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GAS STORAGE

Some Technical and Economic Aspects Of Underground Gas Storage

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Abstract

This article deals with comparative technical and economic aspects of conventional and some nonconventional methods of storing gas. Conventional gas storage was first begun by injection and subsequent production of gas in a depleted gas field in Ontario, Canada in 1915.[1] Conventional methods also include storage in depleted oil fields and aquifers. Aquifer storage was first introduced into the United States with the injection of gas into the Galesville aquifer at Herscher, Ill. in 1953. Nonconventional methods include storage of gas in coal mines, mined salt caverns, steel pipe and earth strata with artificial caprock and lateral confinement created by impermeable chemical grouts.[2] Another method is storage of liquified gas in frozen earth or mined caverns.[3] The growth and status of gas storage in the U. S. and Western Europe is summarized and technical and economic factors are related to the probable future direction and growth of storage in these areas.

Introduction

Major markets for natural gas in the U. S. and Western Europe often consume more gas during the four coldest winter months than during the remainder of the year. Peak winter demand usually exceeds three times the average summer consumption rate. Unless some form of near-market gas storage is used, large enough pipelines must be installed from producing fields to handle this peak winter demand. The resulting pipeline load factor, defined as average yearly flow rate divided by maximum or design rate, is then low and gas transmission costs are high. Near-market storage of gas serves as a buffer to allow a high pipeline load factor. Experience shows that the savings in transmissions costs are generally two to three times the cost of storage.

Technical Aspects of Underground Gas Storage

In addition to the basic requirements of size and proximity to market, a gas storage reservoir must possess an impervious roof and lateral confinement. Depleted reservoirs offer a caprock of guarantied integrity and sufficient structural closure or other lateral confinement to contain the gas. Partly for these reasons, we prefer to store gas whenever possible in depleted fields rather than in aquifers. Abandoned or poorly cemented wells are sources of gas leakage in depleted fields. In many cases, considerable time and expense are necessary to locate and recondition or plug such wells. In general, however, this is cheaper than the initial drilling and completion of wells in developing aquifer storage.

In developing aquifer storage, extensive geological and hydrological work is performed to investigate the adequacy of caprock integrity and structural or lateral confinement. In spite of this effort, many of the aquifer storage reservoirs in the U. S. leak gas to shallower formations. Extensive efforts failed to locate a source of the leak at the Galesville aquifer project in Herscher, Ill., and in 1960 over 13 MMcf/D were circulated from shallower formations back into the Galesville aquifer.[4] This amounted to 4.6 Bcf/year,* a significant fraction of the 34.2 Bcf stored at the end of that year.

Delivery capacity is one of the most important considerations in designing a storage reservoir. For a given number of wells, the delivery rate is proportional to reservoir pressure which, in turn, is proportional to gas in place. This presents a problem since the largest required delivery rates often occur in the latter part of the winter when gas reserves are lowest. In the case of a dry gas reservoir this problem can be solved rather simply since the known, constant reservoir pore volume allows easy prediction of pressure from a given gas withdrawal schedule. From the predicted pressure behavior during the season, delivery capacity can be calculated for a given number of wells or the number of wells necessary to ensure a given delivery capacity.

Water movement in aquifer and water drive fields considerably complicates the calculation of pressure as a function of gas withdrawn over the winter season. In this case, reservoir pore volume can vary considerably, growing with spring and summer injections and shrinking with winter withdrawals. Methods of calculating this water movement and relating it to reservoir pressure and withdrawals have been extensively studied and are described in the literature.[5] A recent technique for characterizing aquifer water movement by applying linear programming

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[1]References given at end of paper.

*Billion cubic feet.

to reservoir operating data is also described in the literature.[6]

Delivery rates from single wells in storage fields vary typically between 1 and 30 MMcf/D. In some cases, wells are produced at rates below their capacity to prevent sand particles from being carried up the well. In other cases, reduced drawdowns are necessary to prevent water coning.

