent, these new storage services stem from the nature of salt dome facilities, where about 60 percent of the new storage deliverability is located. The balance of capacity is generally being developed in depleted fields, and only minor increases are planned in aquifer facilities. As discussed below, in many instances the salt dome caverns offer major operational advantages over the other types of storage.

Types of Storage and Characteristics of Each

The three types of storage are depleted oil and gas fields, aquifers, and salt caverns. These types of facilities have different capabilities and characteristics. The following figure illustrates the various types of storage.

Table 6 summarizes several statistical characteristics of the different storage types. Following this table are specific discussions related to each.

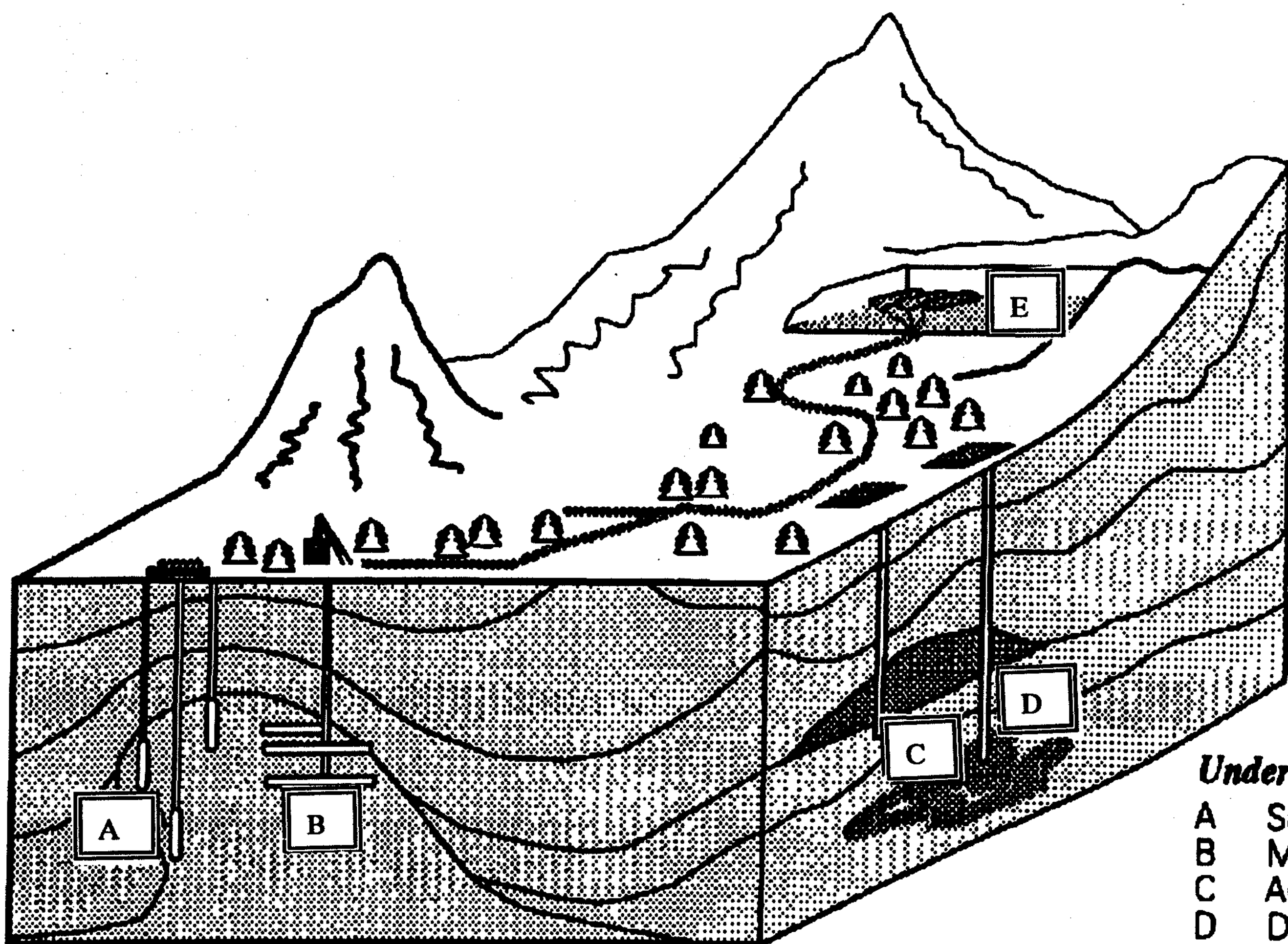
Table 6

GENERAL STATISTICAL CHARACTERISTICS
OF U.S. UNDERGROUND STORAGE

Characteristics	Depleted Fields	Aquifers	Salt Caverns
Number	332	46	20
Capacity			
Working (Bcf)	3,081.2	329.0	90.8
Maximum Deliverability (Bcf/d)	54.4	7.8	8.1
Maximum Injection (Bcf/d)	23.7	3.5	2.5
Maximum Days to Withdraw a/	57	42	11
Maximum Days to Inject a/	130	94	36
Percentage of Cushion Gas a/	52%	72%	33%

a/ Based on average of all facilities. Major variation exists among facilities. Also, in many instances, maximum days to withdraw working gas from storage is overstated because most storage facilities cannot maintain maximum deliverability rates at low inventory levels.

Illustration of the Various Types of Underground Storage



Underground Storage In:

A Salt Caverns
B Mines
C Aquifers
D Depleted Reservoir
E Hard-rock Caverns

Source: PB-KBB Inc., "Underground Storage and Subsurface Systems": Recreated by Energy Information Administration, Office of Plan Management, and Information Services.

Depleted Oil and Gas Fields

By far, the largest proportion of existing underground storage is in depleted oil and gas fields, which account for 88 percent of working capacity and 77 percent of current deliverability.

Developed oil and gas fields used for underground storage are gas pools or "traps" filled with gas. All traps consist of porous rock, sealed overhead by an impermeable rock layer called "cap rock," and sealed laterally either by impermeable rock, structural closure or a water contact. The trap may or may not have a bottom seal.

Depleted oil and gas reservoirs are the most commonly used underground storage sites because of their wide availability. These reservoirs use the pressure of stored gas, in some cases assisted by water infiltration pressure, to drive withdrawal operations. Daily deliverability rates from depleted fields vary widely because of differences in the surface facilities, base gas levels and the flow characteristics of each reservoir. In order to use abandoned gas reservoirs for storage, one or more wells used for extraction may be used to inject gas. As with extraction, the more porous the rock, the faster the rate of injection can be, but as pressure builds up in the reservoir, the rate of injection slows down.

Depleted fields have an advantage in that large working gas capacity makes them useful for meeting seasonal requirements, and may allow gas cost savings via offseason purchases. In addition, depleted gas fields have native gas present that can be used as base gas. Base gas requirements can be as low as 20 percent, but average slightly over 50 percent.

High deliverability can be achieved in a depleted oil and gas reservoir if the reservoir rock has high porosity and permeability (allowing a rapid flow of gas) and the reservoir has sufficient base gas pressure to maximize withdrawals. In general, however, storage withdrawal capability in depleted fields is lower and the cycling capability is generally longer in duration relative to capabilities of salt caverns. Horizontal drilling techniques are now being used to develop storage capabilities of newly depleted fields' facilities as well as to enhance withdrawal capabilities of existing storage fields.

Aquifers

An aquifer is a porous and permeable geological formation that contains water under pressure. Approximately 9 percent of total underground gas storage capacity is of this type. Aquifer storage is similar to structural trap storage. The only difference is that gas is originally present in the structural trap storage, but not in aquifers. Gas is injected at high pressure into an aquifer via wells and displaces water from the top of the structure. Once an aquifer is filled with gas, the gas/water contact stabilizes at that level. At this point, a portion of the gas can be withdrawn for storage use, although base gas (or cushion) must be left in the structure to prevent water from refilling the reservoir. Gas loss and water contamination are common problems with aquifer storage.

A large portion of U.S. aquifer storage capability is located in Indiana and Illinois. While aquifer storage reservoirs are typically high capacity, the cushion gas requirements are also high, averaging about 72 percent of total gas in the reservoir. In addition, withdrawal capability is about the same as depleted fields (i.e., depletion generally takes a full winter season).

Aquifer sites are usually used as storage reservoirs only when depleted producing reservoirs are not available. Aquifer storage facilities can be costly to build, and they must be managed according to carefully defined injection and withdrawal schedules. Several reasons tend to limit development of aquifer storage sites: (1) about four years are needed to explore, test and prepare the site -- completely new equipment must be installed, including well pipes, dehydration facilities and compressor operations; (2) no native gas is present in an aquifer formation, thus base or cushion gas must be injected into the reservoir to build and maintain pressure; and (3) the Environmental Protection Agency (EPA) has issued new regulations that tightly restrict future development of aquifer storage facilities in an effort to avoid potential contamination of available water supplies.

Salt Caverns

Salt cavern storage pools are developed in thick salt formations (beds or domes) by using water as a solvent to mine a cavern out of salt. Only about 3 percent of existing working gas capacity and 12 percent of deliverability are attributable to salt caverns. However, a larger proportion of the planned new storage is in salt caverns -- about one-third of the new working capacity and two-thirds of the new deliverability.

Promoters of salt cavern projects identify the following service features:

- Provide peaking service to meet needle peaks;
- Provide gas supply to replace lost production due to weather-related outages;
- Provide short-term balancing of load swings to avoid pipeline imbalance penalties; and
- Provide spot gas purchase strategies including off-peak and weekend injections followed by peak/weekday withdrawals and monthly or daily spot hedging.

Salt domes have unique properties that make them ideal for gas storage, including (1) structural strength, permitting large caverns to be constructed, (2) virtual impermeability to liquids and gaseous hydrocarbons, thus ensuring that stored products cannot escape through the salt, (3) behavior similar to plastic, allowing domes to close and seal fractures that might occur, and (4) easy mining by water.

Both salt bed and dome storage are prepared by injecting water (leaching) into the salt cavern to create or reshape the cavern. Due to this development process, salt cavern formations are the most costly of the three types of facilities to construct. Because they are susceptible to cavern wall deterioration over time and to salt movement closure, high workover costs may be incurred, as well as additional expenses for special equipment on site.

On the other hand, deliverability rates are high because salt formation reservoirs are essentially high pressure storage vessels. In addition, operators have the ability to shift between injections and withdrawals within a short period. Thus, salt cavern storage (1) generally provides an ideal means of daily and monthly balancing, and (2) permits coverage of a large supply outage for as long as five to ten days until other supplies can be purchased and transported during a period of sustained gas demand. Base gas requirements are generally low, around 30 percent, and even some of this gas can be withdrawn in an emergency. Salt cavern formations are also capable of multiple cycling of inventories, in comparison to the typical one-year cycling for depleted oil and gas fields and aquifer storage. However, the relatively low working capacity does not make salt caverns the most suitable type of storage for seasonal load use.

Most salt cavern storage is designed for rapid cycling: an operator can change from injection to withdrawal mode and vice versa within half an hour. Most new salt cavern installations are designed for 10 to 20 day service, permitting the working gas to be withdrawn in this period. The combination of this withdrawal capability and the necessary compression to replenish the field in a short period allows working gas volumes to be cycled monthly.[1] Deliverabilities can be as high as 300-500 MMcf per day from a single cavern with 3 to 5 Bcf of working gas capacity.

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1 While maximum cycling capability of this degree is advertised, such ability has yet to be proven useful to users.

Another advantage of salt cavern storage is that it can be developed in phases. Because of the time needed to construct caverns and market the capacity, most companies prefer to develop and operate one cavern at a time.

Economics of Storage

The economics of using storage are determined by its relative costs and benefits. An analysis of the relative economics must consider, on the one hand, the variety of benefits offered by different storage uses and, on the other, the array of rates and other costs (such as associated transportation) of contracting and using storage.

For convenience, this discussion is organized by industry segments -- producers/marketers, pipelines, and LDCs. To an important extent, the usage of storage, and therefore the benefits, relate to the type of business of the user, as well as the storage location. The fact that a large share of producer/marketer storage is located in upstream producing areas, while a large share of the LDC storage is located downstream in the market area, is not coincidental.[1] Pipelines own or offer storage capacity in both upstream and downstream markets because of traditional benefits to users in both locations.

Producers/Marketers

Producers/marketers, as users, derive benefits from storage as the result of greater field production efficiency, contractual advantages, and its use as a risk management tool. A primary storage benefit to producers is the reduction in wellhead production costs. Producers can operate at a relatively constant production rate year-round, with gas produced during the offseason being injected into storage. If storage were not available,

[1] Notwithstanding this general relationship, there are increasing exceptions: producer/marketers are contracting for market area storage and LDCs are contracting for producing area storage.

seasonal demand peaks would have to be met by greater production deliverability, resulting in higher wellhead drilling costs. This might also result in lower field efficiency.

Figures 1 and 2 presented earlier exemplify this situation. Over the past two years, U.S. summer base load monthly demand averaged only about 47 Bcf per day, compared with the coldest month's average demand of over 80 Bcf per day. Because of storage, monthly variation in production is much lower. In other words, the U.S. has a relatively high utilization of production wells. Offseason minimum monthly production is 49 Bcf per day, compared with maximum (monthly) producibility of 53 Bcf per day. Productive well deliverability would need to be 51 percent higher if storage were not available in order to meet U.S. maximum monthly requirements.

While wellhead cost savings represent the most important benefit offered by production area storage, other efficiency gains accrue. Gas fields can be developed in a manner to maximize overall production, rather than to meet seasonal (or peak day) requirements. In addition, revenues might be enhanced as a result of scheduling field development to meet high load factor market requirements, as opposed to low load factor markets (e.g., seasonal heating load). Further, revenues from natural gas byproducts (such as natural gas liquids) can be generated more quickly and on a more constant basis.

Producers/marketers can also use storage as a management tool to minimize risk. For example, daily capacity nominations have to be balanced with the deliveries at both ends of the pipe. If producers' deliveries fall short of nominations, this can be made up by storage withdrawal. As a result, producers and/or transporters minimize the risk of imbalance penalties. This, of course, is only possible if there are flexible delivery points and flexibility in storage withdrawals and injections (e.g., rapid switching from injections to withdrawals and vice versa).

Furthermore, producers/marketers can use storage in case of disruption of deliveries to the market (e.g., pipeline failure). Here, storage injection would be preferable to shutting-in production or selling supplies at depressed prices. Again, in order for storage to be used in this way, rapid switching from injection to withdrawal and vice versa is required.

Storage also assists in gas marketing because a producer/marketer may possibly obtain better options on when and how to sell gas. As an example, a producer/marketer can inject gas into storage in order to be in a better position to obtain a higher price in the future. This use might require the availability of multiple cycling capability and/or quick injection and withdrawal turnaround capability.

Because of storage, a producer/marketer may be in a position to offer better contract terms. Certain contractual provisions might create market advantages and/or higher prices. A producer may be able to aggregate supplies and/or provide higher deliverability. Further, since storage enhances supply security (in that stored gas has already been produced), a producer/marketer can guarantee delivery with less concern about incurring performance penalties. A producer/marketer with storage as a backstop can also assure deliverability, thereby helping to justify reservation charges. And lastly, a seller can use gas in storage to guarantee a stable price for a season by using storage gas as a physical hedge against rising prices.

Pipelines

While interstate pipelines own a large share of U.S. storage capability, since FERC Order No. 636 pipeline uses of storage have been reduced to quantities supporting no-notice service and pipeline operations. In fact, the vast majority of the pipeline storage (some 87 percent) has been contracted to the pipelines' customers, primarily LDCs. These customers have full tariff rights to use the storage, as well as to release it if it is not needed.

The cost of storage retained and used by interstate pipelines for operational purposes or providing no-notice service is generally embedded in the pipeline's cost of service-based transportation rates. Pipelines that sell storage capacity have a separate unbundled storage rate filed with the FERC. In a number of instances, the no-notice service rate is either a stand-alone rate, or it is embedded with the FT rate as a NNFT rate. In either event, the additional no-notice cost is quite often the pipeline's reservation charge for its storage service.

Intrastate pipelines only own 6 percent of U.S. storage capacity. These companies are primarily located in Texas, subject to the Railroad Commission's jurisdiction. The vast majority of this capacity is used to inject and withdraw company-owned or market affiliate gas supplies; however, a few intrastate pipelines contract storage to third-party marketers, producers and/or end-users.

Local Distribution Companies

Local distribution companies (LDCs) probably derive the greatest value from storage.[1] These companies own a large share of storage (about one-third), particularly in the Midwest and on the West Coast, and they contract for the vast majority of storage owned by pipelines.

The benefits of storage to LDCs include the following:

- Assist in meeting seasonal and peak day demands, thereby minimizing firm transportation and/or no-notice costs;
- Permit offseason gas purchases
- Offer a risk management tool.

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1 While this discussion focuses on the advantages of storage to LDCs, many of these advantages also directly accrue to end-users in downstream markets.

Illustrative Savings from Storage

As discussed previously, many gas markets exhibit extreme seasonal variations in demand as a result of heating load. Satisfying these peaks with only pipeline capacity could be quite expensive, especially under a straight fixed-variable cost allocation and rate design methodology. To illustrate, let us assume a pipeline firm transportation reservation charge of $11 per Mcf per month and a market load factor of only 35 percent. The annual average transportation cost per Mcf would be $1.03 per Mcf.[1] If an LDC owns storage or can contract for storage (at the city gate), then the company can use its firm pipeline capacity at a higher utilization rate throughout the year by injecting gas into storage during the non-heating season and withdrawing it from storage when needed to meet peak requirements during the heating season. To continue the above example, if the use of storage enabled the LDC to use its pipeline capacity at 100 percent load factor, its average annual transportation rate would be reduced to only $0.36 per Mcf. To some extent, of course, this transportation cost savings would be offset by the cost of storage, as explained below.

Figure 5 is a hypothetical load duration curve illustrating the use of storage to minimize these costs. The load duration curve depicts the LDC's requirements, arrayed from the coldest to the warmest day of the year. The highest requirement on the system is the design peak day, while the lowest requirement is the base load year-round requirement.

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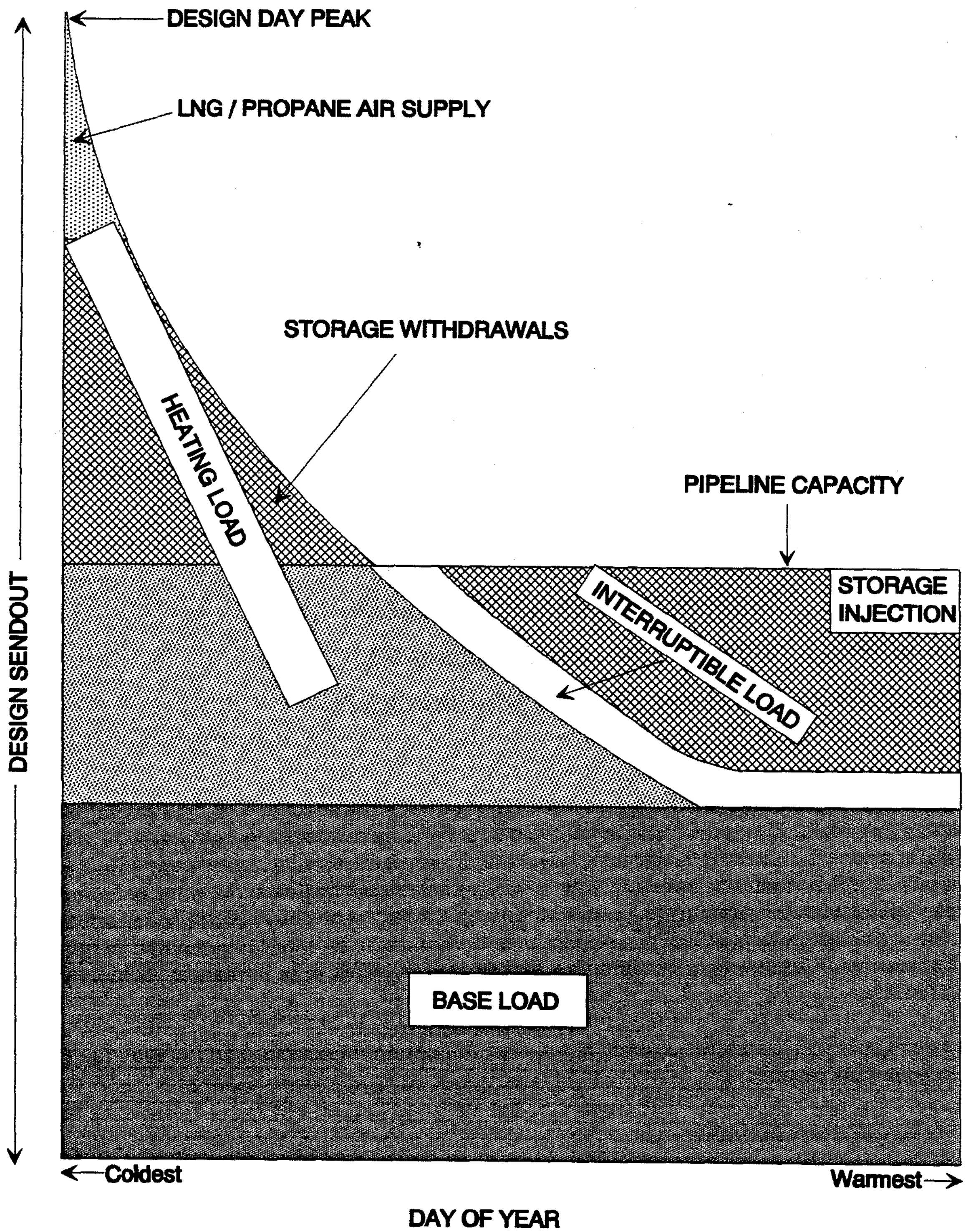
[1] This example excludes variable costs, such as commodity rates and fuel. The average reservation charge at the given load factor is calculated as $11 divided by 30.4166 days divided by .35.

FIGURE 5

HYPOTHETICAL LOAD DURATION CURVE



Pipeline capacity is labeled as a horizontal line. Storage withdrawal capability is represented by the checkered area, as labeled;[1] and the lightly shaded dotted area is the needle peak supply (e.g., propane air or LNG, as labeled). In order to minimize firm transportation costs to the greatest degree possible, capacity must be used at 100 percent load factor. For this to occur, the area depicted as storage injection plus interruptible load must equal the area labeled as storage withdrawals plus LNG/propane air supply (e.g., needle peaking).[2]

As stated earlier, storage capacity can also be used to manage purchases of offsystem gas at a lower summer price, relative to winter prices. In today's market, the majority of LDC gas supply portfolios are geared to spot prices, either as direct spot purchases per se or through firm contract prices tied to spot price indices.

Summer spot gas prices have historically been lower than those experienced in the winter, except for the 1994-1995 winter. The following compares the third quarter U.S. average spot price per Mcf with the average spot price for the first quarter of the following year.[3]

3Q91 vs. 1Q92:	\$1.19 vs. \$1.28 per Mcf (plus \$.09)
3Q92 vs. 1Q93:	\$1.72 vs. \$1.81 per Mcf (plus \$.09)
3Q93 vs. 1Q94:	\$2.02 vs. \$2.14 per Mcf (plus \$.12)
3Q94 vs. 1Q95:	\$1.64 vs. \$1.40 per Mcf (minus \$.24)

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1 Many LDCs are concerned about storage deliverability during the latter half of the heating season, because many seasonal storage facilities are unable to maintain maximum deliverability throughout the heating season. The lower the inventory level and the lower the reservoir pressure results in lower deliverability. This is referred to as ratcheting. Many new storage facilities, and some old ones, are advertising constant deliverability (e.g., non-ratcheting). Examples of this are described in a number of the new storage projects included in Appendix A to this report. Non-ratcheting generally requires quick turnaround of injection and withdrawal and vice versa, which is an advantage offered by salt dome facilities.

2 This assumed the LDC has an IT market. If not, then storage injection must equal storage withdrawal plus needle peak supplies.

3 Source: Natural Gas Intelligence

Assuming that historical seasonal price patterns prevail in the future, then potential cost savings resulting from the use of storage may also prevail, although these savings are probably not sufficient to offset the overall storage cost. In addition, as new and expanded storage capacity comes on line, along with the continued growth of high load demands, (e.g., power generation demand) the seasonal price differential may narrow.

The last benefit of storage for LDCs discussed here is its use as a risk management tool. Under FERC Order No. 636, gas supply management responsibility was shifted to the distributors. As a result, the value of storage to LDCs has increased. First of all, shippers must balance nominations and deliveries on a daily and monthly basis within a specified tolerance level or face imbalance penalties.[1] This balancing issue is crucial, given the unpredictability of weather and demand in many markets, the fact that nominations generally have to be made one day in advance, and the level of imbalance penalties on interstate pipelines. Daily imbalance penalties are generally equal to pipeline IT rates. Monthly imbalance penalties typically require volumetric makeup or reduction (in-kind provisions) or payment as a fraction or multiple of spot prices (cash out provisions), while overrun charges are typically in the $15 to $25 per Mcf range.

As with seasonal gas purchase savings, avoidance of imbalance penalties alone would probably not justify contracting for firm storage, particularly since many LDCs have some no-notice service from pipelines. In addition, short-term storage with the ability to turn around injection and withdrawal quickly is generally required to assist in avoiding penalties.

Another gas supply management use of storage is as an emergency supply backup in case of a supply disruption. Depending on the severity and duration of disruptions, LDCs use short-term storage and seasonal storage for this purpose. Short-term storage has the advantages of being available more quickly (e.g., greater turnaround capability) and

[1] An exception occurs where the LDC has contracted no-notice service.

providing higher deliverability levels. Seasonal storage allows emergency supplies for a longer duration but at a lower deliverability level. In addition, seasonal storage is still potentially affected by downward ratcheting of deliverability capability at lower inventory levels. This may also be true for short-term storage if injections cannot be made. In any event, the storage facilities have to be located downstream of the supply disruption in order for storage to be effective.

Cost of Storage

The above discussion addresses the benefits of storage; however, storage does not come without costs. Besides the storage cost itself, users must evaluate other cost components, including fuel costs, costs associated with transportation capacity to and from storage, and inventory cost of holding gas in storage.

Typical storage rates include several components:[1]

- Reservation (or deliverability) charge
- Space (or capacity) charge
- Injection and withdrawal charges
- Fuel use charges
- Surcharges (as applicable)

We have chosen a new enhanced service offered by one storage company[2] to illustrate an actual storage cost.[3] This company has about 7 Bcf of available capacity. The enhanced storage service being profiled provides for 10 to 126 days of firm delivery

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[1] Many new storage operators also require customers to supply their own cushion gas, which will add to the inventory cost. Otherwise, cushion gas cost is embedded in the storage provider's rates.

[2] ANR Storage.

[3] Many existing storage operators are enhancing their services in order to compete in today's environment. Enhancements include year-round injections and withdrawals, shorter notice periods, and non-ratcheting features.

capability.[1] The delivery point of this service is either near Kalkaska or Deward, Michigan. The service would be available year-round and subject to a three-hour notice period.

FERC-approved maximum rates for this company are:

Deliverability	$2.39997/Mcf/mo.
Capacity	$0.02449/Mcf/mo.
Injection & Withdrawal	$0.00804/Mcf
Fuel -- Injection	1.3%
-- Withdrawal	0.2%
ACA Surcharge	$0.0024/Mcf

The average storage unit costs to a customer using these rates are depicted in Figure 6. These average cost levels are for single and multiple cycles, the latter of which allows the demand charges to be spread over greater volumes. The average storage costs for single and maximum cycling during the year are compared on the following table.

Table 7

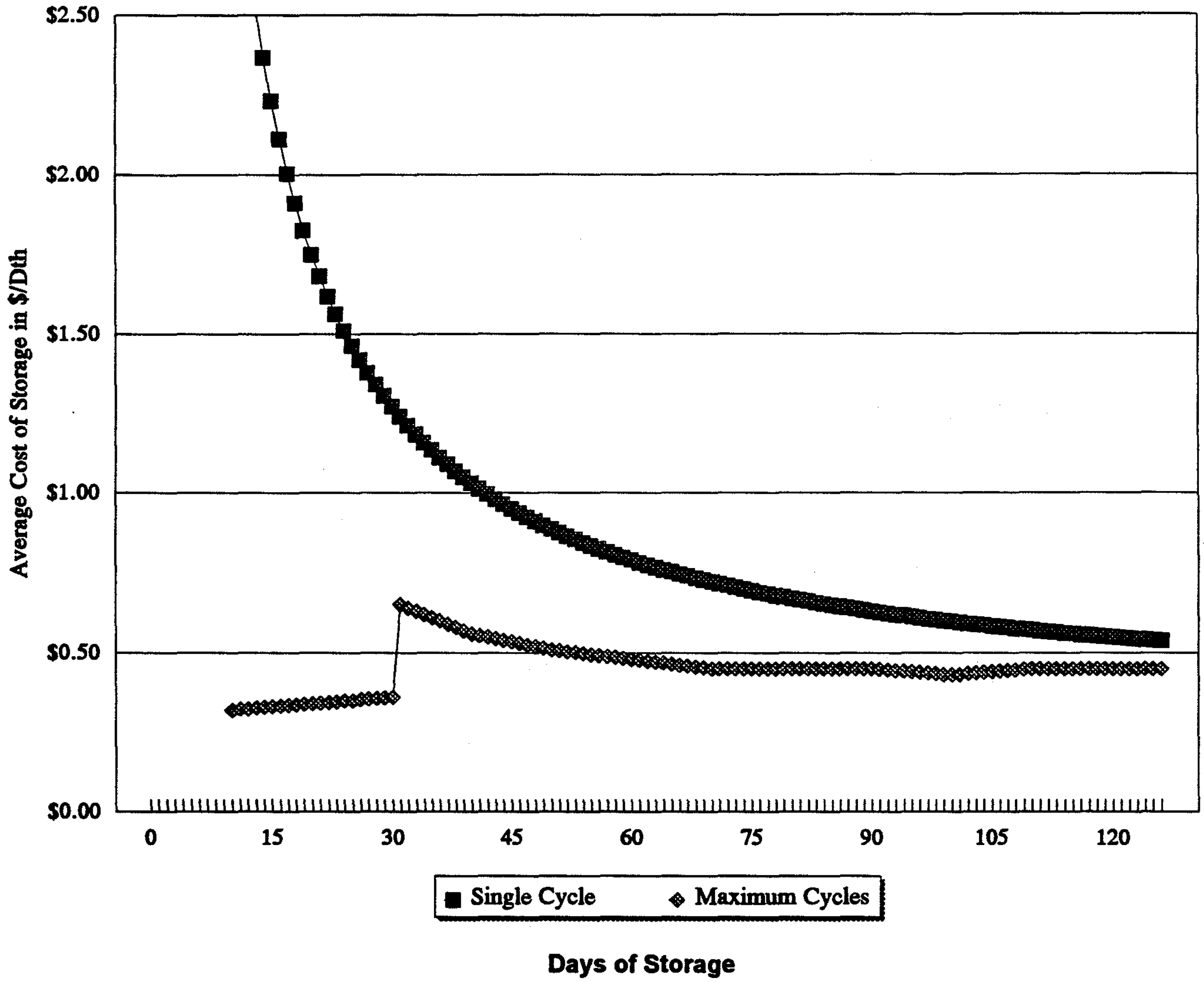
COST OF SERVICE
(ANNUAL BASED ON 100% UTILIZATION)

	Average Storage Cost ($/Mcf)	
	Single Cycle	Maximum Cycle
10-Day	$3.19	$0.31
30-Day	$1.27	$0.36
50-Day	$0.89	$0.51
100-Day	$0.60	$0.43
126-Day	$0.54	$0.44

1 Maximum day withdrawal drops to 70 percent of contract quantity when inventory falls to 20 percent of capacity, and to 40 percent of contract quantity when inventory drops to 10 percent of capacity for 31 to 126 day service. There is no rachet for 10 to 30 day service.

Illustrative Storage Cost Curve

Average Annual Cost of Storage per Dth



Rate:

Storage Rate (Firm)			
Reservation	$2.399970	/Dth	(D1)
Monthly Capacity Charge:	$0.024490	/Dth	(D2)
Injection Charge:	$0.008040	/Dth	(I)
Delivery Charge	$0.008040	/Dth	(W)

Average Rate:

At 60 Days of Withdrawal	$0.789954	
At 100 Days of Withdrawal	$0.597956	

Table 7 shows averages for various levels of service from a needle peaking service of 10 days to a seasonal service of 126 days. For a given working gas capacity, the lower the days of withdrawing the capacity, the higher the daily contract demand (DCQ) levels. Since storage rates generally have a reservation (deliverability) charge applied to the DCQ, there is a higher cost for greater levels of service (e.g., 10 days) compared to longer withdrawal services (e.g., 100 days).

Table 8 shows the distribution of representative storage costs for a selected group of storage companies, calculated for 100 day seasonal service. These costs include services offered by interstate pipelines and other providers (e.g., LDCs or new projects). Most storage rates fall in the \$.41 to \$.60 per Mcf category, however the average of all costs is \$.66 per Mcf.

Table 8

DISTRIBUTION OF STORAGE COSTS
(Average Cost for 100-Day Service)
(\$/Mcf)

	\$0-.40	\$.41-.60	\$.61-.80	\$.81-1.00	>\$1.01	Total
No. of instances	4	15	8	6	4	37
Average Cost	\$.31	\$.52	\$.70	\$.86	\$1.12	\$.66

The average storage costs presented alone do not reflect inventory cost or transportation costs to and from storage (to the city gate). With respect to inventory cost, this is a function of gas price itself, the length of the holding period, and the carrying rate. If, for example, the cost of gas injected into storage is \$1.60 per Mcf with a holding period of six months and an annual carrying charge of 10 percent, the inventory cost would average about \$.10 per Mcf.

The cost of transportation service associated with storage is more difficult to assess, primarily because many variations of getting gas to and from storage are possible. Some scenarios include no additional costs at all because the LDC can use existing, reserved transportation capacity and have the storage located at its city gate. In other words, no additional (incremental) transportation is required to get the gas to or from storage to the LDC system. In other situations, additional transportation costs are incurred to get gas to storage and from storage to the city gate. These costs represent an important component in evaluating the relative economics of contracting for storage.

III. MARKET HUBS

Hub Services

While existing and new storage facilities offer traditional tangible services, market hub services are less defined and are evolving as dictated by customers. As one market hub developer explained, new services will depend on "sufficient customer interest" and "whatever the market needs." The advertised services being offered by most market hubs include parking, loaning, wheeling and title transfers. These, as well as administrative and operational services, are short-term in nature and subject to changes in market requirements. However, the fact that the number of pipeline interconnects and the availability of storage are some of the most important characteristics of hubs indicates the role of hubs in providing flexibility and reliability to the market.

Market hub services generally require the existence of a market center, and the definition of a market center can be found in FERC's Order No. 636-B (page 29):[1]

> A market center is an area where (a) pipelines interconnect and (b) there is a reasonable potential for developing a market institution that facilitates the free exchange of gas.

Not all market centers are hubs, however, because an administrator is required in order for hub services to be provided. An administrator has a number of functions, including (1) making arrangements for customers to utilize the hub, (2) tracking physical and administrative gas volumes flowing across the hub facility, (3) performing credit checks, (4) guaranteeing hub transactions, and (5) filing and reporting transactional information. The hub service administrator is not necessarily the owner of hub facilities, although usually the owners of the hub facilities have the right to approve all transactions.

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[1] FERC's general policy is to encourage hub development, i.e., pipeline tariffs must not contain elements that would hinder them.

Certain hub owners/operators have contracted with another company to administer the hub services. For example, Enerchange[1], an affiliate of Natural Gas Clearinghouse, administers the Chicago Hub (owned by Northern Illinois Gas), the Cal Hub (owned by Southern California Gas) and the Ellisburg-Leidy Hub (owned by National Fuel Gas Supply).

Market centers are transforming themselves into hubs that offer a greater menu of services, and many of these hubs are being integrated into the gas service network. Specific services offered by market hubs include both physical and transactional services:

(1) Wheeling -- transporting gas into the hub on one pipeline and sending it out on another.[2]

(2) Parking -- temporarily storing a shipper's excess gas so that a shipper does not have to sell it or otherwise dispose of it. Parking (and loaning) also can be considered a balancing service -- keeping shippers "in balance" with their pipelines by adding or withdrawing gas (e.g., loaning or parking), thereby helping those shippers avoid financial penalties.

(3) Loaning -- shipper's taking title of gas on the hub for delivery to market off an interstate pipeline, creating a negative balance on the hub at the end of the day for a shipper. Loaning can also be considered a peaking service -- supplying the gas that an LDC or another shipper needs to survive an unexpected, high demand period.

(4) Title transfer -- changing the name and/or contract under which gas is flowing on connecting pipelines.

(5) Electronic trading -- "blind," real-time matching of gas suppliers with buyers, either at a hub or between hubs.

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[1] In June 1995, Natural Gas Clearinghouse, NICOR, Pacific Enterprises and National Fuel created Enerchange to develop, administer and operate market-area hubs. Formerly, Hub Services, Inc. administered these hubs.

[2] Wheeling can be conducted either on a "straight" basis, where gas is actually transported, or on a "displacement" basis, where gas is redelivered to an alternative point on behalf of a shipper.

Market hubs are being developed and promoted by various industry participants, including pipelines, distributors, producers, marketers and independent operators, and the services they provide depend on hub location and available facilities. Some interstate pipelines, e.g., CNG Transmission, National Fuel Gas Supply, and Pacific Gas Transmission are proposing system-length market centers, as are some distributors, e.g., Northern Illinois Gas and Southern California Gas. Producers are participating as well, e.g., Texaco owns the Gulf Coast Star Center in Louisiana and proposes to use its Bridgeline Distribution system as a market center.

Canadian industry participants are also actively promoting hubs, in both the U.S. and Canada. For example, Union Gas uses it transmission and storage facilities in Canada to provide hub services and is a partner in U.S. hubs (e.g., Grands Lacs). In addition, Alberta Energy Co. (AEC) is operating the AECO C Hub at its Suffield storage site in southeastern Alberta.

Two general types of market hubs are system hubs and point-specific hubs. System hubs are sometimes referred to as floating hubs, i.e., services are offered at any place on the LDC's or pipeline's system. Examples include the Chicago hub and the CNG/Sabine Center. Point-specific hubs, such as the Henry Hub, are found at locations where multiple pipelines interconnect or storage facilities operate.

To some extent, hub services can be considered a by-product of the main services offered by the owner of the facilities. Large capital investments are not usually necessary to offer hub services, unless one considers new storage facilities as part of the investment. In this report, we segregate storage and hub capabilities, but many of the new storage facilities are advertising hub services. Services offered at hub facilities that are part of LDC or pipeline systems may also be considered as byproduct services. Companies owning these facilities have primary responsibilities in other areas, in particular, providing firm transportation and distribution services to their customers. Examples include the following:

- National Fuel Gas Supply's Ellisburg-Leidy Hub
- Southern California Gas' Cal Hub
- Northern Illinois' Chicago Hub
- CNG/Sabine Center System Hub
- PGT's System Hub

In part, because the primary responsibility of transporters and distributors is to firm ratepayers, hub services are generally offered on an interruptible basis. While enhanced (e.g., firm) hub services can be offered at times, these are generally more expensive -- about equal in cost to normal services provided by the same companies to their firm ratepayers.

Hub operators must address a number of issues, such as protecting the confidentiality of clients and avoiding conflicts of interest that could arise if a hub operator or its owner is involved in other natural gas-related businesses. Some hub administrators are presently affiliated with marketers and/or producers. Some other issues in regard to hubs involve (1) regulatory jurisdiction, and (2) revenue sharing.

With respect to jurisdiction, those hub servicers using facilities dedicated to interstate commerce must obtain FERC authorization to provide these interstate services.[1] Companies offering interstate services must have maximum rates on file with the Commission, unless market-based rates have been approved, and services offered (and tariff provisions) must be consistent with FERC's rules and policies. For example, FERC recently ruled that certain system hubs, i.e., Cal Hub and Chicago Hub, cannot perform services to points off their facilities by using capacity of upstream pipelines or other companies because that would circumvent the Commission's capacity release and "shipper-must-have-title" rules under Order No. 636.

[1] Filings relative to interstate hub services have been submitted under Section 4 of the Natural Gas Act and Section 311 of the Natural Gas Policy Act.

For LDCs offering hub services, state versus federal jurisdiction may be an issue. For example, Northern Illinois Gas insists that FERC has sole jurisdiction over the services offered at the Chicago Hub because they all involve interstate commerce, rather than intrastate services subject to jurisdiction of the Illinois Commerce Commission. SoCal Gas obtained both FERC and California PUC authorization to provide hub services, but the terms of these are the same for interstate and intrastate customers.

Finally, there is the issue of crediting hub service revenues. If the hub uses facilities that are being paid for as part of a regulated company's cost of service, then most of the hub revenues are credited back to the firm ratepayers' cost of service. Because providers are not going to take risks without some potential returns, regulators allow companies and thus shareholders, to retain a share of the net revenues. However, this is not a relevant issue for unregulated hubs.

Identification of Market Hubs

There are about 35 hubs and market centers that have sprung up across the U.S. and in Canada (see Schedule 5 in Appendix C). Table 9 identifies the major hubs and the following map (Figure 7) shows the general location of selected hubs in relationship to the interstate pipeline network. Appendix B-1 to this report presents descriptions of 12 hubs across the country and one electronic trading system. As with the descriptions of the storage projects (Appendix A-1), the sources of much of this information are the developers themselves, and the projects are subject to change over time.

While a few market centers existed prior to implementation of FERC Order No. 636, most of the new market hubs have developed in response to the service unbundling and enhanced competition promoted by that ruling. The majority of the market centers in existence prior to 1993 were located in supply areas, at points where multiple pipelines interconnect and/or at processing plants or storage facilities, such as Henry (Louisiana), Katy and Waha (Texas), and Blanco (New Mexico). The primary function of these early

Table 9
SUMMARY OF MAJOR NORTH AMERICAN MARKET HUBS **

Hub/Market Center	Operator/Owner	Number of Interconnecting Pipelines	Services Offered: Parking	Wheeling	Loaning	Title Transfer	Electronic Trading
MIDDLE ATLANTIC							
CNG / Sabine Center	CNG Trans. / Sabine PL	8	x	x		x	
Ellisburg–Leidy, PA	Enerchange a/	6	x	x	x	x	
National Fuel, NY & PA	National Fuel Gas Supply	5	x	x			
EAST NORTH CENTRAL							
Chicago, IL	Enerchange a/	5	x	x	x	x	
Columbia Energy Market Center	Columbia Gas System	s/	x	x		x	x
Grands Lacs/ Marysville, MI	CMS Gas Trans. & Storage Market Hub Partners b/, St.Clair Pipelines, Enron Gas Services	7	x	x	x	x	x
WEST NORTH CENTRAL							
Mid–Continent, KS	Western Resources	9	x	x			
WEST SOUTH CENTRAL							
Buffalo Wallow, TX & OK	KN Interstate	12	x	x		x	x
Carthage, TX	Union Pacific Fuels (East TX Gas Systems/ EasTrans)	20		x		x	x
Gulf Coast Star Center, LA	Texaco	12 c/	x	x	x	x	x
Henry (Erath), LA	Sabine Pipe Line	13		x		x	
Houston, TX	Eastex Energy	10		x		x	
Katy, TX	Western Gas Resources	13	x	x	x	x	x
Louisiana	LA Resources	22	x	x		x	
Moss Bluff, TX	Market Hub Partners b/	6		x		x	x
Perryville, LA	NorAm Gas Transmission	10	x	x	x	x	x
Waha/Permian, TX	Valero	8	x	x	x	x	x
ROCKY MOUNTAIN							
Blanco, NM	Transwestern	5					
Rocky Mountain Market Ctr. Opal, WY	Williams Energy	3				x	x
Western Market Center / Muddy Creek, WY	Tenneco, Questar, Entech (MT Power), Union Pacific	5	x	x	x	x	x
PACIFIC							
California Energy Hub (CAL Hub) / SOCAL	Enerchange a/	9	x	x	x	x	
Pacific Gas Transmission	PGT / PG&E	s/	x		x		
CANADA							
AECO C Hub	Alberta Energy	2	x	x	x	x	
Union Gas Service	Union Gas	5	x	x	x	x	

NOTES:

** Other market centers include Niagara NY, Pittsburgh PA, Tuscola IL, Detroit MI, Guymon OK, Houston Ship Channel TX, New York NY, Lebanon OH, Kosciusko MS, Monroe LA, Longview/Atlanta TX, Waha (Interchange, Header and Midland) TX, Topock AZ, South Texas, Wamsutter WY, Intra–Alberta and NOVA.

a/ Hub operations formerly administered by Hub Services, Inc. (HSI), an NGC affiliate.

b/ Partnership of Tejas Power, NIPSCO, New Jersey Resources, Miami Valley Leasing (Dayton Power & Light affiliate) and PSE&G.

c/ Excludes interconnects through the Henry Hub.

s/ System–wide hub services. Total interconnects unknown.

