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UNDERGROUND STORAGE OF NATURAL GAS IN ILLINOIS—1967

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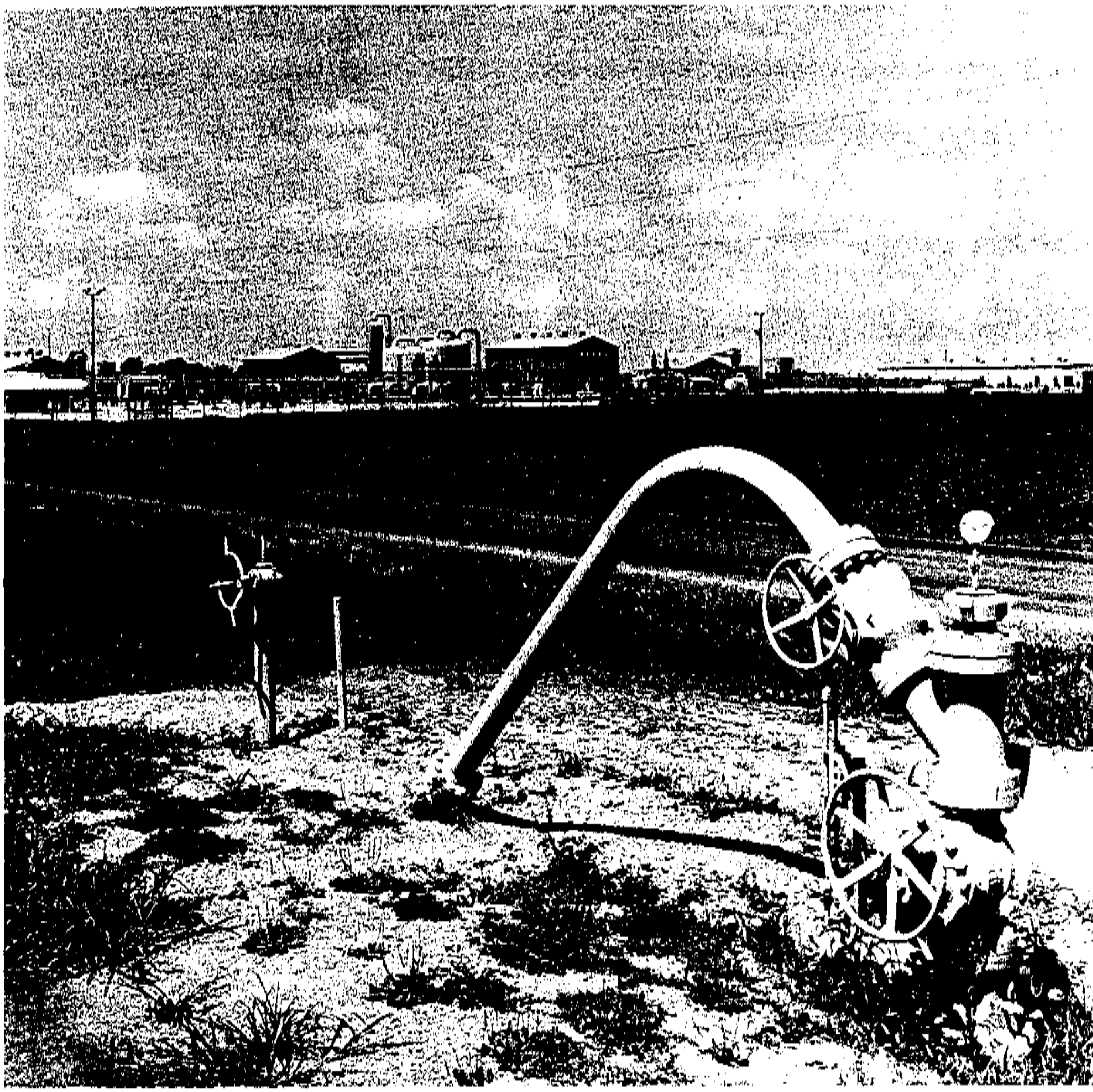

Surface installation for underground gas storage project at Troy Grove, Illinois. Operating well is in foreground; plant for treating and handling gas is in background.
(Photograph courtesy of Northern Illinois Gas Co.)

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ABSTRACT

Natural gas is stored in underground reservoirs at 22 locations in Illinois. These reservoirs contain 200 billion cubic feet of gas, about half of which is working gas and half is cushion gas. Potential capacity of these reservoirs is estimated to be 600 billion cubic feet. At 8 of the storage projects, gas is stored in depleted gas reservoirs; in the remaining 14 projects, gas is stored in aquifers that originally contained no hydrocarbons in commercial quantities.

All systems of rocks from Cambrian to Pennsylvanian are used for storage in Illinois. Most of the storage volume, however, is in sandstone aquifers of Cambrian and Ordovician age.

This report includes a brief discussion of some of the technology associated with the underground storage of gas. Also included is information on the geologic setting and the history of development of each project.

INTRODUCTION

In 1961, Dr. A. H. Bell issued his report "Underground Storage of Natural Gas in Illinois." Since then, the number of Illinois gas storage reservoirs has grown from 7 to 22. The estimated total capacity for underground storage of gas has likewise increased, from 184 to about 600 billion cubic feet. Furthermore, during this period, considerable improvements have been made in gas storage technology.

The present report was prepared (1) to give a brief introduction to the subject of underground gas storage for the layman or for the geologist or engineer who is just entering the field and (2) to present up-to-date information about Illinois gas storage projects in operation or under development.

In many places, liquefied petroleum gas, "LPG," is stored underground in natural or artificial caverns; this LPG is usually liquefied propane or butane. In a few states, though not in

Illinois, liquefied natural gas, "LNG," is stored in the ground or above ground. However, our report is not concerned with liquid products such as LPG or LNG; it deals only with the underground storage of natural gas in the gaseous state.

Acknowledgments

This report would not have been possible without the help of many people in the gas industry. The following men supplied valuable information about gas storage in their companys' operations: Central Illinois Light Co.—Robert Ryan; Central Illinois Public Service Co.—R. H. Rector; Gas Utilities Co.—R. L. Gower, M. J. Imlay; Illinois Power Co.—C. V. Crow, K. W. Robertson; Midwestern Gas Transmission Co.—James H. Deborah, J. P. Fortenberry; Mississippi River Fuel Corp.—Richard H. Fulton, Jack Thomas; Natural Gas Pipeline Co. of America—W. R. Clark, R. A. Younker; Northern Illinois Gas Co.—Bruce Engquist, Carl G. Nelson; Panhandle Eastern Pipeline Co.—R. L. Jones, W. R. King; Peoples Gas, Light & Coke Co.—L. C. Foehner, Kenneth Larson.

Helpful discussions on gas storage were held with P. A. Witherspoon, of the University of California, and with a number of people at the Illinois State Geological Survey, especially W. F. Meents, who checked much of the data in this report, and R. F. Mast, who gave helpful criticism of the section on engineering of gas storage projects.

Figure 2, "Development of gas bubble in an aquifer," was taken from Katz et al. (1963). We are grateful to the publishers, the American Gas Association, for permission to use this illustration.

Why Gas Storage?

Space heating in homes and other buildings consumes large amounts of gas. Because of the seasonal fluctuation in the demand for gas for space heating, the total gas demand generally varies considerably from summer to winter.

One way to accommodate this fluctuating demand would be to build a pipeline from the gas fields large enough to supply the greatest amount of gas that would be needed in the middle of winter. In the summer, then, pipeline pressure could be reduced so that gas would flow at a fraction of the pipeline capacity. This, however, would be an inefficient use of an expensive facility. Instead, the pipeline companies usually have operated the pipelines at full capacity throughout the year; in summertime, they (or the gas distributing companies) have sold the excess gas at reduced prices to manufacturers and other industrial users. In the winter, then, when the gas was needed for heating, the industrial users switched to other fuels such as oil or coal.

To make better use of the pipelines throughout the year, the gas distributors acquired more heating customers than the pipelines could supply in the middle of winter. Then, any deficiency in gas supply was made up by using gas that was stored above ground during summer months in "gas holders" at atmospheric pressure, or gas that was stored under high pressure in pipelines or cylinders, or by using a mixture of stored propane and air. (These expedients are often called "peak shaving" in the industry.)

None of these measures, however, has been very satisfactory. The pipeline companies did not make much money on the gas that they sold to industry in the summer, and the gas distributing companies could not store enough gas or propane to handle many customers. Thus, both the pipeline and the distributing companies have been under great economic pressure to develop ways to store large amounts of gas. Underground gas storage has proved to be the answer to this problem in many cases.

The daily capacity for "peak shaving" in the United States is over 30 billion cubic feet. It is available in these forms:

	Billion cubic feet
Underground storage	25.29
Propane ("LPG") - air	4.17
Manufactured	1.58
Liquefied natural gas ("LNG")	0.37

Illinois has over 25 LPG-air plants but no LNG plants. A number of plants are used for the manufacture of gas, but their contribution to "peak shaving" demand in the state is negligible. In Illinois, as in the United States as a whole, underground storage supplies most of the gas needed for peak shaving (Hale, 1966).

What Is Underground Gas Storage?

In a few places, such as Michigan and Saskatchewan, gas is stored in underground caverns leached out of natural salt deposits. In one case, in Colorado, an abandoned coal mine has been used to store gas. More commonly, however, gas that is stored underground is pumped down wells into a porous sandstone or carbonate rock. In the case of sandstone, the stored gas occupies pores or void spaces between the sand grains. In a typical sandstone used for gas storage, the pores are generally a few millionths of an inch in size. In the case of carbonate rocks, gas may occupy void spaces between grains of dolomite or oolitic limestone. In some cases, as at Glasford, Illinois, much of the porosity is apparently due to fractures and openings caused by solution of the carbonates by natural chemical agents. In a typical storage rock, the pores make up about 15 to 25 percent of the total volume of the rock; that is, 75 to 85 percent is "solid" rock and 15 to 25 percent is void space available for storage of gas.

HISTORY OF UNDERGROUND GAS STORAGE

Gas was first successfully stored underground in Welland County, Ontario, Canada, in 1915. The first successful underground storage of natural gas in the United States was made in 1916 by the Iroquois Gas Company in the Zoar Field, south of Buffalo, New York. In 1919, a much larger storage project was developed by the United Fuel Gas Company in the Menefee Field of eastern Kentucky. Both of these projects were in depleted gas fields.

By 1936, the United States had 13 storage reservoirs, with a total capacity of 39 billion cubic feet. In the next year, the number of reservoirs rose to 22, with a capacity of 103 billion cubic feet. Growth was steady until 1950, when the number of reservoirs jumped from 80 to 125, with a capacity of 774 billion cubic feet. At the end of 1965, reservoirs numbered 293 in 24 states, with a capacity of 4.1 trillion cubic feet (Perkins, 1962).

The first known experiments in Illinois with underground gas storage were made by Superior Oil Company at New Harmony in 1941. Fifteen million cubic feet of gas was injected into a Pennsylvanian water sand. When the well was opened, some gas flowed back, but then salt water shut off the flow and the experiment was abandoned. The first practical use of underground gas storage in Illinois was by Mississippi River Fuel Corporation at Waterloo in 1950. In 1952, Natural Gas Pipeline and Panhandle Eastern Pipeline Companies started their large projects at Herscher and Waverly, respectively. Since then, the number of projects and their capacity have grown continuously (fig. 1).

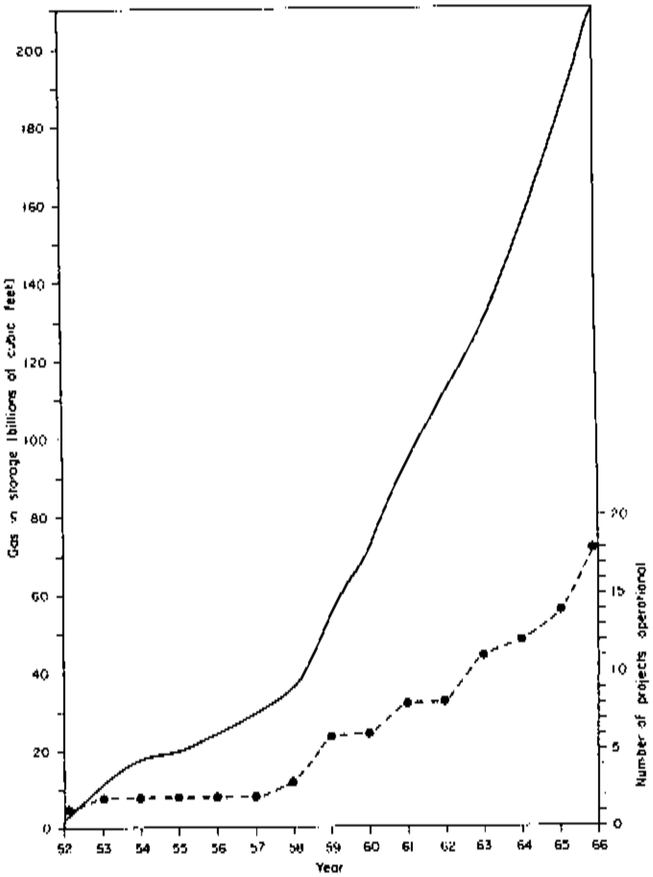


Figure 1 - Number of underground natural gas storage projects and amount of storage gas in Illinois, 1952-1966.