In aquifer development, the effect of sand permeability is an important property for two reasons. First, if permeability is low (100 md) then several years may be required to push back enough water to create the desired gas-filled space. During this time, winter withdrawals must be small and cushion gas is typically 75 to 85 per cent of total capacity. Permeability also has a pronounced effect on the efficiency with which the injected gas displaces the water. Fig. 1 illustrates this effect for homogeneous sands of high and low permeabilities. Low permeability causes a pronounced override or tongue of gas fingering downstructure under the caprock. Gravity drainage of water from the gas zone is slow, and the gas-water interface may assume nearly the same inclination as the formation itself. For the same rate of injection but a high sand permeability, gas will displace the water more efficiently with a nearly horizontal gas-water interface and a high rate of gravity drainage of water out of the gas zone. The average water saturation in the gas zone will be appreciably lower than in the former case.

The productivity of gas in the two cases shown in Fig. 1 (low and high permeability) will differ by more than the ratio of sand permeabilities. For the low-permeability case, water will flow toward and, after a short while, into the wellbore along with gas; total gas withdrawals before the wells water out will be small, and effective cushion gas will be significantly greater than the customary 50 per cent. In respect to these effects of permeability, a 1,000-md sand is quite satisfactory. Permeabilities below 100 md may result in an extended time necessary for bubble growth, inefficient water displacement and difficulty in sustaining water-free gas production.

The dip or inclination of the structure has the same type of effect as permeability on the gas-water displacement. Injection of gas into a formation of slight dip angle may cause a long, thin wafer of gas reaching far downstructure; withdrawal of gas in such a situation is difficult, if not impossible. Injection at the same rate into an identical formation inclined at a significantly greater angle would produce a thick gas zone with a nearly horizontal, advancing gas-water interface.

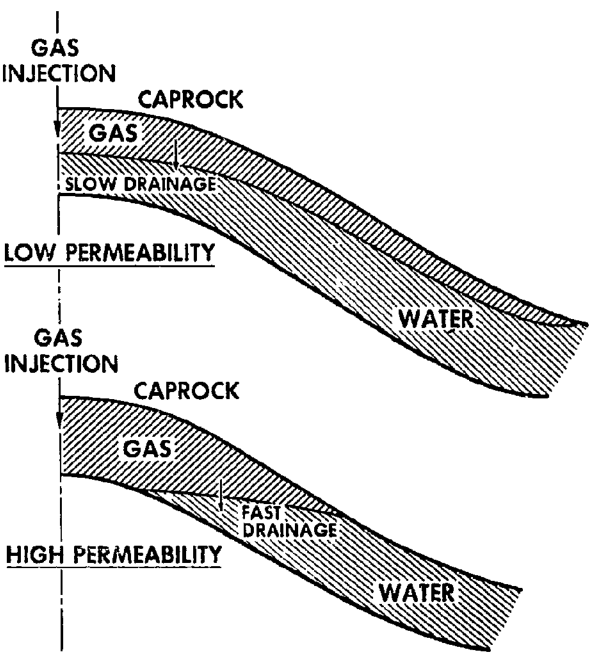

Fig. 1—Effect of permeability on gas bubble growth.

Dehydration is necessary in storage projects involving aquifers or water drive fields. The produced gas is saturated with water and, in cold weather, hydrates form and plug surface fittings. This is often prevented by wellhead heaters or by methanol injection at the wellhead. The gas then loses its water to diethylene glycol or a dry dessicant before it travels on to the market.

Storage of gas in depleted oil fields involves some unique technical problems such as equilibration of the residual oil with injected gas and secondary oil production. In general, added costs are incurred in treating or purifying the withdrawn gas before sending it to market although these costs may be offset by sale of extracted liquids. We have had relatively little experience in the U. S. to date with gas storage in oil fields. The Lone Star Gas Co. initiated storage in the early 1950s in their New York City Pool near Dallas, Tex.[7] Primary oil recovery in this field before gas storage was only 17 per cent. Lone Star reported in 1956 that they recovered up to 1,000 B/D of secondary oil by cycling 25 MMcf/D of gas during the spring and summer. Data on technical problems associated with gas storage in oil fields, as well as numerous other technical aspects of gas storage, are available.[8]

Economic Aspects of Gas Storage

Underground storage investment includes the cost of wells, cushion gas and gathering, dehydration and compression facilities. Cushion gas represents a sizable fraction of this investment. In 1958, 522 Bcf of the 918 Bcf of gas in storage in the U. S. was cushion gas valued at \$122 million of 23.3¢/Mcf;[9] this represented 32 per cent of the total investment of \$388 million in underground storage facilities.