SOURCES: Schedule 5 of Appendix C.

MAJOR MARKET CENTERS (HUBS) AND PIPELINE NETWORKS

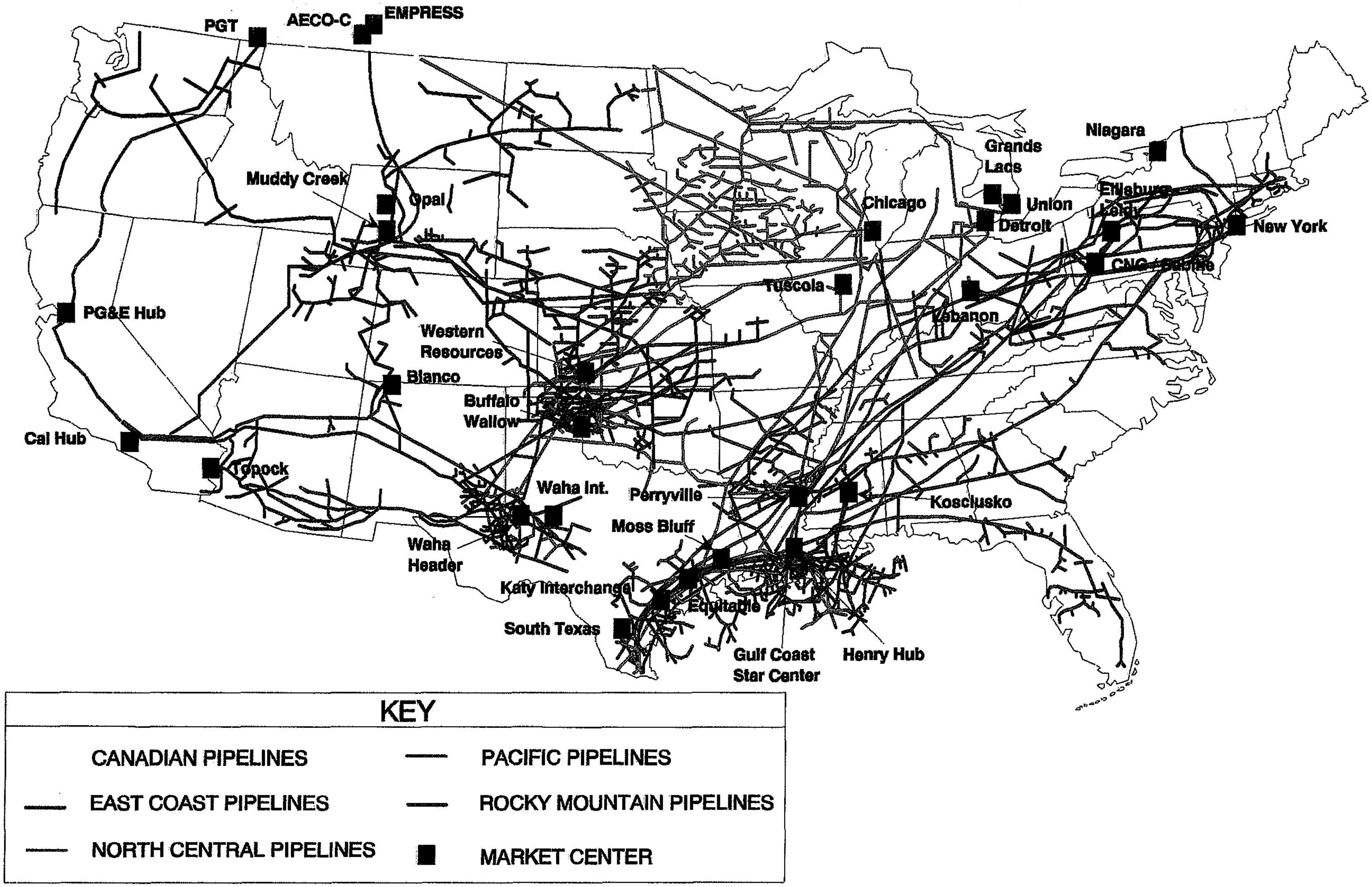

FIGURE 7

market centers was to enhance gas supply transactions and/or route supplies from one pipeline to another. Services offered at these and other producing area market centers included hub transfers or transportation, compression, processing, storage and balancing.

Probably the best known market hub is the Henry Hub, which was established in 1988, and designated as the delivery point for the NYMEX natural gas futures contracts. This hub is owned by Sabine Pipe Line and operated by Sabine Hub Services, both units of Texaco. It is located 18 miles from Lafayette in Erath, Louisiana, the site of a 860 MMcf per day Texaco gas processing plant. About thirteen pipelines, both interstate and intrastate systems, are connected to this hub. As the operator, Sabine Hub Services tracks physical and administrative gas volumes flowing across the hub facility. Sabine Pipe Line provides wheeling at the hub for a flat volumetric fee, regardless of path of physical flow, and offers title transfers.[1]

<u>Important Hub Characteristics</u>

Besides serving as important trading points, two important characteristics of market hubs are the number of pipeline interconnections (along with associated capacity) and the availability of storage. Schedule 5 of Appendix C identifies most of the pipelines connected to the hubs. The higher the number of pipeline interconnections through header systems, the greater the flexibility and reliability because (1) buyers have access to more supply points, (2) sellers have more access to different markets, and (3) transporters have a variety of routing choices to reach markets.

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[1] While the Henry Hub is the trading point for NYMEX gas futures contracts, the Kansas City Board of Trade has recently developed a western futures contract market, located at Waha Hub (TX). According to the Kansas City Board of Trade, Waha was chosen because (1) it offers market characteristics distinctive from the Henry Hub, allowing price arbitrage between the two centers, and (2) has sufficient summer and winter capacity and volume in and out of the market center. Valero Transmission is the Waha Hub operator. There are 9 interconnecting pipelines with about 1.2 Bcf per day of capacity into and 0.9 Bcf per day out of the hub. Waha is currently an active hub offering wheeling, balancing, and title transfer services along with electronic trading capability.

Most hubs advertise either the number of pipelines connected to their system or the number of pipelines that they are going to interconnect. Shown below are the number of connecting pipelines (counting the hub's own pipeline facility):

♦ Chicago	5
♦ CNG/Sabine Center	8
♦ Ellisburg-Leidy	6
♦ Henry	13
♦ Katy	13
♦ Perryville	10
♦ Cal Hub	9
♦ Waha	8
♦ Western Market Center	5

This advertisement of increased interconnections and capacity is not limited to market centers or hubs. For example, Midwestern Gas Transmission has recently publicized the completion of its "Header System," linking major interstate pipelines along its 352-mile system (from its connection with Tennessee Gas Pipeline at Portland, Tennessee to the Chicago area). In 1994, Midwestern constructed an interconnection with Natural Gas Pipeline allowing bi-directional flow of 300 MMcf per day. This interconnection permits access to "lower cost" mid-continent supplies on Midwestern, and complements the other interconnecting systems -- Texas Gas Transmission, ANR Pipeline, Texas Eastern Transmission and Trunkline Gas.

Operational balancing agreements (OBAs) can assist in managing the gas flows among multiple pipelines connected to a hub. One of the first OBAs at a hub was implemented by Sabine with Natural Gas Pipeline at the Henry Hub. Now Sabine has OBAs in place with 12 feeder systems into the hub.[1]

OBA agreements contain volumetric terms that parties negotiate among themselves and implement without regulatory approval. Terms may differ from interconnection to

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[1] Valero, the operator of the Waha Hub (which was chosen as the trading point for the Western futures contract market) is working to put OBAs into place.

interconnection, but they set out procedures for resolving imbalances and confirming that gas nominations actually flow. OBAs assure shippers that their nominations will be kept whole and limit their exposure to large imbalance penalties. They also simplify accounting, administration, and billing procedures. In short, OBAs may be important to the success of a hub because shippers can judge hubs by their operational efficiency and administrative ease in which they can move gas across pipelines.

Many market hubs are located at underground storage facilities, or are along systems that have access to such storage. Because parking and loaning are principal services being offered, hubs do require some ability to store gas. Hubs with onsite underground storage generally have the ability to park or loan volumes for a longer period of time. These hubs include Cal Hub, Chicago Hub, CNG/Sabine Center, Ellisburg-Leidy, Katy, Grands Lacs, and Union Gas. Other hubs (such as the PGT System Hub) must rely on line pack to provide this flexibility, although this method restricts the duration of parking service.

Benefits of Hub Services

Overall economic advantages of hub services include ready access to current price and other market data, promotion of competition, improvement of system efficiency in terms of capacity utilization, reduction of transaction costs (through new and faster electronic ways of completing transactions), and reduction of market transaction barriers. Similar to storage service, hubs offer other benefits to both buyers and sellers, such as enhanced reliability, operational flexibility, supply management and financial management options -- business opportunities that have arisen from the unbundled and restructured natural gas industry environment. These services are generally short-term or temporary in nature.

Operationally, hubs (1) assist in monitoring and/or resolving transportation imbalances by coordinating shippers' "long" and "short" supply positions on interstate pipelines or at city-gate markets; (2) help manage intra-day gas supply swings by offering shippers the time, facilities and capacity to wheel, displace, park or loan gas within the current day to satisfy contractual obligations; (3) facilitate pooling arrangements, allowing a producer or a marketer to meet its contractual obligations at a connected pipeline pooling point; (4) add flexibility in available receipt and delivery points (e.g., a hub can permit centralizing multiple delivery points to a contract or a supply portfolio); and (5) help shippers unable to transport supplies to market when operational flow orders are issued by pipelines to keep their market whole through use of hub services.

As an indication of the competitive nature of this business, many hub services are being offered under descriptive names or acronyms. For example, CNG/Sabine Center offers "Park-Folio" (parking) and "MARS" (Market Activity Reporting Service); Texaco's Gulf Coast Star Center offers "StarSource" services; and Western Market Center promotes "OneStep" services.

Electronic Trading Systems

Electronic trading systems are emerging in conjunction with market hubs. These systems are linking market centers and hubs in the U.S. and Canada to provide intra- and inter-hub trading capabilities. Examples of these systems include the following:

- Williams' "Streamline" (see Appendix B-1)
- NYMEX and EnerSoft's "Channel 4"
- Columbia's Fast Lane
- NOVA/TCPL/Westcoast's NrG Information Service
- NOVA/AEC Energy Exchange
- Joint Alberta Energy Co./Union Gas hub-to-hub services link.

Electronic trading provides real time control of customers' gas supply trading activities. These systems generally offers standardized contracts, credit and operating procedures. Bids and offers for gas supply are matched instantaneously and anonymously. In other words, electronic trading workings like the stock market -- the system provides "blind" matching of buy and sell orders. Regional gas prices are continuously posted at hub centers. Because information is posted on a real time basis, market prices are immediately transparent which assists with market uncertainties, and allows buyers and sellers to respond quickly to market changes using actual prices.

These real time trading systems can be along a pipeline (or LDC) system, or between market hubs. In April 1995, for example, Columbia Energy's Fast Lane went online to bring electronic trading to key points along Columbia's two major interstate pipelines. Fast Lane provides real time trading of gas supplies and pipeline and storage capacity.

An example of specific hub-to-hub trading is a new joint service announced by Alberta Energy Co. (AEC) and Union Gas Ltd. This service allows hub-to-hub deliveries between AECO C Hub storage facilities in southeastern Alberta and Union Gas' hub at the Dawn storage facility near Sarnia, Ontario. The cost of the service is negotiable, and it will vary depending on difference in the delivered prices between the two hubs.

Williams' electronic trading system, StreamLine, permits electronic trading among multiple hubs and market centers. StreamLine is scheduled for use in hubs across North America, although current hubs using the system include Waha, Opal, Lebanon, Carthage, Station "65", and Empress in Calgary. (For greater details pertaining to this electronic system, including rates, see Appendix B-1.)

Cost Of Hub Services

The following table (Table 10) shows illustrative rates of five market hubs as of early 1995. While rates are shown for three services (parking, loaning and wheeling), the services offered are not necessarily comparable among the providers.

Table 10 Posted Hub Service Rates ($/MMBtu)			
	Parking	Loaning	Wheeling
Hub 1	$.0604 per day	--	$.0721
Hub 2	$.0082 per day	--	$.1513 (S) a/ $.1989 (W) a/
Hub 3	$.0079 per day c/	$.0032 per day c/	$.0502 b/
Hub 4	$.08909 1st day $0.0067 subsequent days	$.1063 1st day $.0080 subsequent days	--
Hub 5	$.025 per 10 days maximum	$.036 on delivery to customer per 10 days $.036 on re-delivery to customer per 10 days	$.15

a/ (S) - Summer; (W) - Winter.
b/ A lower "fly-by" rate ($.01 per MMBtu) is available for equal volumes tendered and received on the same day.
c/ These parking (P-2) and loaning (IR-2) rates are used for single receipt and delivery points. Higher P-1 and IR-1 rates are used for different receipt and delivery points and include a transportation cost component.

Several rates among the hubs are difficult to compare because the services vary. For example, some hubs provide firm services while others only provide interruptible services. In addition, a number of the hubs establish parking and loaning rates that include a wheeling component.

Competition and the uncertainty of value added by hub services have resulted in the sharp discounting of rates. In addition, some partners in new hubs (as well as new storage facilities) are discounting transportation services into the hub centers in order to promote their usage.

Many natural gas industry observers believe that the number of hubs will be reduced by competitive forces. Several geographic areas have or will have multiple hubs offering similar services. Furthermore, the actual services that are going to be demanded are still being defined. To date, for example, hub service activity has been sporadic with parking and loaning services being in demand more than the trading services. Only those that offer the greatest "value added" to the market and/or unique services to buyers and sellers are likely to prosper.

APPENDIX A-1

STORAGE PROJECT DESCRIPTIONS

APPENDIX A-1

STORAGE PROJECT DESCRIPTIONS

TABLE OF CONTENTS

AVOCA

Location:	Steuben County, western New York state, near Ellisburg-Leidy (PA) Hub (see map in Appendix A-2).
Owners:	Joint interest partnership of subsidiaries of J. Makowski,[1] Equitable Resources, Natural Gas Clearinghouse and Union Gas Ltd.
Pipeline Connections:	Tennessee Gas Pipeline (H-C or 400 Line) Penn-York Energy Under evaluation: direct connections to CNG, National Fuel, Columbia Gas, Texas Eastern and/or Transco.
Type:	Salt cavern
Status:	The $90 million three-phase project was first announced in 1993 and received FERC approval late in 1994. Construction began in 1995 with operation of Phase I to begin in 1996; Phases II and III will be online over three years. Phase I capacity is fully subscribed through open season bidding. Customers are Orange & Rockland, Consolidated Edison, Natural Gas Clearinghouse, Altresco-Pittsfield and JMC Fuel Services. Avoca conducted open season for Phase II capacity in mid-1994, although these results are currently unavailable.
Capacity:	5 Bcf working gas Maximum withdrawal rate: 500 MMcf per day, 10 days Maximum injection capability: 250 MMcf per day, 20 days
Services/Benefits:	The benefits and services offered by Avoca result primarily from its high deliverability and injection rates and the "unparalleled" cycling ability (e.g., 30-day cycle), affording customers several operational and economic advantages:

[1] In mid-1994, PG&E and Bechtel Group announced an agreement to purchase J. Makowski.

AVOCA (continued)

- firm peaking supplies,
- seasonal purchases (including price arbitrage),
- emergency supply sources,
- load balancing, and
- no-notice services.

Terms of Service:

Term - 20 years

Quantity - MDWQ 1/10th of capacity entitlement
MDIQ 1/20th of capacity entitlement

Rates -

Demand charge -	\$3.75/Dth/mo.; escalated at half of the rate of inflation
Injection and withdrawal charge -	\$.01/Dth
Fuel rate -	2 percent
Cushion gas -	supplied by customers, estimated at 34 percent of capacity entitlement

BAY GAS (MCINTOSH)

Location:	Washington County, Alabama
Owners:	Limited partnership of MGS Storage Services, Inc. (MGS) (87.5 percent) and Olin Corporation (12.5 percent). MGS is a subsidiary of Mobile Gas Service.
Pipeline Connections:	Mobile Gas Service Corp. system at Axis, Alabama and Koch Gateway Pipeline at Hatters Pond, Alabama.
Type:	Salt cavern
Status:	Received certification from the Alabama Public Service Commission in May 1992 and became operational during the 1994/95 winter.
Capacity:	Working capacity -- 2.6 Bcf Maximum withdrawal rate -- 100 MMcf per day Maximum injection rate -- 33 MMcf per day With additional compression, Bay Gas could reach maximum withdrawal and injection rates of 260 MMcf per day and 90 MMcf per day, respectively.
Services/Benefits:	Bay Gas will provide storage on a non-discriminatory basis but it will provide no stand-alone transportation. Bay Gas has FERC approval for market-based storage rates for firm and interruptible service for a portion of the 2.6 Bcf of capacity not already subscribed by intrastate storage service customers.
Terms of Service:	Bay Gas has two contracts in place to provide intrastate storage service: (1) a 20-year contract with Mobile Gas Service for 0.8 Bcf of storage capability and withdrawal of up to 80 MMcf per day; (2) a 50-year contract with Alabama Electric Cooperative for 0.3 Bcf of capacity and 2.5 MMcf per day of service (April-September) that can be converted to peak service. Bay Gas proposes to serve other parties under Section 311.

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BLACKHAWK

Location:	Approximately 13 miles southeast of Terre Haute, Indiana (see map in Appendix A-2).
Owners:	Hamilton Natural Gas
Pipeline Connections:	About 1.5 miles from a Texas Gas Transmission line and 10 miles from Midwestern Gas Transmission's header system that is under development. Texas Eastern Transmission is also in the vicinity.
Type:	Aquifer
Status:	Planned for winter 1996-97.
Capacity:	Working gas -- 3.1 Bcf (initial design) Working gas -- 5.3 Bcf (ultimate) Withdrawal -- 44 MMcf per day
Services/Benefits:	Deliverability will be tailored to individual customer's needs and market-based rates will be offered. Hamilton predicts that these rates should fall in the range of $1.10 to $1.25 per Mcf for a single cycle. Hamilton forecasts a huge demand for storage service in the area since Texas Gas and Midwestern do not have any storage capacity to offer. In addition, Hamilton envisions market opportunities due to Midwestern's link with the Chicago Hub.
Terms of Service:	Not available

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CALCUTTA-CARBON

Location:	Clay and Parke Counties, Indiana
Owners:	Midwest Gas Storage
Pipeline Connections:	Panhandle Eastern Pipe Line, Indiana Gas Co.
Type:	Aquifer
Status:	Operational; injection commenced in mid-1994.
Capacity:	Maximum capacity -- 5.5 Bcf Base gas -- 1.9 Bcf (initial year), declining to 1.6 Bcf Working gas -- 1.475 Bcf (initial year), increasing to 3.9 Bcf
Services/Benefits:	In mid-1994, Midwest Gas Storage received its certificate from the FERC to market working capacity to customers who want hourly peaking and weekend parking service to avoid balancing penalties on interstate pipelines. As of December 1994, Midwest was offering winter peaking service to end users and municipalities and announced that it had finalized peaking arrangements with Vesta Energy regarding summer/winter storage for customers downstream on Columbia Gas Transmission.
Terms of Service:	The FERC approved rates for firm service at the facilities and a deliverability charge of $4.257 per Mcf, capacity charge of $.0463 per Mcf, and injection and withdrawal rates of $.0056 per Mcf.

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CHANDELEUR

Location:	The first commercial underground gas storage facility to be located entirely in Louisiana offshore waters.
Owners:	Entre Energy Corporation
Pipeline Connections:	Proposed interconnection with Texas Eastern Transmission. Other pipeline connections are being explored.
Type:	Depleted field
Status:	Entre advised FERC in June 1995 of difficulties in developing Chandeleur, but is not withdrawing its application. The summer 1994 open season did not result in any acceptable offers. In addition, the application will likely be amended to reroute the proposed Texas Eastern interconnection, because of difficulties in negotiations.
Capacity:	Total initial gas capacity -- 72.4 Bcf Working gas -- 25.6 Bcf Initial withdrawal capacity -- 300 MMcf per day and 193 MMcf per day at the end of the withdrawal period Injection capacity -- 300 MMcf per day Working gas capacity might be increased to 41.0 Bcf, depending on demand. Future expansion of the project to an ultimate working gas capacity of 75.0 Bcf with 850 MMcf per day of injection/withdrawal capabilities is possible.
Services/Benefits:	One reason for developing the offshore facilities is to relocate gas supplies into depleted areas. Ample pipeline capacity should be available to transport the gas to market since the block is in an area of the Gulf of Mexico that has seen major production declines in recent years. Entre believes that gas to fill the facility could come from "a multitude of supply sources" and reach the Chandeleur block via "a number of backhaul opportunities."
Terms of Service:	Chandeleur is proposing market-based rates, determined through arm's-length negotiations for long-term firm and interruptible storage service.

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EGAN

Location:	Acadia Parish, Louisiana, 35 miles upstream of Henry Hub (see map in Appendix A-2).
Owners:	Egan Gas Storage Co., subsidiary of Tejas Power Corp. Tejas Power has transferred ownership to Market Hub Partners, a partnership among Tejas Power, NIPSCO Industries, New Jersey Resources, Miami Valley Leasing (affiliate of Dayton Power & Light) and Public Service Electric & Gas.
Pipeline Connections:	After the construction of approximately five miles of pipeline during Phase I, the facility will interconnect with ANR Pipeline, Columbia Gulf Transmission, Tennessee Gas Pipeline, Texas Gas Transmission, Transcontinental Gas Pipe Line and Trunkline Gas. Egan will evaluate possible additional pipeline interconnects with Transcontinental Gas Pipe Line and Koch Gateway Pipeline.
Type:	Salt cavern
Status:	Under development, to begin service in fall 1995. Through the Phase I open season held in January 1994, Egan entered into two long-term storage contracts. Together, Tejas Power, Northern Indiana Public Service and East Ohio Gas have reserved over 2.8 Bcf of working gas capacity, 124 MMcf per day of deliverability, and 87 MMcf per day of injection rights. Information concerning other contracts secured during the open season for Phase I is unavailable.
Capacity:	Currently, three caverns are planned for development, as shown below. If market demand warrants, two additional caverns can be developed.

EGAN (continued)

	Phase		
	I	II	III
Total # of Caverns	1	1	1
Total Working Gas Volume (Bcf)	4	8	12
Cumulative Deliverability (MMcf/d)	400	800	1,200
Cumulative Injection (Average) (MMcf/d)	150	300	450
Start Date	9/95	9/96	9/97

Services/Benefits:

By offering firm injection and withdrawal services of 10 to 30 days, Egan is designed for high deliverability and relatively small storage volume. Tejas will have the ability to provide "ultra" firm daily deliverability on demand from the Egan facilities. In addition, that deliverability can be "swung down" on less than one hour's notice by injecting gas into storage, thereby accommodating extreme variations in customer gas demand almost instantaneously. Customers may tailor gas services to meet virtually any need -- from daily peaking to winter peaking to year-round swing -- with "unmatched" reliability.

Terms of Service:

Egan has applied to FERC to offer market-based rates for storage and hub services. The hub service rates to be charged will be restrained by the interruptible transportation rates on the interconnecting pipelines.

EMINENCE

Location:	Covington County, Mississippi
Owners:	Transcontinental Gas Pipe Line
Pipeline Connections:	Transcontinental Gas Pipe Line
Type:	Salt caverns
Status:	Operational since 1970s; expansion underway.
Capacity:	Phase I of the expansion, put into service on December 1, 1993, increased working gas capacity to 9.2 Bcf and deliverability to 1,300 MMcf per day. Phase II, scheduled to be completed during the 1994-95 heating season, is designed to provide an additional 2.9 Bcf of top gas capacity and 200 MMcf per day of deliverability. Upon completion of Phase III in December 1995, the Eminence field will offer 15.0 Bcf of working gas capacity.
Services/Benefits:	Transco intends to place each cavern in service as it is completed. FERC granted Transco the authority to file three limited section 4 rate filings corresponding to the three phases. This procedure will allow Transco to adjust rates to recover its construction costs upon completion of each phase.
Terms of Service:	Transco's rate schedule ESS (Eminence Storage Service) provides firm storage service. Storage capacity and injection/withdrawal rights of a customer are specified in the executed service agreement. Unless Transco agrees to discount its rate, buyers shall pay the maximum rates as follows:

	$/Mcf
Demand Charge	$0.4100
Capacity Quantity Charge	$0.0509
Injection Charge	$0.0086
Withdrawal Charge	$0.0086

Intentionally blank

EMPRESS

Location:	Empress, Alberta (see map in Appendix A-2).
Owners:	St. Clair Pipelines Ltd.
Pipeline Connections:	TransCanada PipeLines and NOVA
Type:	Salt cavern
Status:	Scheduled to be available in January 1997.
Capacity:	Capacity -- 5.0 Bcf Peak withdrawal capability -- 1,000 MMcf per day Maximum withdrawal quantity is 1/5 of capacity entitlement. Maximum injection quantity is 1/20 of capacity entitlement until 75 percent of capacity is full and then the maximum is 1/40 of capacity entitlement. Other withdrawal and injection schedules can be tailored to meet customer needs.
Services/Benefits:	Empress will provide a package of diversified hub services, including peaking, parking, cycling, and exchange capability. Cycling up to 12 times per year will be possible. Empress is designed to serve customers (1) requiring firm receipts from or deliveries to TransCanada at Empress; (2) requiring operational flexibility; (3) delivering at less that 100 percent load factor on NOVA to Empress who can use storage to optimize their transportation; (4) requiring price risk management at Empress; (5) optimizing transportation on TransCanada; (6) optimizing transportation on NOVA; and (7) requiring needle peaking services. Because of its direct tie-in to NOVA and TransCanada, the facility provides firm storage flows between TransCanada and Empress Hub Storage, and can also help customers avoid NOVA imbalance problems. Operationally, Empress' customers can use high deliverability storage in conjunction with production for scheduled/nonscheduled interruption. Empress can offer emergency supply replacement as protection against supply failure or system-related outages.

EMPRESS (continued)

Terms of Service:

Empress Hub Storage will charge a fixed monthly demand fee of about U.S. $.97 per Mcf (1997 dollars) for maximum daily withdrawal quantity (delivery entitlement) plus $0.012 per Mcf injection and withdrawal charge. Demand and variable charges escalate annually by 4 percent. A compressor fuel charge of 2 percent applies to injected volumes. Royalties must be prepaid on gas delivered to storage. Taxes are not included. Cushion gas is to be provided by the customer or can be provided by the operator for an additional fee.

A 10-year contract term will be standard although other contract lengths will be considered.

HATTIESBURG

Location: Forrest County, Mississippi (see map in Appendix A-2).

Owners: Owned and operated by First Reserve Gas Company (Dallas); the principal stockholders of First Reserve are two investment funds managed by First Reserve Corp. Crystal Oil plans to buy First Reserve Gas by the end of June 1995.

Pipeline Connections: Direct connections to Transcontinental Gas Pipe Line, Tennessee Gas Pipeline, Koch Gateway and Mississippi Fuels (an Associated Natural Gas subsidiary) with expansion potential to interconnect directly with Florida Gas Transmission, Texas Eastern Transmission and Southern Natural Gas.

Type: Salt dome

Status: Operational since 1990; Phase I capacity is fully contracted to three East Coast combination gas and electric utilities -- Public Service Electric & Gas (New Jersey), Consolidated Edison (New York), and Long Island Lighting (New York) , five gas distribution utilities (Brooklyn Union, Connecticut Natural, Elizabethtown, Mississippi Valley Gas and Piedmont Natural Gas), two major oil companies (Amoco and Arco) and one gas marketing company (Associated Natural Gas).

Capacity: Working capacity - 3.5 Bcf (Phase I)
Injection - 175 MMcf/d (Phase I)
Maximum deliverability capacity - 350 MMcf per day (Phase I)

Under Phase II, the facility will be expanded to add 2.1 Bcf of working gas capacity with deliverability of 210 MMcf per day. New injection capacity would be 40 MMcf per day.

Services/Benefits: Hattiesburg offers firm storage service and interruptible storage/balancing service in its low volume/high deliverability facility.

HATTIESBURG (continued)

Terms of Service:

	Firm Service	Interruptible Balancing Service	Firm Backup Service (Proposed)
Description	Firm high deliverability salt dome storage providing 10-day withdrawal service and 20-day injection services. Connects with Tennessee (500 leg), Transco & Koch Gateway	This service allows the customer to inject and withdraw gas into Hattiesburg to handle load swings.	Firm gas deliveries on short notice into Transco, Tennessee (500 leg), or Koch Gateway. 3-day gas reserve; 15-day replacement period
Availability	Existing capacity 100% subscribed. Released capacity available from existing customers. Planned expansion of 2 Bcf of working gas.	Fully interruptible on a first-come first-served basis. Firm customers will have priority over any interruptible nominations.	30,000 MMBtu/day - winter only 90,000 MMBtu total 3000 MMBtu/day through expansion
Rates	Demand: $2.63/Mcf ($2.28/Mcf after expansion) Injection: $.01/MMBtu + fuel Withdrawal: $.01/MMBtu + fuel Overrun: No penalty or fees for utilizing excess injection and withdrawal capacity	Storage: $.02/day Injection: $.01/MMBtu + fuel Withdrawal: $.01/MMBtu + fuel Limits: 15 day maximum stay	Demand: $1.50/month deliverability Commodity: $.01/MMBtu + fuel on repaid gas only
Nominations	24 hrs/day, 7 days/week Midday changes accepted	Receipt of nomination determines IT priority. Nominations will be accepted 24 hrs/day, 7 days/week	Accepted 24 hrs/day, 7 days/week. Flow constrained only by pipelines' limitations.
Term	7-15 year terms available for expansion space. Negotiated rates and terms for all released capacity.		
Penalty		$.10/day per MMBtu on balances older than 15 days based on FIFO	

HNG SULPHUR MINES

Location:	Near Lake Charles, Louisiana in Calcasieu Parish.
Owners:	HNG Sulphur Mines, a wholly owned subsidiary of HNG Storage Co.
Pipeline Connections:	Transcontinental Gas Pipe Line, Texas Eastern Transmission, Tennessee Gas Pipeline, Florida Gas Transmission and Sabine Pipe Line. Proposes to construct two pipelines: a 12.5-mile pipeline northward to connect Transco, Texas Eastern, Tennessee and Florida Gas, and a 9-mile south header connecting Sabine Pipe Line. The company may also connect to Koch Gateway Pipeline and Trunkline Gas, as well as Louisiana Gas Systems, an intrastate, through this southern line. Sabine Pipe Line is connected directly to the Henry Hub and opens up access to virtually every interstate and intrastate pipeline system operating in Southern Louisiana or the Gulf of Mexico. The maximum delivery and receipt capacity to the northern pipeline would be 400 MMcf per day and 200 MMcf per day on the southern connection to Sabine.
Type:	Salt domes
Status:	In January 1995, HNG Sulphur Mines withdrew its application (CP93-716) for authority to convert and operate leased storage capacity in the salt dome and to construct and operate a related facility necessary to provide firm and interruptible excess storage at market-based rates. HNG initially proposed to place the subject facilities in service by the 1994/95 heating season. According to HNG, the company "is currently working on a restructuring of its storage project, and believes that it would be in the best interests of HNG and the Commission to withdraw its certificate application, without prejudice to its later resubmission." HNG indicated previously that it is seeking additional customers as well as additional partners to help defray the project's estimated costs of $61 million. Further, HNG states that "there is a lot of interest" in the project, but "no one wants to make long-term commitments."
Capacity:	Total -- 12.1 Bcf Working gas -- 6.5 Bcf

HNG SULPHUR MINES (continued)

Services/Benefits:	HNG Sulphur Mines plans to offer three rate schedules: firm storage service (FSS), firm capacity service (FCS) and interruptible service (ISS). The initial working capacity of 6.5 Bcf was being proposed for the FSS rate schedule. Capacity development over time would amount to additional working capacity of 1.5 Bcf and this capacity would be sold pursuant to the FCS rate schedule. After completion, working gas capacity would be about 8 Bcf, with design deliverability of 400 MMcf per day and injection capacity of 150 MMcf per day.
Terms of Service:	Not available

JEFFERSON ISLAND

Location:	Jefferson Island, near Henry, Louisiana (see map in Appendix A-2).
Owners:	Equitable Resources
Pipeline Connections:	Plans to connect a lateral to Texaco's Henry Hub and Equitable's affiliate, Louisiana Intrastate Gas (LIG). Equitable is also negotiating with Sabine Pipe Line, operator of the Henry Hub, for approval of a direct interconnection. Equitable plans to connect Columbia Gulf Transmission, Tennessee Gas Pipeline, Texas Gas Transmission, Koch Gateway Pipeline and Southern Natural Gas.
Type:	Salt dome
Status:	In February 1995, Equitable Storage announced completion of the first phase of construction at Jefferson Island, costing $11.5 million. Over the next ten months, Equitable Storage will leach a cavern within the salt dome, creating the storage capacity. The facility is running about two months behind its original schedule and should be online in December 1995. LIG plans to subscribe to long-term service at Jefferson Island.
Capacity:	Working gas capacity -- 3 Bcf Total capacity -- 4.7 Bcf Withdrawal capability -- 300 MMcf per day Injection capability -- 150 MMcf per day
Services/Benefits:	Physical support for trading at the Henry Hub. Market hub products available at Jefferson Island will include title transfer services and real-time flow information. Cash trading opportunities will be introduced at Jefferson Island if customer interest indicates a need for this service. Equitable announced formation of a Houston-based operation called the Equitable Resources Market Center, to integrate the storage services into a "one-stop" marketplace.
Terms of Service:	Not available

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KIOWA

Location: Kiowa, located in southern Kansas (Kiowa County), near the Texas and Oklahoma panhandles (see map in Appendix A-2).

Owners: HNG Storage (HNG) and Williams Underground Gas Storage Company (WUGS).

Pipeline Connections: With the construction of an estimated 5 or 6 miles of pipeline, the facility will connect directly with pipelines with more than 5 Bcf/d of throughput, including ANR Pipeline, Northern Natural Gas, Panhandle Eastern Pipe Line, and Williams Natural Gas. Shippers on other systems such as Western Resources, KN Interstate Gas Transmission, Natural Gas Pipeline Co., and Colorado Interstate Gas, could also be offered service. Supply areas connected to the facility include Kansas, Oklahoma, Texas, Colorado, and Wyoming. Accessible markets include Michigan, Illinois, Indiana, Iowa, Minnesota, eastern Nebraska, Missouri, eastern South Dakota, and Wisconsin.

Type: Salt caverns

Status: Under development; after the project's marketing is concluded and an environmental review of the project and associated pipeline routes is completed, the partnership will file for a certificate with the FERC.

Capacity: The project is planned for development in four phases, as shown on the following table.

PROJECT TIMELINE AND PHASED SERVICE AVAILABILITY

Service Parameter	Phase I	Phase II	Phase III	Project Completion
In-Service Date (months)	20	27	34	41
Number of Caverns	4	8	12	16
Working Gas Capacity (Bcf)	1.4	2.8	4.2	5.6
Base Gas Requirement (Bcf)	0.65	1.3	1.95	2.6
Deliverability (MMBtu/day)	125,000	250,000	375,000	500,000
Injection Capacity (MMBtu/day)	100,000	150,000	200,000	250,000
Total Cycle Time (Days)	25.2	29.9	32.2	33.6
Available Number of Cycles/Year	14.5	12.2	11.3	10.9

KIOWA (continued)

Kiowa Gas Storage will provide its storage customers with the ability to cycle their entire inventory fully more than 10 times, dramatically reducing the actual per unit cost of storage.

Services/Benefits:

HNG expects the facility to evolve into a multi-pipeline trading center, offering its customers some of the benefits of a hub.

Kiowa Gas Storage customers wishing to use the facility as a trading center hub to move gas from one pipeline system to another can park gas for short periods of time; use storage gas for balancing; provide gas for emergency needs; inject and/or sell excess gas during periods of imbalance; and serve multiple pipeline supply and demand needs from a common gas supply portfolio.

This cycling capability can be further enhanced by each storage customer through the utilization of any available injection and withdrawal capabilities not used by other firm service customers. As a matter of tariff right, each firm service leaseholder will have a first priority right to its pro rata share of any firm services unsubscribed by any other firm service customer. Taking advantage of these under-subscribed services can dramatically increase available cycles for a heavy-use customer and further significantly reduce annual unit storage fees.

Terms of Service:

All rates for Kiowa service will be reached through arm's-length negotiations between storage service customers and the project's management. While reservation charges have not been determined, they are expected to be about $3.00 per Mcf per month.

In addition to these demand-based charges, there will be a commodity charge assessed on each injection and withdrawal transaction. This fee will offset the variable costs (primarily of electricity) of physical facility operation, including compression, dehydration, maintenance and dispatching operations. This charge will be about $.05 per Mcf.

LAUREL FIELDS

Location:	Southeastern New York and northern Pennsylvania (see map in Appendix A-2).
Owners:	National Fuel Gas Company
Pipeline Connections:	National Fuel Gas Supply
Type:	One existing storage reservoir (Limestone storage) and one depleted production field (Callen Run field).
Status:	New required facilities include five miles of pipe connecting the Limestone field, 25 miles connecting the Callen Run field, and 60 miles of pipe from a central location between the two storage fields to Leidy. National is planning for injections to begin at Laurel Fields in the spring of 1996, assuming timely certification by FERC. Of the total 19 Bcf of available capacity, 12 Bcf was bid upon during National's open season; however, only one 20-year precedent agreement was arranged, covering 2.5 Bcf under contract to affiliate National Fuel Gas Distribution. Other customers (Brooklyn Union, Enron, Eastern Shore, Yankee Gas Services and Eastern Natural Gas) signed up for 10 years of storage service.
Capacity:	Working gas capacity -- 19.1 Bcf 7.0 Bcf -- Limestone 12.1 Bcf -- Callen Run Total firm peak day withdrawal capability -- 207 MMcf per day Total injection capability -- 171 MMcf per day
Services/Benefits:	Laurel Fields intends to offer open access firm (SS-110 and SS-60) and interruptible (SSI) storage service. Maximum storage capacity for the 110-day service will be 15 Bcf, and the capacity for the 60-day service will be 4 Bcf. Firm service will be offered with 365-day injection and withdrawal capability. Inventory transfer service will be available.

LAUREL FIELDS (continued)

Terms of Service:

Term - 10-20 years
Quantity -

(1) 110-day service
MDWQ - 1/100 of max. storage quantity (MSQ) from 100 percent to 16 percent of MSQ, declines thereafter
MDIQ - 95 MMcf/d

(2) 60-day service (available to subscribers to 110-day service in proportion to contracted volume)

MDWQ - 1/50 of MSQ from 100 percent to 26 percent of MSQ, declines thereafter
MDIQ - 69 MMcf/d

Initial proposed maximum rates:

	Rate Schedule	
Rates per Dth	SS-110 and SS-60	SSI
Storage Demand Charge	$3.7315	--
Storage Capacity Charge	$0.0404	--
Injection Charge	$0.0045	$1.2398
Withdrawal Charge	$0.0045	--

Fuel rate - 2 percent for storage and 2 percent for transportation.

Laurel Fields supplies base gas.

LODI

Location:	Northern California (see map in Appendix A-2).
Owners:	Northern California Gas Storage Corp, in turn owned by HNG Storage Co. (the majority stockholder) and Sofregaz (a subsidiary of Gaz de France).
Pipeline Connections:	PG&E and Mojave Pipeline
Type:	Depleted field
Status:	Planned to begin service in the fall of 1997 on the PG&E system.
Capacity:	Two shallow reservoirs (about 2,500 feet), with working gas capacity of about 6 Bcf each. The project is designed to allow up to 250 MMcf per day of injection and 500 MMcf per day of withdrawal capacity. Full withdrawal capability can be sustained until depletion of 75 percent of working gas.
Services/Benefits:	High and constant deliverability service through a schedule of services allowing rapid injection and withdrawal "similar to characteristics typically associated with salt caverns." Lodi will provide "real-time" (no-notice) dispatching services. Uses of Lodi include no-notice balancing, price arbitrage, seasonal supply arrangements, protection against emergency system disruptions, ability to sell firm supply at more than 100 percent of contracted firm pipeline capacity, back-up futures trading, and maximization of firm capacity utilization. Market-based rates are proposed.
Terms of Service:	The annual reservation fee for firm storage will range from $1.00 to $1.25 per Mcf. Interruptible services will be provided and costs will be negotiated.

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MANCHESTER

Location:	Oklahoma/Kansas border in Grant County, Oklahoma on the northeast shelf of the Anadarko Basin (see map in Appendix A-2).
Owners:	Manchester Pipeline Corp., an Oklahoma gatherer (the pipeline plans to sell the project once it is developed).
Pipeline Connections:	Williams Natural Gas, Peoples Natural Gas, Western Gas Resources and Oklahoma Natural Gas. Deliveries from Williams Natural Gas and Oklahoma Natural Gas can be made into other key interstate systems, including Northern Natural Gas, ANR Pipeline, Panhandle Eastern Pipe Line, Natural Gas Pipeline, El Paso Natural Gas, and Transwestern Pipeline.
Type:	Depleted gas reservoir
Status:	Phase I design and development is completed. Originally scheduled to be operational in early 1995.
Capacity:	Injection capability -- 100 MMcf per day Withdrawal capability -- 250 MMcf per day Total capacity -- estimated at 28 Bcf Maximum withdrawal rates of nearly 250 MMcf per day can be sustained for an initial period of 8 to 10 days. Maximum withdrawal rates after 20 days are still over 200 MMcf per day. Manchester has low cushion gas requirements because of economic reservoir conversion to storage due to horizontal drilling. The reservoir integrity and sand quality offer multiple storage cycles per year.
Services/Benefits:	In addition to its "excellent" geographical location, Manchester Pipeline has eliminated common problems associated with gas storage by having leased the surface and subsurface storage rights from both surface and mineral owners. Currently, the surface is devoted to both gas operations and agriculture. Due to Manchester's control over the entire property, problems that often "plague" other storage fields, such a severed ownership, do not exist.

MANCHESTER (continued)

Manchester will offer bi-directional pipeline and hub services, as well as firm and interruptible storage contract, no-notice storage and gas balancing services. Storage customers receive system-wide hub services and local and Midwest regional market accessibility. Different service programs available include seasonal, short-term, long-term, balancing, and price hedging.