Illinois ranks fifth in total reservoir capacity among states that have underground gas storage. Pennsylvania, Michigan, Ohio, and West Virginia each have $1\frac{1}{2}$ to 2 times the capacity of Illinois (Martinson et al., 1966).

GAS STORAGE ECONOMICS

In a study of 181 United States storage fields, Coats (1966) showed that fixed charges accounted for 80 percent of total storage costs. These fixed charges included depreciation, return on investment, and taxes. About one-third of the total investment was for "cushion" gas—gas that cannot be withdrawn for practical reasons during the normal operation of the storage project (see page 14). About 50 to 60 percent of this cushion gas is considered nonrecoverable and should be depreciated. The depreciated investment for all 181 fields was 92 cents per thousand cubic feet (Mcf) handled or 27¢/Mcf in storage at the end of the year. For 11 aquifer storage reservoirs, investment was $1.26/Mcf handled or 41.3¢/Mcf inventory. The investment per Mcf per day delivery capacity was $46.50 for all 181 fields and $66 for the 11 aquifer storage reservoirs.

Coats also showed that the average cost of aquifer storage was about 24¢/Mcf withdrawn, compared with about 16 cents for storage in depleted dry gas fields. This results partly from the fact that aquifer storage requires exploratory testing and development to establish the presence of a structure with a satisfactory caprock. Also, aquifer storage sometimes is plagued by leakage problems that must be overcome by reinjecting gas, withdrawing water, or other costly expedients. Furthermore, dry gas storage generally requires less expenditure for new wells. Sometimes storage gas taken from a depleted gas reservoir requires no dehydration. Finally, the depleted gas reservoir itself may supply a considerable amount of the cushion gas, at reduced cost.

ENGINEERING OF GAS STORAGE PROJECTS

Many complex problems arise when a gas storage project is planned. These problems generally must be handled by experienced engineers and geologists. Anyone who wishes to make a serious study of the subject should consult the literature on gas storage, in particular, the comprehensive monograph by Katz et al. (1963). The following gives a brief introduction to some of the engineering aspects of gas storage.

Nature of Underground Gas Storage Reservoirs

To store natural gas underground the following are needed: (1) rock layers with sufficient permeability and porosity to accept and hold the gas, (2) an impermeable caprock overlying the storage rock to prevent upward migration of gas, and (3) a geologic trap to keep the gas from moving in a horizontal direction; this trap may be a dome or closed anticline caused by gentle upward arching of the strata, a stratigraphic trap caused by updip gradation of the reservoir rock from sandstone to shale, or a trap caused by faulting that seals the updip side of the reservoir by emplacement of an impermeable bed adjacent to the reservoir. Exploration for an underground gas storage site is discussed by Buschbach (1965).

The porous storage rock in a geologic trap under the caprock is called a reservoir. This reservoir may have been filled originally with oil or gas and thus may be a depleted oil or gas reservoir. On the other hand, the reservoir may have been filled originally with water; in this case, it is called a natural aquifer. The water in an aquifer could be fresh or salty; in Illinois, however, freshwater aquifers are not used for gas storage because they are too valuable as sources of water for human consumption.

Illinois has more aquifer storage capacity than any other state (Martinson et al., 1966, p. 14). More than 90 percent of underground gas storage in Illinois is in aquifers; some gas is also stored in small abandoned or partially depleted gas reservoirs. Thus far, no abandoned oil reservoir has been used for gas storage in Illinois, but Natural Gas Pipeline Company of America is preparing to store gas in the Devonian oil reservoir in the Louden Field, Fayette County.

In a few cases, gas is stored in a reservoir associated with an oil producing structure; for example, at St. Jacob, Illinois, oil is produced from the Galena (Trenton) Limestone Group and gas is stored several hundred feet below, in the St. Peter Sandstone.

A variety of traps are used to hold storage gas in Illinois. The Herscher Dome is an example of a structural trap, and Tilden is a stratigraphic trap. Trapping at Troy Grove is partially the result of faulting. Hookdale is a combination structural and stratigraphic trap. In some cases, the reservoir not only has a tight caprock, but it is bounded on all sides and on the bottom by relatively impervious rock. The reservoir in the Cypress Sandstone at Cooks Mills is a sand lens of this type. Such a reservoir behaves like a closed container. In predicting its behavior, the engineer needs to consider only the compression and expansion of the storage gas as it is injected and withdrawn.

Illinois gas storage projects show a great diversity with respect to lithology, original fluid, and type of trap (table 1). However, over 90 percent of the storage capacity is in Ordovician and Cambrian sandstone aquifers; thus, we will concentrate our discussion on that type of reservoir.

In many ways, a gas storage reservoir behaves like a reservoir that produces gas naturally. Therefore, gas storage engineers and geologists have been able to borrow much of the technology used in the gas producing industry. On the other hand, when gas is withdrawn from storage, parts of the reservoir may resemble an oil reservoir subjected to certain primary and secondary recovery processes. Therefore, the gas storage industry has also used techniques that were developed by the oil recovery engineers (Katz et al., 1959; Craft and Hawkins, 1959).

Although gas storage reservoirs and natural oil and gas reservoirs are similar in some respects, they differ in many ways. In a storage reservoir, the injection rates and deliverabilities of wells generally must be considerably higher than those that might be used in some gas production or secondary recovery operations. In a storage reservoir, the engineer must not inject at too high a pressure or he may fracture the caprock. This is not a problem in gas production, although it may be in secondary oil recovery. During the initial injection of storage gas, because of the high flow rate, the gas fingers and channels, as a result of permeability variations. Also, because of the high flow rate in a storage reservoir, gravity and capillary effects are less pronounced than in many oil and gas reservoirs, at least in the early stages of injection of storage gas. Finally, the volume of storage gas changes very rapidly during the injection and withdrawal parts of the storage cycle, in comparison with the changes in the volume of a gas producing reservoir. For this reason, the movement of the outer boundary of the storage reservoir is generally more rapid and more complex than that of a gas producing reservoir.

Because of the differences between storage reservoirs and oil and gas reservoirs, gas storage engineers have greatly extended the techniques and concepts of petroleum reservoir engineering.

Behavior of Fluids in Storage Aquifers—Development of Storage "Bubble"

When gas flows through a porous, water-saturated rock, it does not displace all of the water from the pores of the rock. Even after a large volume of gas has been injected, the rock still contains a "residual water saturation." This residual water saturation varies from about 15 to 30 percent of the pore space in typical aquifers; it must be taken into account when an estimate is made of the amount of gas in a given volume of aquifer rock. As relatively dry gas is cycled into and out of the aquifer, the water in the rock around the well evaporates. As the rock dries out, it develops a greater capacity for gas; the permeability of the rock to the gas also increases, resulting in higher injection and withdrawal rates in the operating wells.

Let us consider an ideal aquifer that has the same permeability throughout. Further, let us assume that the reservoir is isotropic—that is, it has the same permeability in all directions. One would expect that when gas was injected into a well in such an aquifer, the gas would displace water uniformly in all directions and form a "bubble" with a circular interface between the gas and the water. In practice, however, no aquifer has such ideal uniform properties. Generally, the permeability of the rock varies with depth; also, the horizontal permeability is usually greater than the vertical permeability. The result is that gas that is first injected into such an aquifer preferentially flows into the zones of higher permeability. Later, gas rises into the rock above these permeable zones, while water trickles down into them because of gravity. Gradually, the entire space around the well becomes filled with gas to some degree to form a bubble with more or less uniform saturations of gas and water (fig. 2). This

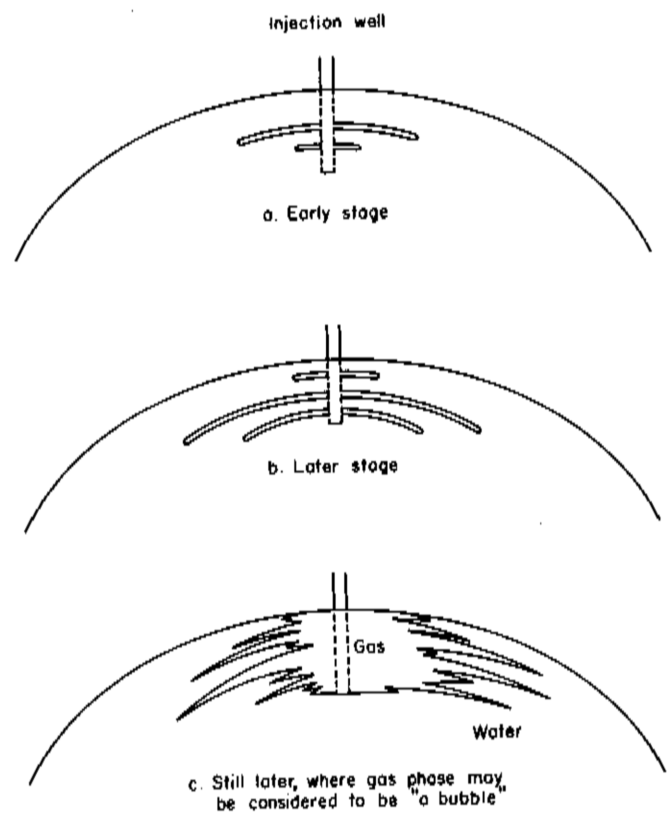


Figure 2 - Development of gas bubble in an aquifer (Katz et al., 1963, p. 130).

TABLE 1 - UNDERGROUND NATURAL GAS

Project	Company	County Township Range	Operational dates (initial) Devel-opment	Stor-age	With-drawal	Number of wells Oper-ating	Obser-vation	Other	Geologic data Stratigraphic unit	Lithol-ogy	Trap	Native fluid
Ancona-Garfield	Northern Illinois Gas Co.	LaSalle & Livingston 29, 30N 2, 3E	1961	1963	1965	36	14	—	Mt. Simon	sand	dome	water
Ashmore	Central Illinois Public Service	Coles & Clark 12N 10E, 11E, 14W	1960	1963	1963	23	9	—	Spoon Salem	sand lime	anti-cline	gas
Centralia East	Illinois Power Co.	Marion 1N 1E	1960	1964	1966	15	6	0	Pennsylvanian	sand	strati-graphic	gas
Cooks Mills	Natural Gas Pipe-line Co.	Coles & Douglas 14N 7, 8E	1956	1957	1958	22	9	8	Cypress Spar Mountain ("Rosiclare")	sand	lens	gas
Crescent City	Northern Illinois Gas Co.	Iroquois 26, 27N 13W	1959	1967	—	5	20	—	St. Peter	sand	dome	water
Elbridge	Midwestern Gas Transmission Co.	Edgar 12, 13N 11W	1961	1964	1966	4	6	0	Grand Tower	lime	reef	water
Freeburg	Illinois Power Co.	St. Clair 1, 2S 7W	1958	1959	1959	68	6	0	Cypress	sand	strati-graphic	gas
Gillespie-Benld	Illinois Power Co.	Macoupin 8N 6W	1958	1958	1959	7	0	0	Pennsylvanian	sand	strati-graphic	gas
Glasford	Central Illinois Light Co.	Peoria 7N 6E	1960	1964	1964	7	12	0	Niagaran	dolo-mite	dome	water
Herscher	Natural Gas Pipe-line Co.	Kankakee 30N 10E	1952	1953	1953	65	15	107	Galesville	sand	anti-cline	water
			1957	1957	1958	55	27	—	Mt. Simon[c]	sand	anti-cline	water
Herscher-Northwest	Natural Gas Pipe-line Co.	Kankakee 30, 31N 9E	(being developed)			10	1	—	Mt. Simon[c]	sand	anti-cline	water
Hookdale	Illinois Power Co.	Bond 4N 2W	1962	1963	1963	10	2	0	Yankeetown ("Benoist")	sand	strati-graphic & struc-tural	gas
Mahomet	Peoples Gas, Light & Coke Co.	Champaign 21N 7E	1960	1964	1966	15	10	—	Mt. Simon	sand	anti-cline	water
Nevins	Midwestern Gas Transmission Co.	Edgar 12, 13N 11W	1961	1965	1966	7	7	0	Grand Tower	lime	reef	water
Pontiac	Northern Illinois Gas Co.	Livingston 27, 28N 6E	(being developed)			5	11	—	Mt. Simon	sand	dome	water
Richwoods	Gas Utilities Co.	Crawford 6N 11W	1966	1966	1966	1	2	0	Pennsylvanian	sand	—	gas
St. Jacob	Mississippi River Fuel Corp.	Madison 3N 6W	1963	1963	1965	9	3	2	St. Peter	sand	dome	water
State Line	Midwestern Gas Transmission Co.	Clark, Ill., & Vigo, Ind. 12N 10W	1961	1962	1964	7	6	—	Grand Tower	lime	reef	water
Tilden	Illinois Power Co.	St. Clair & Washington 3S 5, 6W	1957	1961	1961	45	4	0	Cypress	sand	strati-graphic	gas
Troy Grove	Northern Illinois Gas Co.	LaSalle 34, 35N 1E	1957	1958	1959	84	27	—	Eau Claire Mt. Simon	sand	dome	water
Waterloo	Mississippi River Fuel Corp.	Monroe 1, 2S 10W	1950	1951	1951	6	6	22	Ordovician	sand & dolo-mite	dome	water
Waverly	Panhandle Eastern Pipeline Co.	Morgan 13N 8W	1952	1954	1961	27	19	8	St. Peter	sand	dome	water