In a developed storage reservoir about 50 per cent of the gas is considered cushion gas; 50 to 60 per cent of this is considered nonrecoverable and should be depreciated. The recoverable cushion gas is included in investment, but is not depreciated. Fixed charges of depreciation, return on investment and taxes dominate the operating costs of gas storage. Table 1 lists 1964 costs and operating data for 181 U. S. storage fields and shows a fixed charge equal to 80 per cent* of total storage costs.[10]

As shown in Table 1, the average cost of aquifer storage was 24.17¢/Mcf, considerably greater than the 15.69¢ cost of storage in dry gas fields. This is partly because aquifer storage requires considerable exploratory and development work to prove the existence of caprock integrity and sufficient structural closure to contain the gas. In addition, conversion of depleted fields to storage only requires the reworking of some wells and incremental investment in new wells and surface facilities, whereas aquifer storage finds no such facilities initially present. Finally, at time of conversion a depleted field already contains a portion of the required cushion gas at zero or small cost.

The depreciated investment for all 181 fields was 92¢/Mcf handled** or 27¢/Mcf in storage at year-end. For 11 aquifer storage reservoirs, investment was \$1.26/Mcf handled or 41.3¢/Mcf inventory. The investment per Mcf/D

*The \$28,533,939 operating expense was reduced to \$24 million in calculating this percentage, since one company leased storage facilities and reported about \$4.5 million operating expenses with no fixed charges.

**Mcf handled is the average of Mcf injected and withdrawn over the year.

TABLE 1—1964 GAS STORAGE STATISTICS FOR 33 U. S. PIPELINE COMPANIES[10]

Number of fields	
Dry gas	146
Water drive	20
Aquifer	15
	181
Average Bcf injected and withdrawn	714.97
Depreciated storage plant investment	$618,679,353
15 per cent of depreciated storage plant investment	$ 92,801,902
Storage, operating and maintenance expense	$ 28,533,939
Total cost of storing gas	$121,335,841
Cost per million cubic feet (cents)	
181 fields	16.97
146 dry gas fields	15.69
20 water drive fields	16.52
15 aquifers	24.17
Tcf* inventory, end of 1964	2.3
Bcf withdrawn to market	670.5
Delivery capacity	13.3 Bcf/D
Depreciated investment	
Per Mcf withdrawn	92¢
Per Mcf inventory	27¢
Per Mcf/D delivery capacity	$46.50

*Trillion cubic feet.

delivery capacity was $46.50 for all 181 fields and $66 for 11 aquifer storage reservoirs. The storage cost per Mcf withdrawn falls appreciably as total winter withdrawal increases due to the large fixed expense portion of storage costs. The 1964 winter was milder than in 1963, and withdrawals from the 181 fields mentioned above dropped 7.2 per cent from 1963. The lower withdrawal caused storage costs to increase 12 per cent from 15.14¢/Mcf withdrawn in 1963 to 16.97¢ in 1964. One company reported a 1964 cost of 23.55¢/Mcf compared to 14.33¢ in 1963 as its percentage of active storage capacity used fell from 72.4 to 46.8.

The average cost of storing gas in six West European aquifers in 1964 was 19¢/Mcf working gas,* somewhat less than the average U. S. aquifer storage costs of 24.17¢. Comparison of Western Europe and U. S. costs is difficult, however, for two reasons. First, the annual fixed-charge portion of West European storage costs is generally about 9 per cent of capital outlay, compared to 15 per cent of net plant investment in the U. S. Second, the costs for the six West European aquifers range from 11.7¢ to $1.15/Mcf (Table 9); therefore, the significance of an average cost is questionable. Table 2 compares storage investment costs in Western Europe with those in the U. S.

A U. S. storage company prepared cost estimates shown in Table 3 for a proposed storage project in a watered-out oil reservoir. This venture is similar to depleted field storage in that some well and surface facilities are initially present, but it resembles aquifer storage in that development requires several years of pushing water back to create storage space. A debt-equity ratio of 60:40 was assumed so that the federal income taxes were figured at

*Working gas is the volume withdrawn to market.

TABLE 2—GAS STORAGE INVESTMENT COSTS IN WESTERN EUROPE AND THE U. S.