- Seasonal service allows gas storage during the nine months from March to December and withdrawal during the winter.
- Short-term service provides injection and withdrawal of specified volumes over a short period, typically one or two months, thus allowing more than one cycle per year.
- Long-term service is an arrangement for inexpensive long-term storage with limitations on withdrawals.
- Balancing service allows day-to-day (or hour-to-hour) injections and withdrawals to balance transportation and utilization.
- Price hedging service allows gas to be purchased during the lower-cost summer months and resold in the winter months at a higher price.

Terms of Service: Not available

MOSS BLUFF

Location: Liberty County, Texas, about 60 miles east of Houston (see map in Appendix A-2).

Owners: Tejas Power Corp. and CMS Gas Transmission and Storage.

Tejas Power has transferred its share to Market Hub Partners, a partnership among Tejas Power, NIPSCO Industries, New Jersey Resources, Miami Valley Leasing (affiliate of Dayton Power & Light) and Public Service Electric & Gas.

Pipeline Connections: Texas Eastern Transmission, Natural Gas Pipeline, and intrastates Channel Industries, Houston Pipe Line, MidCon Texas, and Tejas Gas. A connection to Trunkline is also proposed.

Type: Salt cavern

Status: Approximately 96 percent of presently available storage capacity (Phases I and II) at Moss Bluff is contracted to four customers: Channel Industries, Tejas Power, Northern Indiana Public Service, and Northern Illinois Gas. An open season was held in January 1995 for Phase III's capacity of 2 Bcf. Moss Bluff stated that proposed bids would be individually negotiated at market-based rates. Open season results are not public.

In November 1994, Moss Bluff submitted a petition to FERC for the approval of market-based rates and unveiled a new menu of interruptible services including parking, wheeling, balancing with loaning and parking, peaking loans, imbalance trading, and title transfers.

Capacity:

	PHASE		
	I	II	III
Total # of Caverns	1	1	1
Total Working Gas Volume (Bcf)	1.7	5.6	7.6
Cumulative Deliverability (MMcf/d)	300	900	1,200
Cumulative Injection (MMcf/d) (Average)	100	150	200
Start Date	12/90	12/93	9/95

MOSS BLUFF (continued)

Services/Benefits:

Tejas will have the ability to provide "ultra" firm daily deliverability on demand from the Moss Bluff facilities. In addition, that deliverability can be "swung down" on less than one hour's notice by injecting gas into storage, accommodating extreme variations in customer gas demand almost instantaneously. Customers may tailor Moss Bluff's gas services to meet virtually any need -- from daily peaking to winter peaking to year-round swing -- with "unmatched" reliability.

Moss Bluff is promoted as ideal for needle peaking, daily balancing, supply management and guaranteeing takes/deliverability.

Terms of Service:

Each customer has capacity, injection, withdrawal, transportation, and exchange capabilities provided at cost-based rates that are discounted. The cost-based charges are:

Reservation	- $.10-.21/MMBtu
Injection and withdrawal	- $.01/MMBtu
Transportation/interchange	- $.005-.05/MMBtu
Fuel	- 1.5%

MS-1

Location: Copiah County, Mississippi near Hazelhurst, about 80 miles upstream of Kosciusko, Mississippi (see map in Appendix A-2).

Owners: Partnership of Tejas Power as operator, and TETCO.

Tejas has transferred its share to Market Hub Partners, a partnership among Tejas Power, NIPSCO Industries, New Jersey Resources, Miami Valley Leasing (affiliate of Dayton Power & Light) and Public Service Electric & Gas.

Pipeline Connections: On Texas Eastern's system and near pipeline facilities of Southern Natural Gas, Koch Gateway Pipeline, and Mississippi Fuels (an Associated Natural Gas subsidiary).

Type: Salt cavern

Status: The scheduled startup date of Phase I operation is September 1997, assuming firm storage commitments are made by September 1995. Estimated cost of the two-phase development is $89-90 million. A portion of the project's capacity has already been reserved by Texas Eastern for its operational, balancing and transportation needs. Texas Eastern is reported to have signed a 15-year contract for 6 Bcf.

Capacity:

	Phase	
	I	II
Total number of caverns	2	3
Total working gas volume (Bcf)	6	9
Cumulative deliverability (MMcf/d)	600	900
Cumulative injection (MMcf/d) (average)	200	300
Start Date	9/97	9/98

Services/Benefits: MS-1 has the ability to provide "ultra" firm daily deliverability on demand and will be able to "swing down" that deliverability on less than one hour's notice by injecting into storage (when necessary), and accommodate extreme variation in customers' gas demands almost "instantaneously."

Tejas will be able to "custom tailor" services to meet virtually any need -- from daily peaking to winter peaking to year round swings. Other claimed benefits are daily balancing, supply management and take/deliverability guarantees.

Terms of Service: Not available

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NAPOLEONVILLE

Location:	Assumption Parish, Louisiana, south of Baton Rouge (see map in Appendix A-2).
Owners:	Enron Storage
Pipeline Connections:	Louisiana Resource Company (LRC), Koch Gateway Pipeline and Acadian Gas Pipeline; access to Henry Hub via LRC.
Type:	Salt dome
Status:	Began operation in December 1993.
Capacity:	Working gas capacity (Phase I) -- 4.6 Bcf Maximum withdrawal capability (Phase I) -- 400 MMcf per day Maximum injection capabilities (Phase I) -- 200 MMcf per day The bulk of the capacity has been leased to third parties, including pipelines, local distribution companies and marketers who are major players in the southeast, northeast and midwest regional gas markets. Phase II will add 3 Bcf of working gas with an additional 200 MMcf per day of deliverability capability. This capacity will be developed over the next two to five years, depending on market responses.
Services/Benefits:	Enron's Louisiana hub "will serve as a buffer between the real world and the strict NYMEX rules [at the Henry Hub] and pipeline tolerances." As an intrastate pipeline, LRC has more flexibility and less stringent policies on balancing, nominations and other provisions than on interstate pipelines. Enron also expects its Louisiana hub services to enhance NYMEX trading. Enron is offering a new hub trading program, EnServ Flow Management, that will provide access to the Henry Hub and numerous other pipelines in the area through Enron's LRC intrastate pipeline system. These services will be backed by the Napoleonville storage facilities.
Terms of Service:	Enron is seeking market-based rates from the FERC covering Section 311 services at Napoleonville, allowing the company to move gas out of storage to interstate markets.

Intentionally blank

NE-1/TIOGA

Location:	Tioga County, Pennsylvania (see map in Appendix A-2).
Owners:	Market Hub Partners -- a partnership among Tejas Power, NIPSCO Industries, New Jersey Resources, Miami Valley Leasing (affiliate of Dayton Power & Light) and Public Service Electric & Gas.
Pipeline Connections:	CNG near Tioga, Pennsylvania . Tennessee Gas Pipeline near its Station 315 in north central Pennsylvania. Investigating connecting to the Leidy line.
Type:	Salt caverns
Status:	Open season held during May and June 1995. Firm service is expected to be available in the winter of 1997/98.
Capacity:	Working gas capacity -- 10 Bcf, to be developed in two phases. Available marketable capacity -- 2.5 Bcf Maximum withdrawal capacity -- 500 MMcf/d Maximum injection capacity -- 125 MMcf/d
Services/Benefits:	Services will be customized for each user's needs. Withdrawal services of five to 60 days and injection capabilities of 20-60 days are possible.
Terms of Service:	Market Hub Partners lists the following representative rates but plans to request market-based rates.

Firm -	\$.30-.45/MMBtu of nominated capacity per month
Capacity-	\$.015 for each MMBtu injected and withdrawn, plus actual fuel

Intentionally blank

OUACHITA RIVER

Location:	Depleted South Downsville field in Union and Lincoln parishes, Louisiana (see map in Appendix A-2).
Owners:	Operated by Matrix Partners, Inc. and owned by Leucadia Financial Corp. and Ouachita River Partners, L.L.C.
Pipeline Connections:	An interconnection with Mississippi River Transmission's Perryville station provides access to eight interstate pipelines -- ANR Pipeline, Mississippi River Transmission, NorAm Gas Transmission, Tennessee Gas Pipeline, Texas Eastern Transmission, Koch Gateway Pipeline, Southern Natural Gas, and Texas Gas Transmission, and one intrastate -- Transok. Through these interconnects, customers can access 2,105 MMcf of receipt and 3,430 MMcf of delivery capacity.
Type:	Depleted field
Status:	The original plan was to have the South Downsville project in service by the winter of 1995-96. To meet that in-service date, Ouachita must begin construction by spring 1995.
Capacity:	Working gas -- 27 Bcf Cushion gas -- 13.5 Bcf The facility can be expanded to handle an additional 8 Bcf of working gas capacity if market conditions are favorable. Proposed withdrawal capacity is 550 MMcf per day and proposed injection capacity is 250 MMcf per day.
Services/Benefits:	Will offer service profiles ranging from 15-day high deliverability peaking/balancing service to an 80-day seasonal/balancing service. Key features of firm storage service include firm injections and withdrawal rights on any day, the ability to cycle working gas capacity multiple times each year, the ability to roll over quantities from year to year, inventory transfer rights and capacity release rights. Under Rate Schedule FSS, a prospective customer can stipulate a maximum storage quantity (MSQ) and a maximum daily withdrawal quantity (MDWQ) to establish a unique storage profile.

OUACHITA RIVER (continued)

As a result of the integrated nature of the storage and header facility, Ouachita River will not offer firm hub services at this time. Firm hub capacity will be reserved for firm storage customers. Customers who enter into storage service agreements under Rate Schedules FSS or ISS shall also receive firm or interruptible transportation service through the header system.

Under Rate Schedule IHS, Ouachita River proposes to offer interruptible hub service with 250 MMcf of capacity utilizing its header facilities located near Monroe, Louisiana. IHS service will include interruptible transportation among the pipelines connected to Ouachita River's header system, interruptible daily hub storage service, imbalance management and title transfers consistent with development of Perryville as a national market center.

Terms of Service: Rate Schedule FSS and ISS include a storage capacity charge, storage injection and withdrawal charges, and a fuel reimbursement charge, all to be negotiated. Upon receipt of certificate authorization, Ouachita will hold an open season and evaluate bids received on a non-discriminatory, net present value basis. Rate Schedule IHS includes a hub transportation charge, a hub storage charge, and a fuel reimbursement charge, all to be negotiated.

PETAL

Location:	Forrest County, Mississippi (see map in Appendix A-2).
Owners:	Petal Gas Storage, subsidiary of Chevron U.S.A., Inc.; operated by Warren Petroleum Co., a division of Chevron.
Pipeline Connections:	Koch Gateway Pipeline and Tennessee Gas Pipeline
Type:	Salt dome
Status:	Operational since February 1, 1994. As a result of the initial open season held in December 1993, Chevron U.S.A. Production Co. was allocated 2.7 Bcf (approximately 84 percent) of working gas capacity. The remaining 0.5 Bcf (approximately 16 percent) was allocated to an unaffiliated third party. Chevron U.S.A. Production supplies all 1.8 Bcf of base gas.
Capacity:	Working gas capacity -- 3.2 Bcf Injection capability -- 160 MMcf/d Withdrawal capability --320 MMcf/d Cycling can be completed in 30 days
Services/Benefits:	Firm and interruptible storage services are designed and negotiated to meet user's needs. Operating features include the following: ♦ high deliverability ♦ rapid supply replenishment ♦ no supply requirements for base gas ♦ intra-day service 365 days per year ♦ rapid response to nominations ♦ EBB communications ♦ interconnects downstream of major bottlenecks
Terms of Service:	All contract conditions, including the capacity and reservation demand charges, injection and withdrawal charges, fuel reimbursement charge, and minimum storage terms are developed through negotiation.

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PUTAH SINK

Location:	Northern California, just southwest of Sacramento (see map in Appendix A-2).
Owners:	Nahama & Weagant Energy Co. and John Hancock Life Insurance Co.
Pipeline Connections:	PG&E's Line 400 (1 Bcf/d) PG&E's regional transmission lines (10-60 MMcf/d) Mojave's extension via the proposed S.M.U.D. pipeline (85 MMcf/d) Dow/Shell Pipeline (50 MMcf/d)
Type:	Depleted field with two pools
Status:	Pre-development
Capacity:	Two separated pools, 6,700 feet deep, each with good permeability and porosity and the following capacity:

	East Pool	West Pool
Working Capacity	13.2 Bcf	9.5 Bcf
Withdrawal Rates	300 MMcf/d	300 MMcf/d
Injection Rates	90 MMcf/d	90 MMcf/d

Services/Benefits:

Putah Sink will offer firm, semi-firm and interruptible storage with the following advantages:

- reliability: firm service to core customers
- balancing: short-term gas cycling service during the injection/withdrawal season
- peaking service
- managing gas contracts
- storage in close proximity to northern California's industrial customers
- accessibility and storage of low-cost Canadian gas
- an independent storage project in a growing California market

Terms of Service: Not available

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RICHFIELD

Location:	Morton County, Kansas
Owners:	Richfield Natural Gas, Inc., Centennial Storage Corporation and Houston Gas Storage, Inc.
Pipeline Connections:	Northern Natural Gas, Panhandle Eastern Pipe Line, Colorado Interstate, and Western Resources.
Type:	Depleted field
Status:	Began operation in 1994.
Capacity:	Working gas capacity -- 3.5 Bcf Maximum withdrawal capability -- 50 MMcf per day
Services/Benefits:	Richfield had four distribution companies sign precedent agreements for firm service prior to construction of the facility: Midwest Gas (a division of Iowa Public Service Co.) with 1.3 Bcf of working gas and maximum withdrawal capability of 21.2 MMcf per day; (2) Iowa Gas and Electric with 1.5 Bcf of working gas and maximum withdrawal capability of 15 MMcf per day; (3) Michigan Gas Co. with 0.3 Bcf of working gas and maximum withdrawal capability of 5 MMcf per day; and (4) City of New Ulm, Minnesota with 0.3 Bcf of working gas and 2.4 MMcf per day of maximum withdrawal capacity.
Terms of Service:	Richfield has obtained FERC permission for market-based rates. The storage project's proposed rates filed with its application are as follows: ◆ Monthly reservation charge -- \$2.71 per MMBtu ◆ Annual capacity charge -- \$.39 per MMBtu of quantity of gas to be stored annually ◆ Injection and withdrawal charges -- \$.025 per MMBtu In addition, the company charges a winter delivery charge of \$0.26 per MMBtu and would impose penalties for overages or underages. Customers leaving gas in the field would continue to pay the applicable rate. Base gas of 2 Bcf is provided by Richfield.

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RIVERSIDE

Location:	Greene and Fayette counties in southwestern Pennsylvania
Owners:	General partners are ET Storage Co., (subsidiary of Equitrans Inc.), and Texas Eastern Riverside Co., (subsidiary of Texas Eastern Corp.)
Pipeline Connections:	Texas Eastern Transmission
Type:	Depleted field
Status:	FERC application initially filed in March 1994. Estimated development cost was $27.6 million. Delayed beyond 1995-96 winter heating season. In May 1995, Riverside filed an amended application because further testing has indicated that Riverside will not be able to achieve the capacity and deliverability stated in the certificate application. Texas Eastern and Equitrans are meeting with proposed customers to discuss permanent alternative projects to satisfy their needs. The associated Riverside transportation project's certificate application has been amended to account for the delay in completion of the storage facilities and loss of Eastern Shore Natural Gas as a firm customer. PECO Energy (29.2 MDth/d) and UGI Utilities (4.0 MDth/d) are the only remaining firm shippers. Because of the delay in the storage project, PECO has made alternate permanent storage arrangements with Panhandle Storage.
Capacity:	Total capacity -- 5.1 Bcf Working gas -- 3.1 Bcf Cushion gas -- 2.0 Bcf
Services/Benefits:	Two firm storage services -- 90-day withdrawal service under Rate Schedule 90SS, and 30-day withdrawal service under Rate Schedule 30SS: (1) 2.54 Bcf of firm baseload storage under Rate Schedule 90SS with an aggregate maximum daily withdrawal quantity (MDWQ) and maximum daily injection quantity (MDIQ) of 29.21 MDth per day, and (2) 560 MMcf of peak storage service under Rate Schedule 30SS, with an aggregate MDWQ and MDIQ of 19.32 MDth per day.

RIVERSIDE (continued)

Under these services, customers may inject or withdraw gas on any day during the year, subject to the requirement that customers must fully inject 100 percent of contract storage entitlements on one occasion during the summer period of each year and must withdraw at least 75 percent of contract entitlements on one occasion during the winter season.

Tariff contains storage withdrawal ratchets, whereby customers will be limited to 85 percent of MDWQ during the last days of the withdrawal season when aggregate storage inventory falls below 2.5 Bcf.

Interruptible storage service under Rate Schedule ISS-1.

Terms of Service: As amended, the proposed reservation charge will be $10.90/Dth.

RUSH CREEK

Location:	15 miles south of Kimball, Nebraska, in Weld County, Colorado (see map in Appendix A-2).
Owners:	Williams Storage Company and Piceance Natural Gas
Pipeline Connections:	KN Interstate Gas Transmission and Trailblazer Pipeline
Type:	Depleted gas field
Status:	Expected to begin December 1996.
Capacity:	Working gas capacity -- 3.5 Bcf Injection rights -- 100 MMcf per day Deliverability -- 120 MMcf per day Results of the open season indicate adequate demand to fully subscribe the working gas capacity.
Services/Benefits:	According to Williams, "by providing the shortest available cycling time in the region, Rush Creek can serve as a traditional baseload facility or as a high-performance peaking and balancing facility. Rush Creek will have the "least expensive" single-cycle rates in the region and multiple cycle rates as low as $0.20/Mcf." In addition, the new project will offer daily electronic posting of field and account information, and will work with pipelines to develop a single rate and nomination system.
Terms of Service:	Not available

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SOUTHWEST WYOMING

Location:	Near Evanston in Uinta County, southwest Wyoming (see map in Appendix A-2).
Owners:	Questar Pipeline
Pipeline Connections:	Major pipelines near the project site are: Questar, Kern River Gas Transmission, Northwest Pipeline, Overland Trail Transmission, Overthrust Pipeline, Colorado Interstate Gas and Williams Natural Gas.
Type:	Salt cavern
Status:	Proposed development

Capacity:

Although a maximum of five storage caverns are identified, with a potential 12.5 Bcf of capacity, Questar has two development alternatives for the first two caverns: the first option puts one half of the first cavern in service with 1.5 Bcf of working capacity within three years, and the second cavern and the remainder of the first cavern would be completed within seven years. The second option fully develops the first cavern in just under three years, and develops the second cavern within the seven-year period.

Expected performance of the two caverns:

♦ Working capacity	5 Bcf
♦ Withdrawal rate (100%-20% inventory)	500 MMcf/d
♦ Withdrawal rate (minimum inventory)	60 MMcf/d
♦ Injection rate	40-300 MMcf/d[1]
♦ Potential Cycles per year	2 to over 12[2]

Services/Benefits: Not available

1 The injection rate will depend upon the capacity of installed compressors. Final facility configuration will be based upon customer requirements.

2 Actual cycling depends upon injection rate, to be determined.

SOUTHWEST WYOMING (continued)

Terms of Service: Questar has estimated the rates for storage service from the two caverns with 5 Bcf of working gas capacity under the two development alternatives. The per unit rates depend on the number of cyclings per year (e.g., spreading fixed costs over greater volume).

Cost Per Cycle, Maximum Utilization* ($/Mcf)		
Maximum Cycles Per Year	Option 1	Option 2
2	1.68	1.33
4	0.86	0.69
8	0.45	0.37
12	0.32	0.26

* Does not include royalties to Wyoming, estimated at $0.0135/Mcf/cycle

SPINDLETOP

Location: East Texas (see map in Appendix A-2).

Owners: Centana Intrastate Pipeline Co., a subsidiary of Panhandle Eastern Corp.

Pipeline Connections: Connected by Centana Pipeline (450 MMcf/d) to Texaco's Sabine Pipe Line. Many other pipelines are in the general vicinity.

Interconnects Available	
Pipeline	MMcf/d
Texas Eastern Transmission	200
Florida Gas Transmission	75
Sabine Pipe Line Company (Texaco)	130
Natural Gas Pipeline Company	60
Amoco Gas Company	60
Channel Industries	65
Tejas Gas	270 a/
MidCon Texas	325 a/
Houston Pipe Line Company	100
Sonat Searim	25
Lonestar	40

a/ Includes proposed interconnect expansions.

NOTE: Only Texas Eastern, Florida Gas, Sabine, Tejas Gas, MidCon are bi-directional.

Type: Salt domes

Status: Began operation in 1993; currently has seven firm customers including marketers (Natural Gas Clearinghouse), producers (Chevron and Mobil) and end-users.

Capacity: Working gas capacity -- 5.2 Bcf
Maximum deliverability -- 600 MMcf per day

The third cavern is currently being leached to create an additional 6 Bcf of working gas capacity by late 1997.

Total hub wheeling capacity is 700 MMcf per day.

Services/Benefits:

In addition to the firm and interruptible storage services, Centana is also offering hub services at Spindletop -- parking, lending, balancing, wheeling, and title transfer.

Currently, Spindletop has seven firm customers.

Terms of Service:

Spindletop is under the jurisdiction of the Texas Railroad Commission. Reported rates are demand charge of $.10 per Mcf, deliverability charge of $.12 to $.27 per Mcf, injection and withdrawal charge of $.01 to $.02 per Mcf, with fuel retention of 2 percent.

TEN SECTION

Location:	Kern County, about 10 miles from Bakersfield, California (see map in Appendix A-2).
Owners:	McFarland Energy
Pipeline Connections:	Pacific Gas & Electric, Kern River Gas Transmission/Mojave Pipeline, and Southern California Gas.
Type:	Partially depleted oil and gas field
Status:	Proposed in-service date of April 1996. McFarland Energy has been working on the development of the project since about 1992. The company's initial efforts were in the California legislature, where a bill was passed in late 1992 urging the California Public Utilities Commission (CPUC) to require distributors to unbundle storage service from their transportation service. The CPUC mandated service unbundling by Southern California and Pacific Gas and Electric in 1993 and 1994, respectively. Now, California's utility customers have the option of obtaining storage offered either by the utilities or by independent providers. Therefore, independent storage providers will compete directly with the state utility's non-core storage programs. The CPUC's orders also required that non-discriminatory delivery entities will have to obtain a certificate of public convenience and necessity from the CPUC, and market-based rates will be permitted.
Capacity:	Potential to store 25 Bcf of working gas, with base gas of 20 Bcf. Potential maximum deliverability is 500 MMcf per day, and the ultimate project size will depend on the market demand.
Services/Benefits:	Ten Section is "very strategically located" for a storage and/or hub project because of the number of pipelines with delivery points nearby. The most likely customers of the project are large end users with fluctuating demands.
Terms of Service:	Not available

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THOMAS CORNERS

Location:	Steuben County, New York, south of Rochester (see map in Appendix A-2).
Owners:	Steuben Gas Storage Co., a partnership of ANR Northeastern Gas Storage and Arlington Associates Limited Partnership.
Pipeline Connections:	CNG Transmission and Tennessee Gas Pipeline
Type:	Depleted gas field
Status:	Pending regulatory approval, the company could begin providing storage service from the field in the fall of 1996.
Capacity:	Working capacity -- 5.3 Bcf Maximum withdrawal capacity -- 70 MMcf per day
Services/Benefits:	Steuben will offer firm storage service ranging from 50 days to 126 days with year-round injection and withdrawal rights on 4-hour notice. Customer will have the option either to provide base gas quantity, or pay a base gas surcharge. Steuben has entered into a firm storage service precedent agreement with Virginia Natural Gas covering 1.35 Bcf of capacity and will hold an open season to allocate the remaining capacity.
Terms of Service:	Steuben has requested FERC approval for market-based interruptible and firm storage rates for the facility. Steuben's key gas storage agreement provisions include the following: ♦ Storage Demand Withdrawal Quantity (SDWQ) shall be defined by the service selected within the range from 1/50th to 1/126th of the customer's Maximum Storage Quantity (MSQ). The Maximum Daily Withdrawal Quantity (MDWQ) shall be equal to the SDWQ until a certain percentage of the MSQ is withdrawn and thereafter reduced in steps until the remainder is withdrawn, as specified for the selected service.

- Storage Demand Injection Quantity (SDIQ) shall be 1/140th of customer's MSQ until 50 percent of the MSQ is injected. Thereafter the Maximum Daily Injection Quantity (MDIQ) shall be reduced to 1/187th of MSQ.

- Volumes in excess of the MDIQ and MDWQ may be provided at no additional cost.

- Volumes may be injected and withdrawn on a firm basis throughout the year.

- Volumes in excess of the Maximum Storage Quantity Volume may be cycled annually with no overrun charge.

- There is no requirement that gas be removed from storage annually nor penalty for failure to do so.

- Changes to nominations for withdrawals or injections can be made at any time upon four hours' prior notice.

- Steuben shall retain fuel equivalent to 1.5 percent of injection volumes and 0.6 percent of withdrawal volumes.

As a guide to interested customers, Steuben developed "base" rates under 20-year contracts for selected services at Thomas Corners. These rates will escalate by 2 percent per year after the first year of service.

Market-Based Rates for Selected Services a/ b/			
Withdrawal Service	100-day	75-Day	50-Day
Annual Unit "Base" Rate ($/Dth)	1.07	1.20	1.30

a/ These rates are based on an 8 percent interest rate for long-term financing.
b/ Excludes base gas.

WASHINGTON 10

Location:	Southeastern Michigan, thirty miles north of Detroit near the village of Romeo (see map in Appendix A-2).
Owners:	W-10 Holdings, Inc. (50 percent) and ANR Washington 10 Company, Inc. (50 percent). Michigan Consolidated Gas Company will be the operator of the field.
Pipeline Connections:	Consumers Power, Great Lakes Gas Transmission, Union Gas, ANR Pipeline, Trunkline Gas, TransCanada PipeLines, Panhandle Eastern Pipe Line, Michigan Consolidated Gas, and Grands Lacs market center.
Type:	Depleted field
Status:	Application was filed with Michigan PSC in 1993 and approved in late 1994. Planned to be in service in April 1997, but could be delayed.
Capacity:	Total gas capacity -- 42 Bcf Peak withdrawals -- 800 MMcf per day Peak injections -- 250 MMcf per day
Services/Benefits:	Affiliates of the partners have signed 20-year contracts for the full capacity of the field. Capacity will be remarketed through various methods to LDCs, Marketers and End Users. The field's proximity to multiple pipelines will make the service available to markets throughout the Midwest, Eastern United States and all of Canada.
Terms of Service:	Service will be provided at market-based rates subject to a $1 per Mcf maximum rate approved by the Michigan Public Service Commission. Both the peak withdrawal rates and peak injection rates are subject to ratchets depending upon the storage volume inventory.

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WILD GOOSE

Location:	Butte County, California
Owners:	The project was originally developed by First Reserve Gas Company of Dallas, Texas, owner and operator of the Hattiesburg Storage facility in Mississippi. In fall 1994, Wild Goose' ownership transferred to the two former top officials at First Reserve.
Pipeline Connections:	A 20-mile, 30-inch high pressure pipeline will connect the storage facility to a compression/gas treating facility and with Pacific Gas and Electric's 400/401 lines.
Type:	Depleted field
Status:	Phased development, projected for completion in mid-1997. Canwest Gas Supply, a Canadian marketer, has contracted for 75 percent of Wild Goose's capacity.
Capacity:	The initial phase will develop 9 to 12 Bcf of working gas capacity. Withdrawal capability is planned to be at least 600 MMcf per day and injection capacity will be at least 200 MMcf per day. The field has the potential to expand to 30 Bcf of working gas capacity.
Services/Benefits:	Firm contract storage with flexible contracts to provide gas supply security and reliability, firm peak day delivery or electric peak load supply in lieu of oil, and balancing services.
Terms of Service:	Long-term contracts are currently available at either fixed or escalating rates under the following terms:

Term	-	15 years
Quantity	-	MDWQ - 1/20th of capacity entitlement MDIQ - 1/60th of capacity entitlement
Rates	-	deliverability demand - \$1.00/Dth, subject to 2% annual escalation injection demand - \$1.66/Dth storage demand - \$0.066/Dth injection and withdrawal rate - \$.015/Dth, plus fuel

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YOUNG

Location:	Morgan County, Colorado
Owners:	Limited partnership with two general partners, Young Gas Storage Company and CIG Gas Storage Company (both subsidiaries of CIG Stock Corporation) and one limited partnership, the City of Colorado Springs, Colorado. Operated by Colorado Interstate Gas Co.
Pipeline Connections:	Colorado Interstate Gas
Type:	Depleted field
Status:	Under development. FERC issued certificate in June 1994. Total estimated cost is $44.4 million (including base gas).
Capacity:	When fully developed by 1998, Young will have total capacity of 10 Bcf, maximum working gas capacity of 5.3 Bcf and maximum daily deliverability of 200 MMcf.
Services/Benefits:	Four potential customers responded to Young's 1993 open season and Young accepted the bids of two to achieve full subscription under 30 year contracts. Public Service Co. of Colorado contracted capacity of 4.8 Bcf and deliverability of 180 MMcf/d while the City of Colorado Springs contracted 0.5 Bcf and 20 MMcf/d, respectively. An important and valuable characteristic of the Young field is the ability to turn around rapidly from withdrawal to injection and then back to withdrawal. This capability will enable the natural gas supply to be replenished between cold winter spells. Young believes that this storage field will offer an excellent natural gas service for the Colorado Front Range customers and provide an adequate delivery service of natural gas to consumers in the future as the Front Range growth generates higher peak day demands. Market growth in the Front Range is expected to average 1.5 to 2.5 percent per year over the next several years.

YOUNG (continued)

Terms of Service: Young's proposed rates (as filed with FERC) are based on a phase-in of the new facility's costs and storage field expansion over the four-year period. Young proposes new rates for each phase, with the new rate becoming effective each year after the in-service date of the facility. The initial filed rates are as follows for years 1 and 4:

	Rate per Mcf	
	Year 1	Year 4
FS-1 deliverability (per day)	$6.4842	$1.8615
FS-1 capacity	0.1556	0.0702
FS-1 injection/withdrawal	0.0461	0.0208[1]

[1] The Commission's Order issued June 22, 1994 found that Young's cost estimates and capital structure were generally acceptable, although the Commission reduced the cost of debt and return on equity. However, the Commission will permit Young to reflect actual and prudent debt cost in its initial rates when it files to establish the tariff rate in this proceeding.

APPENDIX A-2

STORAGE PROJECT MAPS

APPENDIX A-2

STORAGE PROJECT MAPS

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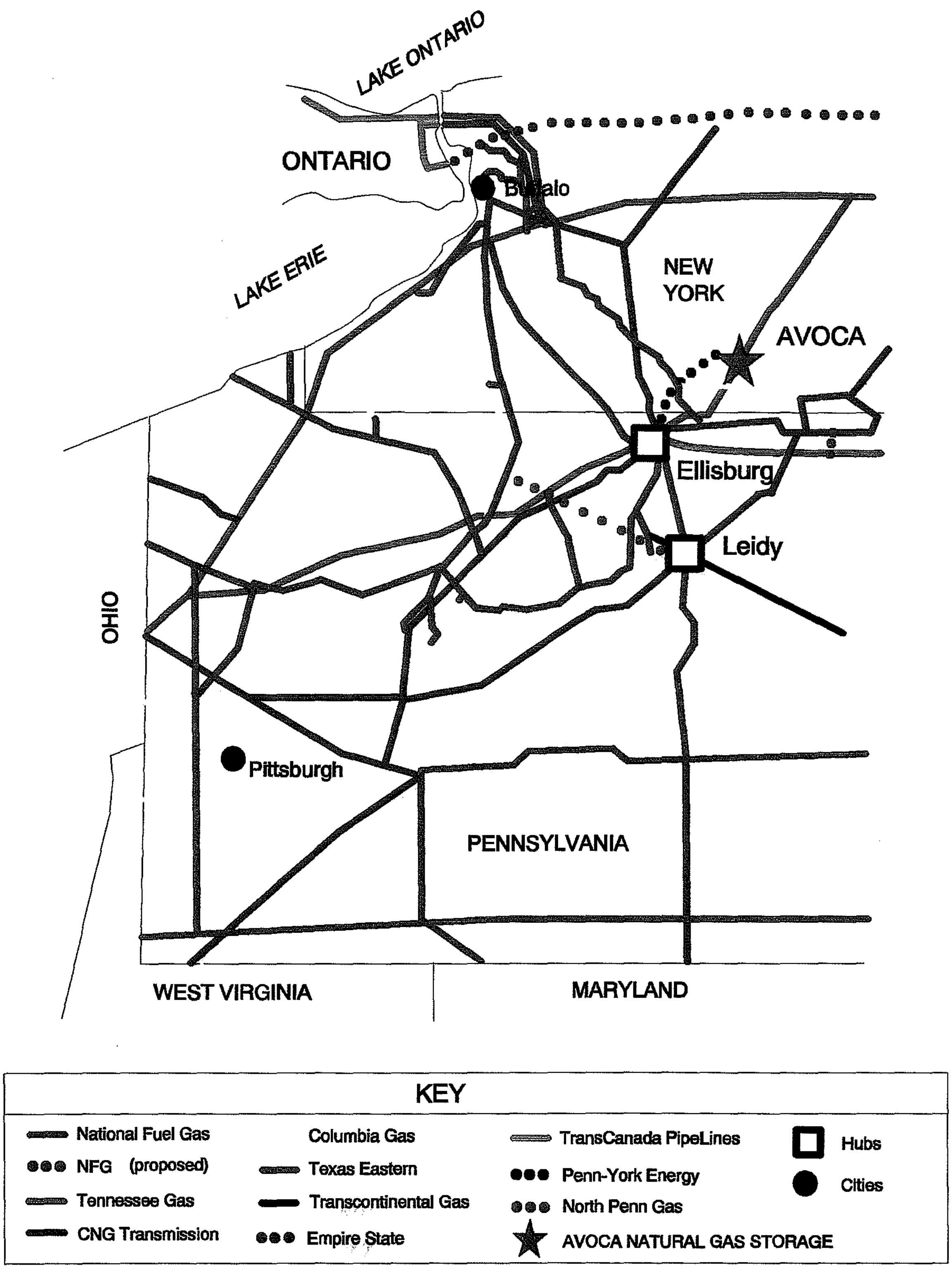
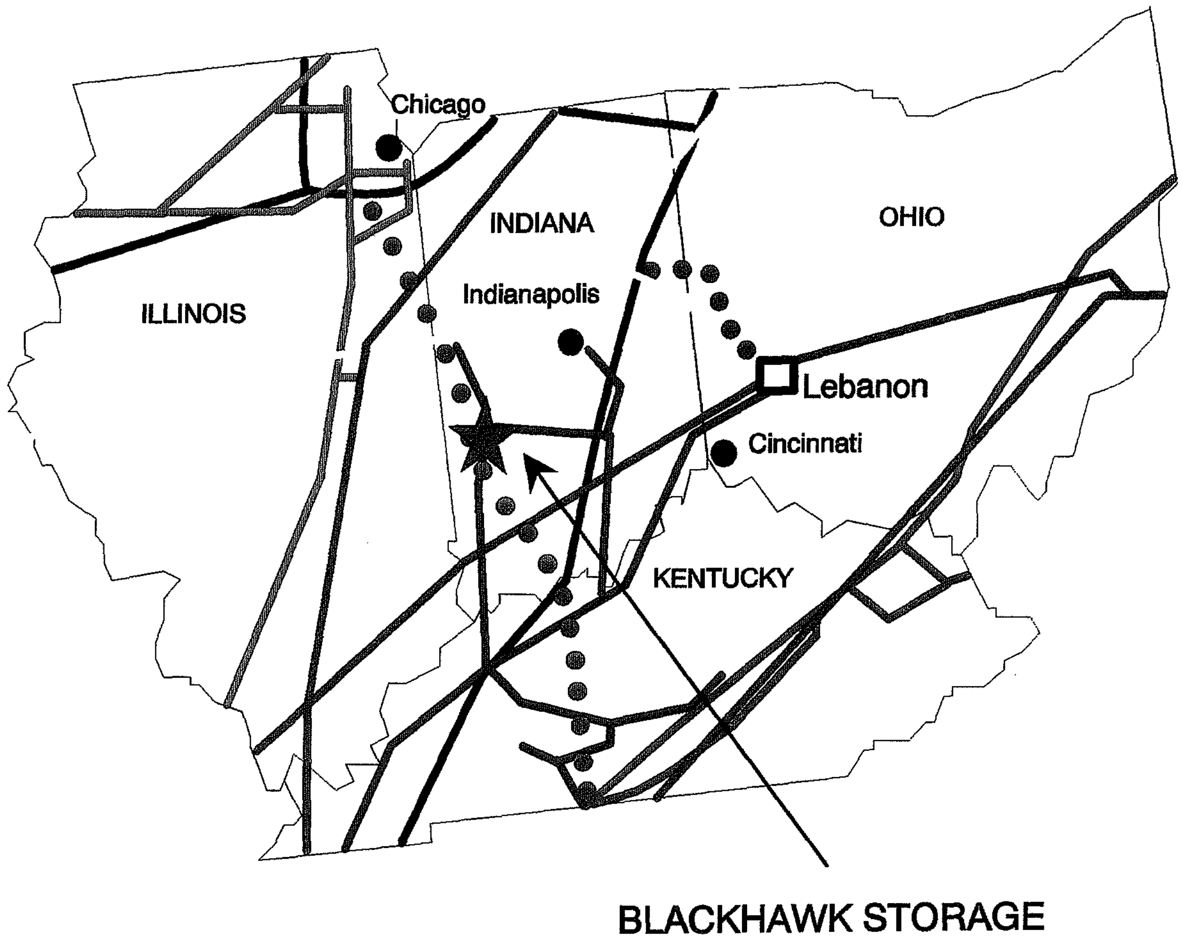
AVOCA NATURAL GAS STORAGE (NY)

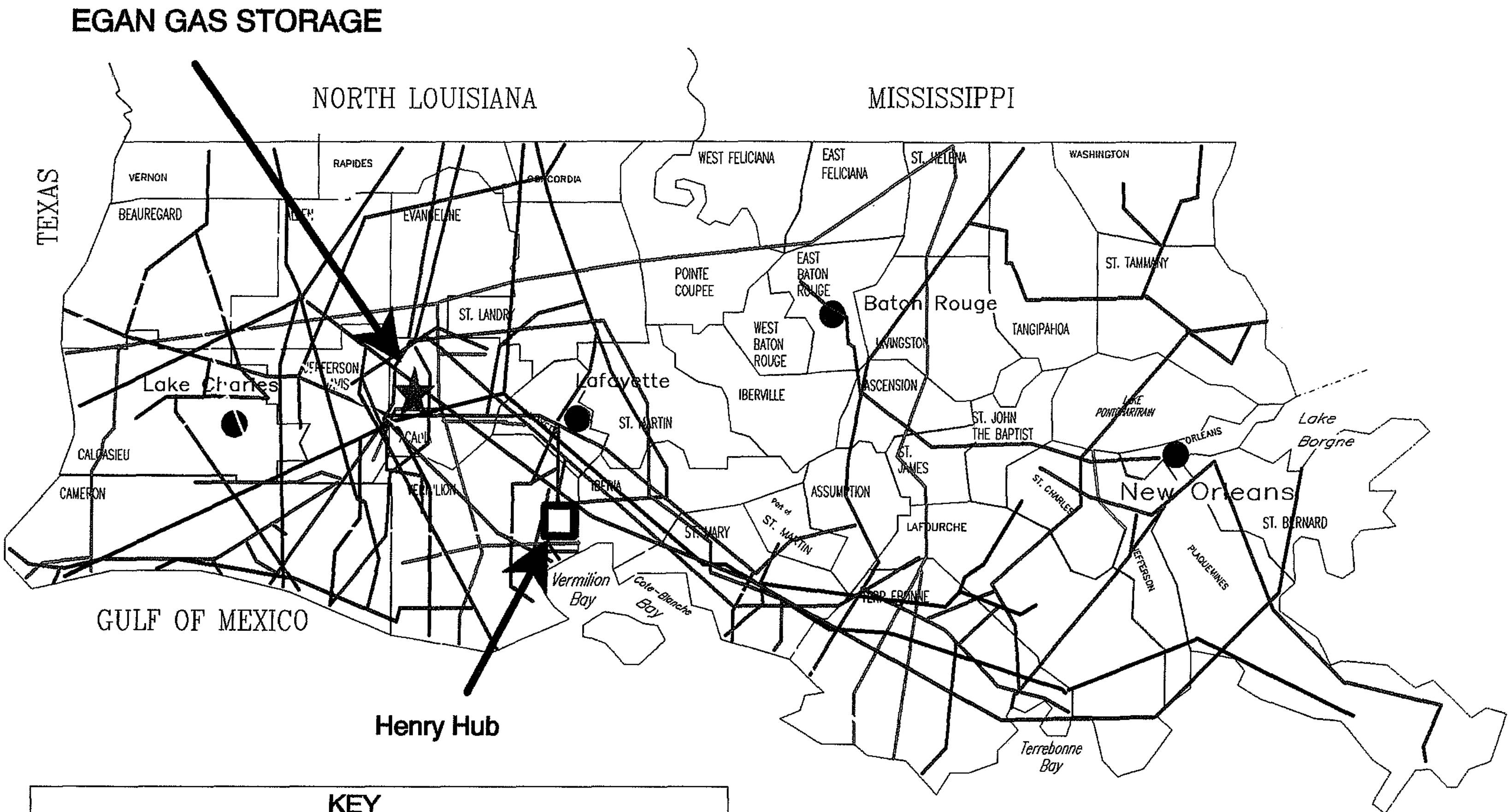


BLACKHAWK STORAGE FIELD (IN)

KEY
Texas Gas
Texas Eastern
Tennessee Gas
Natural Gas Pipeline
ANR Pipeline
Panhandle Eastern
Trunkline Gas
Midwestern Gas
Lebanon Lateral (Texas Eastern/ANR)
BLACKHAWK STORAGE
Hubs
Cities