[a]Million cubic feet
[b]Current storage; ultimate capacity not available
[c]Includes Elmhurst Member of overlying Eau Claire Formation

STORAGE PROJECTS IN ILLINOIS

Reservoir data						Capacities (MMcf)[a]			Withdrawals (MMcf)	
Area in acres		Depth (feet)	Thickness (feet)	Average porosity (%)	Average permeability (millidarcys)	Potential, cushion and working	Present		Peak daily, 1966	Total, 1966
Storage	Closure						Working	Cushion		
—	12,840	2,154	290	12.3	114	100,000	7,000	7,000	77.0	360
—	1,600	400	4–80	15.0	up to 3,000	2,000	929	945	14.0	310
463	—	812	49	18.2	200	615	112	225	4.8	18
—	1,500	1,600	40	16.0	67	3,790[b]	2,224	1,566	56.1	2,392
—	16,725	1,200	150	14.5	138	50,000	—	—	—	—
—	1,691	1,925	145	17.5	18	6,270	—	—	11	81
4,222	—	350	47	21.5	216	6,507	1,871	4,636	37.6	1,551
113	—	510	28	16.0	326	147	32	116	4.4	14.1
—	3,200	800	30–120	12.0	426	9,000	1,000	2,000	30	573.8
6,750	8,000	1,750	100	18.0	467	75,000	18,880	22,283	1,054	16,336
7,500	8,000	2,450	80	12.0	185	67,000	18,990	28,904	148	8,300
—	3,000	2,200	58	15.0	82	20,000	—	—	—	—
414	28	1,125	28	20.3	458	798	512	286	30.4	756.4
—	13,370	3,950	116	11.0	15	30,000	1,500	10,749	21.7	177.8
—	1,650	1,975	90	16.5	25	3,500	—	—	10	210
—	3,500	3,000	100	10.0	—	50,000	—	705	0	0
—	—	700	—	—	—	32	—	—	0.5	4.8
550	650	2,860	100	14.0	400+	4,800	1,200	2,600	41.0	1,708
—	496	1,860	91	17.3	47	2,300	—	—	13.0	653
1,287	—	800	32	20.8	183	2,688	869	1,819	43.4	1,193
—	9,600	1,420	100	17.0	150	64,000	22,227	24,220	650	22,762
100	300	1,650	100	vuggy	—	250	150	100	17.7	548
1,500	7,000	1,800	115	18.0	1,220	150,000	6,000	12,000	142	6,636

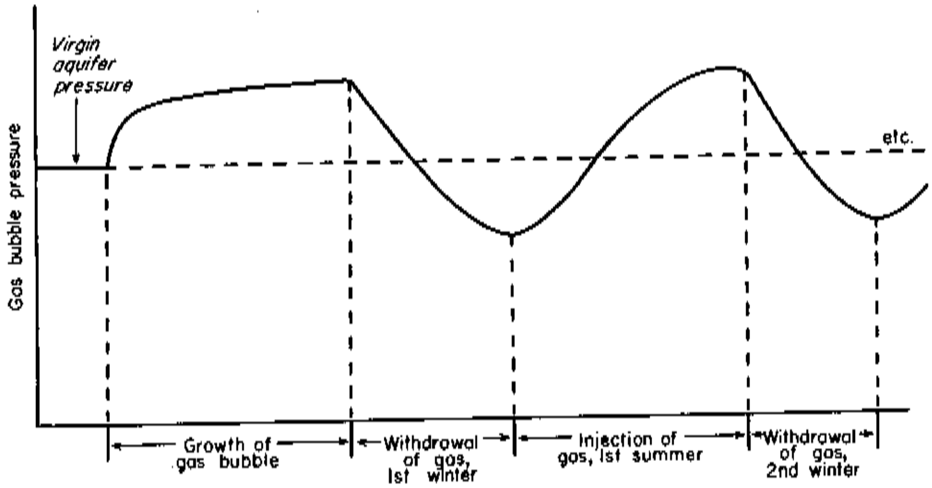


Figure 3 - Change in gas bubble pressure during development and operation of an aquifer storage project (adapted from Katz et al., 1963, p. 13).

may take many months, depending on the permeability and inhomogeneity of the aquifer.

Even after a uniformly saturated bubble has been formed, it will not necessarily have a flat bottom. Katz et al. (1963, p. 131) show that the bottom side of the bubble should be concave downward during gas injection and concave upward during gas withdrawal. Chaumet, Croissant, and Colonna (1966) found that in an actual reservoir, even after 8 years of operation, the bottom side of the bubble was still quite irregular in shape. These effects can seriously reduce the useable storage capacity of a given structure in an aquifer.

The storage engineer must develop a bubble large enough to satisfy his needs for the highest "peak" load that he can anticipate in a heating season. The simplest way to do this would be to start injecting gas into the aquifer, as described above, and to continue injection until the bubble was big enough. This, however, would create a problem, because gas is usually available from the supply pipeline only during the summer when demand is low. Furthermore, the engineer must often withdraw gas long before the bubble has reached the desired size; therefore, the bubble is usually developed through a series of injection and withdrawal periods. Each year more gas is injected than is withdrawn, until the bubble finally reaches the required size. This may take 2 to 5 years, or more.

Figure 3 shows how the pressure in the reservoir varies as the bubble is developed. When gas is injected into an aquifer, water is displaced from the pores of the rock around the injection well. Where does this water go? If the storage formation crops out nearby (or if it is in communication with other formations that crop out nearby), some of the water can be forced to the surface. On the other hand, if the storage formation extends for many miles underground, which is usually the case, the net effect is merely to compress the water and the rock around the storage bubble, as gas is injected. In a typical storage aquifer, roughly half of the space for the injected gas is created by the compression of the solid rock matrix and half is created by the compression of the water in the pores of the rock. Near the storage bubble the fluid pressure in the pores of the rock is the same as it is within the bubble. As the distance from the storage bubble increases, the density of the water-saturated rock and the pressure in the rock decrease. At a distance of several miles, the density and the pressure are practically unchanged, even at the end of the normal injection season.

At the beginning of the gas withdrawal season this process is reversed. The pressure within the storage bubble is reduced, permitting water to flow back into the bubble. The energy for this flow of water is produced by the expansion of the water-saturated rock around the bubble. Thus, the rock around the storage bubble acts like a large elastic reservoir. During the injection period, the rock is compressed, making room for more gas in the storage bubble. Then, during the withdrawal period, it expands, providing the energy to drive water into the bubble and displace some of the gas from it.

The petroleum production engineers encounter similar conditions when they try to predict the behavior of an oil or gas producing deposit in an aquifer. Van Everdingen and Hurst (1949) have presented methods for solving this problem. Katz et al. (1963) have shown how the Van Everdingen and Hurst method can be applied to specific problems in gas storage in aquifers. For example, suppose we know the following: initial pressure, thickness of reservoir, bubble radius, permeability of storage rock, and porosity of storage rock. The storage bubble grows at a constant rate, e_w, that is, water is displaced at the rate e_w. It is assumed that the aquifer is very large in comparison with the storage bubble. How will the reservoir pressure change with time, as gas is injected? This can be found in the following manner. First, the "dimensionless time," t_D, is calculated:

$$t_D = \frac{6.33 \times 10^{-3} Kt}{\mu \phi c r_b^2} \qquad (1)$$

where

K = permeability, millidarcys
t = time, days
μ = viscosity of water, centipoises
ϕ = porosity, fraction
r_b = bubble radius, feet
c = composite compressibility of the water-saturated porous formation, $\frac{\text{volume}}{\text{volume} \times \text{pounds per square inch (psi)}}$.

Then, by referring to Appendix A of Katz et al. (1963), the value of the "dimensionless pressure," P_t, is found that corresponds to this value of t_D. Finally, the reservoir pressure, p, is calculated from:

$$p = p_o - \frac{25.15 e_w \mu}{Kh} P_t \qquad (2)$$

where

p_o = initial reservoir pressure, pounds per square inch absolute (psia)
h = thickness of aquifer, feet
(e_w is given a negative sign if water moves away from the storage bubble; it is given a positive sign if water moves toward the bubble).

On the other hand, suppose we have a bubble of known thickness and radius. We propose to inject gas into the bubble while maintaining the pressure in the bubble at a pressure, p, above the pressure, p_o, in the aquifer. We wish to calculate how much water will be displaced during a given period of gas injection. First, we calculate this cumulative water efflux, W_e, in terms of Q_t, "dimensionless water efflux," by substituting the known values of ϕ, c, r_b, h, p_o, and p in this equation:

$$W_e = 6.283 \phi c r_b^2 h (p - p_o) Q_t. \qquad (3)$$

Next, we calculate the dimensionless time, t_D, from equation (1). Then, from Appendix B of Katz et al. (1963), we find the value of Q_t that corresponds to this value of t_D. Finally, we insert this value of Q_t in equation (3) to give W_e, the volume of water that is displaced. This enables us to estimate how the bubble will grow as gas is injected into the reservoir.

If the aquifer is enclosed, as in a sand lens surrounded by shale, it is called a "limited" aquifer; the treatment of the problem is the same, but different values of Q_t are used.

In the calculations outlined above, the assumption is made that within the gas bubble only gas flows and that outside the bubble only water flows. This assumption does not cause any serious errors after a large bubble has been developed; but in the early stages of development of the bubble, this is an overly simplified picture.

Actually, as gas displaces water from the aquifer, both gas and water flow through the rock in the same direction. In any given part of the rock, the flow of gas depends on the gas saturation—the greater the gas saturation, the higher the flow rate of gas. Likewise, the greater the water saturation, the higher the flow rate of water. Woods and Comer (1962) approach this problem in the following manner:

R_w = radius of well
R_b = radius of bubble
R_c = maximum radius to which bubble grows.

In the region from R_b to R_c, two-phase flow occurs (both water and gas flow). Outside R_c, only water flows. Woods and Comer apply the equations for two-phase flow to the region between R_b and R_c. Outside R_c, they use Van Everdingen's and Hurst's (1949) equations for flow of a compressible liquid. By combining these equations, they obtain a solution that describes the behavior of the aquifer more exactly.

In choosing the upper limit of pressure in the storage bubble (p_{max}), consideration is given to the pressure per foot of depth and to the difference between the initial aquifer pressure and the bubble pressure (see p. 15). The lower limit (p_{min}) during the gas withdrawal period depends on the economics of compressing gas that is withdrawn and the storage capacity that is required. If p_{min} is set at too high a value, the working capacity may be too small. On the other hand, if p_{min} is too low, the cost of compressing the gas for delivery to the pipeline may be too great.

Calculation of the storage capacity for given values of p_{max} and p_{min} would be a simple matter if water at the outer edge of the bubble did not move during the period of gas withdrawal. The amount of water movement can be estimated by the method outlined above for estimating the rate of growth of a storage bubble. Experience shows that in a typical withdrawal season, about 10 to 20 percent of the bubble volume is filled by water that flows inward as gas is withdrawn.

Let us assume that of the rock filled with gas at the start of withdrawal, 10 percent becomes flushed with water during the withdrawal season. This supplies a volume of gas equal to one-tenth of the total amount of gas that was in the storage bubble at the beginning of the withdrawal season. (A small amount of gas is trapped in the rock when it is flushed with water; this usually is so small that it can be neglected). In addition, in nine-tenths of the original bubble, the pressure is reduced from p_{max} to p_{min}. The volume of gas supplied by this pressure reduction can easily be calculated by means of standard formulas involving the known temperature, pressure, and compressibility of the gas.

Reservoir Capacity

The gas content of a reservoir can be calculated from the following equation (Katz et al., 1959, p. 456):

$$Q = 43,560\ A h \phi (1 - S) \frac{P T_b}{P_b T z} \qquad (4)$$

where

Q = gas in place, cubic feet, measured at P_b and T_b
A = areal extent, acres
h = thickness, feet
ϕ = fractional porosity
S = fractional saturation of pore space with water (for Illinois aquifers, S is usually about 0.15 to 0.30)
P = reservoir pressure, psia
P_b = measurement pressure base, psia
T = reservoir temperature, °R
T_b = measurement temperature base, °R
z = compressibility factor for gas

In this calculation, the reservoir is considered to be of uniform thickness, h. If the structure of the reservoir does not permit this assumption, the gross volume of the gas-filled rock is determined by planimetering the isopach map; the sum of the number of acre feet is inserted in the above equation in place of the volume factor, Ah. The quantity, Q, which is obtained in this manner, is the total amount of gas in the reservoir. Experience shows that usually about half of this gas is available for use in meeting peak load needs ("working gas"). The other half is known as "cushion gas."