	Investment, Dollars Per:		
	Mcf Inventory	Mcf Working Gas	Mcf/D Delivery Capacity
Western Europe (6 aquifers)	0.48	1.06	67.5
U. S. (11 aquifers)	0.41	1.26	66.0
U. S. (181 fields)	0.27	0.92	46.5

48/52 × (the return at 6.5 − 5 per cent interest and amortization charge on 60 per cent of the net plant investment). An initial investment of about $20 million was required. The depreciation does not include recoverable cushion gas; i.e., the 3.5 per cent depreciation rate applies to accumulated plant investment which excludes the recoverable 40 per cent of cushion gas. The net plant investment at 10 years was $42.3 million or 40¢/Mcf inventory, 92¢/Mcf withdrawn and $56.50/Mcf/D delivery capacity. These figures are somewhat less than the average investment for 11 aquifers given in Table 2. This is partly because the purchase cost of wells and surface facilities already in place was certainly less than the replacement cost that would be incurred in an aquifer storage project.

Table 4 shows that cushion gas, at 16¢/Mcf, is 38 per cent of the total cost of additional facilities required over the first five years. Desulfurization facilities account for half of the additional investment for compression and purification facilities, while dehydration and compression demand about equal portions of the remainder.

Economic Advantage of Storage

The economic advantage of storage in the U. S. is easy to demonstrate because large distances separate the major producing areas in the Southwest from major markets in the East and Midwest. For example, Michigan Consolidated Gas Co. receives gas from Texas and south Louisiana pipelines which cost $250 million and operate at 100 per cent load factor. The underground storage plant owned by this company cost one-fifth of this amount, but handles 30 per cent of the gas transmitted to market and satisfies 59 per cent of the peak-day demand.[12] Investment costs for 1 Mcf/D of pipeline capacity vary from $200 to $500[13] while underground storage investment is only about $50/Mcf/D capacity.

Space heating, with an annual load factor of about 30 per cent, accounts for about two-thirds of the annual gas sales (dollars) in the U. S. The more uniform industrial gas requirements raise the over-all load factor to about 50 per cent. Transmission costs for gas at this 50 per cent load factor may be nearly double the cost at 100 per cent load factor since large-capacity pipelines will have annual fixed charges about three times the direct operating expenses.[9] The economic incentive for gas storage involves balancing these savings in transmission costs against the incurred cost of storage. Table 5 shows some transmission

TABLE 3—COMPUTATION OF COST OF SERVICE AND COST OF STORING GAS

Line No.	Particulars	Year of Operation 1st	2nd	3rd	4th	5th	10th
1	Operation and maintenance	$ 227,000	$ 326,000	$ 410,000	$ 494,000	$ 544,000	$ 1,021,000
2	Depreciation at 3.5 per cent of line 16	696,000	878,000	1,023,000	1,266,000	1,354,000	1,780,000
3	Taxes (other than income taxes)	106,000	132,000	146,000	171,000	191,000	280,000
4	Federal income taxes at 48 per cent	656,000	813,000	931,000	1,130,000	1,181,000	1,366,000
5	Return at 6.5 per cent	1,320,000	1,636,000	1,873,000	2,274,000	2,377,000	2,749,000
6	Cost of service*	$ 3,005,000	$ 3,785,000	$ 4,383,000	$ 5,335,000	$ 5,647,000	$ 7,196,000
7	Cost of Storing Gas Based on						
8	Mcf withdrawn	66.8¢	50.5¢	41.7¢	37.0¢	30.2¢	15.6¢
9	Average Mcf injected and withdrawn	44.5¢	34.4¢	31.3¢	30.6¢	26.2¢	15.0¢
10	Injections (Mcf)	9,000,000	14,500,000	17,500,000	20,500,000	24,400,000	49,900,000
11	Withdrawals (Mcf)	4,500,000	7,500,000	10,500,000	14,400,000	18,700,000	46,200,000
12	Average (Mcf)	6,750,000	11,000,000	14,000,000	17,450,000	21,550,000	48,050,000
13	Maximum volume in storage (Bcf)	15.0	25.0	35.0	45.0	55.0	105.0
14	Peak day withdrawal (MMcf)	150	200	250	300	375	750
15	Net plant investment	$20,301,082	$25,176,002	$28,819,122	$34,991,472	$36,569,450	$42,297,832
16	Accumulated plant investment**	$19,881,000	$25,095,000	$29,241,000	$36,167,600	$38,690,800	$50,859,800

*Cost of service does not reflect any expenses or revenues applicable to incidental sales of oil.
**This investment is undepreciated and excludes recoverable cushion gas.