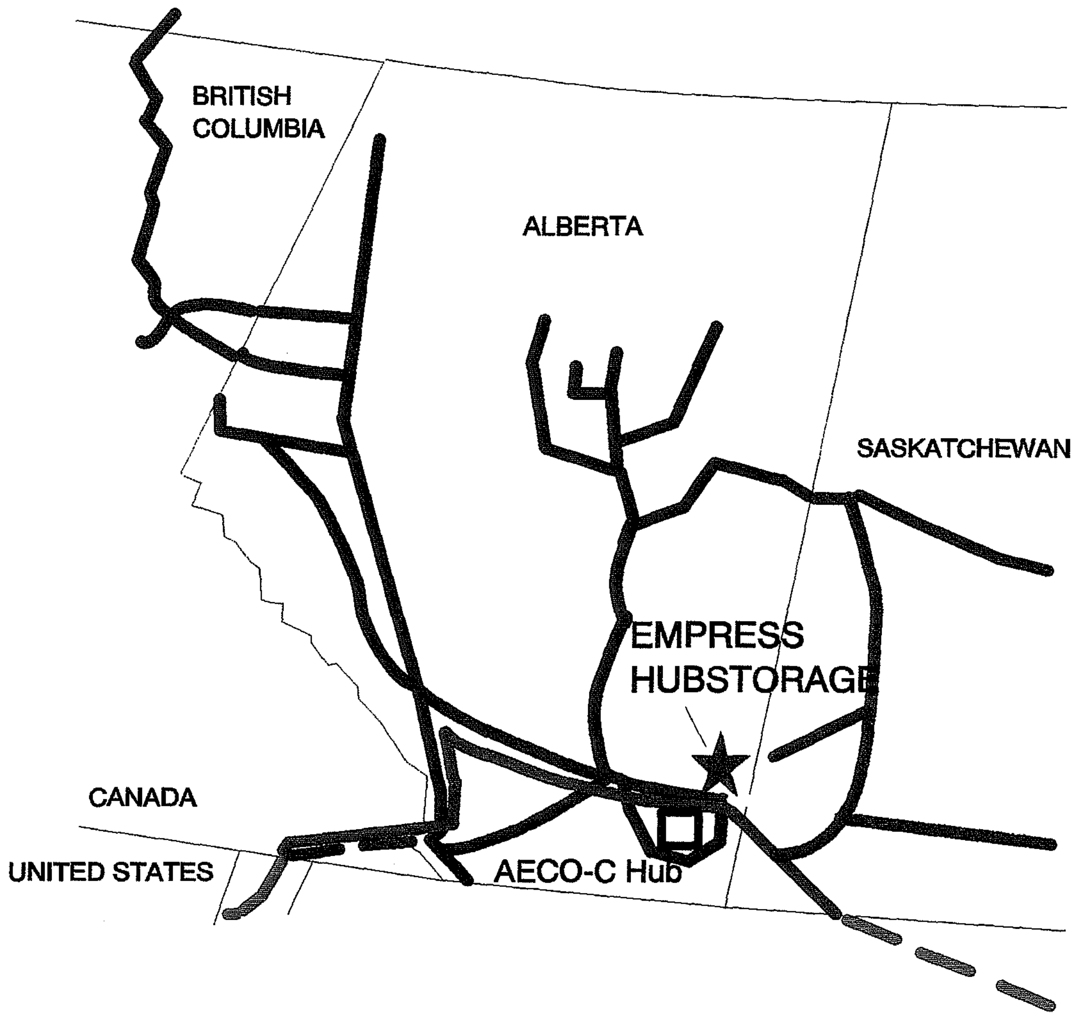


EGAN GAS STORAGE (LA)



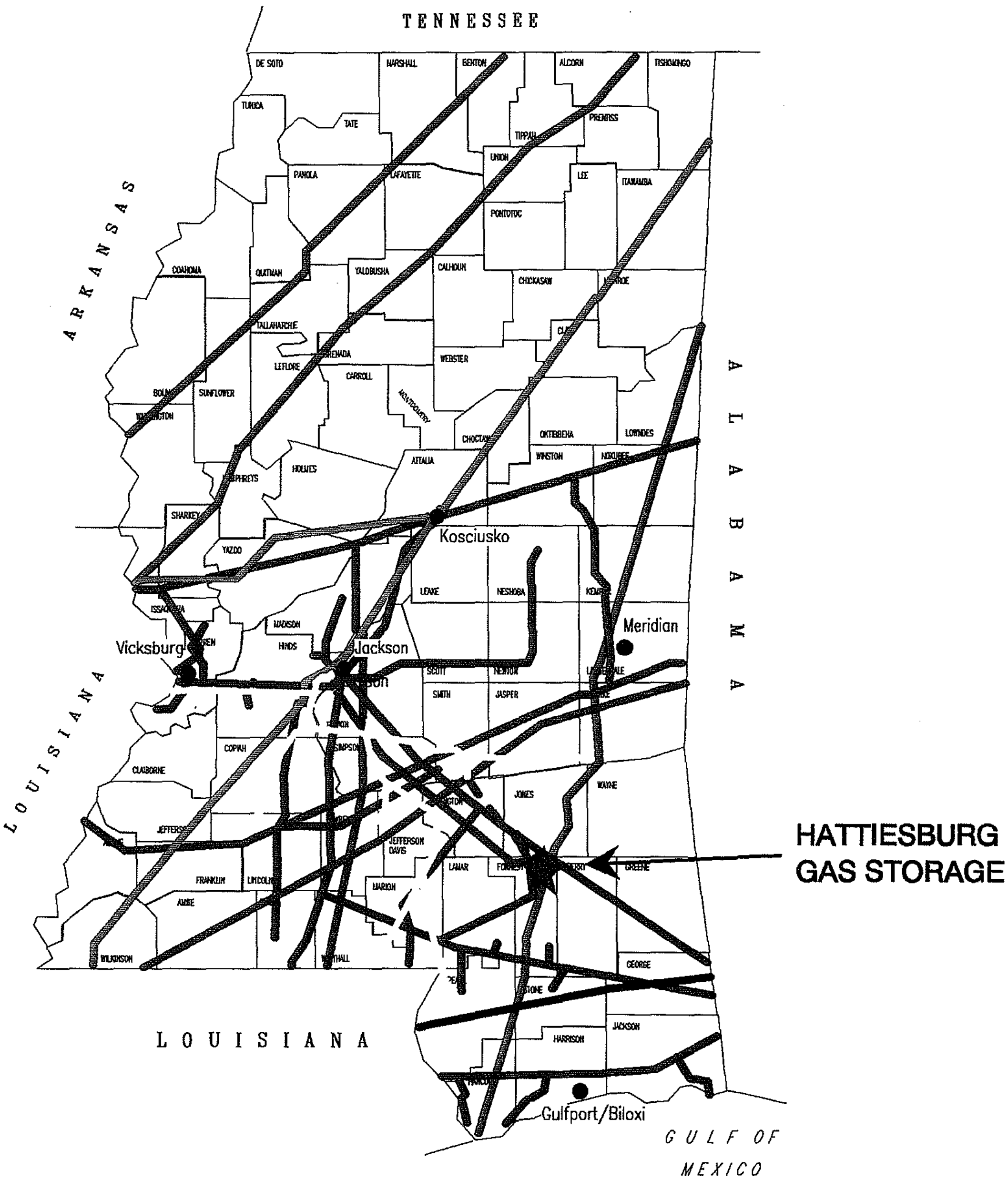
KEY	
Texas Gas Transmission	Trunkline Gas
Koch Gateway Pipeline	ANR Pipeline
Tennessee Gas Pipeline	Transcontinental Gas Pipe Line
Columbia Gulf Transmission	EGAN GAS STORAGE · Cities · Hubs

EMPRESS HUBSTORAGE (ALBERTA)



KEY		
NOVA Corporation	Alberta Natural Gas	★ EMPRESS HUBSTORAGE
Foothills Pipelines	Northern Border	
Transgas Limited	TransCanada PipeLines	□ AECO-C Hub (Includes AEC storage at Suffield, AB)
Pacific Gas Transmission	Westcoast Energy	

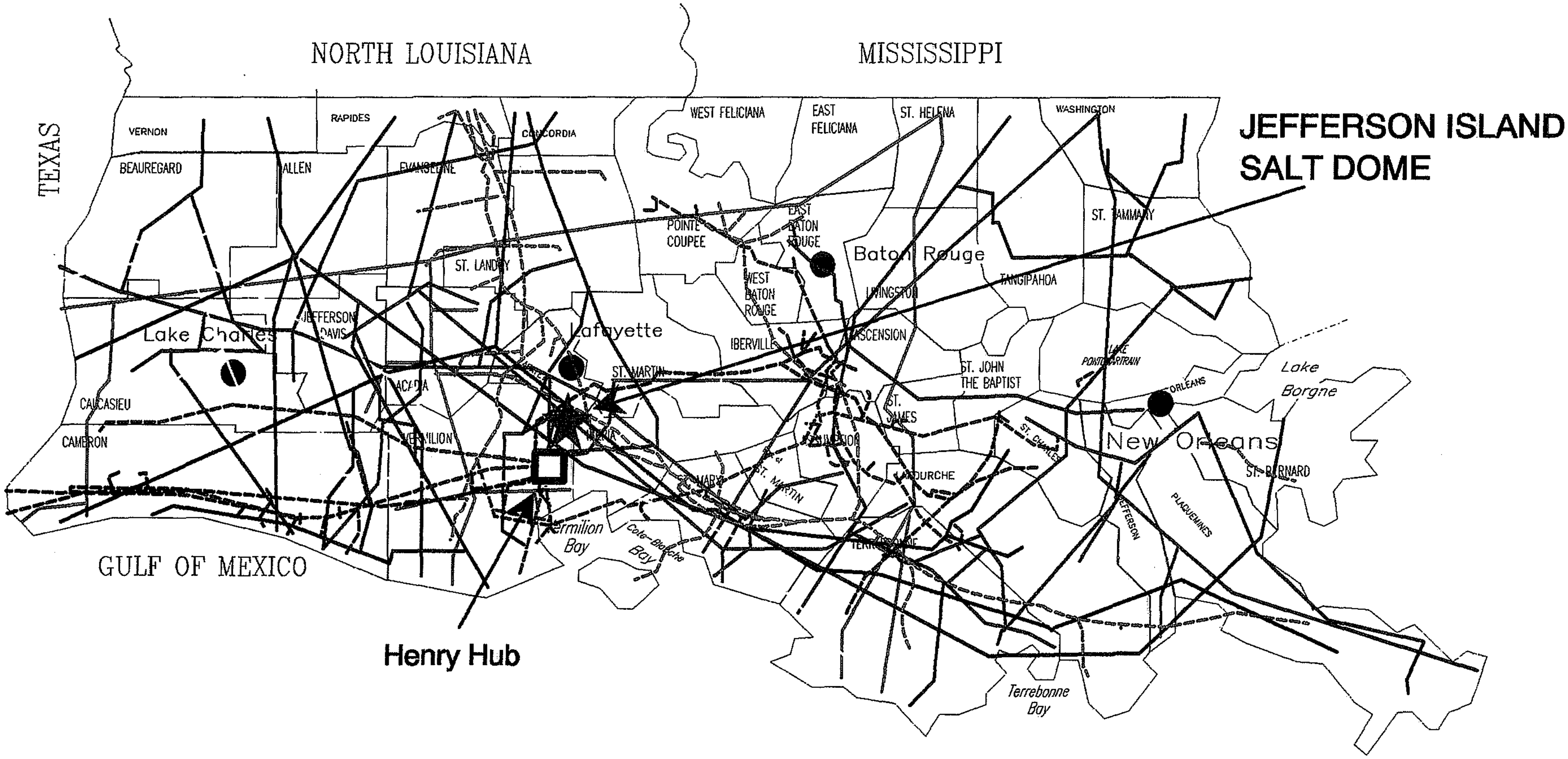
HATTIESBURG GAS STORAGE (MS)



KEY

- Tennessee Gas Pipeline
- Southern Natural Gas
- Transcontinental Gas
- Hattiesburg-Transco Interconnect Extension
- Koch Gateway Pipeline
- Mississippi Fuels (Associated)
- Texas Eastern Transmission
- Florida Gas Transmission
- HATTIESBURG GAS STORAGE
- Cities

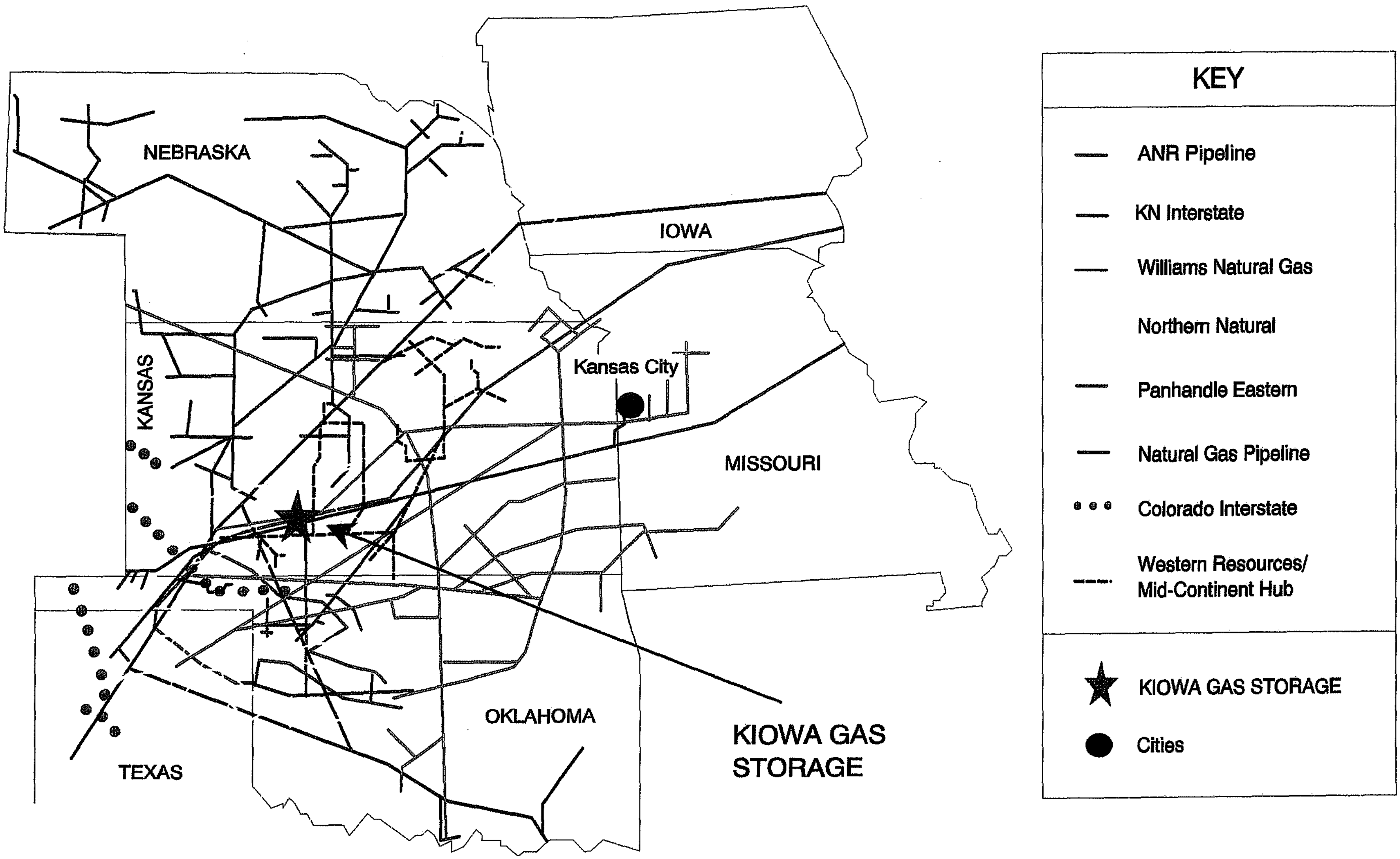
JEFFERSON ISLAND GAS STORAGE (LA)



KEY

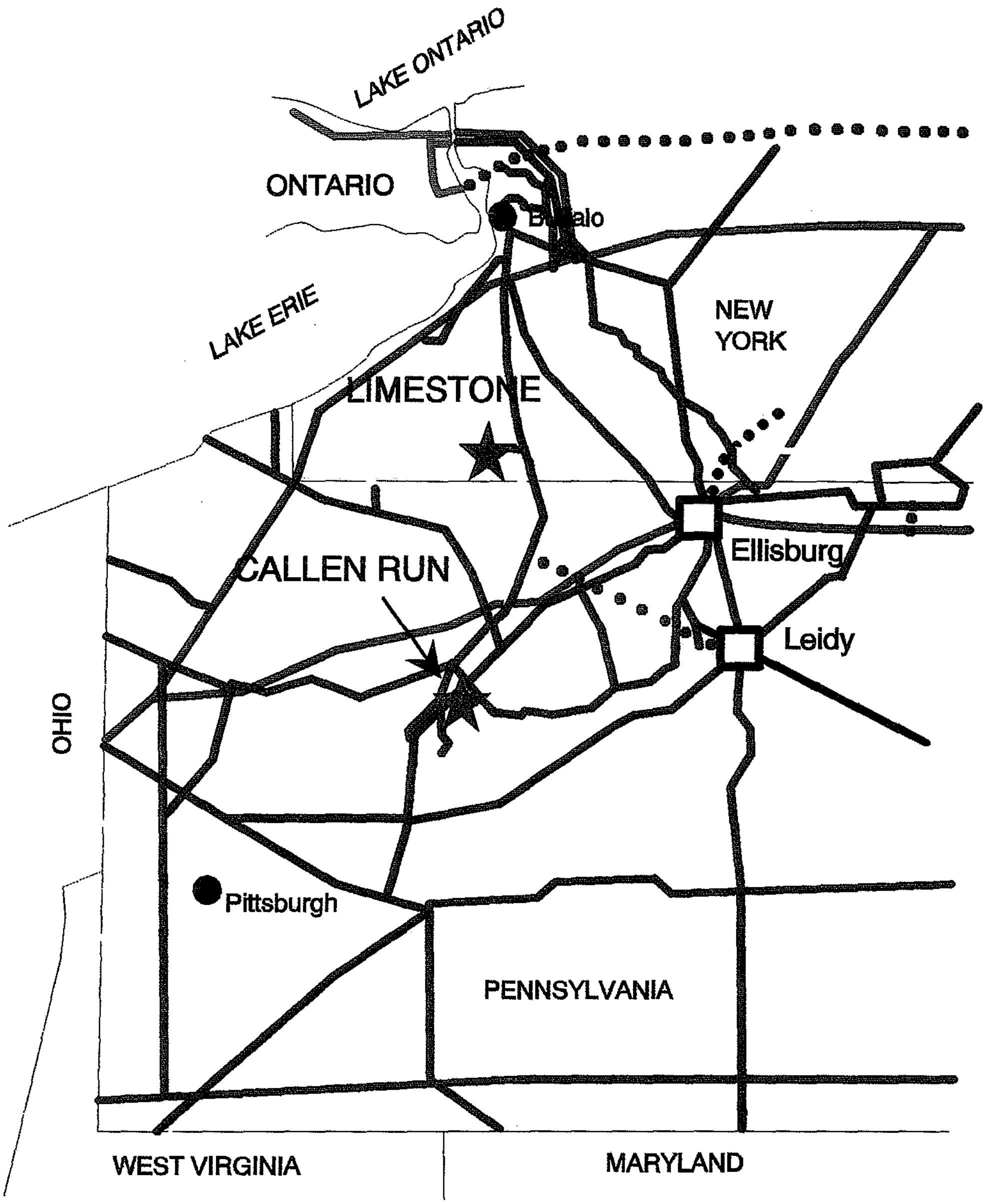
Texas Gas Transmission	Trunkline Gas	Acadian Gas Pipeline
Koch Gateway Pipeline	Transcontinental Gas	Sabine Pipe Line
Tennessee Gas Pipeline	Southern Natural Gas	Louisiana Resources
Columbia Gulf Transmission	Natural Gas Pipeline	JEFFERSON ISLAND GAS STORAGE
Dow Intrastate	Louisiana Intrastate	Sea Robin Pipeline
Cities	Hubs	

KIOWA GAS STORAGE (KS)



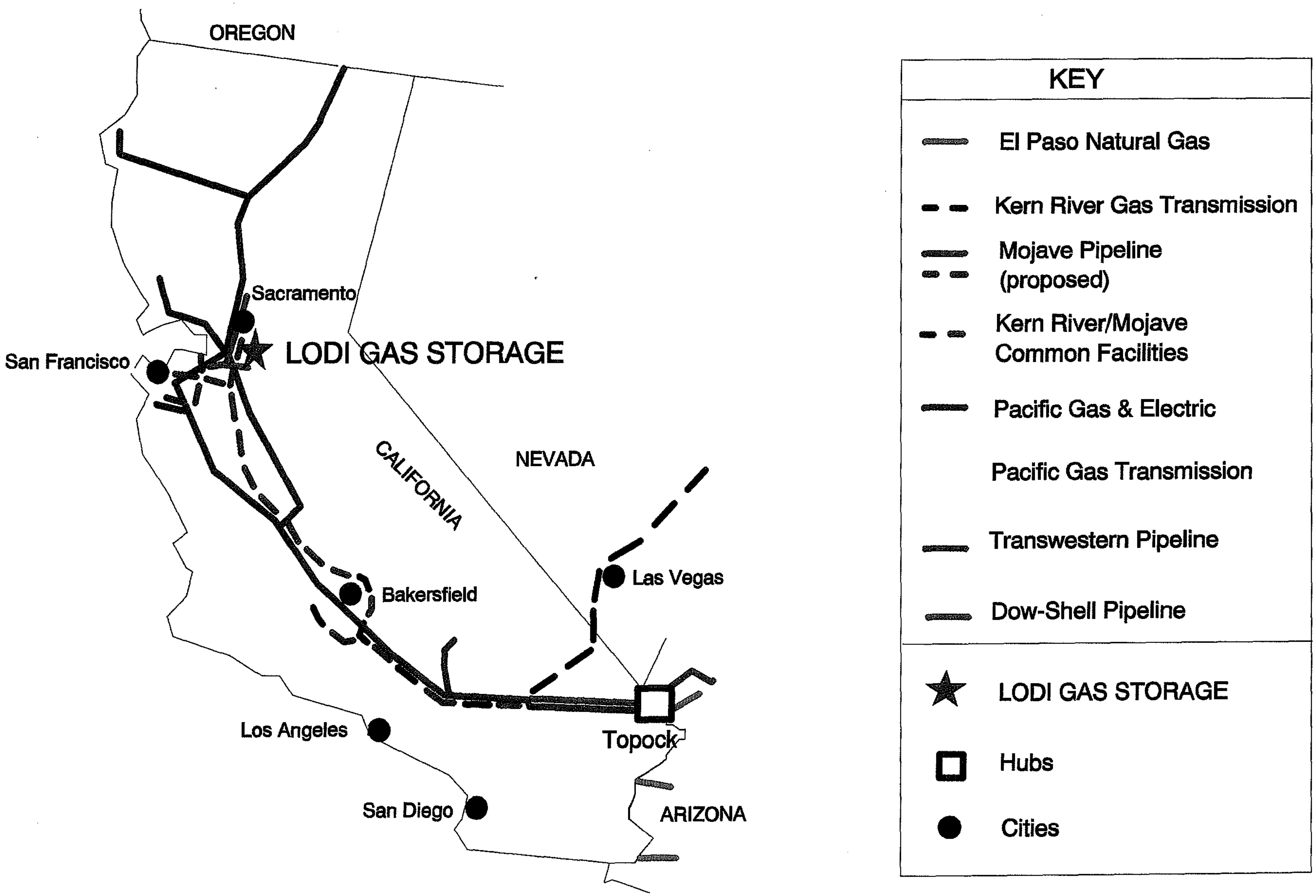
LAUREL FIELDS STORAGE PROJECT (NY and PA)

(LIMESTONE AND CALLEN RUN STORAGE FIELDS)

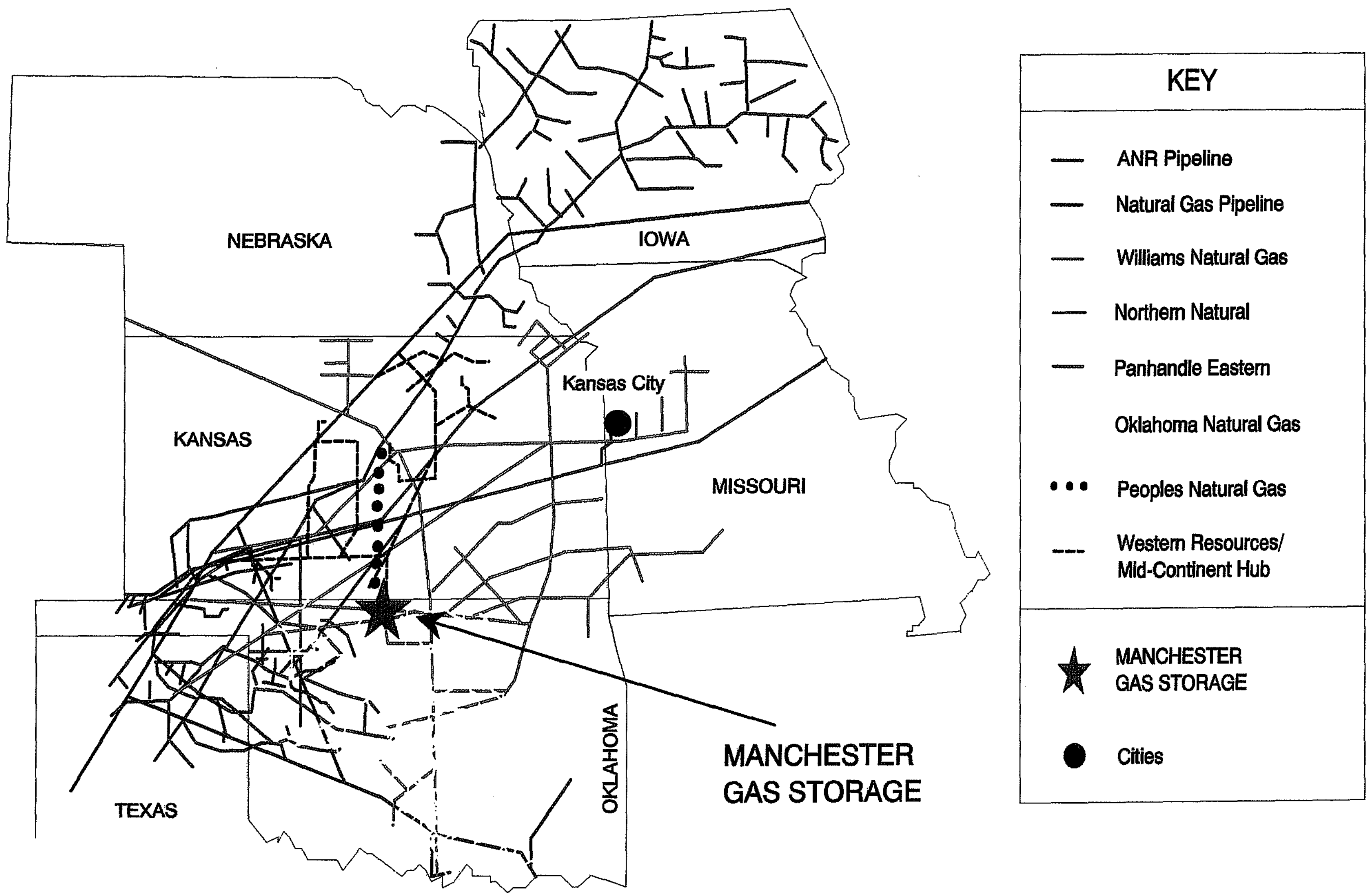


KEY			
National Fuel Gas	Columbia Gas	TransCanada PipeLines	Hubs
NFG (proposed)	Texas Eastern	Penn-York Energy	Cities
Tennessee Gas	Transcontinental Gas	North Penn Gas	
CNG Transmission	Empire State	LAUREL FIELDS STORAGE	

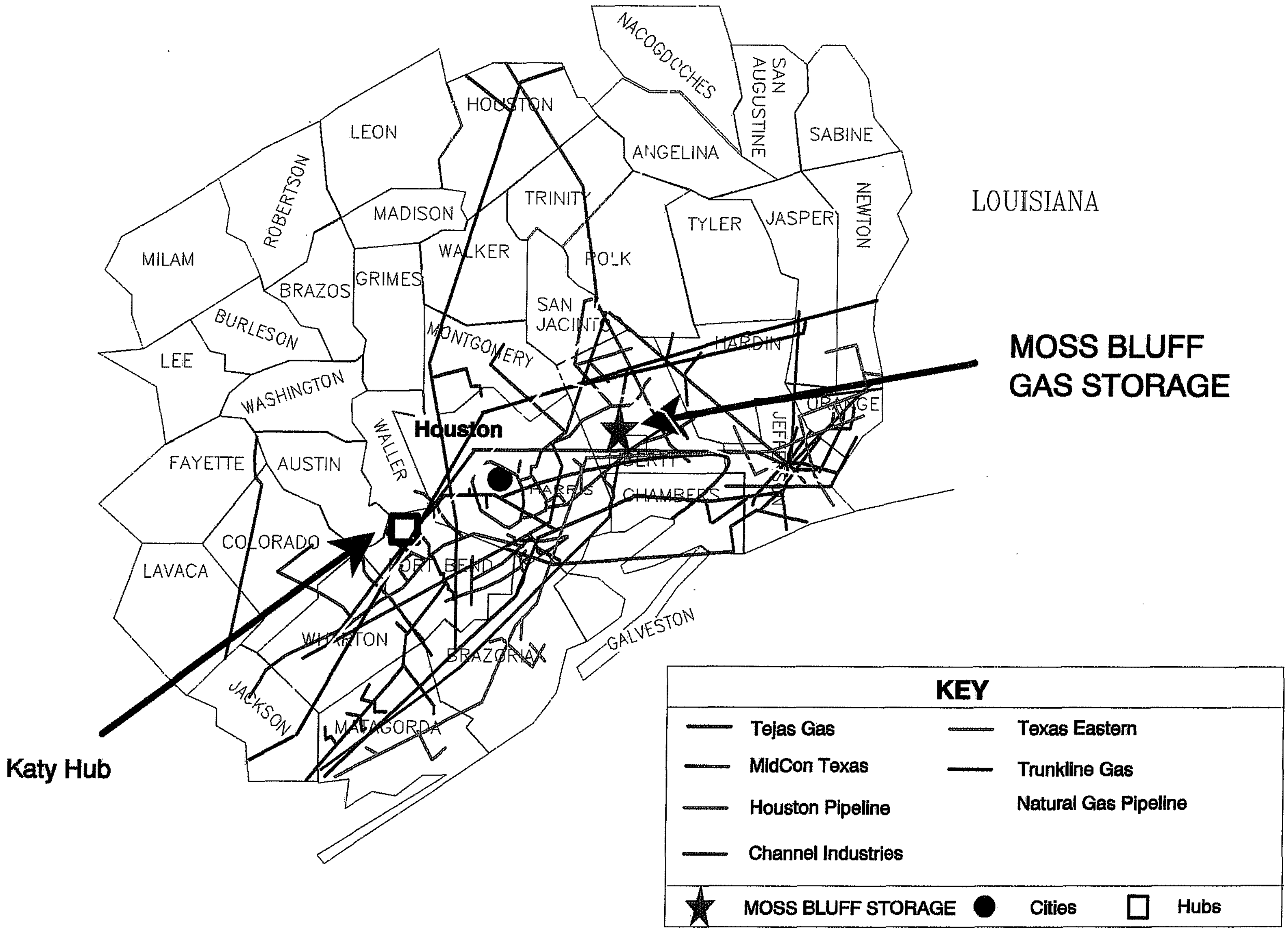
LODI GAS STORAGE PROJECT (CA)



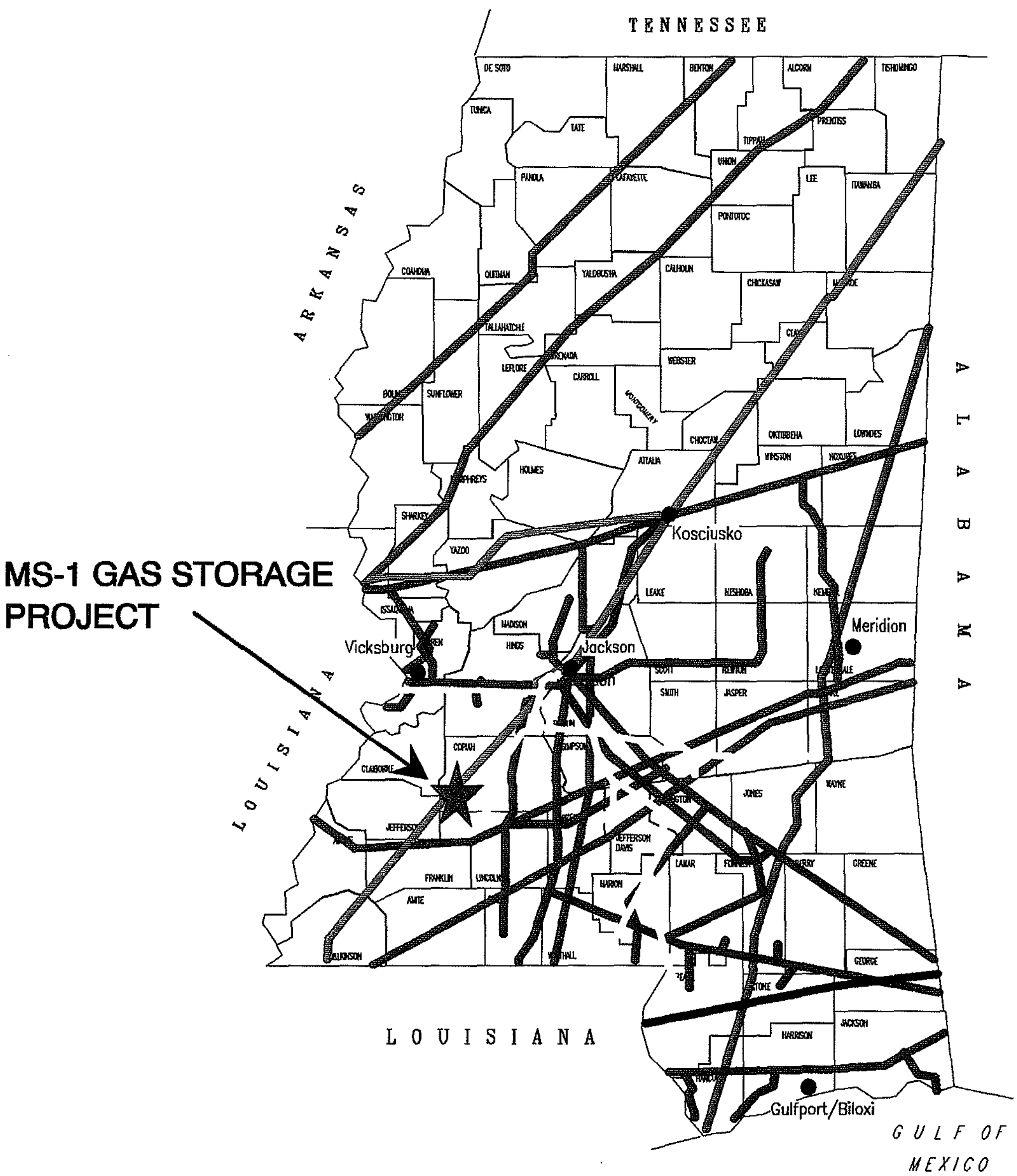
MANCHESTER GAS STORAGE (OK)



MOSS BLUFF GAS STORAGE (TX)



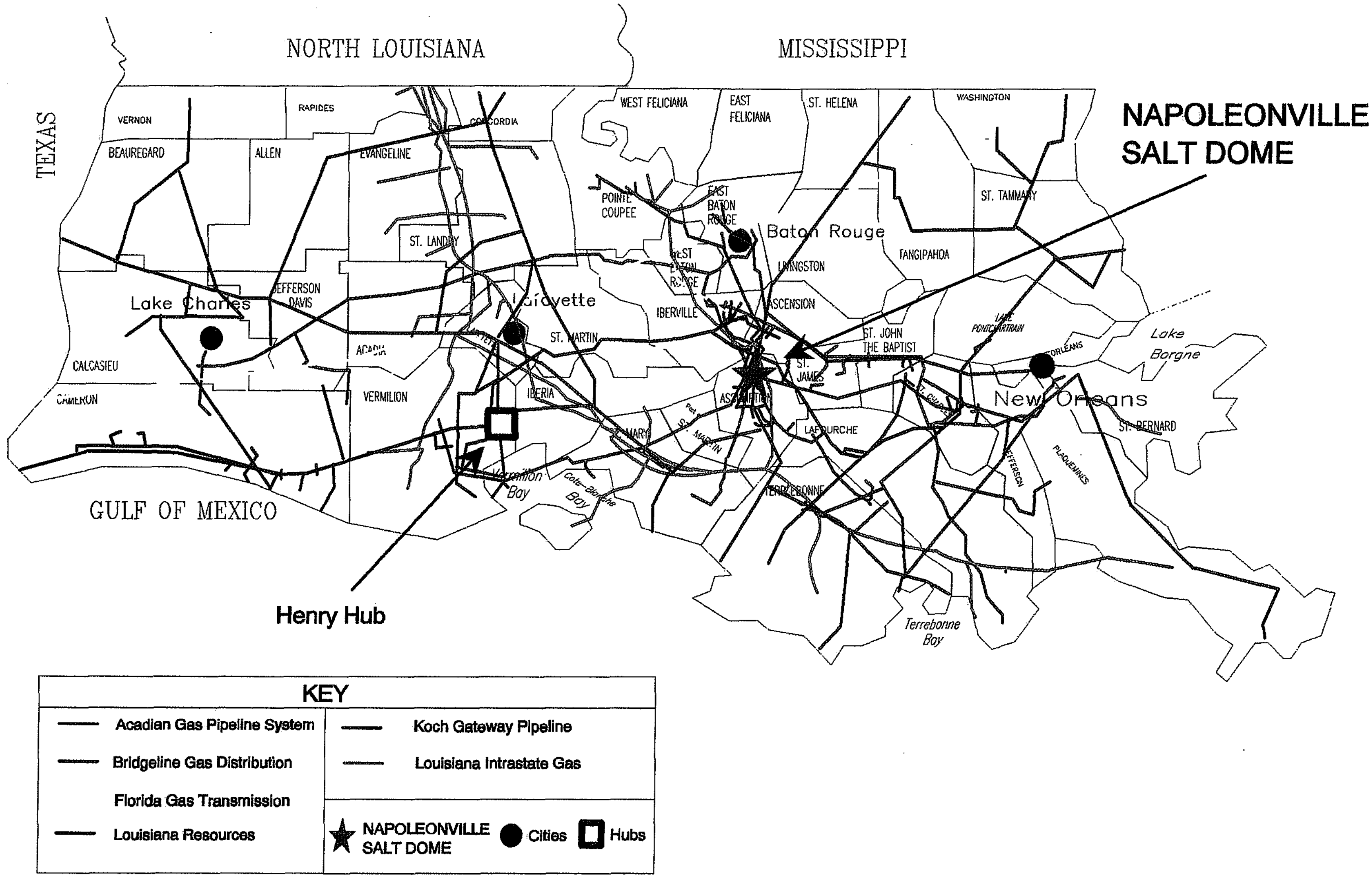
MS-1 GAS STORAGE PROJECT (MS)



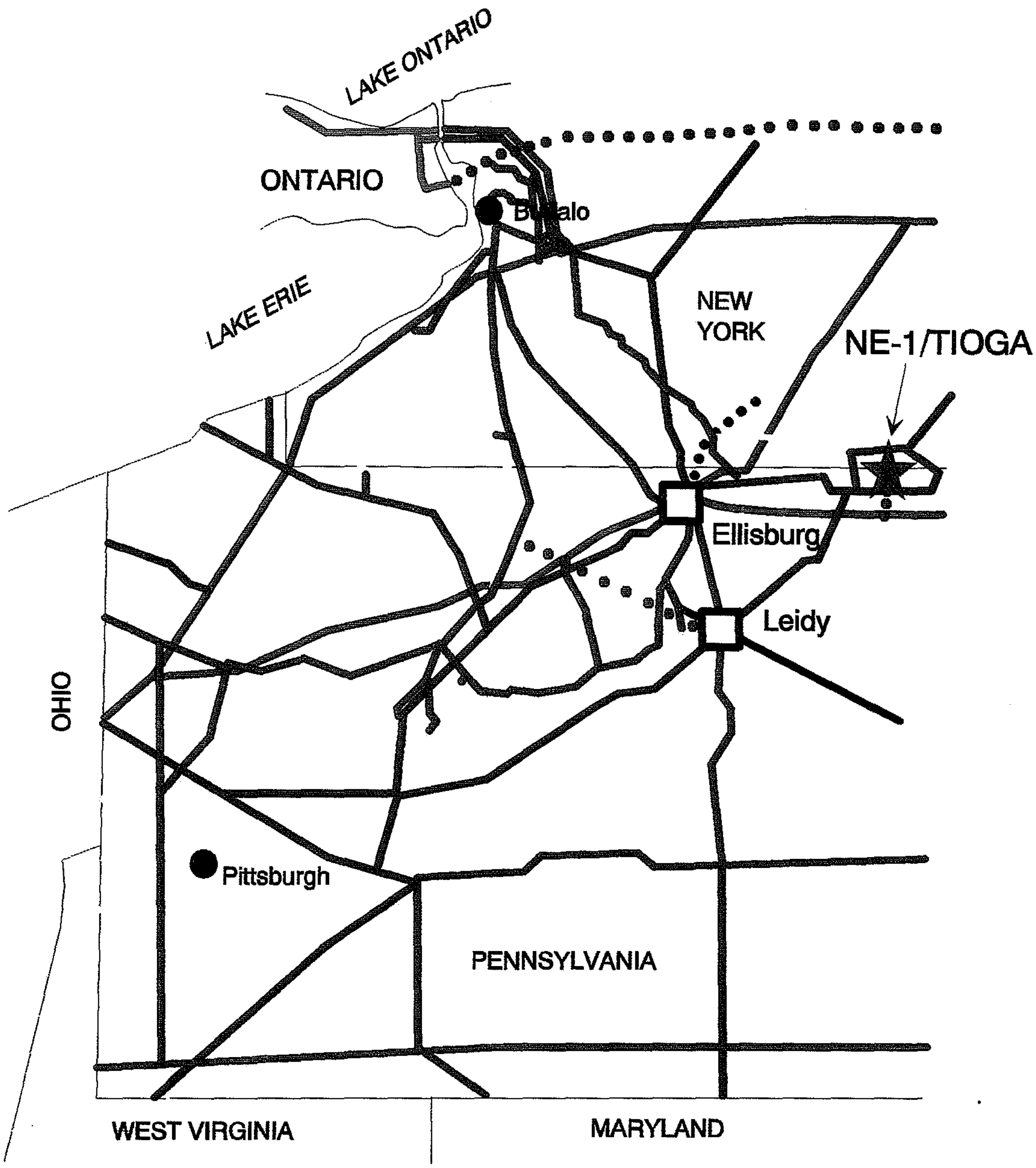
KEY

- Tennessee Gas Pipeline
- Southern Natural Gas
- Transcontinental Gas
- Florida Gas Transmission
- Koch Gateway Pipeline
- Mississippi Fuels (Associated)
- Texas Eastern Transmission
- MS-1 GAS STORAGE PROJECT
- Cities

NAPOLEONVILLE SALT DOME (LA)