Although the cushion gas is not available during the normal cycling of the reservoir, this does not mean that all of the cushion gas will be lost when the storage reservoir is eventually abandoned. Katz (1966) shows that the gas lost at abandonment of an aquifer includes (1) low pressure gas cap at the top of the aquifer (this permits gas to be produced without too much interference from advancing water), (2) gas trapped in the sand below the abandonment gas-water contact, and (3) gas dissolved in the water in and below the original storage bubble. In a typical case, the gas to be lost at abandonment was estimated to be 35 percent of the maximum inventory. This value, of course, will vary from one storage aquifer to another.

After the reservoir has been filled with gas and cycled once or twice, a working plot of gas volume versus observation well pressure can be drawn. Often changes in this working curve can be used to infer changes in the behavior of the reservoir.

Well Performance and Injection Pressures

Water pumping tests can be made on a well that penetrates the storage aquifer; from the results of these tests, the effective permeability of the reservoir rock can be calculated. Then, by standard reservoir engineering methods, the performance curve of a gas injection (or producing) well can be predicted. Or, if the permeability of the aquifer is known from core analyses, the performance curve of a well can be calculated. This enables one to estimate the number of operating wells that will be needed for the anticipated peak production rate. A good general discussion of practical problems in the testing of wells in gas storage fields is given by Guinane and Evrenos (1964).

The higher the injection pressure, the greater the rate at which the storage bubble is developed. However, if gas is injected at too high a pressure, the caprock may be fractured. Experience with hydraulic fracturing of oil and gas producing wells to increase production of these wells shows that sand-face pressures from about 0.7 to 1.0 psi per foot of depth are required to cause fracturing. In gas storage aquifers, injection pressures of approximately 0.55 psi per foot are often used.

Besides pressure per foot of depth, the difference between the injection pressure and the initial fluid pressure in the aquifer must also be considered. In the early stages of the development of the bubble, this difference is usually held at about 100 psi. If experience shows that this causes no leakage problems, the pressure difference is then increased to 200 psi or more. Selection of both the pressure per foot of depth and the pressure difference depends on the judgment of the storage engineer.

Caprocks

As pointed out above, if gas is to be stored in a porous reservoir, the reservoir must be overlain by a caprock that is relatively impervious to gas. In theory, this caprock need not have an extremely low permeability if it has a sufficiently high threshold pressure. (Threshold pressure is the pressure required to force gas into the pores of the water-wet rock.) In practice, the caprocks that are considered for storage purposes generally have extremely low permeabilities (10^{-4} to 10^{-6} millidarcys) as well as high threshold pressures.

A number of criteria are used to indicate whether or not a caprock may leak (Bays, 1964; Witherspoon, Mueller, and Donovan, 1962; Witherspoon and Neuman, 1966). Careful measurements of the head of water in wells drilled into porous zones above and below the caprock sometimes give useful results; a difference in head is an indication that the caprock is tight. Also, samples of formation waters above and below the caprock can be analyzed; a difference in composition of the waters is an indication that leakage may not be severe.

The permeability and threshold pressure of a core sample of the caprock can be determined in the laboratory. As mentioned above, permeabilities generally are in the range from 10^{-4} to 10^{-6} millidarcys and lower. Threshold pressures are usually in the range of several hundred pounds per square inch. Such measurements give the engineer some assurance that the caprock will be satisfactory, but they may not indicate fractures in the caprock through which gas may leak.

Various kinds of pumping tests have been devised to gain information about the *in situ* permeability of the caprock. Hantush (1956) shows how drawdown measurements in an observation well in the storage formation can be used as water is withdrawn or injected into the formation through another well. He also shows that while water is pumped from one well, drawdown measurements in a number of other wells can be used to give an estimate of the caprock permeability. Thus, a plot of r (distance from pumping well) versus log m_i (m_i = slope of the drawdown versus log time curve) gives a straight line. The intercept at r = o is log $(m_i)_o$. Katz et al. (1963, p. 123) show that Hantush's equations reduce to the following expression, which permits the calculation of the permeability of the caprock:

$$\frac{K'}{h'} = \frac{Kh}{r^2}\left[\log\left\{\frac{(m_i)_o}{m_i}\right\}\right]^2 \qquad (5)$$

Where

K = permeability of aquifer, millidarcys
h = thickness of aquifer, feet
K' = permeability of caprock, millidarcys
h' = thickness of caprock, feet
m_i = slope of drawdown curve in well at distance, r, from the pumping well

Witherspoon and Neuman (1966) point out some of the limitations of such methods as those of Hantush, which are based on pressure observations in the aquifer alone. If core analysis shows that the matrix permeability of the caprock is very low, any leakage detectable by these pressure observations is definite evidence of a fractured caprock. (This assumes that the possibility of leakage of water through the bottom of the aquifer has been excluded.) On the other hand, the sensitivity of the method is too low to permit the detection of borderline cases of fracturing that could be large enough to permit a troublesome amount of leakage. In the final analysis, one must rely on some kind of observation in porous zones overlying the caprock.

A method for using drawdown measurements, which were made in an observation well above the aquifer, to determine caprock permeability is described by Witherspoon, Mueller, and Donovan (1962). They utilize the well known Theis solution of certain problems in ground-water flow. In their method, a pumping well penetrates the aquifer; at a distance, r, from this pumping well, an observation well is completed in a zone of some permeability in or above the caprock to a point that is at a height, h", above the top of the aquifer. Water is withdrawn from the pumping well at a rate of q barrels per day for t days, resulting in a measured pressure change, $\Delta p'$ psi, in the observation well.

First, the dimensionless time, t_D, is calculated from

$$t_D = \frac{6.331 \times 10^{-3}\, Kt}{\phi \mu c r^2} . \qquad (6)$$

Then, from the Theis curve (Witherspoon, Mueller, and Donovan, 1962, fig. 4), the corresponding dimensionless pressure, p_D, is read. Next, Δp, the pressure change in the aquifer at distance, r, from the pumping well, is calculated from

$$\Delta p = \frac{p_D\, q\, \mu}{Kh \times 7.082 \times 10^{-3}} . \qquad (7)$$

Equation (6) is similar to equation (1) used by Katz et al. (1963) in calculating pressure change and water efflux. Katz et al. use the symbol P_t for dimensionless pressure, although Witherspoon, Mueller, and Donovan (1962) use the symbol p_D.

The constants in equations (6) and (7), 6.331×10^{-3} and 7.082×10^{-3}, are used when the units for the variables are as given above; that is, permeability is in millidarcys, time in days, viscosity in centipoises, compressibility in volume/(volume x psi), thicknesses and distances in feet, pressure in psi, and flow rate in barrels per day. If other units are used, different values must be used for these constants.

The ratio $(\Delta p'/\Delta p)$ is calculated. Then, the dimensionless height, $\underline{H}$, is calculated:

$$\underline{H} = \frac{h + h''}{h} . \qquad (8)$$

From Witherspoon, Mueller, and Donovan (1962, fig. 7), the parameter α is read. Finally, the permeability of the caprock is calculated from

$$K' = \frac{K\alpha}{t_D r^2} . \qquad (9)$$

Methods like these can give only an effective permeability; that is, the caprock acts as though it were a homogeneous rock with the given permeability. In fact, the observed leakage may be due to a rock of uniform or nonuniform permeability, or a fractured rock.

In some cases, the caprock itself may be tight, but a leak may exist at one point, perhaps because an old unlocated well was not properly plugged. Burnett (1967) gives a method for locating such a leak. As gas is withdrawn from the storage reservoir, the water level is measured in three observation wells in the caprock. The times required for a given response in the wells (for example, a 50-foot drop in water level) are measured. These times are proportional to the square roots of the distances from the wells to the leak. The wells are considered in pairs; the locus of points is constructed whose distance is proportional to the square roots of the response times for each pair. The common point of intersection of the three locus lines is the calculated point of the leakage.

Difficulties caused by leakage of the caprock can often be overcome by cycling the gas from an upper formation into the principal storage aquifer. Sometimes water is withdrawn to reduce the aquifer pressure; in other cases, water is injected into strategic areas to control leakage. Illinois companies have been among the pioneers in the testing and development of such methods.

LAWS AND REGULATIONS CONCERNING UNDERGROUND GAS STORAGE

Pipeline companies and other companies subject to the regulations of the Federal Power Commission must satisfy the requirements of that Commission with respect to any proposed underground gas storage project. Public utilities operating in Illinois are subject to the "Public Utilities Act" (Ill. Revised Statutes, 1965, chapt. 111 - 2/3). Under Section 55 of this Act, the Illinois Commerce Commission is directed to issue an order authorizing a new facility (such as an underground gas storage project) after it has found that the new facility is necessary.

Figure 4 - Southern limits of use of the Mt. Simon, Galesville, and St. Peter Sandstones as sources of potable water (prepared by R. E. Bergstrom).

In addition, gas storage companies that operate in Illinois are subject to certain rules and regulations of the Illinois Department of Mines and Minerals and of the Illinois Sanitary Water Board. Each well that is drilled requires a permit from the Department of Mines and Minerals. The Illinois State Mining Board is authorized to make rules and regulations to prevent the pollution of freshwater supplies by oil, gas, or salt water (Ill. Revised Statutes, 1965, chapt. 104, secs. 62-88; Illinois Dept. Mines and Minerals, Division of Oil and Gas, 1961). Furthermore, the storage company may need to furnish evidence to the State Sanitary Water Board that the proposed storage project will not result in the pollution of potable waters (Ill. Revised Statutes, 1965, chapt. 19, secs. 145-1 to 145-18).

From the standpoint of water pollution, each gas storage project is a separate problem. However, some broad guidelines may be helpful to one who is considering the possibility of underground storage. The principal aquifers used for storage in Illinois are the St. Peter, the Galesville, and the Mt. Simon Sandstones. The map of these sandstones (fig. 4) shows the areas where these are used as freshwater sources. As a general rule, a given aquifer cannot be used for gas storage if it is a potential freshwater source. Of course, no sharp dividing line exists between waters that are definitely fresh and those that are definitely salty, and under some circumstances, waters containing several thousand parts per million of solids may be considered useable. The Sanitary Water Board might require that such waters be protected against pollution; this could prevent the storage of gas in formations where these waters occur, or it could affect the casing program for storage wells in deeper formations.

The Natural Gas Storage Act (Ill. Revised Statutes, 1965, chapt. 104, secs. 104-112) gives storage companies the right to use private property for gas storage purposes in the manner provided for by the law of eminent domain. According to the act, before the right of condemnation can be exercised, the corporation must receive an order from the Illinois Commerce Commission approving the proposed storage project. Furthermore, the Commerce Commission cannot issue such an order unless it finds that the proposed storage (1) will be confined to strata lying more than 500 feet below the surface, (2) will not injure any water resources, and (3) will involve no condemnation of any interest in any geological stratum within the area of the proposed storage containing oil, gas, or coal...in commercial quantities (paraphrased and condensed from parts of the Natural Gas Storage Act; for further details consult the Illinois Revised Statutes and the files of the Illinois Commerce Commission since 1951).

Thus, a company that has difficulty in acquiring storage rights from the owners of the mineral rights in a given storage area must meet the provisions of the Natural Gas Storage Act if it wishes to exercise the right of eminent domain. However, a company that already has leases that permit it to store gas may not need to exercise the right of eminent domain, and thus it may not have to satisfy the depth requirement of the Storage Act. For example, a depleted gas reservoir such as Freeburg can be used for storage even though its depth (350 feet) is less than the 500 feet specified in the Natural Gas Storage Act.

To summarize, in Illinois, a given gas storage project may have to satisfy the requirements of the Federal Power Commission, the Illinois State Mining Board, the Illinois State Sanitary Water Board, and the Illinois Commerce Commission, depending on the circumstances.

FUTURE OF UNDERGROUND GAS STORAGE IN ILLINOIS

Pipeline companies and distributing companies are still actively seeking new reservoirs for storage of gas. The total volume of gas in underground storage in the state will probably be increased by 50 percent or so within the next few years.

Competition from coal and from nuclear energy sources may restrict opportunities for selling gas on an interruptible basis for electric power generation. This could give economic incentive for the development of more underground gas storage to handle excess gas brought into the state by pipelines during the summer months. On the other hand, if the use of high-sulfur coal and fuel oil is cut back because of air pollution controls, demand for gas on a firm as well as an interruptible basis may increase. This could result in decreased pressure for the development of new underground gas storage. At this point, we cannot determine which of these effects will be dominant.

Unless suitable aquifers are found, more depleted oil reservoirs, such as the Devonian in the Louden Field, will probably be used for gas storage. In addition, many small abandoned oil and gas reservoirs may be used for small storage projects. Such reservoirs, although of little value to the large pipeline or distributing company, might be profitably used where an industry or a town needs a small amount of storage. In some cases, the gas storage operation may result in the production of additional oil from abandoned reservoirs, which may pay for a part of the storage costs (Oil and Gas Jour., 1967).