TABLE 4—DISTRIBUTION OF ADDITIONAL FACILITY COST DURING THE FIRST FIVE YEARS

Item	Five-Year Additional Investment (per cent)
Gathering facilities	7.0
Compression and purification facilities	51.0
Measuring and regulating facilities	0.5
Well facilities	3.5
Cushion gas	38.0
	100.0

TABLE 5—GAS TRANSMISSION COST VS RATE[14]

Maximum Daily Rate (MMcf/D)	Cost (¢/Mcf/100 miles)	
	100 per cent Load Factor	50 per cent Load Factor
20	6.6	13.5
60	3.4	6.6
100	2.6	5.0
200	1.8	3.4
400	1.4	2.45
600	1.17	2.06
1,000	0.95	1.75

costs based on southern Louisiana data which were presented to the FPC by Bechtel Corp. in 1964.[14] These costs exclude any return on investment.

These transmission costs can be related to over-all net reduction in gas costs to the consumer in terms of the following variables:

q = average daily market demand over the year, Mcf/D

q_p = peak market demand, Mcf/D

Q = annual market demand, Mcf = $365q$

Q_s = annual withdrawal from storage, Mcf

C_1 = transmission costs for 100 per cent load factor, cents/100 miles/Mcf

C_2 = transmission costs for q/q_p load factor, cents/100 miles/Mcf

C_s = cost of storage plus cost of transmitting gas from storage field to the market, cents/Mcf withdrawn

L = distance from source field to market, hundreds of miles.

If no storage is employed, then the cost of gas at the market to the distributor is wellhead price plus C_2L ¢/Mcf. If near-market storage is employed to allow 100 per cent load factor operation of the pipeline, then the cost to the distributor is wellhead price plus $C_1L + C_sQ_s/Q$ ¢/Mcf. Thus, the savings ΔC in ¢/Mcf due to storage is:

$$\Delta C = (C_2 - C_1)\,L - C_sQ_s/Q \text{ ¢/Mcf} \quad . \; . \; . \; (1)$$

As an example application of Eq. 1, consider the market-demand schedule given in Table 6. Assume that the peak-day demand reaches 3.3 Bcf/D so that the pipeline would operate at an average load factor of about 50 per cent if no storage were employed. Reference to Table 5 indicates that a transmission cost savings $C_2 - C_1$ of about 1¢/Mcf/100 miles might be reasonable if return on investment were included. The factor Q_s/Q is 4.227/19.64, or about 0.2. If the market were 1,000 miles from the producing field and storage costs were 20¢/Mcf withdrawn, then Eq. 1 gives the savings due to storage as = 1(10) − 20(0.2) = 6¢/Mcf.

Comparative Storage Costs

Aquifers and depleted fields provide an order of magnitude more storage capacity per invested dollar than any other method of storage (Table 7). The $110/Mcf stored in steel pipe corresponds to the recent Southern Jersey Gas Co. investment of $1.1 million to store 10 MMcf in over 17,000 ft of 42-in. pipe.[16] The $4.85/Mcf cost of liquid

TABLE 6—EXAMPLE MARKET DEMAND AND STORAGE SCHEDULE[8]

Volumes in Bcf/D

Month	Market Demand	Pipeline Supply	Storage Requirements	
			Input	Withdrawal
January	2.793	1.670	—	1.123
February	2.566	1.51	—	1.056
March	2.316	1.67	—	0.646
April	1.679	1.61	—	0.069
May	1.150	1.67	0.52	—
June	0.821	1.61	0.789	—
July	0.717	1.67	0.953	—
August	0.731	1.67	0.939	—
September	0.882	1.61	0.728	—
October	1.372	1.67	0.298	—
November	2.005	1.61	—	0.395
December	2.608	1.67	—	0.938
Total	19.640		4.227	4.227

storage is also a recent figure which describes the San Diego Gas and Electric Co.'s new $3 million plant liquefying and storing 620 MMcf in a double-walled surface tank.[17]

One company estimated the total operating cost of liquefying, storing and revaporizing gas as $1.17/Mcf.[18] This far exceeds the average operating cost of 17¢/Mcf withdrawn from underground storage in the U. S. in 1964.