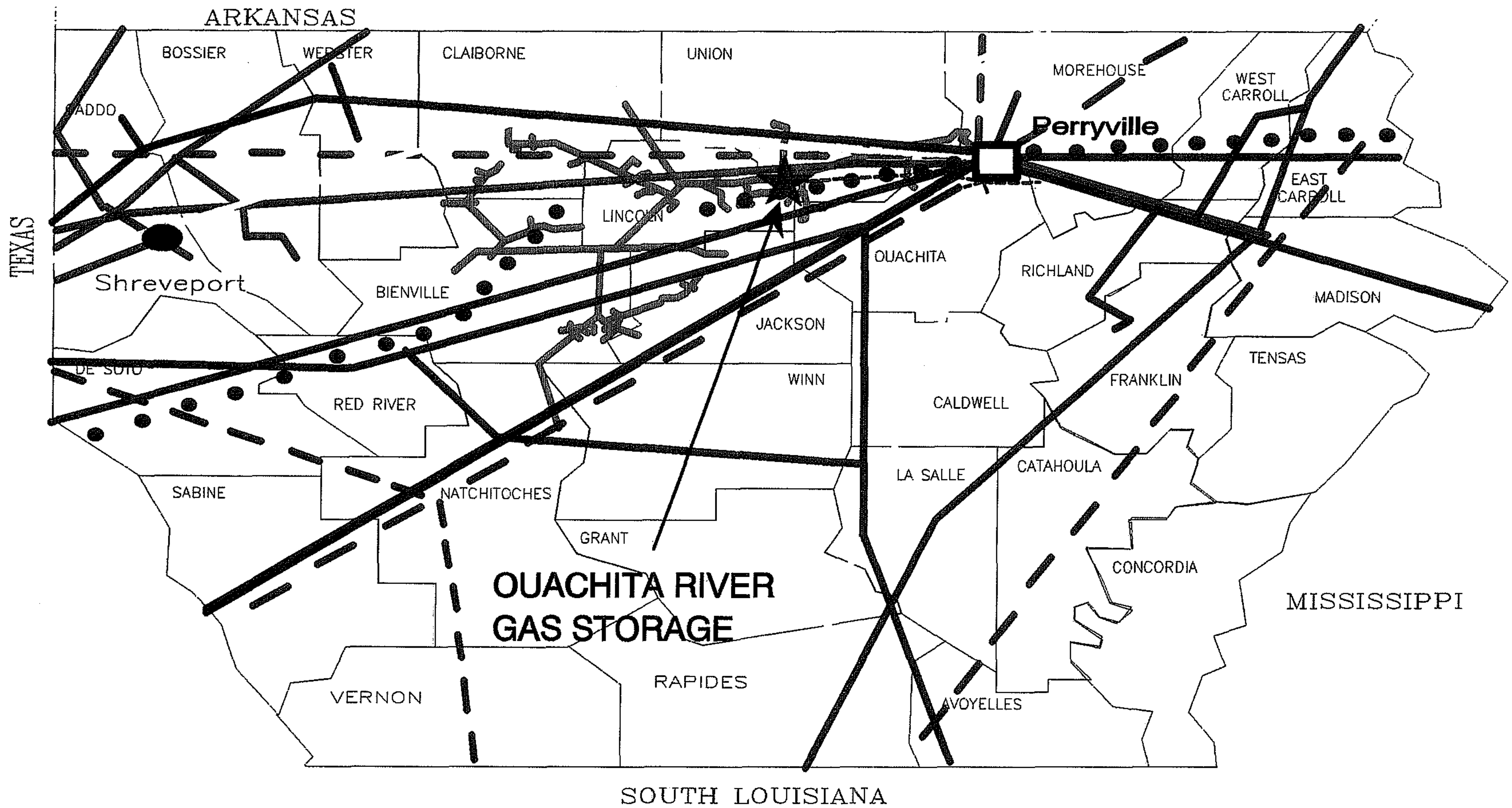
NE-1/TIOGA GAS STORAGE (PA)



KEY

National Fuel Gas
NFG (proposed)
Tennessee Gas
CNG Transmission
Columbia Gas
Texas Eastern
Transcontinental Gas
Empire State
TransCanada PipeLines
Penn-York Energy
North Penn Gas
NE-1/TIOGA GAS STORAGE
Hubs
Cities

OUACHITA RIVER GAS STORAGE (LA)

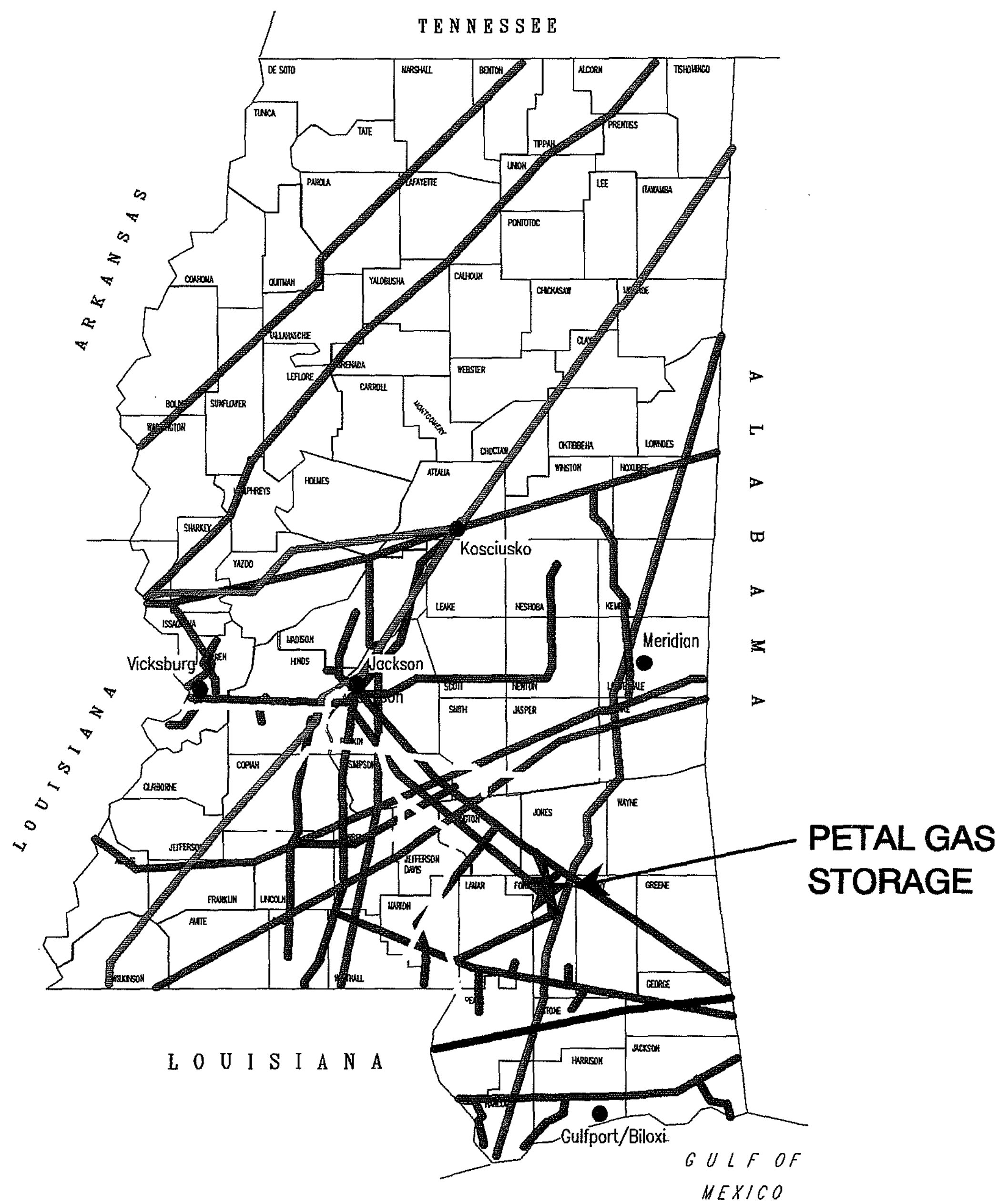


KEY

ANR Pipeline
Koch Gateway
NorAm Gas
Texas Gas
Southern Natural
Transok
Mississippi River Trans.
Texas Eastern
Tennessee Gas
Ouachita Storage Pipeline (proposed)

OUACHITA RIVER GAS STORAGE
Hubs
Cities

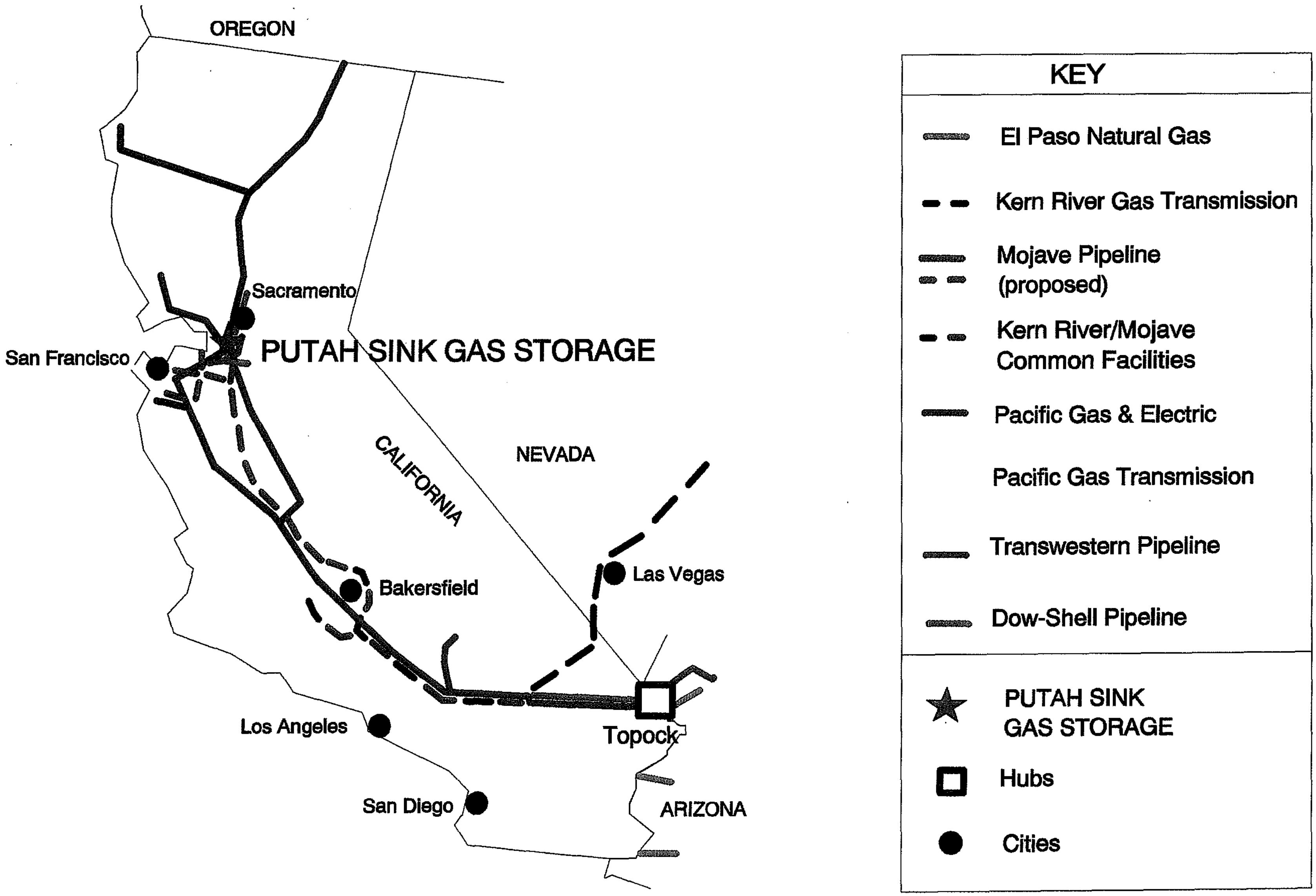
PETAL GAS STORAGE (MS)



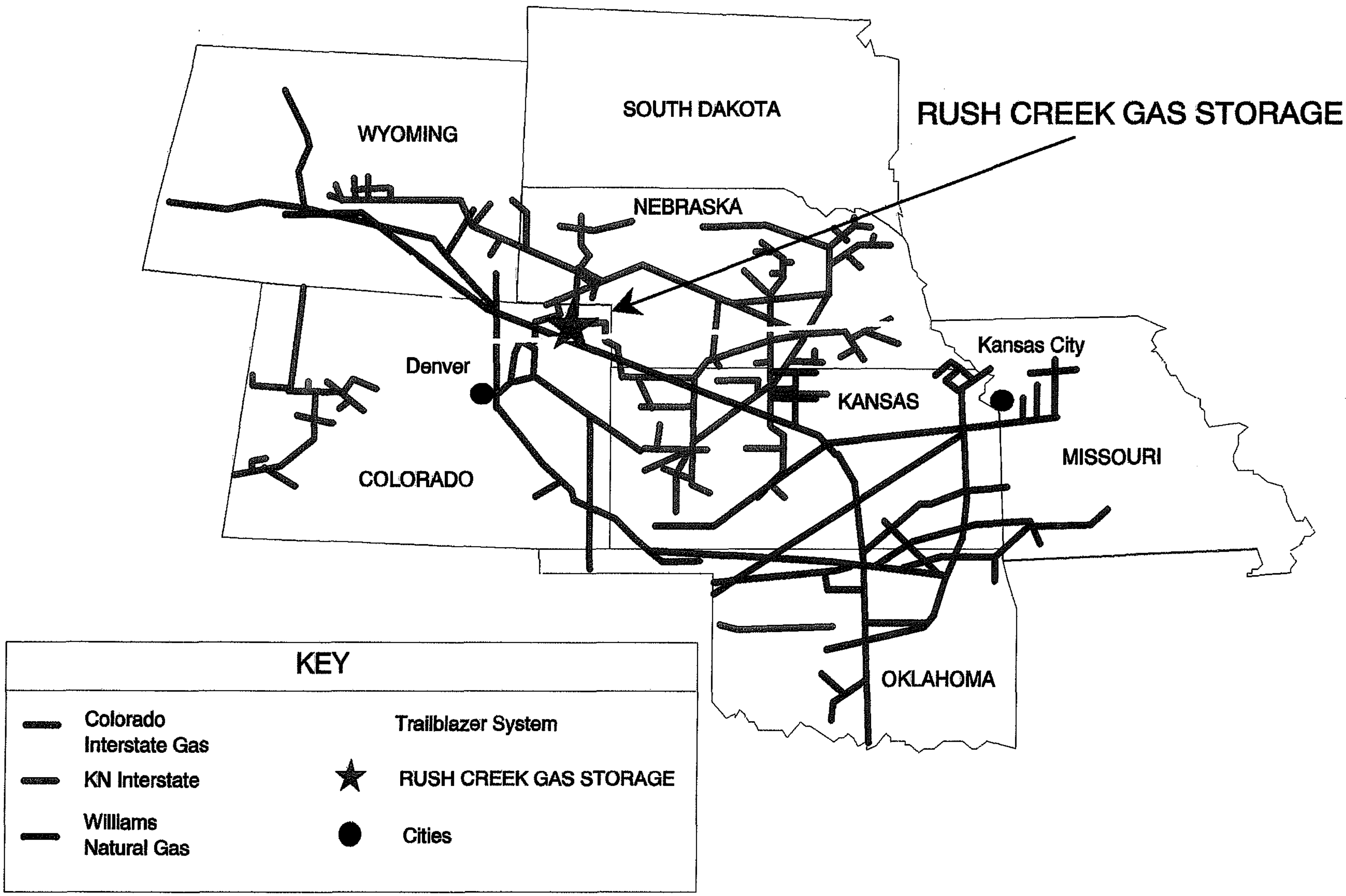
KEY

- Tennessee Gas Pipeline
- Southern Natural Gas
- Transcontinental Gas
- Florida Gas Transmission
- Koch Gateway Pipeline
- Mississippi Fuels (Associated)
- Texas Eastern Transmission
- PETAL GAS STORAGE
- Cities

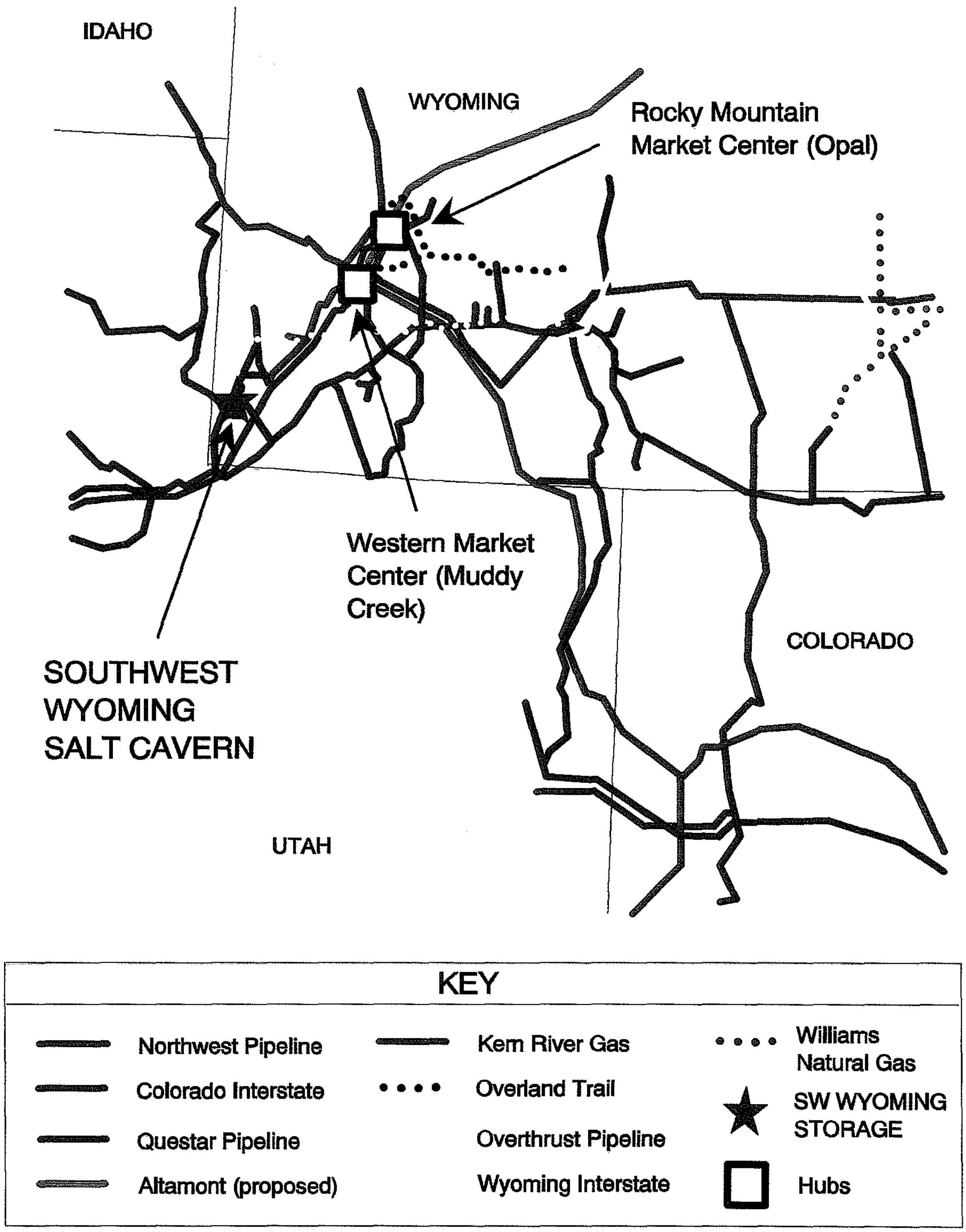
PUTAH SINK GAS STORAGE PROJECT (CA)



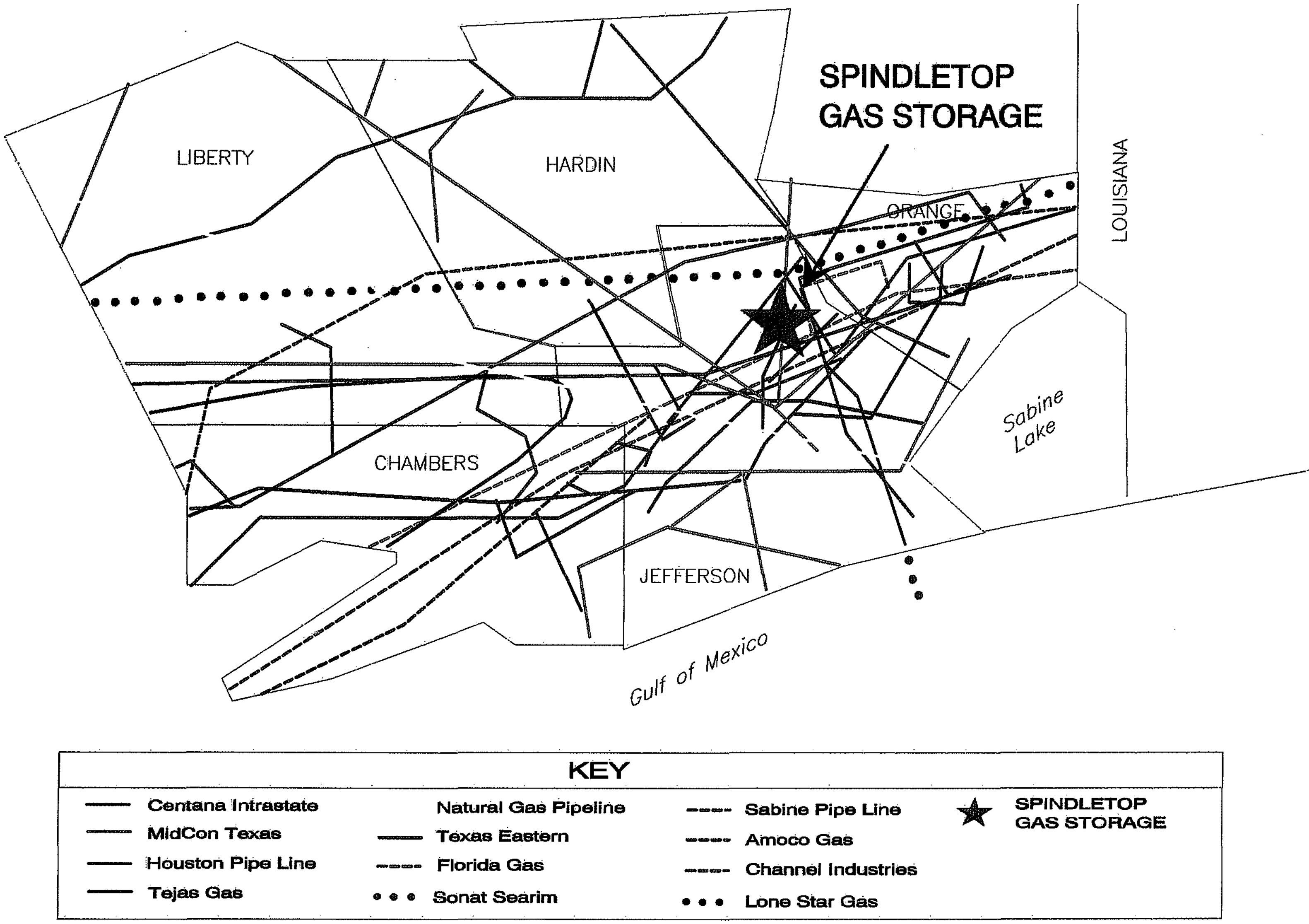
RUSH CREEK GAS STORAGE (CO)



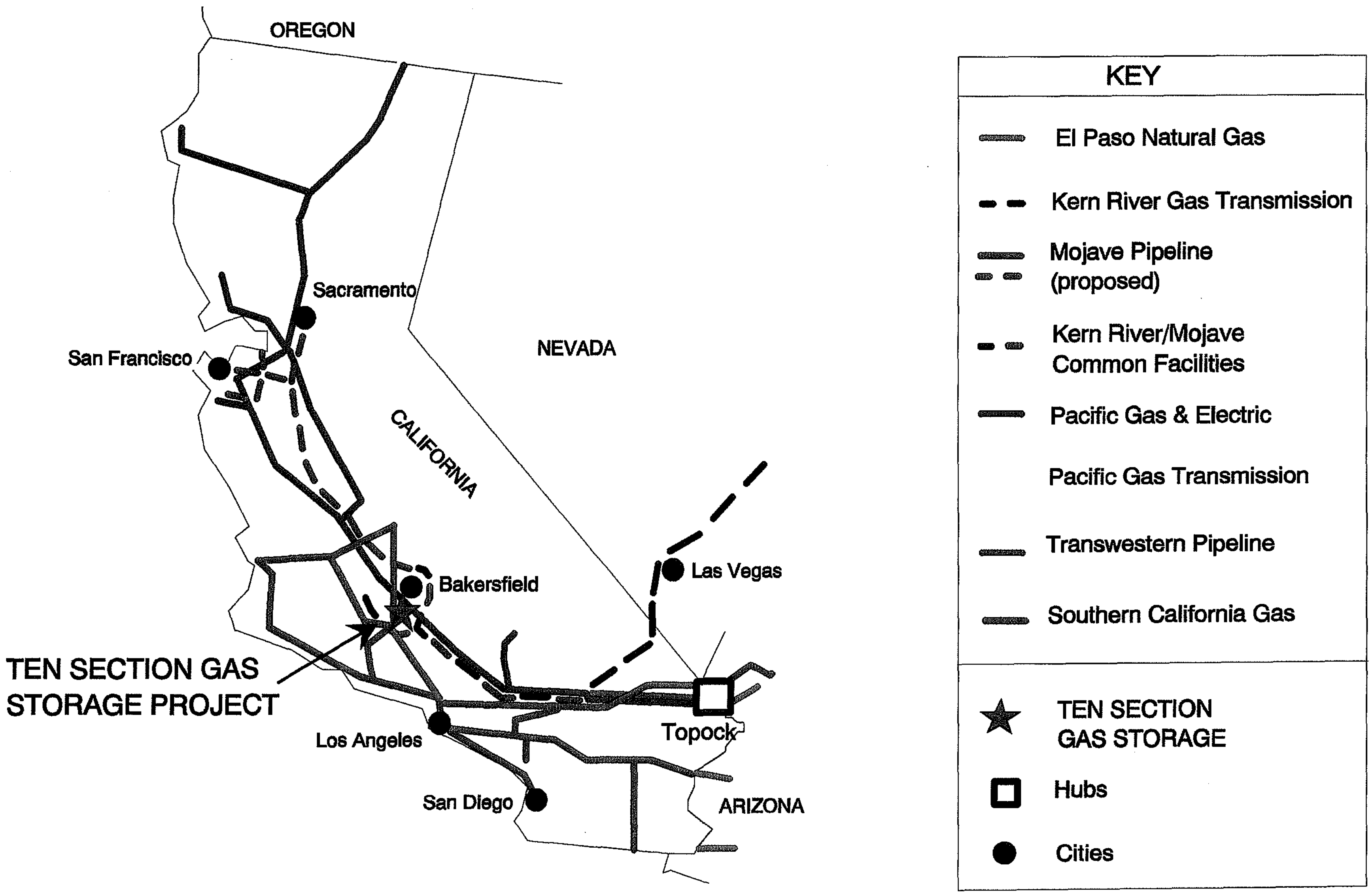
SOUTHWEST WYOMING STORAGE PROJECT



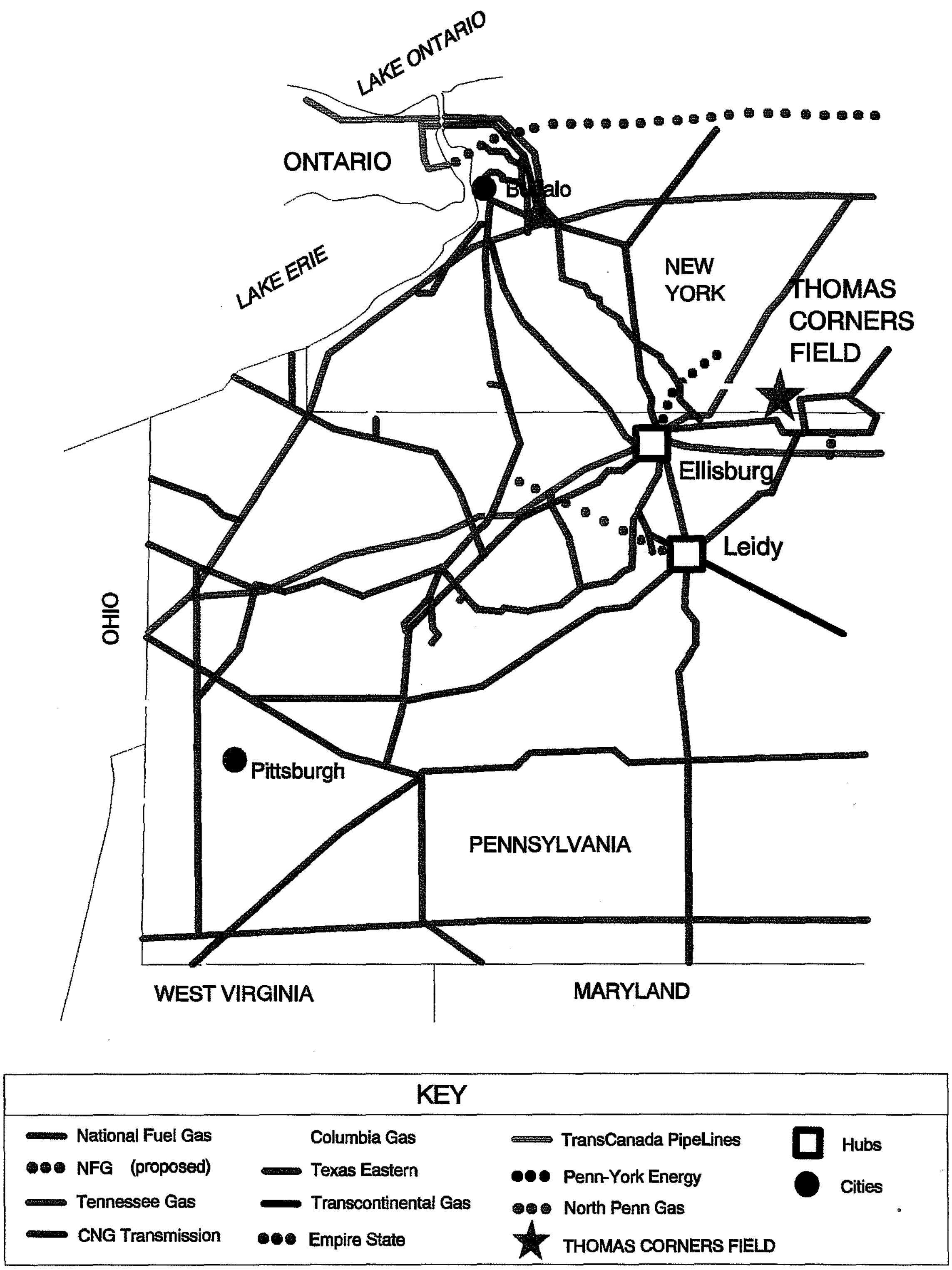
SPINDLETOP GAS STORAGE (TX)



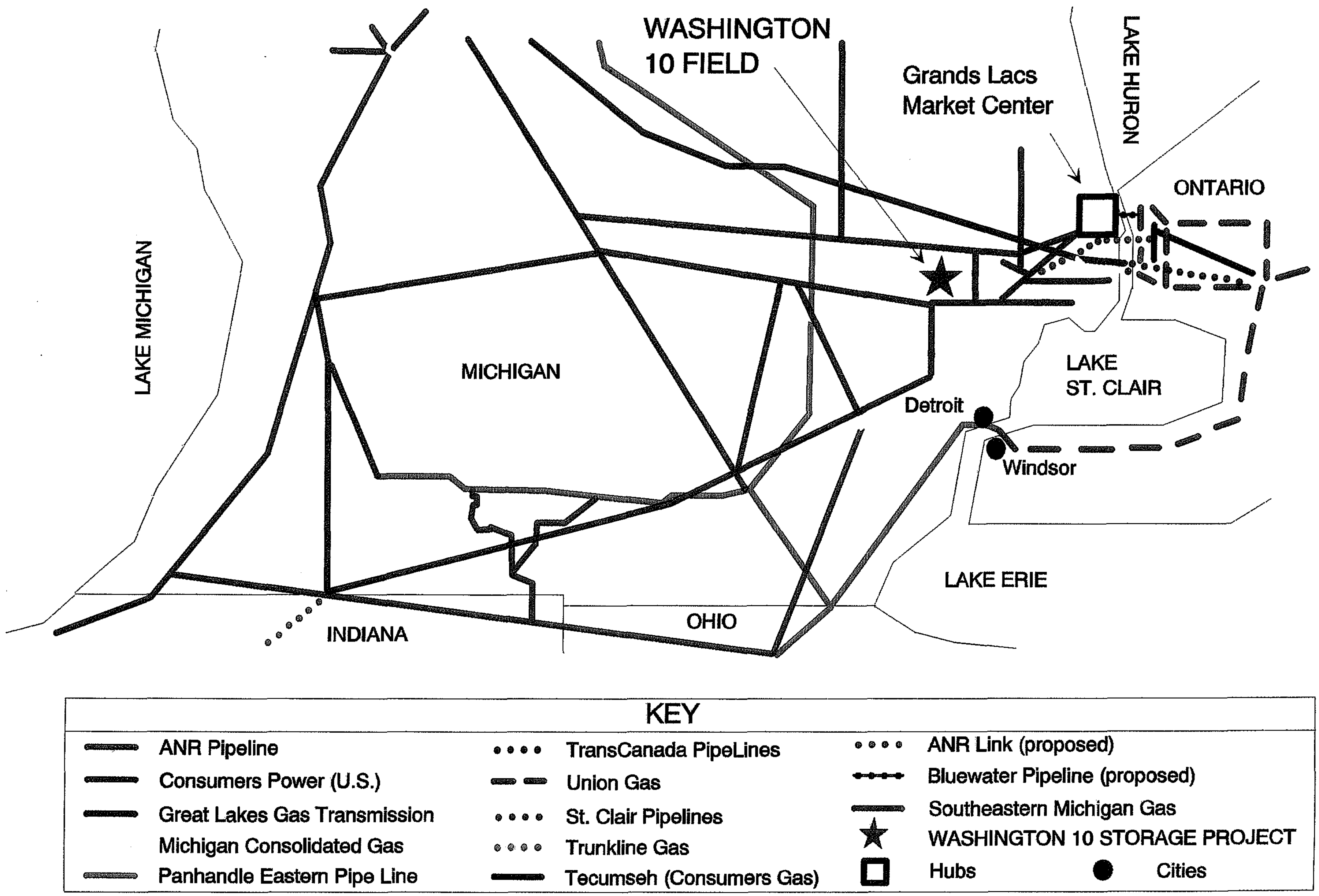
TEN SECTION GAS STORAGE (CA)



THOMAS CORNERS FIELD STORAGE PROJECT (NY)



WASHINGTON 10 STORAGE PROJECT (MI)



APPENDIX B-1

MARKET HUB DESCRIPTIONS

APPENDIX B-1

MARKET HUB DESCRIPTIONS

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AECO C HUB (Storage)

Owner: Alberta Energy Company Ltd. (AEC)

Administrator: AEC

Location: Near Suffield, in southeastern Alberta, adjacent to NOVA's main transmission system, and accessible to the systems of TransCanada PipeLines, Foothills/Northern Border Pipeline and Alberta Natural Gas/Pacific Gas Transmission (see map in Appendix B-2).

Services/Benefits:

AEC will provide firm storage, transportation exchange, parking, direct connection/inventory balancing, loaned gas, AECO-LINK customer access system, title exchange and information services.

Storage services, including parking, are provided to customers in the following order of service levels: (1) firm storage customers, (2) platinum, (3) gold, (4) silver, (5) bronze plus, (6) bronze, and (7) firm storage customers in excess of contract. The platinum, gold, silver and bronze levels of parking have a limited enrollment, ensuring higher reliability and increased value for these higher priority services.

Parking Service (1) allows parking of gas on a firm or interruptible basis at the hub for periods of one day or longer; (2) increases a customer's options for gas acquisition, disposition and transportation; and (3) provides a mechanism for inventory balancing.

Loaned Gas service allows a customer to borrow gas from the AECO C Hub in the form of a negative inventory or a draft against its parking account. Loaned gas (1) allows a customer to access natural gas on a short-term basis to meet market requirements; (2) allows a customer to bridge shortfalls between supply and market positions; (3) provides coverage in case of plant outages and upstream supply problems; (4) provides a form of interruptible backstopping for title exchange customers or as overdraft protection for parking customers; and (5) offers a mechanism for inventory balancing. The customer is obligated to return the gas at a later date, and a fee is charged for the service. A limit exists on the amount of gas loaned to each customer. A loan inventory charge is applied for certain months.

Title Exchange consists of the AECO C Hub taking delivery and title of gas on behalf of a customer from any third-party account and them immediately transferring title back to the same customer while redelivering the gas back to other third-party accounts. Title Exchange service (1) provides an independent alternative to pipeline inventory transfers; (2) creates a supply pooling point for gas purchases; customers can purchase gas delivered to AECO C Hub from a wide range of suppliers; (3) creates a common gas delivery point for gas sales; customers can sell gas delivered to AECO C Hub to a wide range of buyers; (4) creates a common market point for customers to broker a range of supplies to a variety of markets; (5) maintains confidentiality between a customer's supply and markets; (6) eliminates the need for a customer to take assignment of firm field receipt service from a seller, i.e., this prevents month-end field allocation variances; and (7) allows a customer to improve its gas control, with less reliance on others.

Transportation Exchange service allows a customer to purchase or deliver gas at the AECO C Hub and take immediate redelivery at any intra-Alberta delivery point or inter-Alberta firm delivery location. This service (1) allows shippers with firm delivery transportation to mitigate the cost of unutilized service; (2) allows a customer access to firm delivery transportation service held by others; and (3) provides cost savings for customers because often the fee represents a lower cost alternative to a customer moving gas directly under an interruptible delivery tariff.

Direct Connection service links major industrial users, utilities and distribution systems located outside of Alberta with all the producers, aggregators and marketers operating at the AECO C Hub.

Inventory Balancing is an optional service offered to Direct Connection customers, allowing them to balance deliveries at the AECO C Hub with deliveries at a border point within set daily tolerances based on the amount of service contracted for the month. Services (1) allow industrial users, utilities and distributors on downstream pipelines access to the AECO C Hub in order to purchase and/or trade natural gas, (2) provide a larger supply portfolio than is available at Alberta border points; (3) provide downstream pipeline shippers with access to all storage and hub services available at the AECO C Hub; and (4) meet each customer's unique needs through customer-tailored contracts.

AECO-LINK is the electronic connection between the AECO C Hub and its customers. This service (1) provides fully supported software; the customer is required to provide a phone line and, at his option, a printer; full documentation and training programs are available; (2) provides hardware and installation in a customer's office, if required; (3) provides network support if AECO-LINK is attached to a network; features are available to connect AECO-LINK to a gas management system or spread-sheet, minimizing double entry of nominations; (4) allows all nominations to be entered directly into the system, eliminating discrepancies and errors; (5) provides account position reports including all current nominations placed against a customer's account by other customers at the AECO C Hub; (6) allows rapid information distribution between the AECO C Hub and its customers; and (7) provides E-mail and bulletin boards for customer communication.

The AECO C Hub Spot Price Index, as published by Price Waterhouse, is a daily spot price indicator for natural gas within Alberta. All customers at the AECO C Hub can participate in this index. This index offers the following features: (1) accuracy -- based upon actual transactions; (2) credibility -- administered by Price Waterhouse, an independent firm of chartered accountants; (3) consistency -- tracks spot transactions at the AECO C Hub, representing an intra-Alberta market price since November 1, 1993; and (4) timeliness -- allows daily customer access to spot prices through either news services, AECO-LINK, or Price Waterhouse fax.

Status:

Services have grown rapidly since 1988. During 1995, storage capacity will be increased to 80 Bcf with a withdrawal rate of 1.6 Bcf per day.

Rates:

AECO C Hub offers five levels of service, with different fees, priorities and availability:

SERVICE LEVELS			
	Minimum Monthly Charge (US$) a/	Priority b/	Service Available c/
Platinum	7,200	2	25%:16
Gold	5,400	3	25%:16
Silver	3,600	4	25%:16
Bronze Plus	1,080	5	NA
Bronze	180	6	NA

a/ Minimum monthly charge includes parking, loaned gas and title exchange fees.
b/ Priority 1 - firm service.
c/ Percentage indicates the maximum percentage of the facility that all contracts in the service level may represent; number indicates number of contracts allowed at present facility size in each service level.

FIRM STORAGE						
Service Type	Injection Service Days	Withdrawal Service Days	Max. # Cycles Per Year	5-Yr Term Demand Fee a/ ($/MMBtu/Mo.)	10-Yr Term Demand Fee a/ ($/MMBtu/Mo.)	15-Yr Term Demand Fee a/ ($/MMBtu/Mo.)
Injection Rate = 100% of Withdrawal Rate	70	70	2.6	0.0309	0.0237	0.0206
	105	105	1.7	0.0229	0.0175	0.0153
	140	140	1.3	0.0190	0.0146	0.0127
Injection Rate = 70% of Withdrawal Rate	14	10	15.2	0.1276	0.0978	0.0850
	29	20	7.4	0.0695	0.0533	0.0463
	50	35	4.3	0.0455	0.0349	0.0303
	100	70	2.1	0.0252	0.0193	0.0168
	150	105	1.4	0.0188	0.0144	0.0125
	200	140	1.1	0.0155	0.0118	0.0103
Injection Rate = 50 % of Withdrawal Rate	6	3	40.6	0.3349	0.2567	0.2232
	10	5	24.3	0.2016	0.1546	0.1344
	20	10	12.2	0.1118	0.1857	0.0746
	40	20	6.1	0.0610	0.0468	0.0406
	70	35	3.5	0.0399	0.0306	0.0267
	140	70	1.7	0.0222	0.0170	0.0147

a/ Demand fees and commodity fees are escalated each year. Commodity fee effective April 1, 1995 is $0.04/MMBtu and is payable on all injection nominations.

PARKING							
Service Level	Each Nom.a/ Allocation (TJ/Day)	Max. Inventory (TJ) (at AECO Discretion)	Injection Commodity Chg. ($/MMBtu)	Injection/ Withdrawal Storage Charge	Daily Inventory Charge	Daily Inventory Exemption	Guaranteed Reliability b/
Platinum	25	500	0.04	None	Yes	25TJ	50%
Gold	25	500	0.04	None	Yes	25TJ	40%
Silver	25	500	0.04	None	Yes	25TJ	30%
Bronze Plus	25	500	0.04	None	Yes	No	No
Bronze	25	500	0.04	$.04-.11	Yes	No	No

a/ Each nomination allocation indicates the amount of gas allocated to each customer before accepting nominations at a lower level.

b/ The reliability guarantee is a minimum monthly service level available based on minimum of 10 nomination requests per month. If service is not provided at percent shown, then the minimum monthly charge obligation is waived.

DAILY INVENTORY CHARGE ($/MMBTU)			
Parked Gas		Loaned Gas	
Month	+ Inventory	Month	- Inventory
Aug	0.0013	Jan	0.0013
Sep	0.0025	Feb	0.0025
Oct	0.0038	Mar	0.0038

LOANED GAS a/				
Service Level	Loan Charge ($/MMBtu/Day)	Each Nom. Allocation (TJ/Day)	Max. Loan Volume (TJ)	Injection Commodity Charge ($/MMBtu)
Platinum	0.002	25	100	0.04
Gold	0.002	25	100	0.04
Silver	0.002	25	100	0.04
Bronze Plus	0.002	25	100	0.04
Bronze	0.002	25	100	0.04

a/ Loaned Gas is an interruptible service; this applies to both the granting of a loan and the repayment of a loan. Loaned gas is subject to all parking charges and is subject to daily inventory charges

CALIFORNIA ENERGY HUB (System)

Owner:	Southern California Gas Co.
Administrator:	Enerchange (formerly Hub Services, Inc.) (affiliated with NGC, NICOR, Pacific Enterprises, and National Fuel)
Location:	Southern California Gas system, with connections to: Pacific Gas and Electric[1] Pacific Gas Transmission Kern River Gas Transmission[1] Transwestern Pipeline (750 MMcfd) El Paso Natural Gas (1,950 MMcfd) Mojave Pipeline Southwest Gas San Diego Gas & Electric.

Services/Benefits:

(1) parking -- delivery of gas into the hub one day and delivery out of the hub one or more days later.

(2) loaning -- removal of gas from the hub one day and returning gas to the hub one or more days later.

(3) wheeling -- simultaneous receipt of gas into the hub and delivery of gas out of the hub through different receipt and delivery locations.[2]

Gas entering the hub at one location and exiting at a later time and at another location will be considered both a parking and wheeling transaction.