Besides storage in aquifers or in depleted oil and gas reservoirs, alternative methods of storing gas will be developed. For example, the gas may be stored as a liquid (LNG), or storage caverns may be blasted in nonporous rock by means of nuclear explosives (Coffer, 1967; Witherspoon, 1966). In Illinois, LNG storage cannot compete with aquifer storage because of the greater cost of LNG. However, LNG may be used on a relatively small scale to supplement aquifer storage when a large amount of gas is needed for a short time. Underground caverns blasted by nuclear explosives are not likely to be used in Illinois. Nuclear explosions would not be permitted near metropolitan areas, where the storage is most needed. In the less populated areas, where nuclear explosions might possibly be permitted, aquifers and depleted oil and gas reservoirs are available at a fraction of the cost of caverns formed by nuclear explosives.

Within the next 10 to 20 years, a coal gasification industry will probably be built up in Illinois. As it is developed, huge gas storage reservoirs will be needed to act as surge tanks, in case the gasification plants are shut down, and to take care of seasonal variations in the demand for gas. Since many depleted oil reservoirs are near potential sources of coal, these reservoirs may serve the storage needs of the gasification plants.

Underground gas storage should be a growing activity in Illinois for many years to come.

SUMMARY OF ACTIVE STORAGE PROJECTS IN ILLINOIS

At the end of 1966, 19 underground gas storage projects were operating in Illinois, containing a total of over 200 billion cubic feet of gas (fig. 1). These projects, plus three others that have been developed or approved for gas injection, are discussed here. A summary of pertinent data is presented in table 1. Several more projects are in various stages of development, but the available data are insufficient to discuss them at this time. Projects that have been tested and abandoned or that are inactive and awaiting further testing are not included in this report.

Information about each project was obtained from current statistics and structure maps kindly furnished by the operating companies. Also freely used in the preparation of this report was testimony presented to the Illinois Commerce Commission during hearings on petitions for certification to store gas at each project. The testimony contains much valuable information that is available to the public from the files of the Illinois Commerce Commission at Springfield, Illinois.

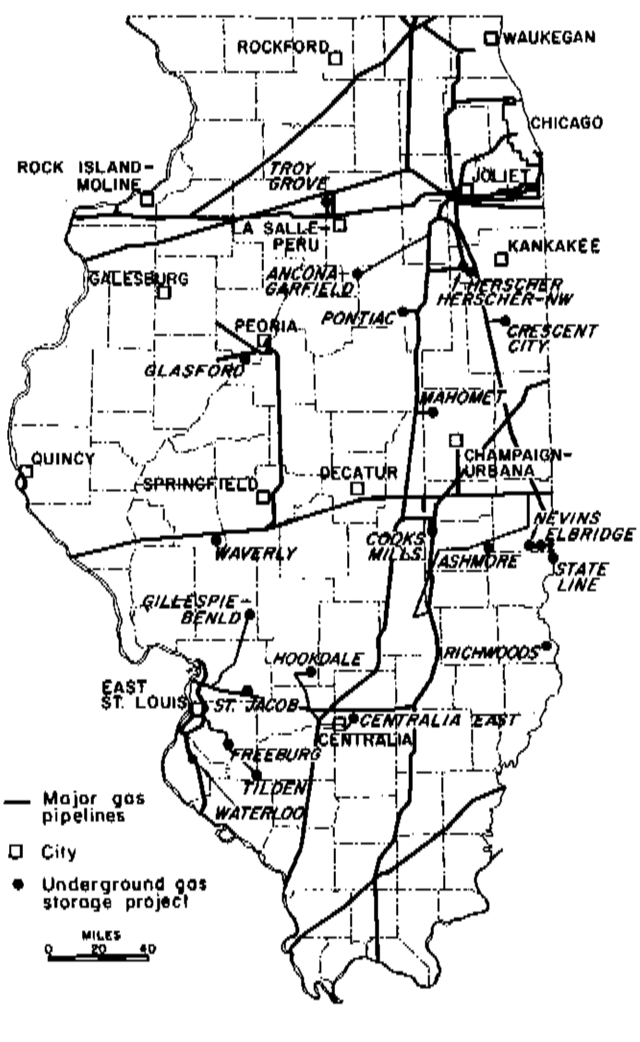


Figure 5 - Underground storage projects and major gas transmission lines in Illinois.

Storage projects in Illinois, in general, are located near the major centers of population, such as Chicago and St. Louis, or they are relatively near the main pipeline systems. Several smaller projects, however, are located in areas of abandoned gas fields (fig. 5).

All systems of rocks from Cambrian to Pennsylvanian are used for gas storage in Illinois (figs. 6, 7), although most of the storage volume is in aquifers of Cambrian and Ordovician age. Eight projects have gas stored in depleted gas reservoirs. Illinois Power Company has five of these projects; Natural Gas Pipeline Company, Central Illinois Public Service Company, and Gas Utilities Company each have one. All the rest of the projects have gas stored in aquifers.

The Mt. Simon, Galesville, and St. Peter Sandstones are the most commonly used aquifers in northern and central Illinois. The Mt. Simon is a thick basal sandstone overlain by shale and siltstone of the Eau Claire Formation. The Galesville is a porous and permeable sandstone that varies from a feather edge to about 100 feet thick in northern Illinois. It is absent in the southern part of the state. Overlying the Galesville is the Ironton Sandstone, which contains several beds of dolomite, and the Franconia Formation, which contains sandstone, shale, and dolomite. The St. Peter is a permeable sandstone of variable thickness. It crops out in northern Illinois and dips southward under younger strata. Overlying the St. Peter are thin beds of shale and sandstone of the Glenwood Formation in the north, and dolomite, shale, sandstone, and anhydrite of the Joachim Formation in the south. The Platteville Limestone Group overlies the Glenwood or Joachim.

At the top of the Ordovician System is the Maquoketa Shale, which is widespread and relatively impermeable. In many areas, the Maquoketa is considered an ultimate caprock in the event of any upward migration of gas stored in underlying formations.

The gas storage capacity of Illinois aquifers in presently developed projects is greater than the aquifer storage in any other state.

GENERALIZED GEOLOGIC COLUMN OF SOUTHERN ILLINOIS

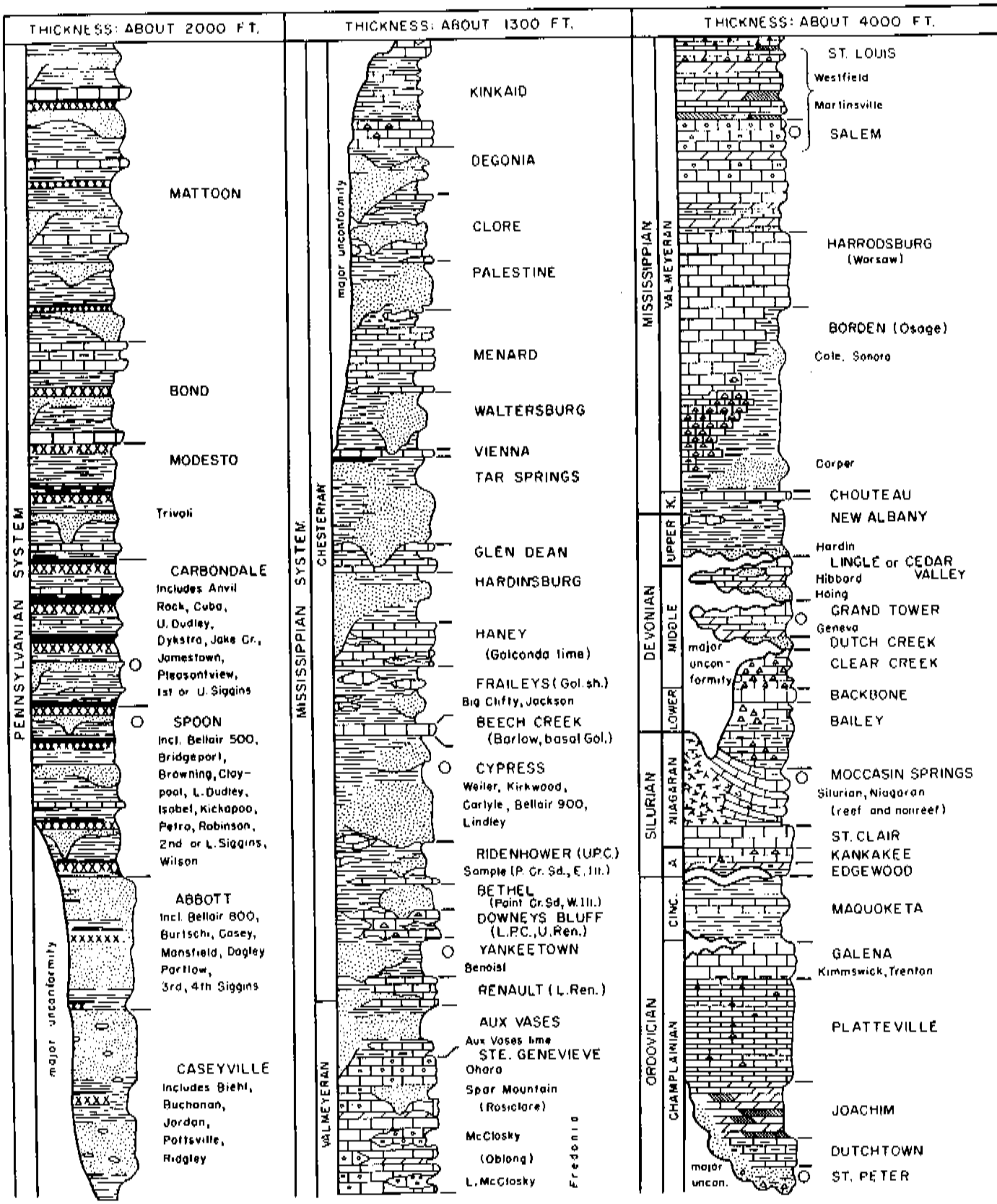


Figure 6 - Generalized geologic column of southern Illinois above the St. Peter Sandstone. Circles indicate gas storage zones (variable vertical scale; stratigraphy by D. H. Swann).

SYSTEM	SERIES	STAGE	MEGAGROUP	GROUP	FORMATION	GRAPHIC COLUMN	THICKNESS (FEET)	LITHOLOGY
ORDOVICIAN	CINCINNATIAN	RICH.		MAQUOKETA	Neda		0-15	Shale, red, hematitic, oolitic
					Brainard		0-100	Shale, dolomitic, greenish gray
					Ft. Atkinson		5-50	Dolomite and limestone, coarse grained; shale, green
		MA. / ED.			Scales		90-100	Shale, dolomitic, brownish gray
	CHAMPLAINIAN	TRENTONIAN	OTTAWA	GALENA	Wise Lake - Dunleith		170-210	Dolomite, buff, medium grained
					Guttenberg		0-15	Dolomite, buff, red speckled
		BLACKRIVERAN		PLATTEVILLE	Nachusa		0-50	Dolomite and limestone, buff
					Grand Detour		20-40	Dolomite and limestone, gray mottling
					Mifflin		20-50	Dolomite and limestone, orange speckled
					Pecatonica		20-50	Dolomite, brown, fine grained
			KNOX	ANCELL	Glenwood		0-80	Sandstone and dolomite
					St. Peter ○		100-600	Sandstone, fine; rubble at base
	CANADIAN			PRAIRIE DU CHIEN	Shakopee		0-67	Dolomite, sandy
					New Richmond		0-35	Sandstone, dolomitic
					Oneota ○		190-250	Dolomite, slightly sandy; oolitic chert
					Gunter		0-15	Sandstone, dolomitic
CAMBRIAN	CROIXAN	TREMPEALEAUAN			Eminence		50-150	Dolomite, sandy; oolitic chert
					Potosi		90-220	Dolomite, slightly sandy at top and base, light gray to light brown; geodic quartz
		FRANCONIAN			Franconia		50-200	Sandstone, dolomite and shale; glauconitic
					Ironton		80-130	Sandstone, medium grained, dolomitic in part
		DRESBACHIAN			Galesville ○		10-100	Sandstone, fine grained
					Eau Claire ○ (*Proviso Mbr.*, *Lombard Mbr.*, *Elmhurst Mbr.* ○)		370-575	Siltstone, shale, dolomite, sandstone, glauconite
			POTSDAM		Mt Simon ○		1200-2900	Sandstone, fine to coarse grained

Figure 7 - Generalized columnar section of Cambrian and Ordovician strata in northeastern Illinois (after Buschbach, 1964). Circles indicate gas storage zones.

Ancona-Garfield Project

Operator: Northern Illinois Gas Company
Location: Near Ancona, 7 miles southwest of Streator, T. 29 and 30 N., R. 2 and 3 E., Livingston and LaSalle Counties

Gas for the Ancona-Garfield project is purchased from Natural Gas Pipeline Company of America. A 24-inch pipeline connects the project to the Natural Gas Pipeline Company of America trunkline at Mazon, Illinois. The gas is consumed in the suburban Chicago area.

Structure drilling in the area began in 1958, and 123 structure tests have been drilled to the Galena Dolomite Group or deeper. A gravity survey was run to help delineate the structure. Gas was first injected in 1963 and the project became operational in 1965 (table 2).