There are many salt cavern storage projects for LP gas, but the Southeastern Michigan Gas Co. was the first to use this for natural gas.[19] The Southeastern Michigan project at St. Clare boasts a 342 MMcf working gas capacity with only 44 MMcf of cushion gas; void space is 4.12 MMcf and working pressure is about 1,100 psi. Costs are not given but may be comparable to aquifer or depleted field storage costs since the caverns cost little or nothing and the only expenses are compression, brine pumping and dehydration. The obvious limitation on this type of storage is the availablility of mined salt caverns.

Status of Underground Gas Storage

United States

Storage capacity has increased far more rapidly than gas production during the last 20 years (Table 8).[20] Capacity increased 2,800 per cent compared to an increase of 314 per cent in production over the 1944 to 1964 period.[21] At the end of 1964, storage capacity was 3.94 Tcf compared to estimated total U. S. proved reserves of about 287 Tcf. About 944 Bcf or 6.1 per cent of total U. S. gas production were withdrawn from storage during the year to meet market requirements. Noncoincident peak-day withdrawal from storage in 1964 was 15.6 Bcf/D.

Total investment in underground storage facilities was $1.2 billion, including cushion gas which was slightly less than 50 per cent of the 3.94 Tcf ultimate capacity.[22] Storage projects completed during 1964 added 268 Bcf of reservoir capacity, an increase of 7.3 per cent over 1963. Construction was under way at that time to add another 171 Bcf of capacity.

Michigan, Pennsylvania, Ohio and West Virginia claim over 50 per cent of storage capacity; Michigan leads at the present time with 712 Bcf, while Pennsylvania is second with 651 Bcf. Of the 278 storage reservoirs at the end of 1963, 232 were dry gas, 12 were oil and gas reservoirs, five were oil reservoirs and 28 were aquifer storage fields.

TABLE 7—CAPITAL COSTS PER Mcf CAPACITY FOR VARIOUS TYPES OF STORAGE

Type of Storage	Dollars/Mcf
Sphere[15]	227
Steel pipe (2,240 psi)[15]	207
Steel pipe (980 psi)[16]	110
Liquefaction	
Surface steel tank[17]	4.85
Mined cavern[8]	5.50 to 6.45
Dissolved salt cavern[8]	4.20 to 4.30
Aquifer storage	0.41
Depleted field storage	0.27
Salt cavern (gaseous state)	low

TABLE 8—STATUS AND GROWTH OF U. S. UNDERGROUND STORAGE OF NATURAL GAS[20]

Volumes in Bcf

Year	Number of Pools	Number of Aquifer Storage Pools	Input to Storage	Output from Storage	Ultimate Capacity	Actual Gas in Storage End of Year	Storage Capacity as Per Cent of Annual Production
1944	—	—	—	—	135	—	3.64
1947	70	—	—	—	250	—	—
1950	125	—	—	—	774	—	12.26
1951	142	—	—	—	916	—	—
1952	151	1	—	—	1292	—	16.04
1953	167	3	—	—	1735	—	—
1954	172	4	—	—	1859	—	21.15
1955	178	5	—	—	2096	—	—
1956	187	6	—	—	2402	—	23.70
1957	199	8	—	—	2603	—	—
1958	205	9	—	—	2718	—	24.51
1959	209	10	805	607	2521	—	—
1960	217	14	899	733	2870	—	22.35
1961	229	13	860	711	3219	—	—
1962	258	21	946	855	3485	2744	25.11
1963	278	28	1140	963	3674	—	—
1964	286	32	1104	944	3942	29·0	25.69

Western Europe

D. K. Blears discusses the status of aquifer storage in Western Europe.[11] Data listed in Table 9 were extracted from that report and show an ultimate capacity of over 100 Bcf in six French and German aquifer storage reservoirs in 1965. This compares with estimated recoverable West European reserves of about 80 Tcf. Actual capacity or inventory at the end of 1965 was 50.6 Bcf; the 21.3 Bcf withdrawn from storage during the year represent about 4 per cent of the total 545 Bcf natural gas produced in Western Europe in 1963.[23] The five operating reservoirs offered a combined maximum daily withdrawal rate of 521 MMcf/D. Two additional aquifer storage developments in the planning stage in 1965 will add 42 Bcf ultimate capacity and 140 MMcf/D peak withdrawal rate.