SoCal will determine whether capacity is available to offer hub services, may bring transactions to the hub, and will approve all hub transactions.

Enerchange may also bring transactions to the hub, will conduct all credit checks, guarantee hub transactions, and perform all billing and reporting.

Cal Hub will allow customers to place nominations directly through GasSelect, SoCal's "state-of-the-art" nomination and communication service.

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1 Up to 800 MMcfd from either Kern River or PG&E.

2 On January 1, 1995, the FERC ruled that two LDCs -- Northern Illinois Gas and Southern California Gas Co. -- must limit hub services to receipt and delivery points on their respective systems and remove references to offsystem points, in order to comply with the FERC capacity release rules and "shipper must have title" rule pertaining to FERC Order No. 636.

CALIFORNIA ENERGY HUB (continued)

Future services of the hub will include title transfer, allowing gas to be purchased and sold through the hub.

All services offered on the hub will be on an interruptible basis.

Status:

Began operations in July 1994. Offers customers both interstate and intrastate services.

Rates:

The rates for parking and loaning include charges for wheeling.

The following maximum one-part volumetric rates apply to hub services:

Parking	\$.6922 per Dth
Loaning	\$.6922 per Dth
Wheeling	\$.7414 per Dth

In addition, SoCal will charge a minimum fee of \$50 per transaction.

CHICAGO HUB (System)

Owner: Northern Illinois Gas

Administrator: Enerchange (formerly Hub Services, Inc.)
(Affiliated with NGC, NICOR, Pacific Enterprises, and National Fuel)

Location: Northern Illinois Gas system, with connections to:
Natural Gas Pipeline (2,000 MMcfd)
Midwestern Gas Transmission (450 MMcfd)
Northern Natural (235 MMcfd)
ANR Pipeline (450 MMcfd)
Through Northern Illinois' system, this hub intends to link major areas of supply (Mid-Continent, Gulf Coast and Canada) and demand (North Central).

Services/Benefits:

Northern Illinois Gas owns and operates a number of underground storage facilities (aquifers) with storage capacity of 165 Bcf and withdrawal capacity of 2.6 Bcfd.

All services offered at the Chicago hub are offered on an interruptible basis and involve only interstate commerce. These services include:

- Straight wheeling -- transporting gas from an interstate pipeline through Northern Illinois Gas' system to another interstate pipeline connected to the company.
- Parking -- short-term transactions in which shippers transport gas into Northern Illinois Gas' system, where it is held for later delivery into an interstate pipeline.
- Loaning -- the shipper takes title to gas on the hub for delivery to the market of an interstate pipeline, and repays the gas in-kind at an agreed-upon schedule and delivery point.

Since all Chicago hub services are interruptible, Northern Illinois reserves the right not to begin any service or to discontinue service whenever firm service would be impaired.

All transportation and stored gas received by the Chicago hub is accounted for on a daily basis. The gas must be scheduled for the eventual redelivery to a designated delivery point or displacement delivery point on Northern Illinois' system.[1]

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[1] On January 1, 1995, the FERC ruled that two LDCs -- Northern Illinois Gas and Southern California Gas Co. -- must limit hub services to receipt and delivery points on their respective systems and remove references to offsystem points, in order to comply with the FERC capacity release rules and "shipper must have title" rule pertaining to FERC Order No. 636.

Enerchange performs all credit checks, billing, and revenue collection functions for those utilizing the hub.

Operational benefits:

- assists in managing transportation imbalances by balancing the shipper's long and short positions between interstate pipelines and/or city gate markets;

- assists in intraday swings by providing shippers the time to wheel, displace, park or loan gas within the current day to fulfill contractual needs;

- facilitates pooling by allowing the producer or marketer to meet its contractual obligation at a connected pipeline pooling point;

- assists shippers when operational flow orders are issued by allowing shippers that are unable to transport supply to a market to use a variety of services to keep their markets whole;

- assists in predetermined allocations (PDAs) by helping to reduce the impact of shortages or overages to a shipper at a receipt or delivery point; and

- benefits users by lowering transaction costs through reduced "search" costs, making pricing information more relevant, allowing for faster market response, increasing the benefit of specialization, and perhaps most importantly, simplifying multiple pipeline exchanges for downstream shippers.

Status:

One of the first, if not the first, market area hubs owned by an LDC that involved interstate commerce. Began operation in June 1993.

Rates:

The rates for services offered by the Chicago hub are negotiated, subject to maximum rates. Each service transaction is subject to a minimum daily charge of $50. The maximum transportation rate is $.0721 per MMBtu and the maximum storage rate is $.0604 per MMBtu each day that gas is left in storage by any shipper. Northern Illinois reserves the right to discount any maximum rate on a non-discriminatory basis.

Northern Illinois will share the revenues generated from the Chicago hub with its firm ratepayers.

CNG/SABINE CENTER (System)

Owners: CNG Transmission, Inc. and Sabine Hub Services (a subsidiary of Texaco).

Administrator: Sabine Hub Services

Location: Market center is on CNG Transmission's full system, and is sometimes referred to as a "floating" hub. CNG's transmission system covers 7,400 miles over a six-state area and interconnects with the following pipelines:

- Texas Gas Transmission (650 MMcfd)
- ANR Pipeline (650 MMcfd)
- Tennessee Gas Pipeline (625 MMcfd)
- Texas Eastern Transmission (580 MMcfd)
- Appalachian production points (290 MMcfd)
- Iroquois Gas Transmission (280 MMcfd)
- Niagara Import Project (100 MMcfd)
- National Fuel Gas Supply (100 MMcfd)
- Transcontinental Gas Pipe Line (100 MMcfd)

Services/Benefits:

CNG Transmission's system has a peak day delivery capacity of 6.2 Bcf per day and working gas storage capacity of 259 Bcf, primarily in Pennsylvania and West Virginia.[1] In addition, one of the major advantages of this market center is the diverse supply potential.

Four services are offered:

Intra-Hub Transfers (IHT) is a non-jurisdictional accounting service that tracks the chain of title to a package of natural gas at a single point. This service does not offer transportation. The service provides customers with written confirmation of their title transfer activity on a daily basis. Utilization of this service provides customers with the ability to protect the identity of their markets and supply sources from disclosure to others in the chain of title, and helps to minimize the hidden costs of doing business. The fee is $.002 per MMBtu for each title transfer.

Park-Folio accesses a portfolio of providers to custom fit "parking" to a customer's needs. Park-Folio also nominates on the customer's behalf, thereby reducing the customer's administrative burden. CNG/Sabine Center provides a premium parking service at market-based rates.

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[1] The 259 Bcf excludes CNG's share of jointly owned storage.

CNG/SABINE CENTER (continued)

Wheeling Service makes acquiring short-term transportation "hassle free," and eliminates the customer's need to add fuel to transportation volumes. For a flat market-based rate, CNG/Sabine Center nominates and confirms transportation on the customer's behalf and "wheels" the customer's gas from point to point at the "SuperHub," saving additional time and money. Wheeling can be arranged as either interruptible or firm service.

Market Activity Reporting Service (MARS) is an accounting service for customers who buy and sell packages of gas where the delivery is deferred to another month. The system is designed to verify the traders' deals and transmit executable deal confirmations. On a daily basis, individual customers receive a written report that outlines trading activity. This information helps the customer to react to price fluctuations and makes contract administration more cost effective and less time consuming.

These services, as well as others under development, are designed to improve markets by minimizing transaction costs, increasing reliability and giving buyers and sellers more options for trading.

According to the sponsor, additional hub services will be offered if there is sufficient customer interest -- "we want to offer whatever the market needs." There are a number of proposed services under consideration, including inter-hub transfers, i.e., allowing shippers to move gas from hub to hub. Initially, the service would be between the Henry Hub and the CNG/Sabine Center, but other hubs can be added.

Status:

Operational

Rates:

The monthly accounting fee depends upon the size of the trading account: $2,000 for 0-25 entries per month; $5,000 for 26-50 entries per month; and $7,500 for over 50 entries per month.

The parking and wheeling fees that CNG/Sabine Center offers are negotiated, market-based rates. However, CNG Transmission does file parking and wheeling fees in its FERC tariff.

- Parking: $.0082 per Mcf per day
- Wheeling: $.1513 per Mcf (April-October)
  $.1989 per Mcf (November-March)[1]

For parking and wheeling services, the FERC has approved CNG Transmission's proposed credit of 80 percent of the revenues received from interruptible market services to its firm customers.

[1] Fuel retention is 2.25 percent for parking and 2.28 percent for wheeling.

ELLISBURG-LEIDY HUB (Storage)

Owners: Affiliates of National Fuel Gas Supply and Natural Gas Clearinghouse

Administrator: Enerchange (formerly Hub Services, Inc.)
(Affiliated with NGC, NICOR, Pacific Enterprises, and National Fuel)

Location: Ellisburg-Leidy, Pennsylvania (see map in Appendix B-2).

Services/Benefits:

Offers imbalance resolution, wheeling, and parking on an interruptible basis with 90 percent of the operating revenues credited back to National Fuel Gas Supply's firm transportation customers.

Offers four services with specific advantages to the user:

Parking is short-term interruptible storage. Flexible injection and withdrawal schedules, along with inter- and intra-month agreements offered by the hub, allow customers to take advantage of different market and transportation opportunities. Customers can avoid pipeline cash-out penalties and take advantage of lower gas prices through lower weekend prices and/or inter-month price variations, for example. Customers may also take advantage of transportation differentials as they occur.

Wheeling provides transportation access to six major interstate pipelines serving the Northeast and Canada:

- National Fuel Gas Supply (154 MMcfd)
- Transcontinental Gas Pipe Line (400 MMcfd at Leidy, 140 MMcfd at Wharton Storage)
- Tennessee Gas Pipeline (154 MMcfd)
- CNG Transmission (103 MMcfd at Ellisburg, 400 MMcfd at Leidy)
- Texas Eastern Transmission (400 MMcfd)
- Columbia Gas Transmission (36 MMcfd)

Gas moving through the Ellisburg-Leidy hub can be routed to markets and storage facilities not physically attached to the hub. Hub customers can use this service to take advantage of price arbitrage opportunities represented by markets on pipelines connected to or adjacent to the hub facilities. Wheeling offers access to numerous pipelines and supply areas and therefore a broader supply portfolio, assistance in avoiding pipeline bottlenecks and capacity constraints, and reduction of transportation and gas procurement costs by allowing more efficient use of released transportation capacity. The hub "makes it possible to complete missing links in transportation paths by providing access to market area interconnections."

ELLISBURG-LEIDY HUB (continued)

Balancing offers a short-term interruptible gas loan. Benefits include the avoidance of pipeline cash-out and scheduling penalties and end-of-month price "spikes."

Title transfer service matches buyers and sellers on a best-efforts or firm basis, offering price swaps, ceilings/floors and other financial hedges for suppliers and markets. Title transfer provides a common marketplace for hub customers to contact a variety of trading partners. The service also allows customers to maintain confidentiality between suppliers and markets, and provides credit and performance guarantees for trading partners. The Ellisburg-Leidy hub can serve as a receipt and/or delivery point for multiple month and long-term gas sales on interconnecting pipelines.

Status:

Partnership formed in 1992 and hub operations began in late 1993.

Rates:

In 1994, the Commission approved, subject to refund, National Fuel's proposed rates and services:

- Wheeling (W-1): \$.0502 per Dth (plus applicable surcharges).[1]

- Parking Service: \$.0079 per Dth when there is a single receipt and delivery point (Rate Schedule P-2) or \$.0867 per Dth for the first day and \$.0079 per Dth for subsequent days when there are different receipt and delivery points (Rate Schedule P-1).

- Imbalance resolution: \$.0032 per Dth when there is a single receipt and delivery point (IR-2), or \$.0928 per Dth for the first day and \$.0032 per Dth for subsequent days when there are different receipt and delivery points (IR-1).

[1] In addition, a lower "fly-by" rate of \$.01 per Dth is available for equal volumes tendered and received on the same day.

GRANDS LACS MARKET CENTER (Storage)

Owners: CMS Gas Transmission and Storage Co. (subsidiary of CMS Energy), Tejas Power Corp.[1], St. Clair Pipelines (subsidiary of Westcoast Energy and affiliate of Union Gas Ltd.), and a subsidiary of Enron Gas Services Corp.

Administrator: CMS Gas Transmission and Storage

Location: Near Marysville in southeastern Michigan (see map in Appendix B-2).

Services/Benefits:

Grands Lacs considers itself strategically located within the North American pipeline grid and claims to have superior geology because of vast deposits of bedded salt in the area that are conducive to the further development of high-deliverability storage. Initially, Grands Lacs will have 3 Bcf of working gas capacity and 150 MMcf per day of initial deliverability.

Through interconnections with Consumers Power and Union Gas, Grands Lacs will be accessible to pipelines in the U.S. and Canada, as well as Michigan's LDCs. The estimated $5.3 million Bluewater project will traverse the St. Clair River and terminate near Sarnia, Ontario, providing up to 100 MMcfd of bi-direction flow to U.S. and Canadian markets. Bluewater, which has a target in-service date of November 1, 1995, will be in direct competition with the ANR Link project being jointly developed by ANR Pipeline and Consumers Gas of Toronto.

Cited benefits to customers include the following:

- reduced risk of supply interruption
- increased liquidity for buyers and sellers
- increased convenience since transactions may be performed from an office personal computer

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1 In late 1994, Tejas Power announced formation of Market Hub Partners L.P. -- a partnership among Tejas Power, NIPSCO Industries, New Jersey Resources, Miami Valley Leasing (affiliate of Dayton Power & Light) and Public Service Electric and Gas to develop storage and market hubs. Market Hub Partners will participate in development of five projects in which Tejas Power or its subsidiaries have been involved over the past few years -- Moss Bluff (Texas), LA-I and LA-II/Egan (Louisiana), MS-1 (Mississippi), Grands Lacs (Michigan) and NE-I/Tioga (Pennsylvania). In total, these projects will offer 6 Bcf per day of deliverability and 46 Bcf of high deliverability storage. Market Hub Partners will not sell or provide pipeline transportation or make purchases or sales of natural gas, but will market high deliverability storage, cash market trading, real time title tracking and other hub services to producers, marketers, LDCs and consumers.

GRANDS LACS MARKET CENTER (continued)

Prospective services include the following:

- Gas Storage
    - Parking services
    - Peaking
    - Gas balancing
    - Seasonal storage
- Wheeling
    - Pipe-to-pipe transfer
    - Nomination coordination
    - Title tracking
- Risk Management
    - Credit clearing
    - Hedging
    - Delivery insurance

Plans for the use of advanced electronic gas handling and trading technology to access other emerging market centers and trading systems throughout North America are being developed.

Status:

The market center at Grands Lacs is scheduled to be in service in mid-1995, and the initial storage facility should be developed by 1997.

Rates:

Grands Lacs has filed for market-based rates with the Michigan Public Service Commission.

GULF COAST STAR CENTER (System)

Owner: Texaco, Inc.

Administrator: Texaco, Inc.

Location: The Gulf Coast Star Center consists of Texaco's Bridgeline pipeline and distribution system that spans the state of Louisiana, several large gas processing facilities including the Henry Hub gas plant, and Texaco's gas storage and marketing operations along the Gulf Coast. [1]

Bridgeline's system interconnects with many major pipelines, including:

- Columbia Gulf Transmission
- Transcontinental Gas Pipe Line
- Koch Gateway Pipeline
- Tennessee Gas Pipeline
- Sabine Pipe Line
- Trunkline Gas
- Texas Eastern Transmission
- ANR Pipeline
- Texas Gas Transmission

Services/Benefits:

Texaco has established this center to provide "seamless" service to customers from the Gulf Coast to midwest, southeast and northeast markets. Star Center enables Texaco's customers, through a single contract, to secure multiple services such as long-term sales commitments, delivery rate flexibility, multiple pipeline options, transportation, storage and price risk management.

Four principal customer service areas involve:

Plant and Pipeline Operations -- The Star Center will make full use of the Louisiana natural gas facilities of Texaco companies. The physical assets include 1,800 miles of natural gas pipeline; 1.8 Bcf per day of Texaco's natural gas supply; 1.2 Bcf per day of gas processing capacity; 60 Bcf per day of natural gas liquids (NGL) fractionator capacity; 6.8 Bcf of high deliverability gas storage capacity; and over 50 interconnects with other pipelines.

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[1] Texaco also owns Sabine Pipe Line Co., an open access interstate pipeline that transports gas in Louisiana, Texas and the Outer Continental Shelf. Sabine's main line begins at Henry Hub near Erath, Louisiana and extends 133 miles to Port Arthur, Texas. Sabine's Henry Hub is a major interchange center that offers shippers supply and market opportunities through twelve interconnecting pipelines and one gathering company. The Henry Hub is the physical delivery point for standard deliveries under the NYMEX natural gas futures contracts.

GULF COAST STAR CENTER (continued)

Customers will have access to four gas processing plants (Floodway, Henry, Paradis and Sea Robin) and their related gathering systems. The result is be an integrated approach to serving customers, providing "the full range of services they require, all within one Texaco organization."

<u>StarSource Customer Service</u> -- The StarSource Account Management team provides a single-point contact for all natural gas customers, including gas producers, suppliers, processors, LDCs and end users. When this service was introduced in 1994, the focus was on long-term sales customers. Texaco will now offer its complete array of marketing services to customers throughout the gas delivery chain.

<u>Commercial Development</u> -- This service has focused on sales customers, but will be expanded to include third party purchase and processing customers as well. It also will be responsible for new asset development and acquisitions to provide improved customer services.

<u>Trading and Transportation</u> -- In addition to spot gas trading, risk management, storage, parking, advancing and transportation, this group has been expanded to include gas control. The intent is to improve gas flow management by using one centralized group for each movement from the wellhead to the burner tip.

Status:

The StarCenter concept was introduced in January, 1994. In December, 1994, Bridgeline completed the expansion of gas compression equipment at its Sorrento, Louisiana storage facility.

Rates:

Bridgeline's blanket certificate permits a maximum charge of $.3106 per MMBtu for firm and interruptible transportation.

For firm storage service, Bridgeline can charge a maximum of $1.1322 per MMBtu per month for deliverability, $.125 per MMBtu for capacity, $.0146 per MMBtu for injection and withdrawal and 1.8 percent for fuel. The maximum rate for interruptible storage is $.2188 per MMBtu on an average monthly balance and an injection and withdrawal rate of $.0146 per MMBtu and 1.8 percent fuel. Bridgeline states, however, that actual rates are negotiable.

KATY HUB AND GAS STORAGE (Storage)

Owner: Western Gas Resources, Inc.

Administrator: Western Gas Resources Storage, Inc.

Location: Located 20 miles from Houston, Texas, the facility consists of a pipeline header system connected to 13 major pipelines and a partially depleted natural gas reservoir. The Katy Hub is designed to facilitate receipt or delivery from each of the 13 interconnections, which include the following capacities:

Amoco Gas	150 MMcfd
Dow-Tenngasco	150 MMcfd
Exxon's Katy plant	230 MMcfd
Houston Pipeline	150 MMcfd
Koch Gateway Pipeline	150 MMcfd
Lone Star Gas	230 MMcfd
Midcon Texas Pipeline	230 MMcfd
Natural Gas Pipeline	230 MMcfd
Oasis Pipeline	230 MMcfd
Tejas Gas	150 MMcfd
Tennessee Gas Pipeline	150 MMcfd
Transcontinental Gas Pipe Line	150 MMcfd
Trunkline Gas	150 MMcfd

Services/Benefits:

Include wheeling and balancing, and because of its storage assets, parking and readily available supply.

Shippers and storage customers have the ability to wheel gas wherever they need it via bi-directional service with the interconnecting pipelines, as well as transportation from low pressure to high pressure pipelines.

According to Katy, what makes this hub different than other hubs is its design. Western constructed its header by building two pipelines to and from the storage system. One is a high pressure line and the other is a low pressure line. The facility was designed as a system so that displacement would not be used. While most hubs offer wheeling, or the movement of gas from one pipeline to another, the vast majority do it by displacement or paper trades. Western wanted the ability to move actual volumes from pipeline to pipeline.

KATY HUB AND GAS STORAGE (continued)

Utilizes a state-of-the-art computerized gas control system and gas accounting system to provide customers with both real time gas flow information and timely, accurate bills. The technology includes telemetering, automatic control systems, and information systems.

Incorporates 13 receipt/delivery interconnects, header deliverability of 800 MMcf per day, working gas capacity of 20 Bcf, gas withdrawal capability of 400 MMcf per day and gas injection capability of 400 MMcf per day.

As a dual-pressured header, the Katy Hub was designed to provide large physical volume transfer, parking and storage services. Western constructed its header by building two pipelines to and from the storage system.

Western signed a letter of intent with NYMEX and Enersoft to provide electronic trading at the Katy facility using the Channel 4 system.

Western expects gas flows from west to east across Texas to continue. A purchase agreement has been signed with Oasis Pipeline Co. for certain west Texas gathering and processing assets. These gathering systems will be used to deliver gas into Oasis, which operates a 36-inch intrastate pipeline running to the Katy Hub from Waha Hub in west Texas.

Status:

Operational since summer 1993; ultimate working capacity of 22 to 24 Bcf, and 415 MMcf per day of deliverability could be online as early as 1995/96.

Rates:

Petitioned the FERC for approval to use rates on file with the Texas Railroad Commission for firm storage and related transportation of intrastate gas. Although FERC granted Western permission to use rates not greater than those approved by the Texas Railroad Commission, Western must file cost-based rates.

Negotiated rates, subject to maximum filed rates, for short-term storage or hub services vary for a number of reasons, including the length of term of service, the number of services used, the time of year and demand.

PACIFIC GAS TRANSMISSION HUB (System)

Owner: Pacific Gas Transmission (PGT)

Administrator: Pacific Gas Transmission

Location: Kingsgate, British Columbia (on the British Columbia-Idaho border) to Stanfield, Oregon (interconnection with Northwest Pipeline) to its terminus at Malin, Oregon (on the Oregon/California border), the interconnection point with Pacific Gas & Electric, PGT's parent.

Services/Benefits:

Provides hub services at all major receipt and delivery points on PGT.

Offers parking and lending services, allowing customers to respond to short-term market fluctuations by using available space on the system as storage capacity.

Parking allows customers to "store" gas for a period of one day up to one month. Storage withdrawals must be made from the same point where the gas was parked. PGT will open an account for those requesting this service, and volumes "parked" will be credited to the account. Later, the shipper can elect to nominate a withdrawal up to the amount collected in the account, and that quantity will then be debited.

Lending (also referred to as "authorized imbalance") is a service that allows customers to borrow gas for a short time to respond to market conditions, replacing the gas at the same point at a later date. The account of gas borrowers will be debited for the amount of gas "loaned." At the time this advance is confirmed, the customer will agree to a schedule for the return of the loaned gas.

Status:

Operational

Rates:

PGT is an interstate pipeline with the following maximum FERC-approved rates:

> Short-term parking (PS-1) - $.08909/Dth for first day, $.0066821/Dth for subsequent days.
>
> Authorized imbalancing (lending) - $.106301/Dth for first day, $.007973/Dth for subsequent days.

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PERRYVILLE HUB (Pipeline Interconnection)

Owner: NorAm Gas Transmission, a subsidiary of NorAm Energy Corp.

Administrator: NorAm Hub Services, Inc.

Location: Near Perryville in northern Louisiana (see map in Appendix B-2).

At present, the hub capacity is about 1.5 Bcf per day with interconnections with the following pipelines:

- Tennessee Gas Pipeline
- Columbia Gulf Transmission
- Southern Natural Gas
- Texas Eastern Transmission
- ANR Pipeline
- Texas Gas Transmission
- Koch Gateway Pipeline
- Trunkline Gas
- Mississippi River Transmission
- El Paso Natural Gas
- Transwestern Pipeline

Services/Benefits:

Provides growing natural gas markets in the Northeast and Midwest with greater access to the extensive gas reserves in the Anadarko, Arkoma, East Texas/Northern Louisiana, Permian, San Juan and Hugoton basins of the Mid-Continent.

Development is designed to enhance asset values for certain NorAm facilities, particularly greater utilization of the 1 Bcf capacity potential of Line AC out of the Arkoma Basin to serve eastern U.S. markets.

In late 1994, NorAm completed a connection with El Paso Natural Gas in west Texas that provides Anadarko, Permian and San Juan basin supplies access to the northeast and midwest markets via west-to-east crosshaul to Perryville. In addition NorAm announced two potential expansion projects that could add 150 MMcf per day of capacity from these basins to Perryville.

To further encourage west-to-east gas movement, NorAm is attempting to arrange a single rate for delivery to Perryville, and has talked to Enron to negotiate an "EnRate" joint transportation rate with Enron's subsidiaries, Transwestern and Northern Natural. NorAm also plans to arrange a similar one-stop shipping rate on El Paso.

PERRYVILLE HUB (continued)

NorAm has contracted with Channel 4, a joint venture between EnerSoft Corp. and the New York Mercantile Exchange, for an electronic trading system at the hub.

Two NorAm storage facilities are in operation near Perryville (Unionville and Ruston) and are fully subscribed by firm shippers, although some interruptible storage may be available at these facilities. Additional firm capacity is expected to be developed.

Status:

Opened on August 1, 1994. Most services to date have been customized although Perryville hopes to market its more traditional hub services such as parking, wheeling, title transfer and imbalance management.

Rates:

Not available

UNION GAS SERVICE HUB (Storage)

Owner: Union Gas (Subsidiary of Westcoast Energy)

Administrator: Union Gas

Location: Southwestern Ontario distribution company with interconnects at various points on the Michigan/Ontario border (e..g, St. Clair) that offer bi-directional flow capability in and out of Union Storage (at Dawn) and transportation to eastern U.S. and Canada pipelines (see map in Appendix B-2).

Services/Benefits:

Interruptible Transportation (Wheeling)
Interruptible transport service between any two points on Union's system.

Receipt & Delivery Points
- From TransCanada at Parkway, Kirkwall via Tennessee Spur, and Dawn via Great Lakes
- From Panhandle Eastern at Ojibway
- From MichCon at St. Clair via ANR

Balancing
This service allows a customer to park gas or borrow gas from Union, for a limited time at any of Union's direct interconnects with other pipelines at Parkway, Kirkwall, Dawn, Ojibway and St. Clair. Parked gas must be delivered to, and taken away from, the same point. Loaned volumes must be borrowed from, and returned to, the same point. Customers may complement this service with wheeling and exchanges.

Redirects/Name Changes (Title Transfer)
This administrative service allows customers to change the name and/or contract under which gas is flowing on connecting pipelines at Parkway, Kirkwall, Dawn, Ojibway, and St. Clair. Except for the delivering party, a customer must have a hub contract to utilize this service.

Interruptible Exchanges
Interruptible exchange service is for volumes received at any point on the Union system for delivery to any primary or secondary delivery point on Union's transport contracts.

Delivery Points
- TransCanada (Chippewa, Niagara, Waddington, EDA Empress, Emerson, etc.)
- Panhandle Eastern (Lebanon, Maumee, etc.)
- ANR (Lebanon, Willow Run, etc.)
- MichCon (Belle River Mills, Willow Run, etc.)
- Great Lakes (Carlton, Crystal Falls, Farwell, etc.)

Receipt Points: Parkway, Kirkwall, Dawn, Ojibway, and St. Clair

UNION GAS SERVICE HUB (continued)

Enhanced Hub Services

Through gas balancing or facilities planning, Enhanced Hub Services are short term in nature, may be limited, require separate contracts, and will be offered under negotiated rates.

Peak Storage	Space is available for summer injections and winter withdrawals. Cycling rights are available at negotiated rates. Space is firm; injections and withdrawals, on any day, are interruptible. Queue is in place for this service.
Off Peak Storage	Space is available for seasonal injections and corresponding withdrawals.
Firm Withdrawals and/or Injections	Daily firm rates; may be used to complement peak and offpeak storage or loans.
Loans	Volumes of gas available for predetermined periods of time.
Firm Transport	Firm transport service between any two points on Union's system.
Limited Firm	Firm transport service between any two points on Union's system, with a negotiated number of allowable days of interruption.
Load Balancing	This service can be tailored to meet individual customer demands. Service can be attached to firm contracts on Union's system to alleviate market swings.

Other General Aspects of Hub Services

- Customer may hold accounts at each receipt/delivery point.
- For parties currently holding a separate off-peak storage agreement, after the 60-day parking limit, volumes will be transported automatically to customer's offpeak storage account. Customer agrees to pay transportation/wheeling fee applicable at the time.
- In the event that customer has a balance that has exceeded the days allowed, Union has the irrevocable right to demand that customer reduce the parking balance to zero, or repay loan volumes within 48 hours. To the extent that customer does not comply, Union shall immediately invoke severe penalties.

UNION GAS SERVICE HUB (continued)

Status:

Has been providing a wide range of transactional or hub services since 1987, taking advantage of its location, abundance of storage and its interconnects to numerous pipelines.

Over the past four years, hub service volume has grown from 10 MMcf per day to over 300 MMcf per day.

Rates:

Wheeling -- Commodity Rate $.15 per Mcf

Title Transfer -- Commodity Rate $.0018 per Mcf

Interruptible Exchange -- Commodity Rate $.425 per Mcf

Balancing Service - Parking Rates	10-Day	60-Day
on delivery to Union	$.025 per Mcf	$.043 per Mcf
on redelivery to Customer	$.025 per Mcf	$.043 per Mcf

- Customers will be billed automatically for the difference between the 10-day and 60-day rates for any volumes parked in excess of 10 days.

- Additional charges of $.0018/Mcf per day accrue and accumulate after the 60-day period.

Loan Rates

on delivery to Customer	$.036 per Mcf
on redelivery to Union	$.036 per Mcf

- Additional charges accrue and accumulate on any loan balance outstanding for more than 10 days as follows:

April 1 - December 15	$.0018/Mcf per day
December 16 - March 31	$.007/Mcf on 1st day, plus $.021/Mcf on 3rd day, plus $.014/Mcf on 2nd day, plus $.01/Mcf on nth day

Other Rate Considerations

- No maximum contract quantities
- Economic dispatch
- "No-bump" rule
- Rates include fuel

Intentionally blank

WESTERN MARKET CENTER (Pipeline Interconnection)

Owners: Four equity partners -- Tenneco Gas, Questar Corporation, Entech, Inc., (a division of Montana Power), and Union Pacific Fuels.

Administrator: Overland Trail Transmission Company (Union Pacific's affiliate)

Location: Near Muddy Creek in southwestern Wyoming (see map in Appendix B-2), with interconnects to:

Overland Trail	70 MMcfd
Overthrust	230 MMcfd (by displacement)
Colorado Interstate	129 MMcfd
Questar Pipeline	129 MMcfd
Kern River Gas Trans.	400 MMcfd
Northwest Pipeline	240 MMcfd
Altamont (Proposed)	719 MMcfd

Services/Benefits:

Will offer wheeling, parking, peaking and balancing services, as well as title transfer and electronic gas trading capability. Participating pipelines will interconnect with a single header facility, enabling shippers to redirect gas, on a real-time basis, from one market to another.

The hub will offer several "OneStep" services:

<u>OneStep Data</u>™ tracks cash prices, future tradings, and factors affecting prices, such as regional and national industry, financial and regulatory news. Also available will be the latest weather reports for western North America; maps of pipelines served by the Western Market Center; and a directory of suppliers, markets and major gas customers, such as utilities and industrial users.

<u>OneStep Title</u>™ tracks the details and partners behind every transaction before gas actually moves across the header. Because units of gas are often bought and sold over and over again -- and split in many combinations -- these chains of title are often incredibly complex.

If there is a disruption in gas deliveries due to weather, well shut-ins, or other factors, the title tracking system will notify customers immediately, along with every appropriate party in the chain. The shipper can then respond quickly to the supply or market failure.

With OneStep Title,™ prior to nomination deadlines, customers will be able to identify the party who sold the gas, the volume purchased, and the parties scheduled to receive the gas. OneStep Title™ will combine this information with data submitted by other title tracking customers, creating a complete chain of title for each flow. Customers can use OneStep Title™ at any time to confirm the particulars of their deals.

WESTERN MARKET CENTER (continued)

<u>OneStep Store™</u> will use peaking, parking and balancing services to allow customers to overcome one of the "biggest hurdles in the business" -- assuring access to the right amount of gas when needed. Weather extremes, well-site disruptions and other factors can force customers to scramble for emergency supplies. At other times, customers may just need to "park" some gas for a while.

<u>OneStep Flow™</u> will direct a customer's gas from one market to another by its wheeling service. The Center's header will connect five pipelines and will "wheel" gas in and out of the header with an electronic management system. It keeps real-time accounting records of all gas flowed through the header. About 1.8 Bcf per day of supply is available to customers. Customers can review these records on their PC during the course of a month, or at month's end. In the event of a flow disruption, the operator of the Center's header will alert customers immediately. OneStep Flow™ can then aid customers' efforts to wheel gas from a new supply source or to a new customer.

OneStep Flow™ also makes customer nominations. The Western Market Center will then confirm receipt and delivery of customer gas. The Center will also maintain a customer's gas in a "keep-whole" position. This means that customers will never be out of balance on the header.

Status:

Expected to be operational by mid-1995

Rates:

The Western Market Center rates are as follows:

OneStep Flow™	$0.005/MMBtu
OneStep Store™	Posted Market Price
OneStep Title™	$0.004/MMBtu
OneStep Data™	$600/Month

Questar Pipeline will post an initial discounted interruptible transportation rate on its EBB for transportation to and from the new market center. This rate of $.05 per Dth plus ACA surcharge and fuel reimbursement will be applicable from all receipt points on Questar's system and to all delivery points except for Mountain Fuel Supply's city gates. The rate will be effective when the header system is available for service. This rate is subject to change as warranted by market conditions.

STREAMLINE (Electronic Trading System)

Owners: Joint development by Williams Energy Ventures, Inc., a subsidiary of Williams Companies, and Natural Gas Exchange, Inc., a subsidiary of Westcoast Energy.

Administrator: Williams

Location: Various hubs/market centers.

Services/Benefits:

Provides real time control of customers' gas trading activities and offers standardized contract, credit reporting and operating procedures. Bids and offers are matched instantaneously -- anonymity, security integrity and performance are guaranteed. Provides direct links between buyers and sellers, ensuring that transactions are consummated according to the customers' specifications and without delay.

Handles (1) cash market transactions from the time customers enter a buy or sell position on the network through automatic bid/offer matching, (2) credit information, (3) contract administration, and (4) physical delivery at the market hub.

Efficiency advantages of StreamLine include

- Lower transaction costs
- Expanded market coverage through an immediate network -- buy/sell position exposure
- Immediate information via fiber-optic cable
- Physical gas delivery guarantees
- Expanded market access
- Standardized contracts
- Cleared credit
- 24-hour customer service
- Formal and computer-based training

Status:

Scheduled for rapid expansion in hubs across the continent, but currently serves U.S. hubs at Waha, Opal, Lebanon, Carthage, Station "65", and Empress in Alberta.

Rates:

See separate page for product fee structures.

Williams Energy Ventures Product Fee Structures

Streamline℠

Description	Transaction Fees			Monthly Fees
Dedicated Work Station (DWS)	Carthage, Texas Hub	12/01/94	$.0067/MMBtu/d	$750 One-Time Installation Fee **
Lease Line & Communications	Waha, Lebanon, Opal Hubs	12/01/94	$.0034/MMBtu/d	$650.00 Subscription Fee **
Router (if applicable)				$350.00 Demand Fee **
Streamline Software				
Training and Support				** Waived for all traders until 4/1/95

Capacity Central℠

Description	Fees
Dedicated Work Station (DWS)	$650.00 Monthly Subscription*
Lease Line & Communications	$.0075/MMBtu Transaction Fee paid by the buyer
Router (if applicable)	
Capacity Central Software	
Training and Support	* Waived for all traders for a period of ninety days

Multiple Unit Discounts

Description		Fees	Considerations
Number of ID's	One	$ 650.00 Monthly Subscription	Prices include: One Work Station; One Software Copy; One Lease Line and other Communications; One Router (if applicable). Training and Support covers all licensed traders.
	Two	$1,150.00	
	Three	$1,550.00	
	Four	$1,900.00	
	Five	$2,225.00	
	Six	$2,425.00	
	Above Six	$2,425.00 + 200.00 Each Above Six	

Multiple Product Discounts

Description	Fees	Considerations
One DWS Lease Line & Communication Router (if applicable) Software Version 1.0	$650.00 Monthly Subscription (for first product installed) $350.00 Monthly Subscription (for additional products installed) Minimum Usage Charge (if apply) Transaction Fees	Prices include: One Work Station; One Software Copy; One Lease Line and other Communications; One Router (if applicable). Training and Support covers all licensed traders.

effective 11/7/94 (bmg)

APPENDIX B-2

MARKET HUB MAPS

APPENDIX B-2

MARKET HUB MAPS

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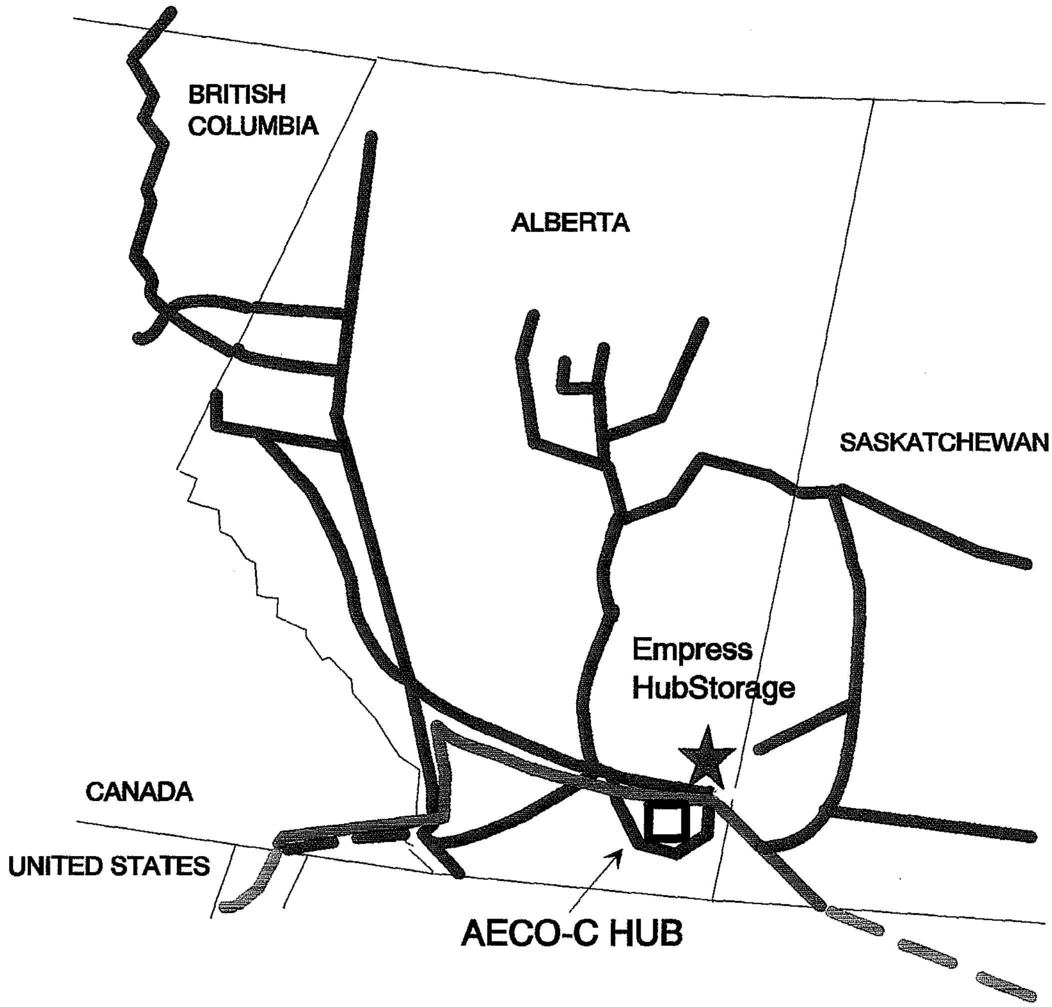
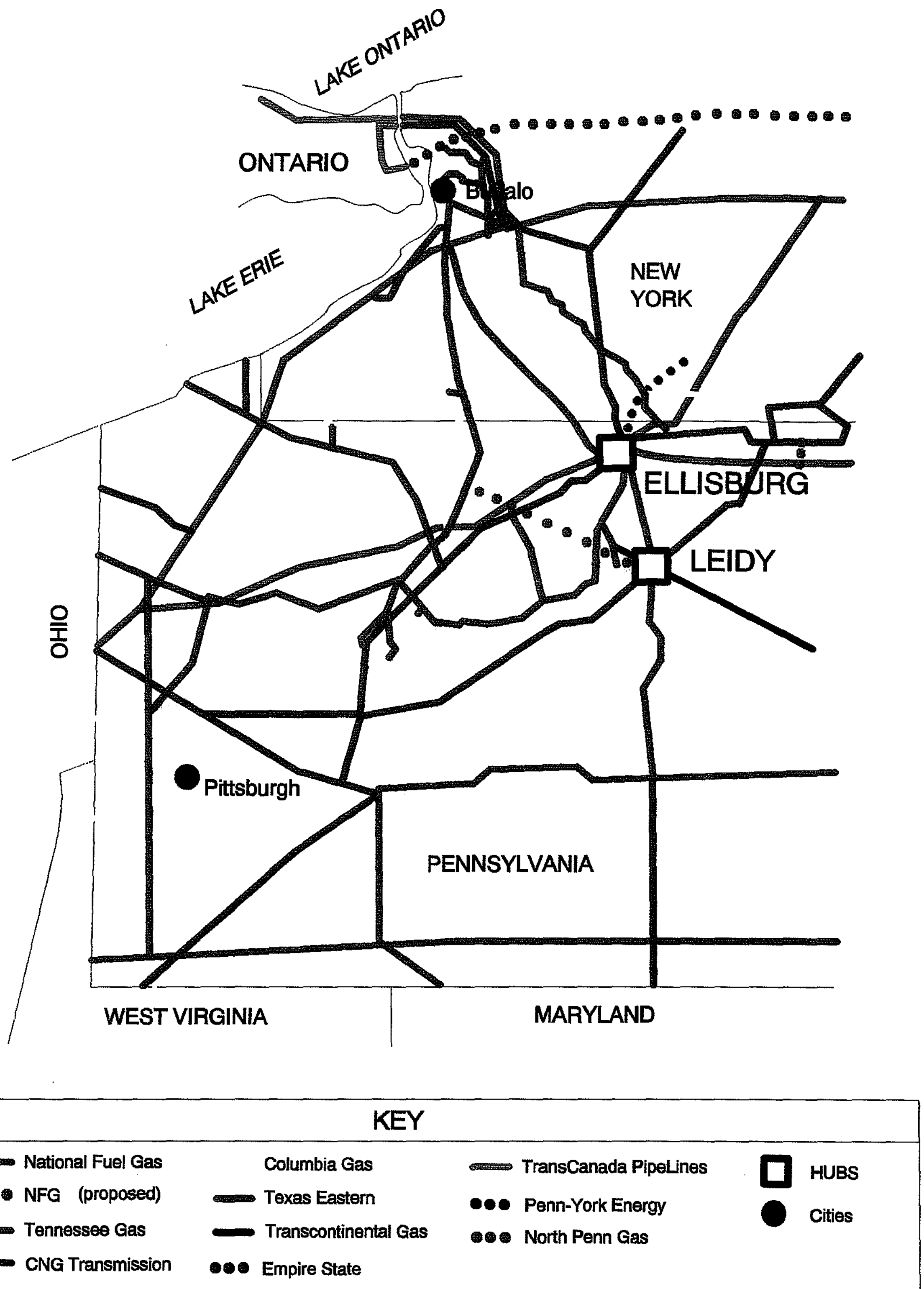
AECO-C HUB (ALBERTA)