TABLE 2 - INJECTION AND WITHDRAWAL HISTORY OF ANCONA-GARFIELD PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	105	0	105	0
1964	1,976	0	2,080	0
1965	4,857	39	6,899	22
1966	9,237	360	14,431	77

The Ancona-Garfield structure is an asymmetrical anticline, 10 miles long and 4 miles wide, that trends northwest (fig. 8). At the crest of the structure are the Ancona and Garfield Domes, separated from each other by a gentle saddle.

The storage reservoir is in the Mt. Simon Sandstone, an aquifer with a porosity of 12.3 percent. The caprock is the Eau Claire Formation, which is 400 feet thick. The upper 250 feet of the Eau Claire consists of shaly and dolomitic sandstones and siltstones; the lower 150 feet consists chiefly of dense, grayish green shale with thin silty and sandy beds at the base.

The Ancona-Garfield structure has 290 feet of closure on top of the Mt. Simon Sandstone. (Closure is considered the difference in elevation between the highest point on the dome or anticline and the lowest structure contour that completely surrounds it.) The Ancona Dome has 96 feet of closure and the Garfield Dome has 89 feet. When injection of gas exceeds the limits of the two domal peaks, the gas will comingle through the saddle area. At that time, the entire anticlinal area can be operated as a single storage project.

The reservoir is 2154 feet deep and covers about 12,840 acres. Ultimate capacity of the dual project has been estimated as high as 100 billion cubic feet, about half of which would be working gas.

The Ancona-Garfield project has 36 injection and withdrawal wells and 14 observation wells. In each operational well, 7-inch casing was cemented through the storage zone and perforated. The normal injection pressure is 1160 pounds per square inch gauge (psig).

Ashmore Project

Operator: Central Illinois Public Service Company
Location: 8 miles east of Charleston, T. 12 N., R. 10 and 11 E., 14 W., Coles and Clark Counties

Gas for the Ashmore project comes from Panhandle Eastern Pipeline Company and Trunkline Gas Company. The gas is consumed in east-central Illinois.

This reservoir originally contained gas that was discovered in 1957. Since then, 43 gas wells have been completed (Meents, 1965, p.2). Ten of these wells were completed in the northern area, where the small volume of gas is used for individual households. The southern part of the field contains 33 gas wells, 23 of which are now being used for injection and withdrawal of storage gas.

Gas is being stored in sandstone of the Spoon Formation (Pennsylvanian) and in the underlying Salem Limestone (Mississippian). No attempt is made to segregate injection or production from the two units. The Pennsylvanian gas sand is 4 to 80 feet thick in the area, generally thickening off structure. Average porosity of the sandstone is 16 percent and permeability is 144 millidarcys. The Salem Limestone has an average porosity of 15 percent with permeability up to 3000 millidarcys. The caprock is several hundred feet of shale and coal of Pennsylvanian age.

The Ashmore structure is an elongate dome. It trends north-south and has closure of 87 feet on top of the gas sand and 144 feet on top of the Salem Limestone and Borden Siltstone (Meents, 1965, p. 13). The dome is about 4 miles long and 2 miles wide (fig. 9). Depth of the reservoir is 350 to 446 feet. Ultimate capacity of the reservoir is estimated to be 2 billion cubic feet.

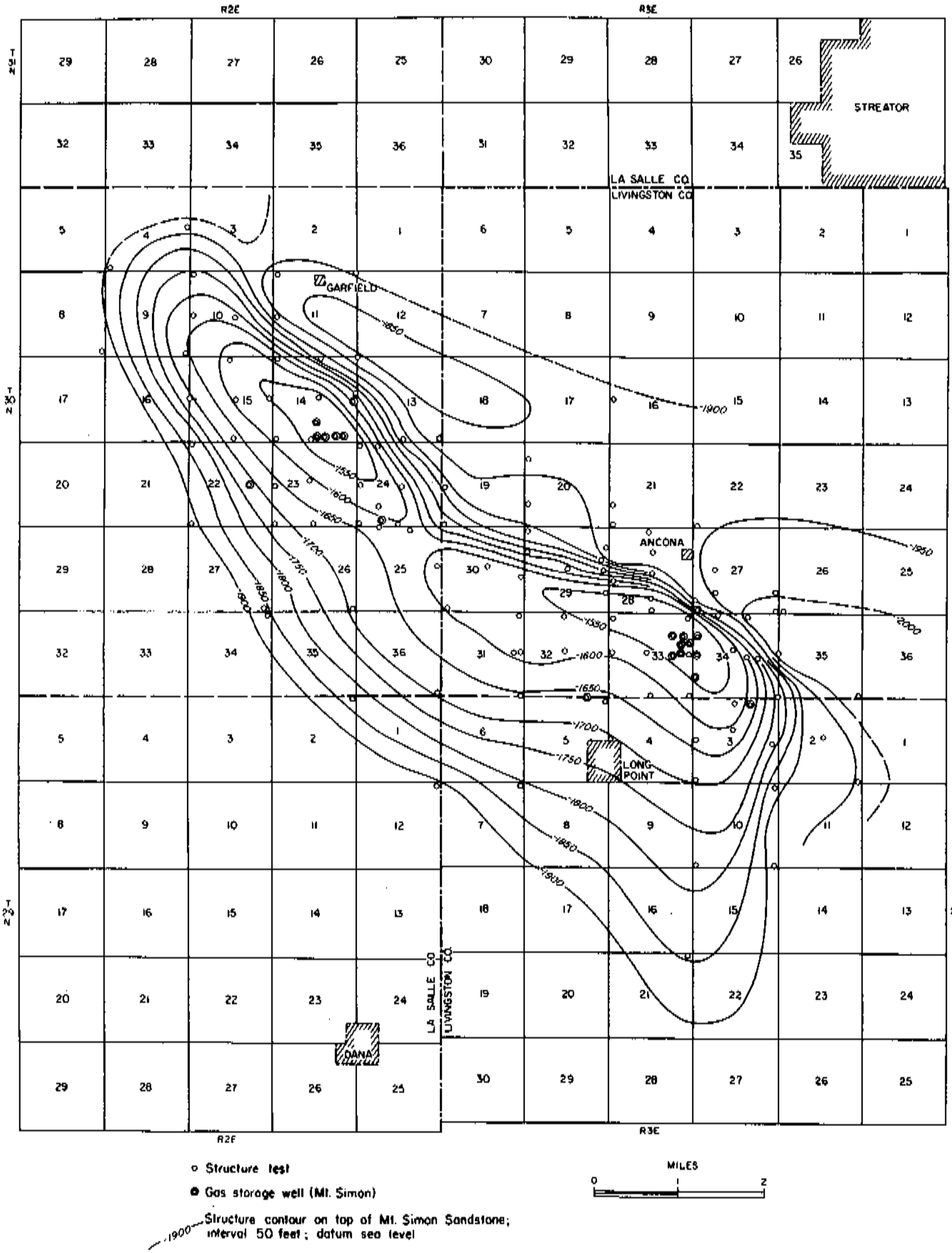


Figure 8 - Top of Mt. Simon Sandstone at Ancona-Garfield, Livingston and LaSalle Counties (Northern Illinois Gas Co.).

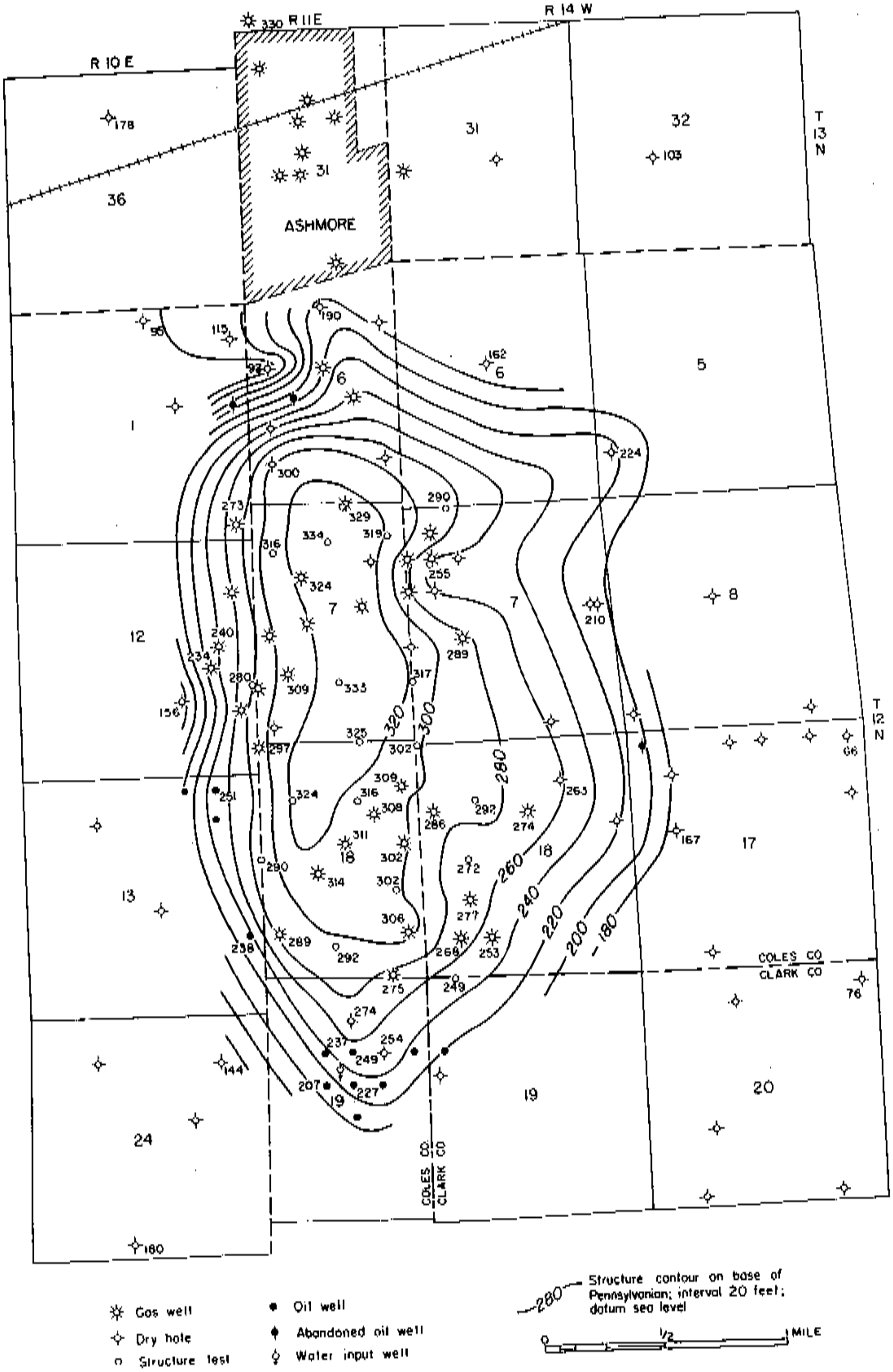


Figure 9 - Top of Mississippian (Salem Limestone or Borden Siltstone) at Ashmore (Meents, 1965).

Most wells have $4\frac{1}{2}$-inch production casing set in the top of the Pennsylvanian gas sand, and the wells are completed as open holes. In a few instances, casing has been set through the Salem porosity with the casing perforated by four shots per foot. No tubing or siphon strings are used.

Normal injection pressure is 145 psig. Open-flow potential of the wells ranges from 200 to 7200 Mcf per day with an average of 800. The Ashmore structure was developed for gas storage in 1960 and became operational in 1963. The amounts of gas injected and withdrawn are shown in table 3.

TABLE 3 - INJECTION AND WITHDRAWAL HISTORY OF ASHMORE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1963	311	58	253	11
1964	458	115	596	10
1965	489	234	851	12
1966	388	310	929	14

*Working gas

Centralia East Project

Operator: Illinois Power Company
Location: 1 mile east of Centralia, T. 1 N., R. 1 E., Marion County

Gas for the Centralia East project is purchased from Natural Gas Pipeline Company of America and is consumed in the Centralia-Mt. Vernon area.

The reservoir is in a former gas field that was discovered in 1958. Gas was produced from 1958 to 1964. Injection of storage gas commenced in 1964 with 272 MMcf injected that year and 61 MMcf injected in 1965. No withdrawals of injected gas were made in 1965, but the project became operational during the 1966-67 heating season (table 4).

The reservoir is a stratigraphic trap in a sandstone of Pennsylvanian age. The sandstone has a maximum thickness of 49 feet and has an average porosity of 18.2 percent. The reservoir is about 812 feet below the surface and covers 463 acres (fig. 10).

The project contains 15 injection and withdrawal wells and 6 observation wells. In all wells, $5\frac{1}{2}$-inch production casing was set 40 feet below the gas-water contact. The casing was perforated with four shots per foot at the gas sand.

TABLE 4 - INJECTION AND WITHDRAWAL HISTORY OF CENTRALIA EAST PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1964	272	—	272	—
1965	61	—	332	—
1966	23	18	337	4.8

Normal injection pressure is 250 to 350 psig. Open-flow potential of the wells ranges from 260 to 9000 Mcf per day with an average of 3016.