All six underground storage projects developed to date in France and Germany are aquifer storage reservoirs, although storage is planned in a spent oil sand near the Reitbrook project. Reasons for developing these reservoirs and their physical characteristics are discussed in detail in the literature.[11,23,24]

Future Direction and Growth of Gas Storage

The future of U. S. underground storage is unquestionably bright. One expert estimates the need for 9 Tcf of storage capacity by 1980 to meet the projected total U. S. natural gas demand of 26 Tcf.[21] The large distances separating producing from consuming areas ensures the need for this growth in underground storage. For example, Texas and Louisiana produced nearly 70 per cent of total production in 1964, but consumed only 18 per cent. However, 13 North Central and Middle Atlantic states, some 1,000 to 2,000 miles distant from Texas and Louisiana, accounted for over 50 per cent of consumption but less than 7 per cent of total production.[20]

Storage techniques such as steel pipe and frozen ground or tank storage of LNG are not really competitive for several reasons with storage in aquifers or depleted fields. First, the cost per Mcf withdrawn to market is many times greater than the cost for underground storage. Second, these other techniques are used for hourly and daily peak shaving, whereas underground storage provides the much larger gas volumes needed to satisfy the entire seasonal demand increase caused by space heating. For example, the planned or operating U. S. LNG storage projects range from 0.25 to 2 Bcf capacity and from 50 to 400 MMcf/D delivery capacity. The Southern Jersey Gas Co. steel pipe project stores only 10 MMcf with delivery capacity of 3 MMcf/D. In comparison, the Galesville aquifer stores over 40 Bcf and has delivered 16 Bcf to market in a single season with a maximum delivery capacity of 900 MMcf/D.[4,25] Thus, underground storage and peak-shaving techniques such as LNG storage largely complement each other and both should experience strong growth in coming years.

Gas consumption in Western Europe is expected to accelerate to supply 10 per cent of Western Europe an energy consumption in 1975, compared to only 2 per cent in 1963.[23] Whether underground storage capacity will keep pace with this growth is a difficult question. Two factors indicate a very slow growth in storage capacity. First, very few depleted fields are available in Western Europe for storage, a fact indicated by the current storage there exclusively in aquifers. Even assuming a strong economic incentive for underground storage, the ability to provide the necessary capacity in aquifers alone must be questioned; less than 12 per cent of the U. S. storage fields are aquifers, while 88 per cent were originally depleted fields. Second, relative to the U.S., shorter distances separate European markets from producing fields and reduce the economic incentive for storage as opposed to oversized transmission lines. However, the reduced incentive caused by these shorter distances may be counterbalanced by the savings in well costs attendant to a uniform field production rate. For example, a 20 MMcf/D North Sea well costing \$2 million is an investment of \$100/Mcf/D capacity. Such wells necessary to meet peak loads in the absence of storage are poor alternatives to underground storage costing less than \$70/Mcf/D capacity.

In Western Europe the feasibility of underground stor-

TABLE 9—UNDERGROUND STORAGE RESERVOIRS IN WESTERN EUROPE

(All Volumes in Bcf, Rates in MMcf/D)