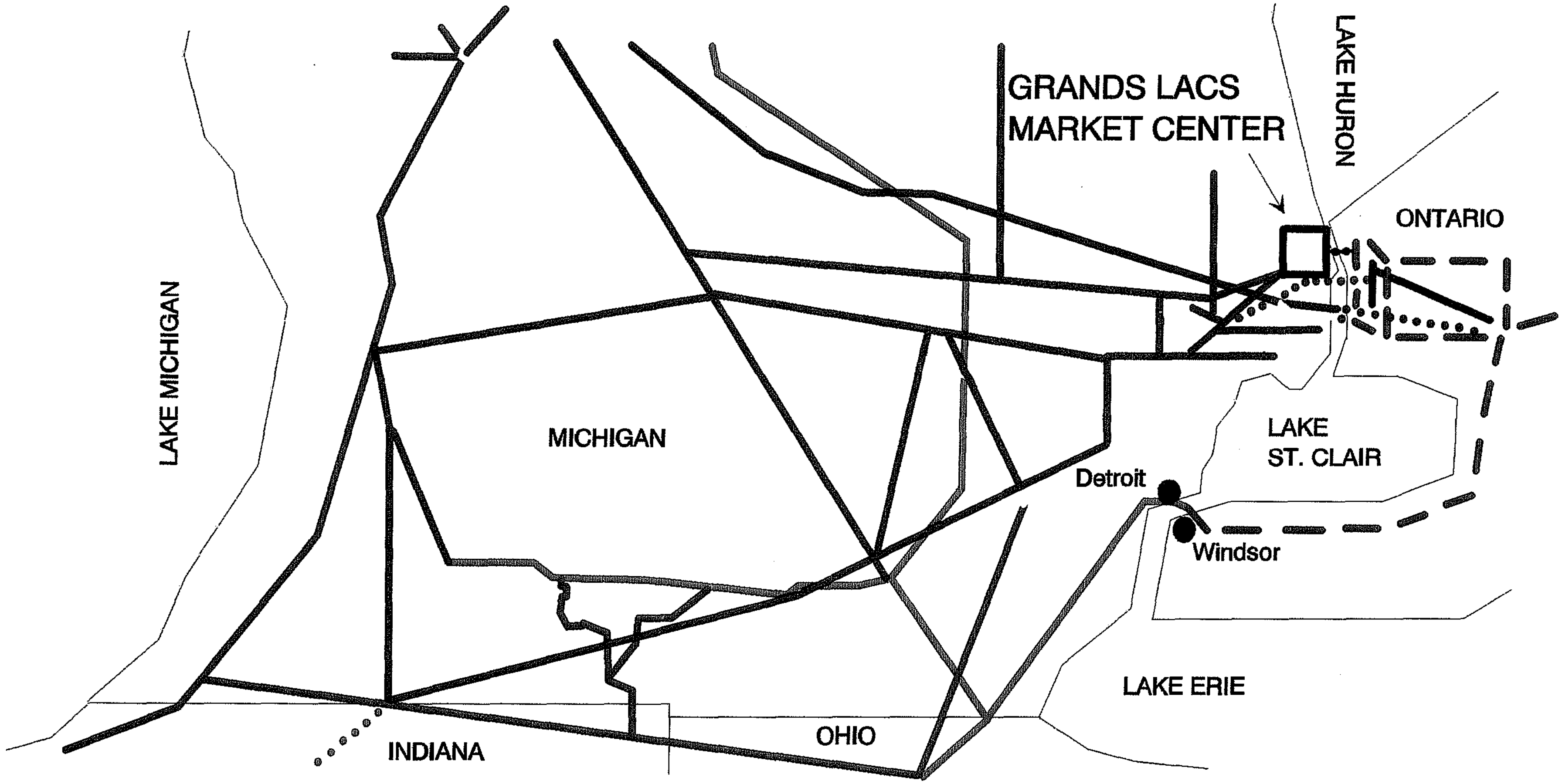


KEY		
NOVA Corporation	Alberta Natural Gas	Empress HubStorage
Foothills Pipelines	Northern Border	
Transgas Limited	TransCanada PipeLines	AECO-C HUB (includes AEC storage at Suffield, AB)
Pacific Gas Transmission	Westcoast Energy	

ELLISBURG-LEIDY HUB (PA)

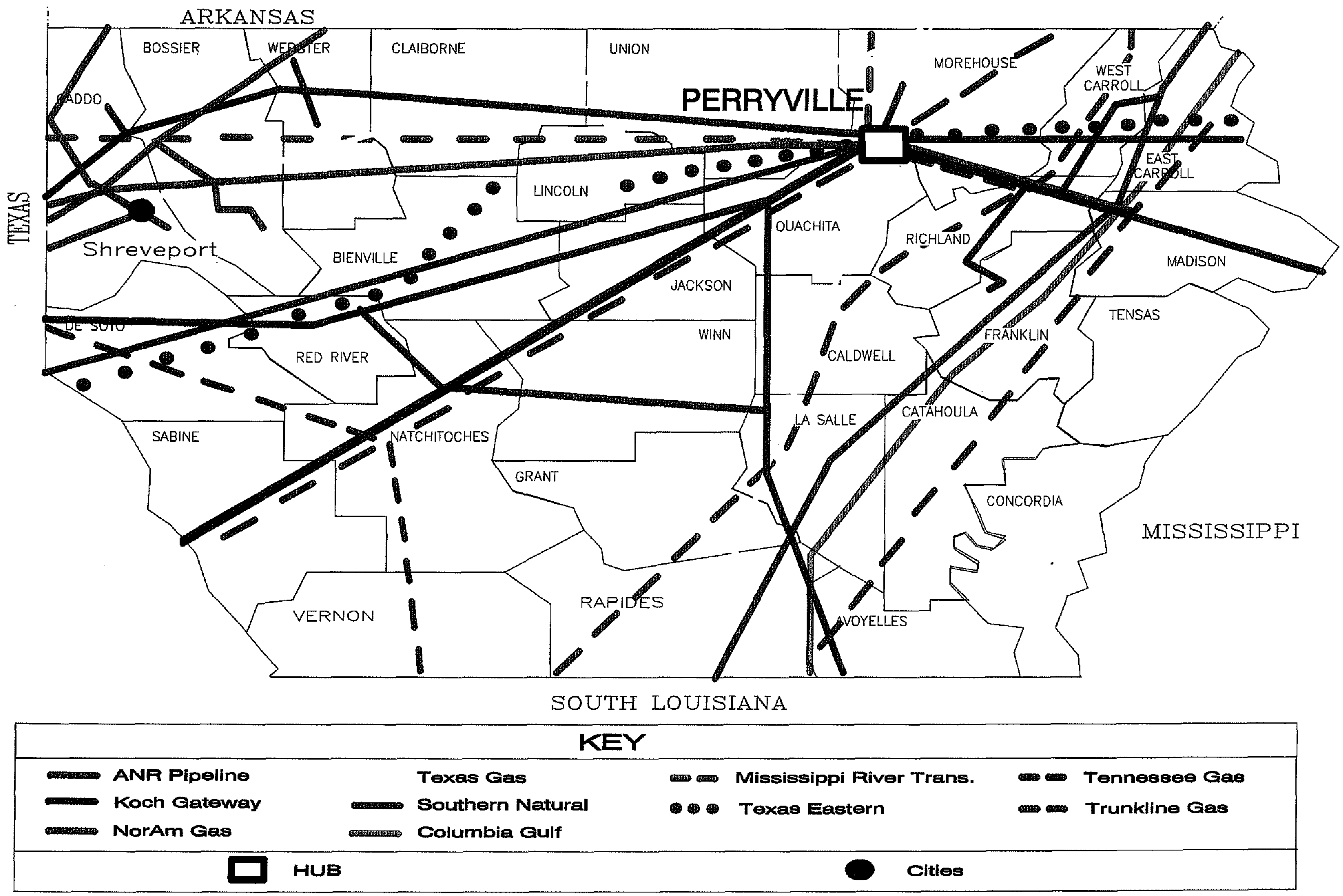


GRANDS LACS MARKET CENTER (MI)

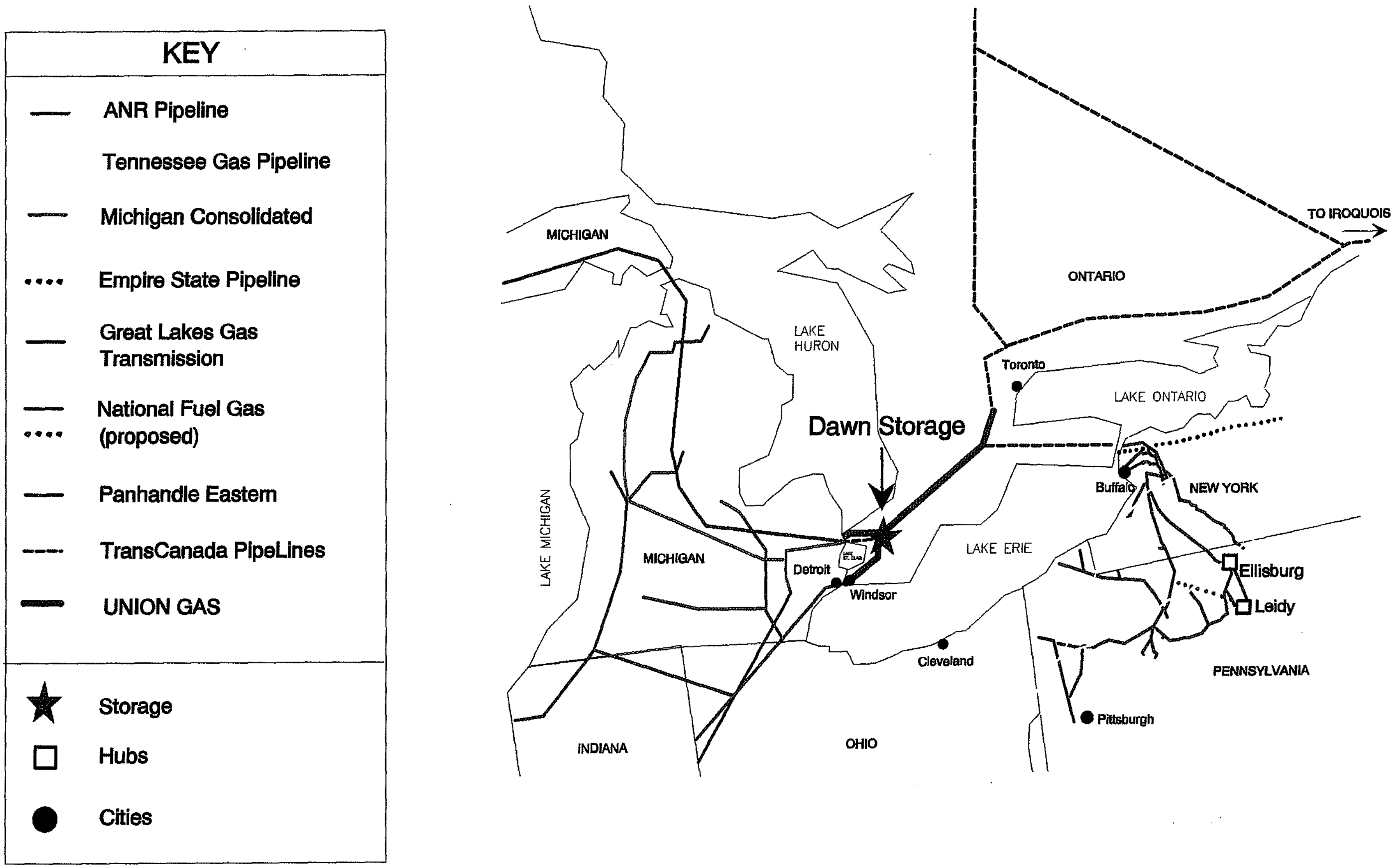


KEY		
ANR Pipeline	TransCanada PipeLines	ANR Link (proposed)
Consumers Power (U.S.)	Union Gas	Bluewater Pipeline (proposed)
Great Lakes Gas Transmission	St. Clair Pipelines	Southeastern Michigan Gas
Michigan Consolidated Gas	Trunkline Gas	GRANDS LACS MARKET CENTER
Panhandle Eastern Pipe Line	Tecumseh (Consumers Gas)	Cities

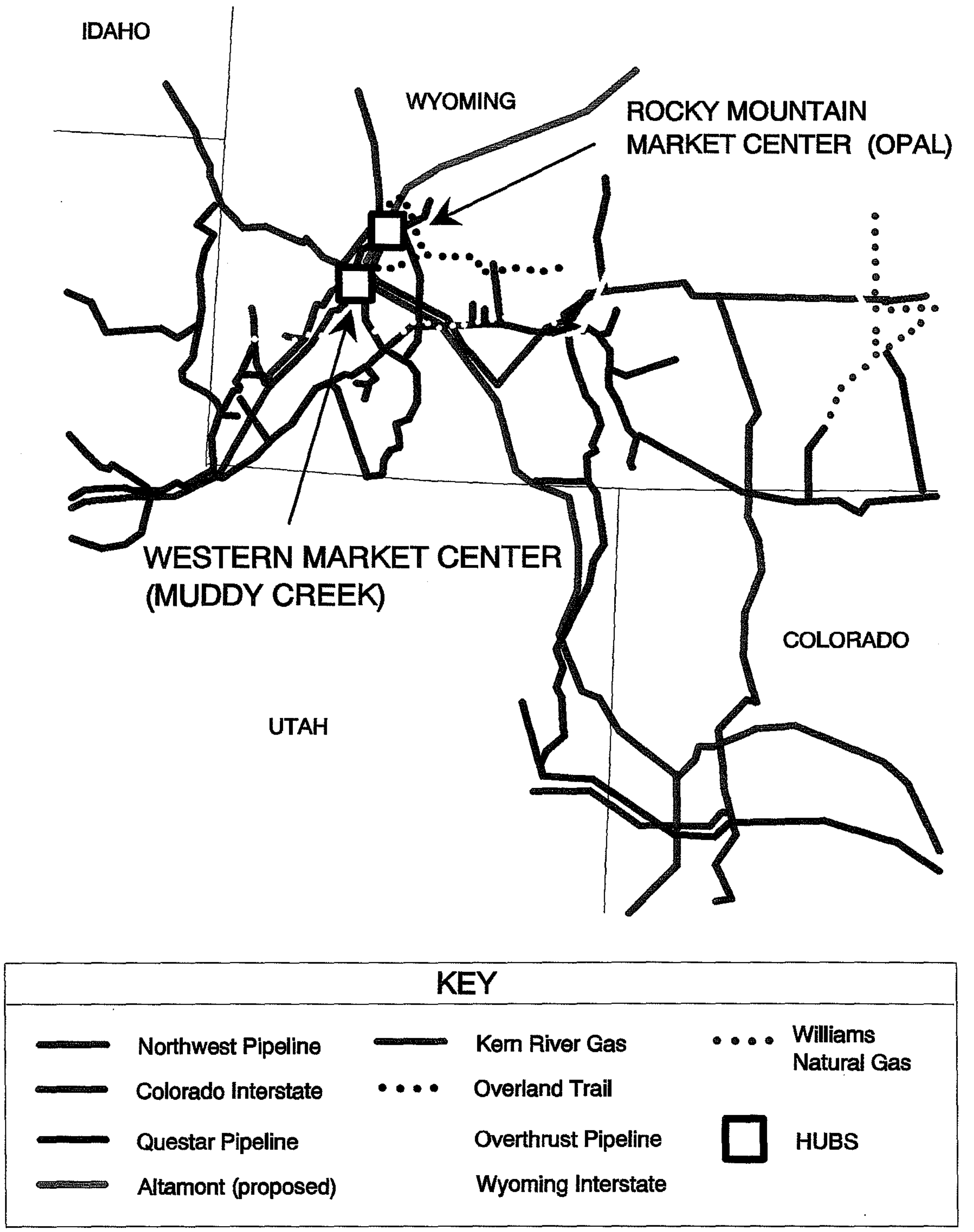
PERRYVILLE HUB (LA)



UNION GAS SYSTEM HUB (ON)



WESTERN MARKET CENTER / MUDDY CREEK (WY)



APPENDIX C

STATISTICAL APPENDIX

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base–Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver–ability (MMcf/d)
ALABAMA							
McIntosh	Bay Gas Storage Co. Ltd d/	3	1,400.0	2,600.0	4,000.0	33.0	100.0
TOTAL ALABAMA			1,400.0	2,600.0	4,000.0	33.0	100.0
ARKANSAS							
Lavaca Deep	Arkansas Oklahoma Gas Corp..	1	3,290.0	63.0	3,353.0	0.3	12.0
Adams–Hale	Arkansas Western Gas Co.	1	4,500.0	277.0	4,777.0	1.3	20.0
King–Casey	Arkansas Western Gas Co.	1	600.0	66.0	666.0	0.3	5.0
Stockton–Casey	Arkansas Western Gas Co.	1	9,400.0	1,973.0	11,373.0	9.2	60.0
Stockton–Orr	Arkansas Western Gas Co.	1	1,600.0	136.0	1,736.0	0.6	10.0
Woolsey	Arkansas Western Gas Co.	1	5,400.0	1,168.0	6,568.0	5.5	90.0
TOTAL ARKANSAS			24,790.0	3,683.0	28,473.0	17.2	197.0
CALIFORNIA							
Los Medanos	Pacific Gas & Electric Co.	1	10,975.0	17,000.0	27,975.0	75.0	250.0
McDonald Island	Pacific Gas & Electric Co.	1	54,075.0	77,050.0	131,125.0	1,000.0	2,000.0
Pleasant Creek	Pacific Gas & Electric Co.	1	5,078.0	2,148.0	7,226.0	50.0	6.0
Aliso Canyon	Southern California Gas Co.	1	91,500.0	70,000.0	161,500.0	465.0	1,860.0
East Whittier	Southern California Gas Co.	1	425.0	800.0	1,225.0	65.0	75.0
Honor Ranch	Southern California Gas Co.	1	19,500.0	17,500.0	37,000.0	330.0	1,000.0
La Goleta	Southern California Gas Co.	1	32,600.0	13,500.0	46,100.0	150.0	600.0
Montebello	Southern California Gas Co.	1	27,500.0	11,700.0	39,200.0	105.0	795.0
Playa del Rey	Southern California Gas Co.	1	4,500.0	2,600.0	7,100.0	170.0	500.0
TOTAL CALIFORNIA			246,153.0	212,298.0	458,451.0	2,410.0	7,086.0
COLORADO							
Flank	Colorado Interstate Gas Co.	1	11,438.0	6,962.0	18,400.0	99.0	149.2
Fort Morgan	Colorado Interstate Gas Co.	1	6,962.0	7,360.0	14,322.0	124.0	348.1
Latigo	Colorado Interstate Gas Co.	1	13,288.0	8,155.0	21,443.0	84.0	149.2
Wolf Creek	Gasco Inc.	1	7,436.0	2,664.0	10,100.0	8.0	20.0
Springdale	KN Natural Gas Inc.	1	4,900.0	791.6	5,691.6	10.0	11.7
Asbury	Public Service Co. of Colorado	1	1,224.0	2,926.0	4,150.0	9.0	16.0
Fruita	Public Service Co. of Colorado	1	38.0	340.0	378.0	1.0	2.0
Leyden	Public Service Co. of Colorado	4	800.0	2,200.0	3,000.0	120.0	205.0
Roundup	Public Service Co. of Colorado	1	3,000.0	6,000.0	9,000.0	30.0	50.0
TOTAL COLORADO			49,086.0	37,398.6	86,484.6	485.0	951.2
ILLINOIS							
Glasford	Central Illinois Light Co.	2	8,121.0	3,714.0	11,835.0	75.0	150.0
Lincoln	Central Illinois Light Co.	2	8,015.0	4,159.0	12,174.0	65.0	63.0
Ashmore	Central Illinois Public Service Co.	1	2,736.0	770.0	3,506.0	10.0	18.0
Belle Gent	Central Illinois Public Service Co.	1	72.0	184.0	256.0	2.0	2.0
Johnson City	Central Illinois Public Service Co.	1	822.0	518.0	1,340.0	6.0	6.0
Richwoods	Central Illinois Public Service Co.	1	15.0	103.0	118.0	0.5	0.9
Sciota	Central Illinois Public Service Co.	2	3,690.0	872.0	4,562.0	7.0	14.0

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
ILLINOIS (cont.)							
Mills	Egyptian Gas Storage Corp.	1	100.0	600.0	700.0	5.0	5.0
Centralia	Illinois Power Co.	1	473.0	143.0	616.0	5.0	14.0
Eden	Illinois Power Co.	1	1,013.0	390.0	1,403.0	4.0	8.0
Freeburg	Illinois Power Co.	1	5,036.0	1,900.0	6,936.0	20.0	35.0
Gillespie	Illinois Power Co.	1	116.0	32.0	148.0	2.0	5.0
Hillsboro	Illinois Power Co.	1	14,110.0	7,600.0	21,710.0	40.0	125.0
Hookdale	Illinois Power Co.	1	285.0	715.0	1,000.0	30.0	18.0
Shanghai	Illinois Power Co.	2	7,712.0	3,600.0	11,312.0	20.0	80.0
Tilden	Illinois Power Co.	1	1,819.0	870.0	2,689.0	20.0	50.0
St.Jacob	Mississippi River Transmission Corp.	2	4,700.0	800.0	5,500.0	3.7	30.0
Cooks Mills	Natural Gas Pipeline Co.	1	2,900.0	2,300.0	5,200.0	60.0	60.0
Herscher-Galesville	Natural Gas Pipeline Co.	2	25,400.0	9,000.0	34,400.0	600.0	900.0
Herscher-Northwest	Natural Gas Pipeline Co.	2	15,500.0	2,000.0	17,500.0	40.0	65.0
Herscher-Mt. Simon	Natural Gas Pipeline Co.	2	56,000.0	11,000.0	67,000.0	120.0	240.0
Loudon	Natural Gas Pipeline Co.	1	42,000.0	38,000.0	80,000.0	250.0	510.0
Ancona	Northern Illinois Gas Co.	2	101,230.0	54,734.0	155,964.0	255.8	850.0
Hudson	Northern Illinois Gas Co.	2	34,025.0	8,884.0	42,909.0	41.5	200.0
Lake Bloomington	Northern Illinois Gas Co.	2	33,909.0	12,350.0	46,259.0	57.7	175.0
Lexington	Northern Illinois Gas Co.	2	38,005.0	10,379.0	48,384.0	48.5	150.0
Pecatonica	Northern Illinois Gas Co.	2	1,956.0	1,053.0	3,009.0	4.9	75.0
Pontiac-Galesville	Northern Illinois Gas Co.	2	12,830.0	3,747.0	16,577.0	17.5	200.0
Pontiac-Mt. Simon	Northern Illinois Gas Co.	2	25,345.0	15,681.0	41,026.0	73.3	50.0
Troy Grove	Northern Illinois Gas Co.	2	33,982.0	28,533.0	62,515.0	133.3	850.0
Waverly	Panhandle Eastern Pipe Line Co.	2	46,473.0	446.0	46,919.0	2.1	70.0
Manlove	Peoples Gas Light & Coke Co.	2	98,144.0	44,256.0	142,400.0	300.0	1,040.0
TOTAL ILLINOIS			626,534.0	269,333.0	895,867.0	2,319.8	6,058.9
INDIANA							
Dixon	Citizens Gas & Coke Utility	1	1,946.0	834.0	2,780.0	19.2	16.8
Howesville	Citizens Gas & Coke Utility	1	2,975.0	1,275.0	4,250.0	24.0	36.0
Mineral City	Citizens Gas & Coke Utility	1	1,458.0	625.0	2,083.0	12.0	12.0
Simpson Chapel	Citizens Gas & Coke Utility	1	1,760.0	440.0	2,200.0	12.0	7.2
Switz City	Citizens Gas & Coke Utility	1	3,944.5	1,690.5	5,635.0	24.0	16.8
Worthington	Citizens Gas & Coke Utility	1	9,240.0	3,960.0	13,200.0	60.0	60.0
Greensburg	Indiana Gas Co.	1	700.0	478.0	1,178.0	1.0	1.0
Sellersburg	Indiana Gas Co.	2	1,200.0	143.0	1,343.0	7.5	12.0
Unionport	Indiana Gas Co.	2	1,001.0	123.0	1,124.0	10.0	20.0
Unionville	Indiana Gas Co.	1	3,000.0	3,275.0	6,275.0	20.0	64.0
West Point	Indiana Gas Co.	2	733.0	257.0	990.0	1.0	9.1
Wolcott	Indiana Gas Co.	2	4,500.0	2,530.0	7,030.0	20.0	61.0
Lawrenceburg Storage	Lawrenceburg Gas Co.	4	0.7	1.0	1.7	0.5	1.0
Calcutta-Carbon	Midwest Gas Storage	2	1,600.0	3,900.0	5,500.0	NA	200.0
Shaw	Midwest Natural Gas Corp.	1	90.0	25.5	115.5	1.5	0.9
Royal Center	Northern Indiana Public Service Co.	2	25,888.0	657.0	26,545.0	45.0	85.0

State / Field	Owner / Operator	Reservoir Type	Base–Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver–ability (MMcf/d)
INDIANA (cont.)							
Glendale	Southern Indiana Gas & Electric Co.	1	215.0	182.0	397.0	0.9	NA
Loogootee	Southern Indiana Gas & Electric Co.	1	75.0	97.0	172.0	0.5	NA
Midway	Southern Indiana Gas & Electric Co.	2	1,304.0	2,179.0	3,483.0	14.0	50.0
Monroe City	Southern Indiana Gas & Electric Co.	1	3,167.0	456.0	3,623.0	18.0	24.5
Oliver	Southern Indiana Gas & Electric Co.	2	1,741.0	1,337.0	3,078.0	18.0	41.5
Alford	Texas Gas Transmission Co.	1	1,530.0	989.0	2,519.0	28.0	15.5
Leesville	Texas Gas Transmission Co.	2	2,244.0	2,531.0	4,775.0	14.0	20.4
Oaktown	Texas Gas Transmission Co.	1	429.0	622.0	1,051.0	8.0	4.6
White River	Texas Gas Transmission Co.	1	204.0	306.0	510.0	5.0	5.1
Wilfred	Texas Gas Transmission Co.	2	1,224.0	2,193.0	3,417.0	18.0	34.0
TOTAL INDIANA			72,169.2	31,106.0	103,275.2	382.1	798.4
IOWA							
Cairo–Galesville	Natural Gas Pipeline Co.	2	12,200.0	3,400.0	15,600.0	50.0	60.0
Cairo–Mt. Simon	Natural Gas Pipeline Co.	2	38,700.0	12,200.0	50,900.0	120.0	170.0
Cairo–St. Peter	Natural Gas Pipeline Co.	2	19,200.0	7,800.0	27,000.0	92.0	150.0
Columbus City–Mt. Simon	Natural Gas Pipeline Co.	2	28,700.0	10,400.0	39,100.0	120.0	117.0
Columbus City–St. Peter	Natural Gas Pipeline Co.	2	11,700.0	2,900.0	14,600.0	49.0	50.0
Keota–St. Peter	Natural Gas Pipeline Co.	2	3,700.0	2,300.0	6,000.0	48.0	50.0
Redfield	Northern Natural Gas Co.	2	90,000.0	27,000.0	117,000.0	300.0	415.0
TOTAL IOWA			204,200.0	66,000.0	270,200.0	779.0	1,012.0
KANSAS							
Boehm	Colorado Interstate Gas Co.	5	15,814.0	6,365.0	22,179.0	79.0	124.3
Adolph	KN Natural Gas Inc.	1	5,300.0	545.0	5,845.0	5.0	8.2
Collinson	NorAm Gas Transmission	1	1,260.0	1,133.0	2,393.0	5.3	10.0
Cunningham	Northern Natural Gas Co.	1	32,000.0	20,000.0	52,000.0	300.0	530.0
Lyons	Northern Natural Gas Co.	1	16,000.0	6,000.0	22,000.0	100.0	130.0
Borchers North	PEPL / Southwest Gas Storage Co.	1	35,081.0	12,176.0	47,257.0	56.9	350.0
Richfield	Richfield Gas Storage	1	2,000.0	3,500.0	5,500.0	NA	50.0
Buffalo	United Cities Gas Storage Co.	1	180.0	65.0	245.0	0.3	1.8
Fredonia	United Cities Gas Storage Co.	1	160.0	114.0	274.0	0.5	1.8
Liberty North	United Cities Gas Storage Co.	1	1,500.0	1,273.0	2,773.0	5.9	30.0
Liberty South	United Cities Gas Storage Co.	1	164.0	34.0	198.0	0.2	1.0
Brehm	Western Resources Inc.	5	1,600.0	2,200.0	3,800.0	20.0	25.0
Yaggy	Western Resources Inc.	3	500.0	2,000.0	2,500.0	120.0	120.0
Alden	Williams Natural Gas	1	10,912.0	3,782.0	14,694.0	35.3 s/	143.0
Colony	Williams Natural Gas	1	7,647.0	5,083.0	12,730.0	39.5 s/	160.0
Craig	Williams Natural Gas	1	5,575.0	264.0	5,839.0	14.3 s/	59.0
Elk City	Williams Natural Gas	1	23,813.0	5,712.0	29,525.0	59.0 s/	239.0
McLouth	Williams Natural Gas	1	11,609.0	1,818.0	13,427.0	43.0 s/	175.0

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
KANSAS (cont.)							
North Welda	Williams Natural Gas	1	10,747.0	4,797.0	15,544.0	17.5 s/	71.0
Piqua	Williams Natural Gas	1	2,864.0	348.0	3,212.0	4.0 s/	16.0
South Welda	Williams Natural Gas	1	11,046.0	7,254.0	18,300.0	31.8 s/	129.0
TOTAL KANSAS			195,772.0	84,463.0	280,235.0	937.5	2,374.1
KENTUCKY							
East Slaughters	Alcan Ingot	2	138.0	629.0	767.0	3.0	3.0
Kettle Island	Delta Natural Gas Co. Inc.	1	785.0	121.1	906.1	1.0	1.2
Cecilia-Laurel	Elizabethtown Natural Gas	2	490.0	813.0	1,303.0	2.0	5.0
Cecilia-Lego	Elizabethtown Natural Gas	2	500.0	1,604.0	2,104.0	2.0	5.0
Center	Louisville Gas & Electric Co.	1	2,720.0	2,386.0	5,106.0	16.8	50.0
Doe Run Upper	Louisville Gas & Electric Co.	2	1,810.0	3,977.0	5,787.0	72.0	60.0
Magnolia Deep	Louisville Gas & Electric Co.	1	2,370.0	2,056.0	4,426.0	24.0	45.0
Magnolia Upper	Louisville Gas & Electric Co.	1	2,460.0	3,489.0	5,949.0	42.0	75.0
Muldraugh	Louisville Gas & Electric Co.	1	1,450.0	2,799.0	4,249.0	20.0	215.0
Dixie	Texas Gas Transmission Corp.	1	4,682.0	2,575.0	7,257.0	93.0	66.3
Graham Lake	Texas Gas Transmission Corp.	1	2,958.0	1,326.0	4,284.0	15.0	15.3
Hanson	Texas Gas Transmission Corp.	1	8,160.0	3,927.0	12,087.0	70.0	71.4
Midland	Texas Gas Transmission Corp.	1	64,474.0	68,668.0	133,142.0	500.0	882.5
West Greenville	Texas Gas Transmission Corp.	1	4,264.0	3,386.0	7,650.0	85.0	81.6
Barnsley	United Cities Gas Storage Co.	1	1,600.0	404.0	2,004.0	1.9	30.0
Bon Harbor	Western Kentucky Gas Co.	1	1,300.0	777.0	2,077.0	13.5	21.0
Grandview	Western Kentucky Gas Co.	1	350.0	242.0	592.0	5.0	2.1
Hickory School	Western Kentucky Gas Co.	1	850.0	470.0	1,320.0	15.0	19.0
Kirkwood Springs	Western Kentucky Gas Co.	1	400.0	223.0	623.0	6.0	10.0
Owensboro	Western Kentucky Gas Co.	1	41.0	19.0	60.0	1.9	2.4
St. Charles	Western Kentucky Gas Co.	1	3,470.0	2,912.0	6,382.0	22.0	35.8
TOTAL KENTUCKY			105,272.0	102,803.1	208,075.1	1,011.1	1,696.6
LOUISIANA							
Bear Creek	Bear Creek Storage Co. c/	1	50,000.0	58,000.0	108,000.0	900.0	900.0
Sorrento	Bridgeline Gas Distribution Co. e/	3	4,000.0	3,200.0	7,200.0	100.0	320.0
Bistineau	Koch Gateway Pipeline Co.	1	62,700.0	60,800.0	123,500.0	189.7	1,100.0
Napoleonville	Enron Storage	3	3,800.0	4,600.0	8,400.0	200.0	400.0
East Unionville	Mississippi River Transmission Corp.	1	31,600.0	20,200.0	51,800.0	94.4	420.0
West Unionville	Mississippi River Transmission Corp.	1	13,700.0	10,000.0	23,700.0	46.7	190.0
Ruston	NorAm Gas Transmission	1	3,500.0	2,200.0	5,700.0	40.0	60.0
Hester	Transcontinental Gas Pipe Line Corp.	1	11,500.0	12,000.0	23,500.0	36.0	102.0
Washington	Transcontinental Gas Pipe Line Corp.	1	45,000.0	75,000.0	120,000.0	370.0	800.0
Epps	Trunkline Gas Co.	1	29,851.0	11,281.0	41,132.0	100.0	120.0
TOTAL LOUISIANA			255,651.0	257,281.0	512,932.0	2,076.8	4,412.0

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
MARYLAND							
Accident	Texas Eastern Transmission Corp.	1	46,677.0	13,098.0	59,775.0	61.2	300.0
TOTAL MARYLAND			46,677.0	13,098.0	59,775.0	61.2	300.0
MICHIGAN							
Austin	ANR Pipeline Co.	1	11,300.0	12,000.0	23,300.0	480.0	800.0
Capac	ANR Pipeline Co.	1	12,200.0	20,000.0	32,200.0	180.0	270.0
Central Charlton	ANR Pipeline Co.	1	2,700.0	16,300.0	19,000.0	140.0	220.0
Coldwater	ANR Pipeline Co.	1	5,000.0	8,000.0	13,000.0	37.0	33.0
Croton	ANR Pipeline Co.	1	900.0	4,500.0	5,400.0	37.0	37.0
Goodwell	ANR Pipeline Co.	1	4,900.0	24,700.0	29,600.0	370.0	370.0
Lincoln	ANR Pipeline Co.	1	13,400.0	22,000.0	35,400.0	350.0	405.0
Loreed	ANR Pipeline Co.	1	15,700.0	32,500.0	48,200.0	325.0	500.0
Muttonville	ANR Pipeline Co.	1	2,300.0	11,100.0	13,400.0	210.0	400.0
North Hamilton	ANR Pipeline Co.	1	7,100.0	5,000.0	12,100.0	46.0	17.0
Norwich	ANR Pipeline Co.	1	4,200.0	4,200.0	8,400.0	35.0	52.0
Orient	ANR Pipeline Co.	1	4,100.0	5,700.0	9,800.0	37.0	48.0
Reed City	ANR Pipeline Co.	1	10,600.0	18,000.0	28,600.0	205.0	400.0
South Chester 15	ANR Pipeline Co.	1	2,600.0	16,800.0	19,400.0	170.0	270.0
Winfield	ANR Pipeline Co.	1	7,100.0	7,400.0	14,500.0	65.0	73.0
Cold Springs	ANR Storage Co.	1	4,400.0	29,100.0	33,500.0	136.0	250.0
Excelsior	ANR Storage Co.	1	1,500.0	9,500.0	11,000.0	44.4	250.0
Rapid River	ANR Storage Co.	1	2,200.0	15,100.0	17,300.0	70.6	250.0
Blue Lake 18A	ANR / Blue Lake Gas Storage Co.	1	7,500.0	42,000.0	49,500.0	210.0	600.0
Eaton Rapids	ANR / Eaton Rapids Gas Storage	1	2,700.0	12,000.0	14,700.0	71.0	116.0
Lacey	Battle Creek Gas Co.	3	41.0	200.0	241.0	2.3	25.0
Lee 11	Battle Creek Gas Co.	1	200.0	700.0	900.0	5.6	6.6
Lee 2	Battle Creek Gas Co.	1	300.0	700.0	1,000.0	5.6	7.0
Four Corners	Consumers Power Co.	1	1,400.0	2,400.0	3,800.0	50.0	80.0
Hessen	Consumers Power Co.	1	6,900.0	11,000.0	17,900.0	100.0	150.0
Ira	Consumers Power Co.	1	3,500.0	4,000.0	7,500.0	200.0	250.0
Lenox	Consumers Power Co.	1	3,500.0	1,500.0	5,000.0	150.0	200.0
Lyon 34	Consumers Power Co.	1	658.0	700.0	1,358.0	20.0	40.0
Northville N-211	Consumers Power Co.	1	14,100.0	10,500.0	24,600.0	50.0	60.0
Overisel	Consumers Power Co.	1	40,000.0	24,000.0	64,000.0	225.0	300.0
Puttygut	Consumers Power Co.	1	7,600.0	9,100.0	16,700.0	225.0	250.0
Ray	Consumers Power Co.	1	22,000.0	44,000.0	66,000.0	600.0	1,200.0
Salem	Consumers Power Co.	1	23,000.0	12,000.0	35,000.0	150.0	200.0
Swan Creek	Consumers Power Co.	1	200.0	400.0	600.0	NA	NA
Belle River Mills	Michigan Consolidated Gas Co.	1	23,100.0	53,000.0	76,100.0	400.0	1,500.0
Columbus	Michigan Consolidated Gas Co.	1	2,500.0	18,000.0	20,500.0	180.0	430.0
New Haven	Michigan Consolidated Gas Co.	1	9,100.0	5,800.0	14,900.0	85.0	58.0
Taggart	Michigan Consolidated Gas Co.	1	31,100.0	55,000.0	86,100.0	575.0	550.0
West Columbus	Michigan Consolidated Gas Co.	1	3,800.0	23,000.0	26,800.0	270.0	780.0
Cranberry Lake	Michigan Gas Storage Co.	1	18,000.0	12,000.0	30,000.0	56.1	120.0

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
MICHIGAN (cont.)							
Riverside	Michigan Gas Storage Co.	1	7,500.0	4,500.0	12,000.0	20.0	40.0
Winterfield	Michigan Gas Storage Co.	1	47,000.0	28,000.0	75,000.0	250.0	360.0
Anderson	Michigan Gas Utilities Co.	1	500.0	300.0	800.0	NA	NA
Campbell	Michigan Gas Utilities Co.	1	200.0	300.0	500.0	NA	NA
Partello-Cortright	Michigan Gas Utilities Co.	1	1,400.0	1,800.0	3,200.0	26.0	50.4
Howell	Panhandle Eastern Pipe Line Co.	1	16,300.0	32,600.0	48,900.0	41.9	360.0
Washington 28	South Romeo Gas Storage / MichCon	1	2,200.0	9,800.0	12,000.0	NA	NA
Collin Field	Southeastern Michigan Gas Co.	1	900.0	1,200.0	2,100.0	NA	NA
Morton	Southeastern Michigan Gas Co.	3	1,200.0	2,000.0	3,200.0	24.0	60.0
TOTAL MICHIGAN			410,599.0	684,400.0	1,094,999.0	6,930.5	12,438.0
MINNESOTA							
Waterville-Waseca	Minnegasco Inc.	2	4,600.0	6,700.0	11,300.0	31.3	60.0
TOTAL MINNESOTA			4,600.0	6,700.0	11,300.0	31.3	60.0
MISSOURI							
St. Louis	Laclede Gas Co.	2	21.6	7.5	29.1	144.0	250.0
TOTAL MISSOURI			21.6	7.5	29.1	144.0	250.0
MISSISSIPPI							
Hattiesburg	Crystal Oil	3	1,800.0	3,500.0	5,300.0	175.0	350.0
Jackson	Koch Gateway Pipeline Co.	1	2,824.0	2,726.0	5,550.0	12.5	250.0
Amory	Mississippi Valley Gas Co.	1	500.0	1,200.0	1,700.0	6.0	20.0
Goodwin	Mississippi Valley Gas Co.	1	1,000.0	1,700.0	2,700.0	13.0	20.0
Petal	Petal Gas Storage Co. i/	3	1,800.0	3,200.0	5,000.0	160.0	320.0
Muldon	Southern Natural Gas Co.	1	61,820.0	31,000.0	92,820.0	750.0	350.0
Eminence	Transcontinental Gas Pipe Line Corp.	3	4,460.0	12,060.0	16,520.0	240.0	1,500.0
TOTAL MISSISSIPPI			74,204.0	55,386.0	129,590.0	1,356.5	2,810.0
MONTANA							
Box Elder	Montana Power Co.	1	3,069.0	6,031.0	9,100.0	8.0	8.0
Cobb	Montana Power Co.	1	26,065.0	11,320.0	37,385.0	120.0	120.0
Dry Creek	Montana Power Co.	1	15,343.0	22,482.0	37,825.0	40.0	40.0
Baker	Williston Basin Interstate Pipeline Co.	1	122,773.0	164,427.0	287,200.0	103.0	114.0
TOTAL MONTANA			167,250.0	204,260.0	371,510.0	271.0	282.0
NEBRASKA							
Huntsman	KN Interstate Gas Transmission	1	30,607.0	8,862.0	39,469.0	50.0	101.0
Big Springs	KN Natural Gas Inc.	1	47,250.0	6,593.0	53,843.0	80.0	120.0
TOTAL NEBRASKA			77,857.0	15,455.0	93,312.0	130.0	221.0