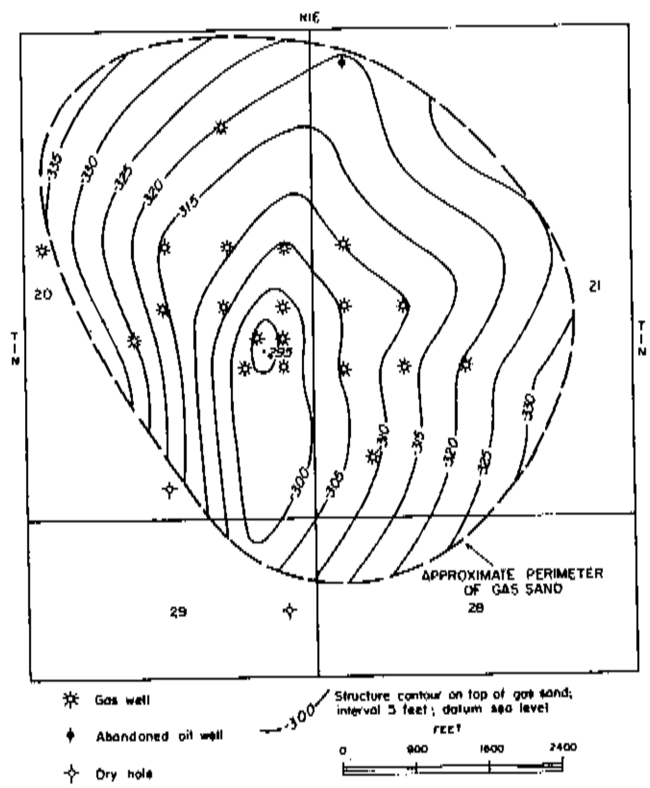


Figure 10 - Top of Pennsylvanian gas sand at Centralia East, Marion County (Illinois Power Co.).

Cooks Mills Project

Operator: Natural Gas Pipeline Company of America
Location: T. 14 N., R. 7 and 8 E., Coles and Douglas Counties

Gas for the Cooks Mills project comes from the Gulf Coast System line of Natural Gas Pipeline Company of America by way of 16 miles of 20-inch pipeline to Cooks Mills. The gas is consumed in the Chicago area.

The Cooks Mills Consolidated oil pool was discovered in 1941 (Whiting, 1959), but it was not fully developed until 1954. Oil and gas are produced from the Cypress and Aux Vases Sandstones and the Spar Mountain ("Rosiclare") Sandstone Member of the Ste. Genevieve Formation, all of Mississippian age. In 1963, some oil was discovered in the underlying Carper sand (Mississippian) and in limestone and dolomite of Devonian age. The pool has produced 2,794,000 barrels of oil through the end of 1966 and is currently under waterflood. In one part of the field, several wells produced gas from the Cypress Sandstone. Natural Gas Pipeline Company of America purchased the gas in place and also the storage rights.

Gas is stored in the Cypress Sandstone, which has a porosity of 16 percent. The trap is a combination of an anticline and a stratigraphic trap (fig. 11). The caprock is shale of Chesterian age. The reservoir is 1600 feet deep, has 40 feet of closure, and covers 1500 acres. Ultimate capacity of the reservoir is unknown, but at the end of 1966, it contained 3.8 billion cubic feet of gas.

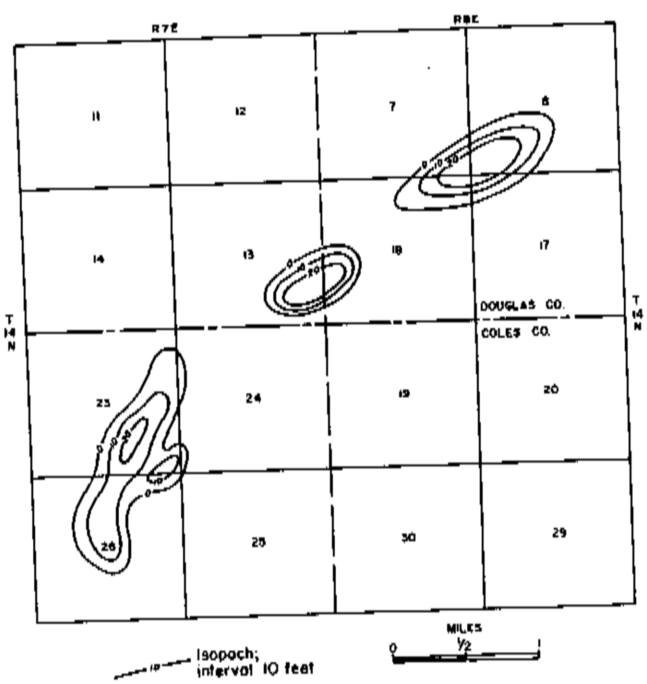


Figure 11 - Thickness of Cypress net gas sand at Cooks Mills, Coles and Douglas Counties (Natural Gas Pipeline Co. of America).

Nine wells are used for injection and withdrawal of gas and eight for observation. Operational wells were drilled through the Cypress and were cased to total depth. The $5\frac{1}{2}$-inch production casing was perforated adjacent to the reservoir.

Normal injection pressure is 840 psig. No records are available on open-flow potential, but 56 million cubic feet of gas has been withdrawn during one day of 1966 (table 5).

TABLE 5 - INJECTION AND WITHDRAWAL HISTORY OF COOKS MILLS PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	—	—	1,769	—
1959	1,206	978	1,998	—
1960	427	304	2,120	32
1961	1,022	1,058	2,083	27
1962	1,142	1,016	2,210	31
1963	1,532	1,327	2,416	45
1964	2,495	1,412	3,499	45
1965	2,099	1,801	3,796	52
1966	2,386	2,392	3,790	56

Crescent City Project

Operator: Northern Illinois Gas Company
Location: Between Crescent City and Watseka, T. 26 and 27 N., R. 13 W., Iroquois County

Gas for the Crescent City project will be supplied by Midwestern Gas Transmission Company through a 6-inch supply main from their 30-inch pipeline. Currently, there is no pipeline from the project to the consuming area, suburban Chicago.

An oil test near Crescent City indicated a structural high that was mapped as a dome by the Illinois State Geological Survey (Meents, 1954).

The Crescent City Dome was delineated in 1959 by structure drilling and gravity surveys. A total of 78 structure tests have been drilled to the Fort Atkinson Limestone (middle Maquoketa) or deeper. The development of the field was delayed by litigation with some land owners. Injection of gas began in 1967.

The trap is an asymmetrical anticline that trends northwest (fig. 12). The reservoir is in the St. Peter Sandstone, an aquifer with 14.5 percent porosity and an average permeability of 138 millidarcys. The reservoir is 1200 feet below surface and covers 16,725 acres within the area leased. The ultimate capacity of the Crescent City project is estimated to be 50 billion cubic feet. The caprock is 400 feet of limestone and dolomite assigned to the Platteville and Galena Groups. The lower part of the Platteville contains beds of very fine-grained limestone. Observation

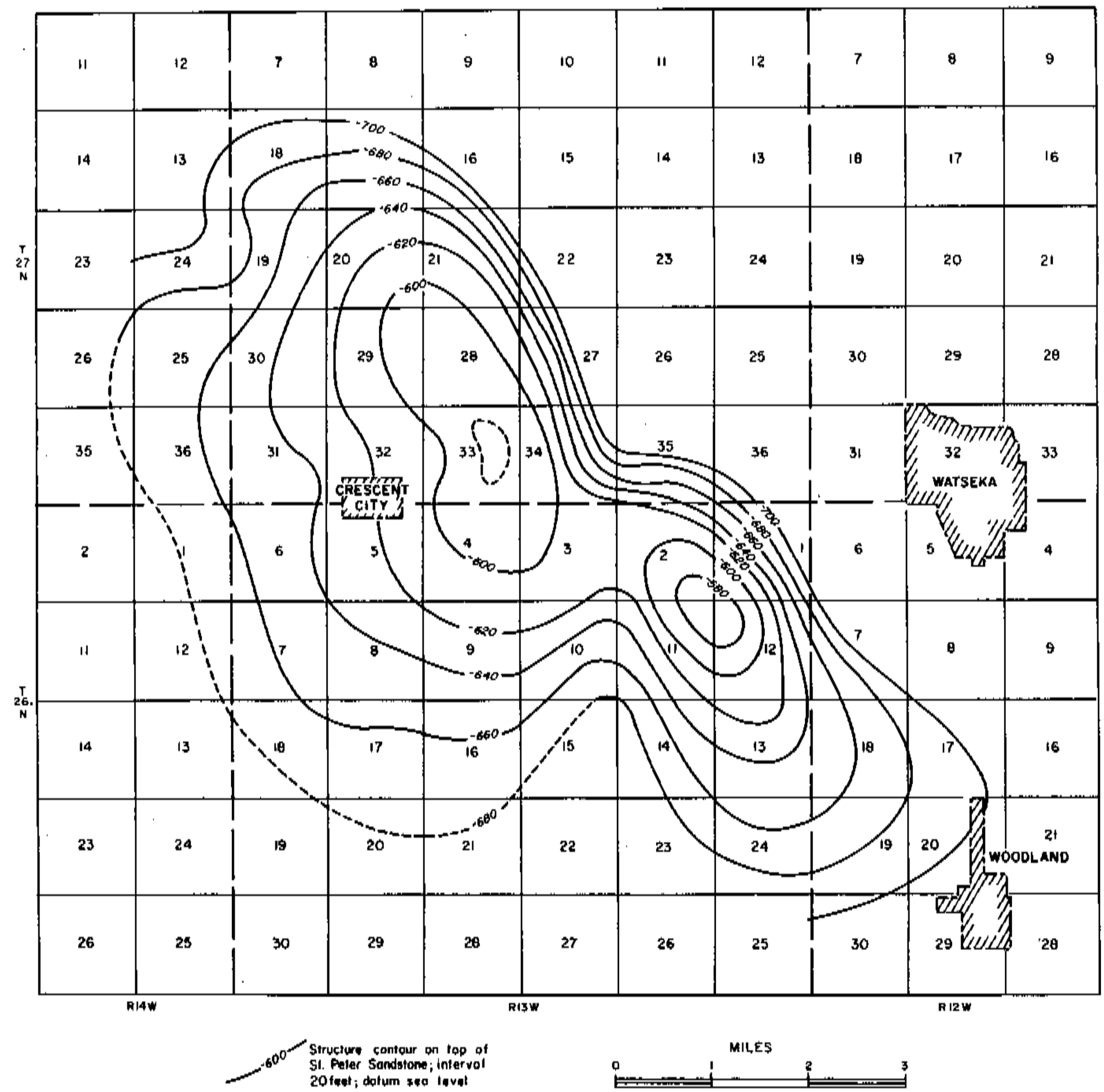


Figure 12 - Top of St. Peter Sandstone at Crescent City, Iroquois County (Northern Illinois Gas Co.).

wells in the overlying Galena will be used to monitor and collect any leakage gas. Overlying the Galena is the Maquoketa Shale Group, which is about 220 feet thick.

Twenty-five wells have been completed for observation, injection, or withdrawal. The operational wells have been cased through the reservoir with 7-inch production casing and have been perforated adjacent to the reservoir. Two deep wells were drilled and cored into the Mt. Simon Sandstone. The Galesville and the Mt. Simon Sandstones, beneath the St. Peter, are considered for future gas storage.

Elbridge Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 and 13 N., R. 11 W., Edgar County

Gas for the Elbridge project comes from Midwestern Gas Transmission Company's 30-inch line through 10- to 16-inch feeder lines. At times of withdrawal, the gas will be returned to the same pipelines. Elbridge is a former oil field that was discovered in 1949. About 1.5 million barrels of oil have been produced from this pool, chiefly from sandstones of Pennsylvanian age and from the Mississippian Ste. Genevieve Limestone.

Gas is stored in porous dolomite and dolomitic limestone beds of the Grand Tower Formation (Devonian). No gas is stored in the oil producing formations. The dome-shaped structural trap was formed by the draping of Devonian and younger strata over a Silurian reef. The caprock is 90 feet of shale of the New Albany Group directly overlying the dolomite and limestone. Observation wells in the porous Carper sand, which overlies the New Albany, will be utilized to monitor any gas leakage from the reservoir upward through the caprock.

The Elbridge Dome has 145 feet of closure on top of the Grand Tower and covers 1691 acres (fig. 13). The reservoir has an average porosity of 17.5 percent and is 1925 feet deep. The ultimate capacity of the Elbridge project is estimated to be 6.2 billion cubic feet of gas, about half of which will be working gas.

Elbridge has four injection and withdrawal wells and six observation wells. The operational wells have $4\frac{1}{2}$-inch casing that is set and cemented 30 feet into the storage formation. The casings are perforated with four shots per foot opposite the top 25 feet of porosity. Packers are run on $2\frac{3}{8}$-inch tubing and set about 50 feet above the perforations. Gas is injected and withdrawn through the $2\frac{3}{8}$-inch tubing.