	Beynes	St. Illiers	Lussagnet	Engelbostel	Hahnlein	Reitbrook	Total or Average
Ultimate capacity	11.3	22 to 35	27	17	7	5	102.3
Present capacity	11.3	—	27	6	4.5 to 5	1.2 to 1.3	50.6
Present working gas	5.3 to 5.7	11 to 17.5*	12	1.5	1.75	0.35	21.3***
Present cushion gas	5.65	11 to 17.5*	15	4	2.5	0.85	28***
Maximum withdrawal rate	216	50 to 88*	175	53	70	7	521***
Capital costs, millions of dollars	11	6.5 to 8.4	11.2	5.05	2.3	3.2	41.1†
Per Mcf working gas	\$2.00	48¢	93¢	\$3.36	\$1.31	\$9.10	\$1.06
Per Mcf capacity	97¢	24¢	42¢	84¢	48¢	\$2.54	48¢
Per cent of capital costs in							
Wells	30.8	—	—	—	39	—	—
Compression and gas treatment facilities	36	—	—	—	22	—	—
Cushion gas	10.8	—	37.5	—	33	21	—
Storage costs, ¢/Mcf	29.3†††	15.7 to 23.2**	11.7‡	42†††	23†††	115†††	19††
Working gas basis for storage costs	5.3	5.3 to 3.5	9	1.6	1.75	0.35	—
Per cent of storage costs in							
Fixed expenses	62.7	—	—	68	50	71	—
Variable expenses	37.3	—	—	32	50	29	—

*When full development is achieved.
**Calculated from yearly charges of 11 per cent of total investment.
***As of 1965; i.e., excluding St. Illiers.
†32.7 excluding St. Illiers.
††This cost is weighted on the working-gas basis volume; i.e., 19¢ = (29.3 × 5.3 + 15.7 × 5.3 + — — —)/(5.3 + 5.3 + — — —).
†††Annual fixed expenses calculated as 9 per cent of capital outlay.
‡This cost is equivalent to an annual charge of 16 per cent of capital outlay.

age in any particular case will require a careful study of storage costs compared to the costs of extra field and pipeline capacity to meet peak demand. The currently high ratio of industrial to residential gas consumption in Western Europe also indicates a need for increased gas storage capacity in the future. Table 10 shows that, relative to the U. S., a greater portion of European gas is consumed by the industrial and a lesser portion by the domestic market sectors. Thus, the future should see an increasing portion of European gas consumption in the residential sector with an attendant reduction in over-all load factor.

A delayed incentive for gas storage in Western Europe may result from the initial laying of oversized transmission lines. For example, assume that a 350-mile, Groningen-Paris pipeline to handle a 500 MMcf/D contract is oversized to handle a peak rate of 1,000 MMcf/D. If another 500 MMcf/D were contracted some years later, then the line could accommodate it at 100 per cent load factor with marked reduction in unit transmission costs. However, large-scale underground storage would then be necessary to handle the seasonal load variation. This might be economically preferable to laying another 500 MMcf/D line with, say, 1,000 MMcf/D peak capacity.

The vast network of coal mine tunnels in England may offer significant storage capacity although little experience exists with this technique on either side of the Atlantic. The Public Service Co. of Colorado is storing gas in the Leyden coal mine 14 miles northwest of Denver.[27] This mine is 700 to 1,000 ft deep and offers a capacity of 3 Bcf up to a 300-psi limit. The major technical problems encountered were finding and sealing ventilating shafts to prevent gas leakage.

Conclusions

Major technical problems in underground storage are gas leakage through abandoned or poorly completed wells in depleted fields, and caprock or spill-point leakage in aquifer projects. The presence of water in water drive and aquifer reservoirs poses additional problems in growing the gas bubble, maintaining water-free gas production, predicting deliverability and in dehydration.

Underground storage cost of 20¢/Mcf withdrawn to market is considerably lower than the costs of alternate schemes such as storage in steel pipe or LNG storage in frozen ground or surface tanks. However, these latter techniques complement rather than compete with underground storage since they handle hourly or daily peak-shaving as opposed to the entire seasonal demand fluctuation caused by space heating.

Storage in aquifers costs about 50 per cent more than storage in dry gas fields because of the greater investment in wells, surface facilities and cushion gas. Also, aquifer projects incur exploratory charges necessary to prove suitability of the structure for storage. The vigorous growth of U. S. gas storage capacity during the last two decades should continue into the future. In Western Europe the short distances separating markets from fields and the small number of depleted fields may retard the growth rate of storage capacity.

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TABLE 10—DISTRIBUTION OF GAS CONSUMPTION AMONG MARKET SECTORS[20]

	United States	Europe
Industrial	61	67
Residential	23	18
Commercial	7	6
Other	9	9

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EDITOR'S NOTE: A PICTURE AND BIOGRAPHICAL SKETCH OF KEITH H. COATS APPEAR ON PAGE 1575.