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
NEW MEXICO							
Washington Ranch	El Paso Natural Gas	1	15,000.0	10,114.0	25,114.0	47.3	250.0
Las Milpas	Gas Co. of New Mexico	2	3,704.0	1,300.0	5,004.0	8.0	10.0
Gramma Ridge	Llano, Inc.	1	NA	2,364.0	2,364.0	11.0	50.0
TOTAL NEW MEXICO			18,704.0	13,778.0	32,482.0	66.3	310.0
NEW YORK							
Woodhull	CNG Transmission Corp.	1	17,500.0	18,477.0	35,977.0	86.3	357.0
Dundee	Columbia Gas Transmission Corp.	1	7,840.0	3,520.0	11,360.0	33.0	73.8
Greenwood	Columbia Gas Transmission Corp.	1	2,751.0	574.0	3,325.0	4.0	4.0
North Greenwood	Columbia Gas Transmission Corp.	1	2,104.0	296.0	2,400.0	2.0	4.0
Honeoye	Honeoye Storage Corporation	1	3,913.0	3,475.0	7,388.0	16.2	40.0
Allegany (Limestone)	National Fuel Gas Supply Corp.	1	7,000.0	3,700.0	10,700.0	17.3	13.0
Beech Hill	National Fuel Gas Supply Corp.	1	13,010.0	9,900.0	22,910.0	46.3	61.0
Bennington	National Fuel Gas Supply Corp.	1	3,330.0	1,800.0	5,130.0	8.4	40.0
Colden	National Fuel Gas Supply Corp. q/	1	2,500.0	3,775.0	6,275.0	17.6	40.0
Collins	National Fuel Gas Supply Corp.	1	3,830.0	2,250.0	6,080.0	10.5	12.0
Derby	National Fuel Gas Supply Corp.	1	220.0	250.0	470.0	1.2	2.0
East Independence	National Fuel Gas Supply Corp.	1	4,200.0	2,200.0	6,400.0	10.3	17.0
Holland	National Fuel Gas Supply Corp.	1	1,770.0	900.0	2,670.0	4.2	10.0
Lawtons	National Fuel Gas Supply Corp.	1	970.0	900.0	1,870.0	4.2	10.0
Nashville	National Fuel Gas Supply Corp.	1	5,050.0	3,930.0	8,980.0	18.4	40.0
Perrysburg	National Fuel Gas Supply Corp.	1	3,200.0	1,850.0	5,050.0	8.6	18.0
Sheridan	National Fuel Gas Supply Corp.	1	3,310.0	1,100.0	4,410.0	5.1	10.0
Tuscarora	National Fuel Gas Supply Corp.	1	2,586.0	3,800.0	6,386.0	17.8	40.0
West Independence	National Fuel Gas Supply Corp.	1	4,500.0	7,300.0	11,800.0	34.1	41.0
Wharton	National Fuel Gas Supply Corp.	1	800.0	3,792.0	4,592.0	17.7	40.0
Zoar	National Fuel Gas Supply Corp.	1	1,650.0	600.0	2,250.0	2.8	20.0
Adrian	Steuben Gas Storage Co. r/	1	1,994.0	6,200.0	8,194.0	44.0	59.0
TOTAL NEW YORK			94,028.0	80,589.0	174,617.0	410.0	951.8
OHIO							
Benton	Columbia Gas Transmission Corp.	1	17,945.0	6,855.0	24,800.0	54.0	81.6
Brinker	Columbia Gas Transmission Corp.	1	4,968.0	2,682.0	7,650.0	20.0	43.1
Crawford	Columbia Gas Transmission Corp.	1	41,720.0	13,400.0	55,120.0	92.0	190.0
Guernsey	Columbia Gas Transmission Corp.	1	5,350.0	1,750.0	7,100.0	10.0	42.0
Holmes	Columbia Gas Transmission Corp.	1	13,692.0	5,403.0	19,095.0	35.0	50.0
Laurel	Columbia Gas Transmission Corp.	1	15,899.0	7,401.0	23,300.0	74.0	152.1
Lorain	Columbia Gas Transmission Corp.	1	8,316.0	2,384.0	10,700.0	11.0	81.1
Lucas	Columbia Gas Transmission Corp.	1	36,459.0	23,941.0	60,400.0	144.0	269.9
McArthur	Columbia Gas Transmission Corp.	1	6,430.0	4,470.0	10,900.0	46.0	94.9
Medina	Columbia Gas Transmission Corp.	1	7,427.0	873.0	8,300.0	19.0	66.8
Pavonia	Columbia Gas Transmission Corp.	1	26,946.0	21,654.0	48,600.0	107.0	309.6
Wayne	Columbia Gas Transmission Corp.	1	11,935.0	5,265.0	17,200.0	37.0	106.6
Weaver	Columbia Gas Transmission Corp.	1	32,119.0	17,881.0	50,000.0	119.0	228.4

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
OHIO (cont.)							
Wellington	Columbia Gas Transmission Corp.	1	16,145.0	6,755.0	22,900.0	38.0	103.7
Zane	Columbia Gas Transmission Corp.	1	60.0	30.0	90.0	0.1	0.1
Chippewa	East Ohio Gas Co.	1	8,700.0	1,857.0	10,557.0	100.0	546.0
Columbiana	East Ohio Gas Co.	1	1,731.0	1,380.0	3,111.0	12.0	25.0
Gabor	East Ohio Gas Co.	1	2,499.0	306.0	2,805.0	25.0	108.0
Stark-Summit	East Ohio Gas Co.	1	70,293.0	56,541.0	126,834.0	300.0	1,522.0
Muskie	National Gas & Oil Corp.	1	724.0	245.0	969.0	1.1	3.5
Perry	National Gas & Oil Corp.	1	0.2	973.0	973.2	4.5	30.0
Zane	National Gas & Oil Corp.	1	900.0	309.0	1,209.0	1.4	6.0
TOTAL OHIO			330,258.2	182,355.0	512,613.2	1,250.1	4,060.4
OKLAHOMA							
Sayre	Natural Gas Pipeline Co.	1	53,000.0	33,000.0	86,000.0	360.0	400.0
Ada	NorAm Gas Transmission	1	11,914.0	6,500.0	18,414.0	150.0	300.0
Chiles Dome	NorAm Gas Transmission	1	14,000.0	11,200.0	25,200.0	130.0	265.0
Depew	Oklahoma Natural Gas	1	37,147.0	10,209.0	47,356.0	47.7	500.0
Haskell	Oklahoma Natural Gas	1	9,610.0	2,881.0	12,491.0	13.5	40.0
Osage	Oklahoma Natural Gas	1	1,892.0	882.0	2,774.0	4.1	60.0
West Edmond	Oklahoma Natural Gas	1	30,334.0	9,866.0	40,200.0	46.1	350.0
North Hopeton	Panhandle Eastern Pipe Line Co.	1	11,600.0	3,316.0	14,916.0	15.5	100.0
Enfisco	Phillips Petroleum Co.	1	550.0	1,219.0	1,769.0	5.7	20.0
Greasy Creek	Transok Inc.	1	2,636.0	12,501.0	15,137.0	58.4	330.0
Webb	Williams Natural Gas	1	45,155.0	13,634.0	58,789.0	55.6 s/	226.0
Oswego Lime	ZC Gas Gathering Inc.	1	180.0	115.0	295.0	0.5	2.5
TOTAL OKLAHOMA			218,018.0	105,323.0	323,341.0	887.1	2,593.5
OREGON							
Miller Station	Northwest Natural Gas	1	4,900.0	7,000.0	11,900.0	100.0	100.0
TOTAL OREGON			4,900.0	7,000.0	11,900.0	100.0	100.0
PENNSYLVANIA							
Ellisburg	CNG Transmission Corp. m/	1	45,900.0	64,090.0	109,990.0	299.5	1,176.0
Greenlick	CNG Transmission Corp.	1	29,759.0	28,830.0	58,589.0	134.7	912.0
Harrison	CNG Transmission Corp. n/	1	13,382.0	20,718.0	34,100.0	96.8	350.0
Leidy-Tamarack	CNG Transmission Corp. o/	1	54,222.0	61,201.0	115,423.0	286.0	1,224.0
North Summit	CNG Transmission Corp.	1	14,851.0	11,500.0	26,351.0	53.7	115.0
Oakford	CNG Transmission Corp. p/	1	54,432.0	71,402.0	125,834.0	333.7	776.0
Sabinsville	CNG Transmission Corp.	1	17,958.0	17,697.0	35,655.0	82.7	418.0
Sharon	CNG Transmission Corp.	1	2,530.0	2,300.0	4,830.0	10.7	25.0
South Bend	CNG Transmission Corp.	1	11,530.0	5,810.0	17,340.0	27.1	200.0
Tioga	CNG Transmission Corp.	1	12,000.0	24,000.0	36,000.0	112.1	325.0
Blackhawk	Columbia Gas of Pennsylvania, Inc.	1	1,700.0	1,300.0	3,000.0	5.0	10.0
Artemas A	Columbia Gas Transmission Corp.	1	8,046.0	5,911.0	13,957.0	54.0	151.8
Artemas B	Columbia Gas Transmission Corp.	1	1,203.0	944.0	2,147.0	7.0	16.9

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
PENNSYLVANIA (cont.)							
Donegal	Columbia Gas Transmission Corp.	1	5,628.0	4,272.0	9,900.0	46.0	232.5
Heard	Columbia Gas Transmission Corp.	1	2,200.0	500.0	2,700.0	11.0	2.0
Holbrook	Columbia Gas Transmission Corp.	1	1,143.0	397.0	1,540.0	3.0	5.0
Majorsville Deep	Columbia Gas Transmission Corp.	1	8,163.0	5,060.0	13,223.0	47.0	40.0
Majorsville Shallow	Columbia Gas Transmission Corp.	1	2,383.0	600.0	2,983.0	10.0	14.0
Munderf	Columbia Gas Transmission Corp.	1	10.0	5.0	15.0	0.1	0.2
Bunola	Equitrans, Inc.	1	3,485.0	2,814.0	6,299.0	13.1	200.0
Finleyville	Equitrans, Inc.	1	331.0	285.0	616.0	1.3	42.0
Hunters Cave	Equitrans, Inc.	1	3,252.0	1,642.0	4,894.0	7.7	36.0
Moley	Equitrans, Inc.	1	3,041.0	4,151.0	7,192.0	19.4	70.0
Pratt	Equitrans, Inc.	1	4,717.0	2,254.0	6,971.0	10.5	40.0
Swarts	Equitrans, Inc.	1	492.0	470.0	962.0	2.2	28.0
Swarts West	Equitrans, Inc.	1	856.0	569.0	1,425.0	2.7	19.0
Tepe	Equitrans, Inc.	1	507.0	448.0	955.0	2.1	40.0
Belmouth	National Fuel Gas Supply Corp.	1	600.0	800.0	1,400.0	3.7	4.0
Boone Mountain	National Fuel Gas Supply Corp.	1	1,129.0	930.0	2,059.0	4.3	4.0
Corry	National Fuel Gas Supply Corp.	1	1,050.0	200.0	1,250.0	0.9	20.0
Deerlick	National Fuel Gas Supply Corp.	1	20.0	100.0	120.0	0.5	0.1
Duhring	National Fuel Gas Supply Corp.	1	290.0	105.0	395.0	0.5	1.0
East Branch	National Fuel Gas Supply Corp.	1	9,310.0	4,500.0	13,810.0	21.0	18.0
Galbraith	National Fuel Gas Supply Corp.	1	1,048.0	900.0	1,948.0	4.2	7.0
Hebron	National Fuel Gas Supply Corp. q/	1	702.0	2,550.0	3,252.0	11.9	25.0
Henderson	National Fuel Gas Supply Corp.	1	2,808.0	2,000.0	4,808.0	9.3	15.0
Keelor	National Fuel Gas Supply Corp.	1	1,550.0	1,330.0	2,880.0	6.2	20.0
Markle	National Fuel Gas Supply Corp.	1	180.0	850.0	1,030.0	4.0	6.0
Owl's Nest	National Fuel Gas Supply Corp.	1	2,110.0	650.0	2,760.0	3.0	1.0
Queen	National Fuel Gas Supply Corp.	1	645.0	300.0	945.0	1.4	2.0
St. Mary's	National Fuel Gas Supply Corp.	1	311.0	170.0	481.0	0.8	1.0
Summit	National Fuel Gas Supply Corp.	1	2,600.0	1,600.0	4,200.0	7.5	30.0
Swede Hill	National Fuel Gas Supply Corp.	1	800.0	300.0	1,100.0	1.4	5.0
Wellendorf	National Fuel Gas Supply Corp.	1	678.0	348.0	1,026.0	1.6	5.0
Wharton	National Fuel Gas Supply Corp.	1	10,650.0	11,647.0	22,297.0	36.7	260.0
Meeker	North Penn Gas Co.	1	1,500.0	3,000.0	4,500.0	14.0	25.0
Palmer	North Penn Gas Co.	1	6,000.0	10,000.0	16,000.0	46.7	80.0
Colvin	Peoples Natural Gas Co.	1	1,883.0	510.0	2,393.0	24.0	25.0
Gamble Hayden	Peoples Natural Gas Co.	1	1,727.0	1,122.0	2,849.0	7.0	20.0
Murrysville	Peoples Natural Gas Co.	1	1,716.0	1,530.0	3,246.0	18.0	35.0
Patton	Peoples Natural Gas Co.	1	85.0	63.0	148.0	0.3	8.2
Rager Mountain	Peoples Natural Gas Co.	1	11,193.0	9,300.0	20,493.0	63.0	110.0
Truittsburg	Peoples Natural Gas Co.	1	1,549.0	2,142.0	3,691.0	18.0	35.0
Webster	Peoples Natural Gas Co.	1	621.0	551.0	1,172.0	5.0	15.0
TOTAL PENNSYLVANIA			366,476.0	396,668.0	763,144.0	1,994.0	7,245.7

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
TEXAS							
Loop	American Gas Storage, LP	1	2,047.9	9,952.1	12,000.0	90.0	200.0
North Felmac	American Gas Storage, LP	1	745.6	5,254.4	6,000.0	150.0	140.0
Salado	American Gas Storage, LP	3	1,000.0	3,000.0	4,000.0	60.0	260.0
Stratton Ridge	Amoco Gas Company	3	1,080.0	1,770.0	2,850.0	80.0	250.0
Ambassador	Aquila Gas Pipeline	1	2,400.0	1,600.0	4,000.0	15.0	30.0
Pottsville	Aquila Gas Pipeline	1	3,000.0	5,750.0	8,750.0	26.9	35.0
Spindletop	Centana Intrastate Pipeline Co. j/	3	1,818.9	5,200.0	7,018.9	130.0	600.0
Janellen	City of Brady, Texas	1	NA	NA	25.0	0.2	0.4
Pickton	Delhi Gas Pipeline Corp.	1	2,248.0	3,852.0 l/	6,100.0	18.0	15.0
Stratton Ridge	Dow Chemical Company	3	5,900.0	7,300.0	13,200.0	80.0	380.0
West Rotherwood	Eastex Gas Storage	1	600.0	400.0	1,000.0	40.0	40.0
North Dayton	HNG Storage Company	3	1,500.0	3,300.0	4,800.0	250.0	500.0
Bammel	Houston Pipe Line Co.	1	65,500.0	52,200.0	117,700.0	300.0	1,239.0
Ambassador	Lone Star Gas Co.	1	660.0	1,620.0	2,280.0	9.2	40.0
Bethel	Lone Star Gas Co.	3	3,000.0	7,100.0	10,100.0	132.0	600.0
Hill	Lone Star Gas Co.	1	2,250.0	8,615.0	10,865.0	43.0	68.0
Lake Dallas	Lone Star Gas Co.	1	1,450.0	2,825.0	4,275.0	17.0	98.0
LaPan	Lone Star Gas Co.	1	1,070.0	3,425.0	4,495.0	40.0	120.0
Leeray	Lone Star Gas Co.	1	2,175.0	4,775.0	6,950.0	12.5	20.0
New York City	Lone Star Gas Co.	1	2,075.0	5,290.0	7,365.0	45.0	95.0
Pecan Station	Lone Star Gas Co.	1	900.0	1,310.0	2,210.0	7.5	38.0
Tri-Cities	Lone Star Gas Co.	1	9,950.0	25,353.0	35,303.0	154.0	325.0
Hilbig	Lower Colorado River Authority	1	1,069.0	4,931.0	6,000.0	66.0	100.0
North Lansing	Natural Gas Pipeline Co.	1	87,475.0	68,525.0	156,000.0	450.0	1,100.0
Clemens	Phillips Petroleum Co.	3	1,042.0	1,808.0	2,850.0	38.0	55.0
Lone Camp 600	Southwestern Gas Pipeline Co.	1	267.5	804.5	1,072.0	27.5	27.5
West Clear Lake	Tejas Gas Storage Co.	1	30,000.0	95,000.0	125,000.0	80.0	225.0
Moss Bluff	Tejas Power Corp.	3	1,718.0	5,575.0	7,293.0	150.0	900.0
Markham	Texas Brine Corp.	3	1,300.0	6,400.0	7,700.0	120.0	250.0
Bethel	Texas Utilities Fuel Co.	3	3,810.0	8,810.0	12,620.0	75.0	350.0
South Bryson	Texas Utilities Fuel Co.	1	2,100.0	5,500.0	7,600.0	100.0	125.0
Worsham Steed	Texas Utilities Fuel Co.	1	3,100.0	12,900.0	16,000.0	60.0	25.0
Wilson	Valero Energy Corp.	3	4,400.0	7,200.0	11,600.0	350.0	800.0
Katy	Western Gas Resources Storage	1	6,873.0	20,127.0	27,000.0	400.0	400.0
TOTAL TEXAS			254,524.9	397,472.0	651,996.9	3,616.8	9,450.9
UTAH							
Clay Basin	Questar Pipeline Co.	1	61,000.0	42,000.0	103,000.0	300.0	700.0
Chalk Creek	Questar Pipeline Co.	2	980.0	256.0	1,236.0	10.0	35.0
Coalville	Questar Pipeline Co.	2	2,100.0	692.0	2,792.0	15.0	75.0
TOTAL UTAH			64,080.0	42,948.0	107,028.0	325.0	810.0
WASHINGTON							
Jackson Prairie	Washington Natural Gas Co. k/	2	18,800.0	15,100.0	33,900.0	450.0	450.0
TOTAL WASHINGTON			18,800.0	15,100.0	33,900.0	450.0	450.0

INVENTORY OF U.S. STORAGE OPERATIONS

State / Field	Owner / Operator	Reservoir Type	Base-Gas Requirement (MMcf)	Working Gas Capacity (MMcf)	Total Capacity (MMcf)	Total Injection (MMcf/d)	Maximum Deliver-ability (MMcf/d)
WEST VIRGINIA							
Bridgeport	CNG Transmission Corp.	1	5,173.0	4,182.0	9,355.0	19.5	76.0
Fink-Kennedy-Lost Creek	CNG Transmission Corp.	1	84,320.0	61,590.0	145,910.0	287.8	900.0
Racket-Newburne	CNG Transmission Corp.	1	4,811.0	4,446.0	9,257.0	20.8	59.0
Terra Alta	Columbia Gas Transmission Corp.	1	30,527.0	9,636.0	40,163.0	68.0	162.2
Terra Alta South	Columbia Gas Transmission Corp.	1	13,222.0	3,378.0	16,600.0	14.0	69.2
Victory A	Columbia Gas Transmission Corp.	1	4,070.0	3,080.0	7,150.0	35.0	43.1
Victory B	Columbia Gas Transmission Corp.	1	14,463.0	9,537.0	24,000.0	92.0	134.8
Browns Creek	Columbia Gas Transmission Corp.	1	3,472.0	95.0	3,567.0	10.0	12.8
Cleveland	Columbia Gas Transmission Corp.	1	6,970.0	200.0	7,170.0	15.0	1.6
Coco A	Columbia Gas Transmission Corp.	1	26,221.0	18,279.0	44,500.0	166.0	217.8
Coco B	Columbia Gas Transmission Corp.	1	7,316.0	2,384.0	9,700.0	49.0	205.4
Coco C	Columbia Gas Transmission Corp.	1	11,012.0	6,258.0	17,270.0	75.0	146.9
Derricks Creek	Columbia Gas Transmission Corp.	1	4,412.0	1,788.0	6,200.0	26.0	24.7
Glady	Columbia Gas Transmission Corp.	1	19,867.0	10,133.0	30,000.0	70.0	303.5
Grapevine A	Columbia Gas Transmission Corp.	1	935.0	200.0	1,135.0	2.0	4.1
Grapevine B	Columbia Gas Transmission Corp.	1	18.0	8.0	26.0	0.1	0.2
Hunt	Columbia Gas Transmission Corp.	1	5,186.0	894.0	6,080.0	16.0	8.8
Lanham	Columbia Gas Transmission Corp.	1	3,211.0	1,589.0	4,800.0	19.0	27.4
Ripley	Columbia Gas Transmission Corp.	1	15,105.0	8,295.0	23,400.0	64.0	141.2
Rockport	Columbia Gas Transmission Corp.	1	5,378.0	2,782.0	8,160.0	39.0	139.5
Sissonville	Columbia Gas Transmission Corp.	1	648.0	200.0	848.0	7.0	7.1
Raleigh	Cranberry Pipeline Co.	1	600.0	1,000.0	1,600.0	7.0	20.0
X-1	Cranberry Pipeline Co.	1	200.0	2,750.0	2,950.0	40.0	40.0
Comet	Equitrans, Inc.	1	2,361.0	2,776.0	5,137.0	13.0	67.0
Hays	Equitrans, Inc.	1	87.0	93.0	180.0	0.4	8.0
Logansport	Equitrans, Inc.	1	758.0	2,504.0	3,262.0	11.7	38.0
Maple Lake	Equitrans, Inc.	1	1,391.0	738.0	2,129.0	3.4	8.0
Mobley	Equitrans, Inc.	1	1,624.0	3,486.0	5,110.0	16.3	43.0
Rhodes	Equitrans, Inc.	1	4,620.0	3,555.0	8,175.0	16.6	66.0
Shirley	Equitrans, Inc.	1	6,019.0	2,816.0	8,835.0	13.2	40.0
Skin Creek	Equitrans, Inc.	1	828.0	837.0	1,665.0	3.9	35.0
Augusta	Hampshire Gas Co.	1	4,428.0	1,180.0	5,608.0	5.5	24.0
Little Capon	Hampshire Gas Co.	1	4,965.0	1,316.0	6,281.0	6.1	26.0
TOTAL WEST VIRGINIA			294,218.0	172,005.0	466,223.0	1,232.3	3,100.3
WYOMING							
Bunker Hill	Northern Gas Co. of Wyoming	1	4,050.0	1,450.0	5,500.0	6.0	4.0
Kirk Ranch	Northern Gas Co. of Wyoming	1	1,440.0	580.0	2,020.0	3.0	2.0
Oil Springs	Northern Gas Co. of Wyoming	1	12,500.0	9,700.0	22,200.0	25.0	30.0
Leroy	Questar Pipeline Co.	2	5,500.0	836.0	6,336.0	20.0	65.0
Billy Creek	Williston Basin Interstate Pipeline Co.	1	2,401.3	542.2	2,943.5	4.5	5.0
Elk Basin	Williston Basin Interstate Pipeline Co.	1	34,825.7	28,379.4	63,205.1	50.0	112.0
TOTAL WYOMING			60,717.0	41,487.6	102,204.6	108.5	218.0
TOTAL UNITED STATES			4,286,959.9	3,500,997.8	7,787,957.7	29,816.1	70,337.8

Footnotes:

a/ KNI applied for authority to abandon these facilities by transfer to affiliate KN Natural Gas.

b/ Currently inactive.

c/ Jointly owned by Southern Natural Gas and Tennessee Gas Pipeline.

d/ 87.5% owned by MGS Storage Services, a wholly owned subsidiary of Mobile Gas Service Corp., and 12.5% owned by Olin Corp.

e/ Subsidiary of Texaco.

f/ Jointly owned by ANR Storage and MCN Corp. ANR Storage acts as operator.

g/ Owned by Consumers Power Company.

h/ Owned by Michigan Consolidated Gas.

i/ Owned by Chevron.

j/ Owned by Panhandle Eastern Pipe Line Co.

k/ Equally owned by Washington Natural Gas, Washington Water Power, and Northwest Pipeline.

l/ Determined by multiplying maximum injection rate by 214 days of injection.

m/ CNG owns 39% and operates the facility, Tennessee Gas Pipeline owns 39%, and National Fuel Gas Supply owns 22%.

n/ Equally owned by CNG Transmission and Tennessee Gas Pipeline.

o/ CNG owns 50% and operates the facility, Texas Eastern Transmission and Transcontinental Gas Pipe Line each own 25%.

p/ Equally owned by CNG Transmission and Texas Eastern Transmission.

q/ Co-ownership between National Fuel Gas Supply and Tennessee Gas Pipeline.

r/ Equally owned by Arlington Storage Corporation and ANR Storage Company.

s/ Injection varies with inventory level. Figures provided by Williams are maximum sustainable tariff injection levels.

Reservoir Type

1: Depleted reservoir

2: Aquifer

3: Salt cavern

4: Converted coal cavern

5: Depleted oil field

Sources

Oil & Gas Journal (9/12/94) and information provided by the Texas Railroad Commission, the Michigan Public Service Commission, individual companies, industry trade press, Federal Energy Regulatory Commission (FERC) Orders and Form No. 2, and the American Gas Association Survey of Underground Gas Storage Facilities (1993).

INVENTORY OF CANADIAN UNDERGROUND STORAGE FACILITIES

Province	Field	Operator	Reservoir Type	Working Gas Capacity (MMcf)	Maximum Deliver–ability (MMcf/d)
BC	Aiken Creek	Unocal Canada	1	36,000.0	250.0
AB	Dunvegan	Anderson Exploration	1	12,000.0	35.0
AB	Suffield	Alberta Energy Company	1	70,000.0 a/	1,600.0 a/
AB	Carbon	Canadian Western Natural Gas	1	38,000.0	470.0
AB	Fort Saskatchewan	Northwestern Utilities	2	3,300.0	470.0
AB	Crossfield b/	Amoco	1	40,000.0	500.0
SA	All Fields	Transgas	2	39,000.0	570.0
ON	Tecumseh	Consumers Gas	1	79,000.0	1,300.0
ON	Dawn	Union Gas	1	122,000.0	1,742.0
QC	Pointe–du–Lac	Intragaz	1	600.0	42.0
TOTAL CANADA				439,900.0	6,979.0

a/ 1994 year–end capacity reported in AEC's Annual Report.
b/ Jointly owned by Amoco (40%), TransCanada PipeLines (40%) and Alberta Natural Gas (20%).

Reservoir Type
1: Depleted reservoir
2: Salt cavern

Source: Natural Resources Canada, Natural Gas Storage: A Canadian Perspective (November 1994).

SCHEDULE 2:

Schedule 3
SUMMARY OF PROPOSED GAS STORAGE PROJECTS, BY REGION

legion and Project Name	County, State	Developer / Owner	Type*	Maximum Capacity Working (Bcf)	Withdrawal (MMcfd)	Injection (MMcfd)
DLE ATLANTIC						
ca Phase 1	Steuben, NY	JMC / Equitrans / NGC / Union Gas	3	2.00	320	160
ca Phase 2	Steuben, NY	JMC / Equitrans / NGC / Union Gas	3	2.00	100	50
ca Phase 3	Steuben, NY	JMC / Equitrans / NGC / Union Gas	3	1.00	80	40
uta Phase 1	Schuyler, NY	JMC / Equitrans / NGC / Union Gas	3	2.00	320	160
uta Phase 2	Schuyler, NY	JMC / Equitrans / NGC / Union Gas	3	2.00	120	50
uta Phase 3	Schuyler, NY	JMC / Equitrans / NGC / Union Gas	3	1.00	60	40
eca Lake	Schuyler, NY	New York State Electric & Gas	3	0.80	80	20
nas Corners	Steuben, NY	Arlington Associates LP / ANR NE Gas Storage	1	5.30	70	33 a/
kins Glen	Schuyler, NY	New York State Electric & Gas / ANR Storage	3	2.00	200	NA
el Fields–Limestone	Cattaraugus, NY	Laurel Fields Storage / National Fuel Gas	1	7.00	77	51 a/
el Fields–Callen Run	Jefferson, PA	Laurel Fields Storage / National Fuel Gas	1	12.10	130	120 a/
-1 / Tioga	Tioga, PA	Market Hub Partners b/	3	10.00	500	125
rside	Greene & Fayette, PA	Equitrans / TETCO	1	3.10	28	28
TOTAL				50.30	2,085	877
TH ATLANTIC						
'ille	Smyth, VA	Tenneco Energy / Virgina Gas Co.	3	2.00	200	NA
T NORTH CENTRAL						
son City	Williamson, IL	Central Illinois Public Service	1	0.50	10	7
khawk	Vigo, IN	Hamilton Natural Gas	2	5.28	44	38 a/
dal	Pike, IN	Har–ken	1	0.40	5	3
ds Lacs	St. Clair	CMS Energy / Market Hub Partners b/, d/	3	3.00	150	NA
aska 30	Kalkaska, MI	CMS Energy	1	17.00	200	150
3	Calhoun, MI	Panhandle Stor. / MG Ventures / Howard Energy	1	3.80	30	NA
gston Expansion	Livingston, MI	Panhandle Eastern Pipe Line	1	0.80	NA	NA
ington 10	Washington, MI	W–10 Holdings / ANR Washington 10 Co.	1	16.00	800	250
TOTAL				46.78	1,239	448
T NORTH CENTRAL						
a Gas Storage Phase 1	Kiowa, KS	HNG / Williams Underground Gas Storage	3	1.40	125	100
a Gas Storage Phase 2	Kiowa, KS	HNG / Williams Underground Gas Storage	3	1.40	125	50
a Gas Storage Phase 3	Kiowa, KS	HNG / Williams Underground Gas Storage	3	1.40	125	50
a Gas Storage Phase 4	Kiowa, KS	HNG / Williams Underground Gas Storage	3	1.40	125	50
wille	Kiowa, KS	Enron Storage	3	5.00	500	250
nville–Waseca Expansion	Le Sueur, MN	Minnegasco	2	1.20	NA	NA
TOTAL				11.80	1,000	500
SOUTH CENTRAL						
bier	Muhlenberg, KY	Har–ken	3	0.90	6	4 a/
reek	Spencer, KY	Har–ken	1	6.50	50	33 a/
Hope	Nelson, KY	Har–ken	1	0.25	5	3 a/
ı St. Charles	Hopkins, KY	Har–ken	1	0.70	6	4 a/
narles	Hopkins, KY	Har–ken	1	14.75	120	80 a/
ence Phase 3	Covington, MS	Transcontinental Gas Pipe Line	3	2.90	NA	NA
sburg Phase 2	Forrest, MS	Crystal Oil	3	2.10	210	40
1 / Hazelhurst Phase 1	Copiah, MS	Market Hub Partners (b/) / TETCO (25%)	3	6.00	600	200
1 / Hazelhurst Phase 2	Copiah, MS	Market Hub Partners (b/) / TETCO (25%)	3	3.00	300	100
TOTAL				37.10	1,297	464

Schedule 3
SUMMARY OF PROPOSED GAS STORAGE PROJECTS, BY REGION

Region and Project Name	County, State	Developer / Owner	Type*	Maximum Capacity		
				Working (Bcf)	Withdrawal (MMcfd)	Injection (MMcfd)
WEST SOUTH CENTRAL						
Chacahoula	Lafourche, LA	Texas Brine Corporation	3	2.70	250	70
Chandeleur	Offshore, LA	Entre Energy	1	25.60	300	300
Cotton Plant	Caldwell, LA	Swift / NGC	1	16.00	450	173
HNG Sulphur Mines	Calcasieu, LA	HNG Stroage Company	3	8.00	400	150
Jefferson Island	Iberia & Vermillion, LA	Equitable Resources	3	3.00	300	150
LA–1 Egan Phase 1	Acadia, LA	Market Hub Partners b/	3	4.00	400	150
LA–1 Egan Phase 2	Acadia, LA	Market Hub Partners b/	3	4.00	400	150
LA–1 Egan Phase 3	Acadia, LA	Market Hub Partners b/	3	4.00	400	150
Napoleonville Phase 2	Assumption, LA	Enron Storage	3	3.00	200	NA
Ouachita River	Union & Lincoln, LA	Ouachita River Partners / Leucadia Financial	1	27.00	550	250
Manchester	Grant, OK	Manchester Pipeline Corp.	1	15.00	250	100
Okfuskee	Okfuskee, OK	Unigas Corp.	1	30.00	600	200
Atkinson Gas Storage	Live Oak, TX	Kebo Oil / Atkinson Gas	1	28.00	400	300
Bethel	Anderson, TX	Bethel Gas Storage	3	3.70	500	300
Moss Bluff Phase 3	Liberty, TX	CMS Energy / Market Hub Partners b/	3	2.00	300	50
Nichols Station Plant	NA	Southwestern Public Service	3	3.00	300	150 a
Spindeltop (Sabine–Cavern 1)	Jefferson, TX	Sabine Gas Transmission	3	3.50	600	240
Spindletop (Expansion)	Jefferson, TX	Centana / Panhandle Eastern	3	6.00	NA	NA
Stratton Ridge	Brazoria, TX	MG Storage	3	7.25	250	100
TOTAL				195.75	6,850	2,983
ROCKY MOUNTAIN						
Pataya Phase 1	Mohave, AZ	Golden Storage / Sphinx	3	6.00	250	120
Pataya Phase 2	Mohave, AZ	Golden Storage / Sphinx	3	6.00	250	120
Tranam Phase 1	Mohave, AZ	Tran Am Energy	3	11.00	1,000	NA
Tranam Phase 2	Mohave, AZ	Tran Am Energy	3	9.00	1,000	NA
Douglas Creek	Rio Blanco, CO	Williams Storage Company	1	10.00	200	250
Rush Creek	Weld, CO	Williams Storage Co. / Piceance Natural Gas	1	3.50	120	100
Young	Morgan, CO	Colorado Interstate Gas et al.	1	5.30	200	100 a
Baker Expansion	Fallon, MT	Williston Basin / MDU	1	NA	40	20 a
Clay Basin Expansion	Daggett, UT	Questar Pipeline	1	4.30	63	NA
Elk Basin Retrofit	Park, WY	Williston Basin / MDU	1	5.50	27	27 a
Southwest Wyoming	Uinta, UT	Questar Pipeline	3	5.00	500	300
TOTAL				65.60	3,650	1,037
PACIFIC SOUTHWEST						
Lodi	San Joaquin, CA	Northern California Gas Storage c/	1	12.00	500	250
Putah Sink	Sacramento, CA	Nahama & Weagant Energy	1	22.70	600	180
Ten Section	Kern, CA	McFarland Energy	1	25.00	500	NA
Wild Goose	Butte, CA	NA	1	12.00	600	200
TOTAL				71.70	2,200	630
PACIFIC NORTHWEST						
Jackson Prairie Phase 1	Lewis, WA	Northwest PL / WA Natural Gas / WA Water Power	2	5.00	40	20 a
Jackson Prairie Phase 2	Lewis, WA	Northwest PL / WA Natural Gas / WA Water Power	2	5.00	40	20 a
TOTAL				10.00	80	40
TOTAL U.S.				491.03	18,601	6,979

* Type: (1) depleted reservoir, (2) aquifer, (3) salt cavern.
a/ Estimated
b/ Partnership of Tejas Power, NIPSCO, New Jersey Resources, Miami Valley Leasing (Dayton Power & Light affiliate) and PSE&G.
c/ Partnership between HNG Storage and Sofregaz.
d/ St. Clair Pipelines and Enron Gas Services Corp. also have ownership interests.

Source: U.S. Department of Energy and Foster Associates, Inc.

Schedule 4

SUMMARY OF NEW CANADIAN STORAGE PROJECTS

Company	Project Name	Province	Type*	Working Gas Added (Bcf)	Deliver– ability Added (MMcfd)
Canadian Western Natural Gas	Carbon	AB	1	10.0	100
AECO C "I" Pool	Suffield	AB	1	15.0	200 a/
Amoco	Crossfield	AB	1	0.0	600
Union/Enron	Empress	AB	2	5.0	1,000
Anderson Exploration	Dunvegan	AB	1	NA	70
Altai Resources	Lac St. Pierre	QC	1	29.0	NA
Transgas	Melville	SA	2	2.7	0
TOTAL				61.7	1,970

Type = depleted field (1) or salt cavern (2)

/ Adjusted to exclude expansion online at the end of 1994.

ource: Natural Resources Canada, Natural Gas Storage: A Canadian Perspective, November 1994

Schedule 5
SUMMARY OF MAJOR NORTH AMERICAN MARKET HUBS **

ub/Market Center	Operator/Owner	Interconnecting Pipelines	Services Offered: Parking	Wheeling	Loaning	Title Transfer	Electronic Trading	Daily Capacity (Bcf)	Storage Capacity (Bcf)
MIDDLE ATLANTIC									
NG/Sabine Center	CNG Transmission/ Sabine Pipe Line	CNG system, interconnects with TGT, ANR, Tennessee, TETCO, Appalachian points, Iroquois, NFGS, Transco, Canadian supplies @ Niagara	x	x		x			259.0
llisburg–Leidy, PA	Enerchange a/	CNG, Columbia Gas, NFGS, Tennessee, TETCO, Transco	x	x	x	x		>5.0	>5.0
ational Fuel, NY & PA	National Fuel Gas Supply	Proposed use of entire system, interconnects with Tennessee, TETCO, CNG, and Columbia	x	x					
ew York, NY	Brooklyn Union	NY Facilities System (Brooklyn Union, ConEd, LILCO), links to Iroquois, Tennessee, TETCO, Transco & Algonquin; upstream to CNG				x			
AST NORTH CENTRAL									
hicago, IL	Enerchange a/	NIGAS system, interconnects with ANR, Midwestern, NGPL and Northern Natural	x	x	x	x			165.0
olumbia Energy Market Center	Columbia Gas System	Columbia Gas, Columbia Gulf	x	x		x	x		
ands Lacs/ Marysville, MI	CMS Gas Trans. & Storage, Market Hub Partners c/, St.Clair Pipelines, (Union Gas), Enron Gas Services	Union Gas, GLGT, ANR, Trunkline, PEPL, MichCon, Southeastern MI Gas	x	x	x	x	x		5.0
banon, OH	East Ohio Gas	ANR, CNG, TETCO, TGT PEPL, Columbia Gas					x	3.0	
EST NORTH CENTRAL									
d–Continent, KS	Western Resources	Western Resources system, interconnects with ANR, CIG, KNI, Mesa Operating, NGPL, Northern Natural, PEPL, Williams	x	x					
ST SOUTH CENTRAL									
sciusko, MS		Koch Gateway, Southern, TETCO		x					
EST SOUTH CENTRAL									
ffalo Wallow, TX & OK	KN Interstate	ANR, Delhi, El Paso, NGPL, NorAm, PEPL, Red River, Transok, TexCon/Transok, Transwestern, Westar, Williams	x	x		x	x	0.2	
rthage, TX	Union Pacific Fuels (East TX Gas Systems/ EasTrans)	East TX Gas System/EasTrans header with connections to Delhi, Koch Gateway, Lone Star MidCon Sonat Venture, NorAm, Southern, Tejas Gas, Tennessee TETCO, TGT, Amoco, Crystal, Verado, TX Gas Gathering and Valero; separate interconnects with Gulf States, MRT, NGPL and Texoma		x		x	x	1.0	

Schedule 5
SUMMARY OF MAJOR NORTH AMERICAN MARKET HUBS **

Hub/Market Center	Operator/Owner	Interconnecting Pipelines	Services Offered: Parking	Wheeling	Loaning	Title Transfer	Electronic Trading	Daily Capacity (Bcf)	Storage Capacity (Bcf)
WEST SOUTH CENTRAL (continued)									
Gulf Coast Star Center, LA	Texaco b/	Bridgeline Gas, Sabine Pipe Line (see Henry Hub), ANR, TETCO, LA Gas Service, LA Intrastate Gas, Neches, Tejas Gas, Winnie PL, Houston PL, Channel Industries, FGT	x	x	x	x	x		
Henry (Erath), LA	Sabine Pipe Line	Koch Gateway, Southern, NGPL, TGT, Transco, Trunkline, Columbia Gulf, Dow Intrastate, Sabine, Acadian, LA Resources, Sea Robin, Texaco Gas Gathering		x		x		19.0	
Houston, TX	Eastex Energy	Koch Gateway, NGPL, Tennessee, Trunkline, with interconnects through Enercorp (Eastex) to Houston PL @ Bammel storage, MidCon TX, Tejas Gas, TETCO, Transco; connections to Valero; includes Rotherwood		x		x			
Katy, TX	Western Gas Resources	Tennessee, Transco, Trunkline, Koch Gateway, NGPL, Amoco, Dow–Tenngasco, Houston PL Lone Star, MidCon TX, Oasis, Tejas Gas, Exxon	x	x	x	x	x	0.8	17.0
Louisiana	LA Resources	LA Resources, interconnects with Acadian, ANR, Bridgeline, Columbia Gulf Cypress, Dow Intrastate, FGT, Sabine, Koch Gateway, LA Gas Service, Sea Robin, LA Intrastate Gas, NGPL, Oxy, Southern, Stingray, Tennessee, TETCO, TGT, Transco, Trunkline	x	x		x			
Monroe, LA	Matrix	Koch Gateway, NorAm, TGT, TETCO, Tennessee, Southern, MRT, Trunkline, Columbia Gulf, ANR, BP Gas, Mid–LA Gas, LA Intrastate Gas, Delhi							
Moss Bluff, TX	Market Hub Partners c/	Channel Industries, Houston PL MidCon TX, NGPL, Tejas Gas, TETCO, Trunkline (proposed)		x		x	x		
Perryville, LA	NorAm Gas Transmission	MRT, NorAm, ANR, Columbia Gulf, Koch Gateway, Southern, TETCO, Tennessee, TGT, Trunkline	x	x	x	x	x	1.5	
South Texas	TransTexas	Channel, Houston PL, Koch Gateway, NGPL, Tejas Gas, Tennessee, Transco, Trunkline, Valero, with interconnects to FGT, TETCO		x		x		2.7	
Waha/Permian Basin, TX	Valero	El Paso, Northern Natural, Transwestern, NGPL, Lone Star, Delhi, Westar, Oasis	x	x	x	x	x	1.2	
Waha Inter–change, TX	Encina Transmission	Encina header with interconnects to Lone Star, Northern Natural, Transwestern, Valero/TUFCO, Westar/Meridian		x					
Waha Header, TX	Lone Star	Oasis PL header connects with Delhi, El Paso, Lone Star, Mobil, NGPL, Red River, Transwestern, TUFCO, Valero, Westar		x					
Waha/Midland, TX		American Oil & Gas, BP Gas, El Paso, Northern Natural, Oasis PL, Transwestern, Lone Star, Koch Gateway, NGPL, Seagull, Oasis PL, Delhi, Red River, Valero		x					

Schedule 5
SUMMARY OF MAJOR NORTH AMERICAN MARKET HUBS **

Hub/Market Center	Operator/Owner	Interconnecting Pipelines	Services Offered: Parking	Wheeling	Loaning	Title Transfer	Electronic Trading	Daily Capacity (Bcf)	Storage Capacity (Bcf)
ROCKY MOUNTAIN									
Blanco, NM	Transwestern	El Paso, Northwest, Transwestern, Gas Co of NM, Western Gas Supply							
Rocky Mountain Market Center/ Opal, WY	Williams Energy	CIG, Kern River, Northwest				x	x	0.6	
Wamsutter, WY	Union Pacific	Williams, Union Pacific							
Western Market Center/Muddy Creek, WY	Tenneco, Questar, Entech (MT Power), Union Pacific	CIG, Kern River, Northwest, Overland Trail, Questar Altamont (proposed)	x	x	x	x	x	1.8	
PACIFIC									
California Energy Hub (Cal-Hub)/ Southern CA Gas	Enerchange a/	SOCAL system inconnects with El Paso, El Paso, Kern River, Mojave, PG&E, Transwestern, Southwest Gas, SDG&E	x	x	x	x			112.0
Pacific Gas Trans.	Pacific Gas Trans./ Pacific Gas & Elec.	Use of entire system as line pack-based hub	x		x				
CANADA									
AECO C Hub	Alberta Energy	NOVA, TransCanada	x	x	x	x		1.3	66.0
Intra-Alberta	NGX					x	x		
NOVA	NOVA					x	x		
Union Gas Service	Union Gas	Union Gas system interconnects with TransCanada, GLGT, PEPL, MichCon	x	x	x	x		300.0	12.0

NOTES: ** Other market centers include Niagara NY, Pittsburgh PA, Tuscola IL, Detroit MI, Guymon OK, Houston Ship Channel TX, Longview/Atlanta TX, and Topock AZ.

a/ Hub operations formerly administered by Hub Services, Inc. (HSI), an NGC affiliate. Enerchange, developed by affiliates of NGC, NICOR, Pacific Enerprises and National Fuel Gas, succeeds and expands services previously offered by HSI.

b/ The Gulf Coast Star Center utilizes all of Texaco's LA facilities, including 4 processing plants, Sorrento storage, and over 50 pipeline interconnects.

c/ Partnership of Tejas Power, NIPSCO, New Jersey Resources, Miami Valley Leasing (Dayton Power & Light affiliate) and PSE&G.

SOURCES: FERC, Office of Economic Policy, Importance of Market Centers, August 21, 1991
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