Normal injection pressure is 1100 psig. Open-flow potentials of the wells range from 600 to 7400 Mcf per day and average 3900 Mcf. Gas injection at Elbridge began in 1965 (table 6).

TABLE 6 - INJECTION AND WITHDRAWAL HISTORY OF ELBRIDGE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	425	0	425	—
1966	2,375	81	2,719*	11

*Estimate - structure presently being tested

Freeburg Project

Operator: Illinois Power Company
Location: 2 miles south of Freeburg, T. 1 and 2 S., R. 7 W., St. Clair County

Gas for the Freeburg project is purchased from the Mississippi River Fuel Corporation. The gas is consumed in the East St. Louis area.

The reservoir is in a former gas field, discovered in 1956 (Meents, 1959) and acquired for use as a storage field in 1958. The reservoir is a monoclinal stratigraphic trap in the Cypress Sandstone. The Cypress dips to the south and east and grades to shale to the north and west. The sandstone has an average porosity of 21.5 percent and has a maximum thickness of 47 feet.

TABLE 7 - INJECTION AND WITHDRAWAL HISTORY OF FREEBURG PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1959	170	181	1,798	19
1960	494	462	1,760	23
1961	534	473	1,821	30
1962	1,085	1,059	1,869	42
1963	301	620	1,541	39
1964	720	632	1,604	40
1965	1,664	1,580	1,686	37
1966	1,463	1,551	1,871	38

*Working gas

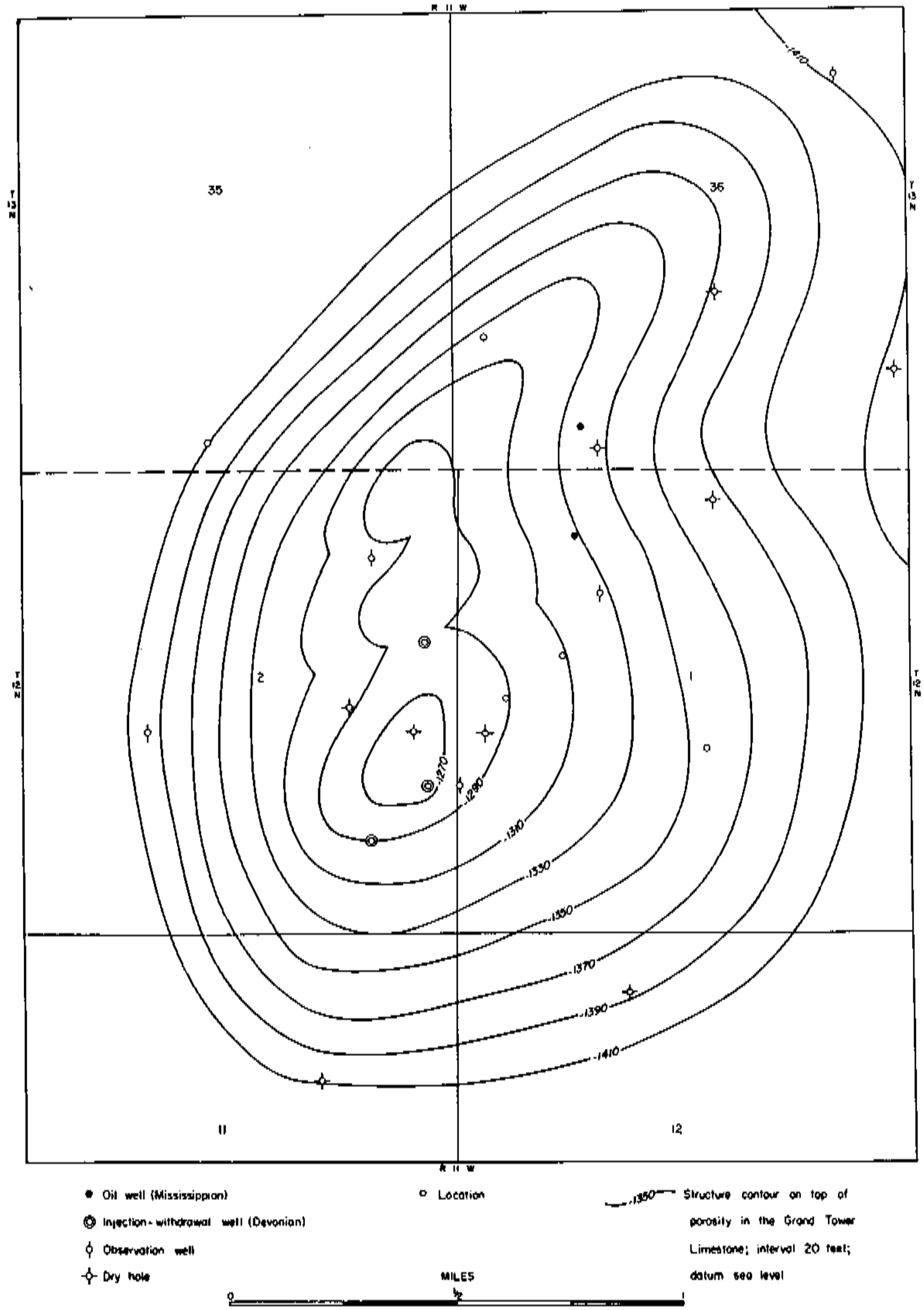


Figure 13 - Top of porosity in the Grand Tower (Jeffersonville) Limestone at Elbridge, Edgar County (Midwestern Gas Transmission Co.).

The reservoir is 300 to 400 feet below the surface and covers 4222 acres (fig. 14). The caprock is 16 to 28 feet of shale overlying the sandstone reservoir.

At the end of 1966, the reservoir contained 1.87 billion cubic feet of working gas (table 7) and 4.63 billion cubic feet of cushion gas. The project has 68 injection and withdrawal wells and 6 observation wells. In all wells, $5\frac{1}{2}$-inch casing was set to the top of the Cypress and the wells were completed open hole with cable tools.

Normal injection pressure is 150 to 180 psig. Open-flow potential of the wells ranges from 60 to 4600 Mcf per day with an average of 1989.

Gillespie-Benld Project

Operator: Illinois Power Company
Location: 2 miles east of Gillespie, T. 8 N., R. 6 W., Macoupin County

Gas for the Gillespie-Benld project is purchased from the Mississippi River Fuel Corporation. The gas is consumed in Gillespie, Benld, and nearby communities.

This reservoir is a former gas field, discovered in 1923 and abandoned in 1935 after it had produced 136 million cubic feet of gas. Storage gas was first injected at Gillespie-Benld in 1958 and withdrawals began in 1959 (table 8).

The reservoir is a stratigraphic trap consisting of a sandstone lens of Pennsylvanian age. The sandstone ranges from a feather edge to 28 feet thick and has a porosity of 16 percent. The reservoir is 500 to 550 feet deep and covers 113 acres (fig. 15).

Seven wells are used for injection and withdrawal. Old gas wells were cleaned and filled with crushed stone to the top of the gas reservoir. New wells were drilled to the top of the reservoir where $4\frac{1}{2}$- or $5\frac{1}{2}$-inch production casing was set. The new wells were then completed open hole into the reservoir with cable tools.

Normal injection pressure is 145 to 180 psig. Open-flow potential of wells ranges from 83 to 5100 Mcf per day, with an average of 2350.

TABLE 8 - INJECTION AND WITHDRAWAL HISTORY OF GILLESPIE-BENLD PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	101	0	115	0
1959	44	10	147	1
1960	37	30	148	4
1961	74	61	146	4
1962	59	47	146	4
1963	8	8	146	1
1964	8	6	147	2
1965	3	2	147	0.09
1966	13	14	147	4.4

Glasford Project

Operator: Central Illinois Light Company
Location: 12 miles southwest of Peoria, 3 miles northeast of Glasford, T. 7 N., R. 6 E., Peoria County

Gas for the Glasford project comes from Panhandle Eastern Pipeline Company through a 24-inch line and an 8-inch line. The gas is consumed in the Peoria market.

Studies of Pennsylvanian rocks in outcrops and coal test borings indicated a structural high northeast of Glasford. The structure was mapped as a dome by the Illinois State Geological Survey (Wanless, 1957).

Field mapping, gravity surveying, and structure drilling delineated the Glasford structure as a circular dome with a diameter of about $2\frac{1}{2}$ miles. A deep well was drilled and cored at the crest of the dome. It penetrated a normal appearing, though slightly thinned, sequence of Paleozoic strata down to the Ordovician Maquoketa Shale Group. The Maquoketa is about 100 feet thicker than normal for the area, and beneath it is a jumble of blocks set at all angles in a matrix of fine breccia (fig. 16). The structure is classed as an explosion structure and has been interpreted as an astrobleme, the result of a meteorite or comet collision with the earth (Buschbach and Ryan, 1963).

Gas is being stored above the disturbed rocks, in gently arched beds of vuggy dolomite of the Niagaran Series (Silurian). The reservoir is slightly over 100 feet thick and has a porosity of about 12 percent. Overlying the reservoir is 40 feet of fine-grained limestone of Devonian age, which is overlain by over 200 feet of shale of the New Albany Group.

The trap is a structural dome. The top of the Niagaran Series has 120 feet of closure, with about 3200 acres included within the last closing contour (fig. 17). The reservoir is 800 feet be-

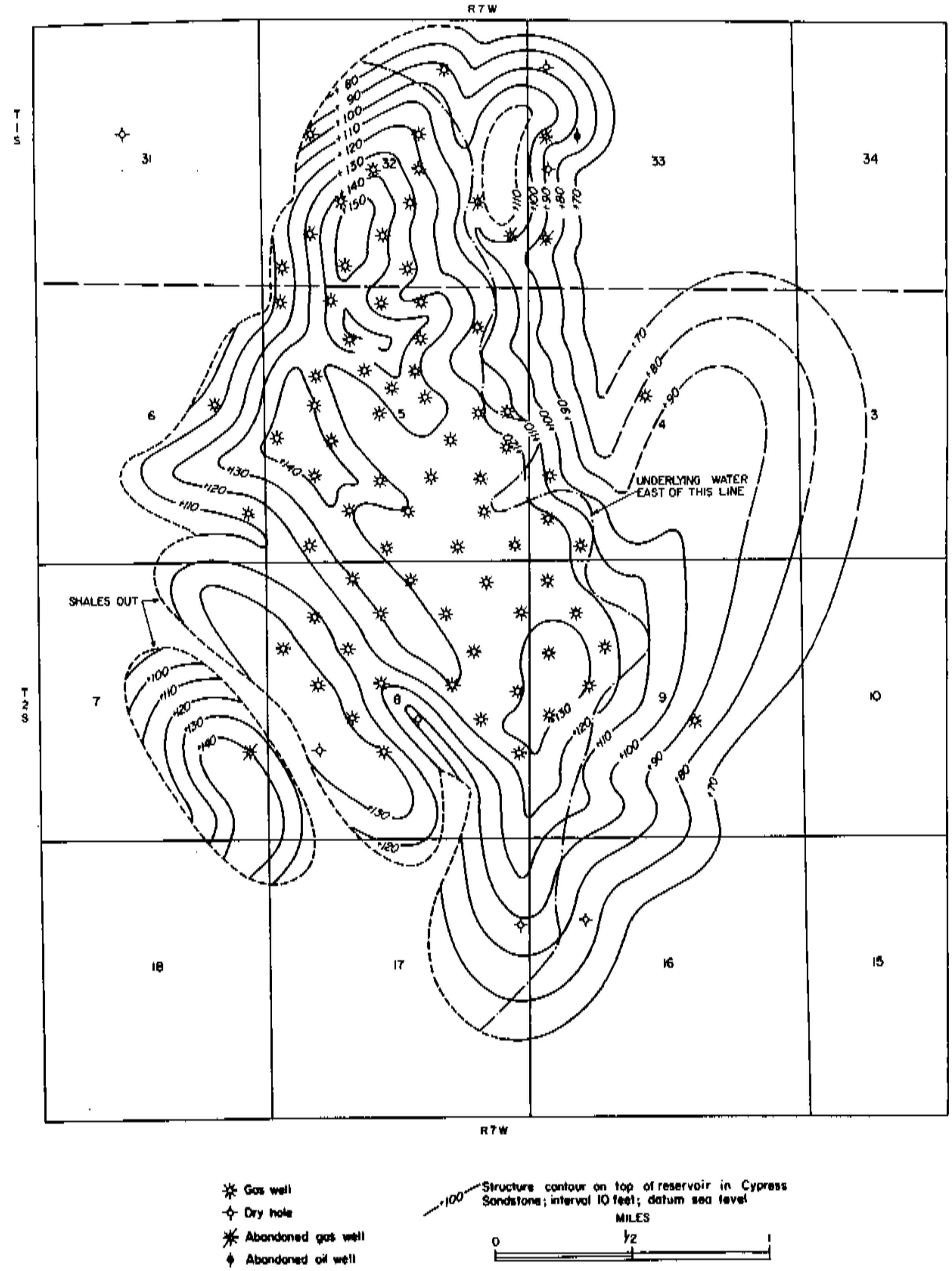


Figure 14 - Top of reservoir in Cypress Sandstone at Freeburg, St. Clair County (Illinois Power Co.).

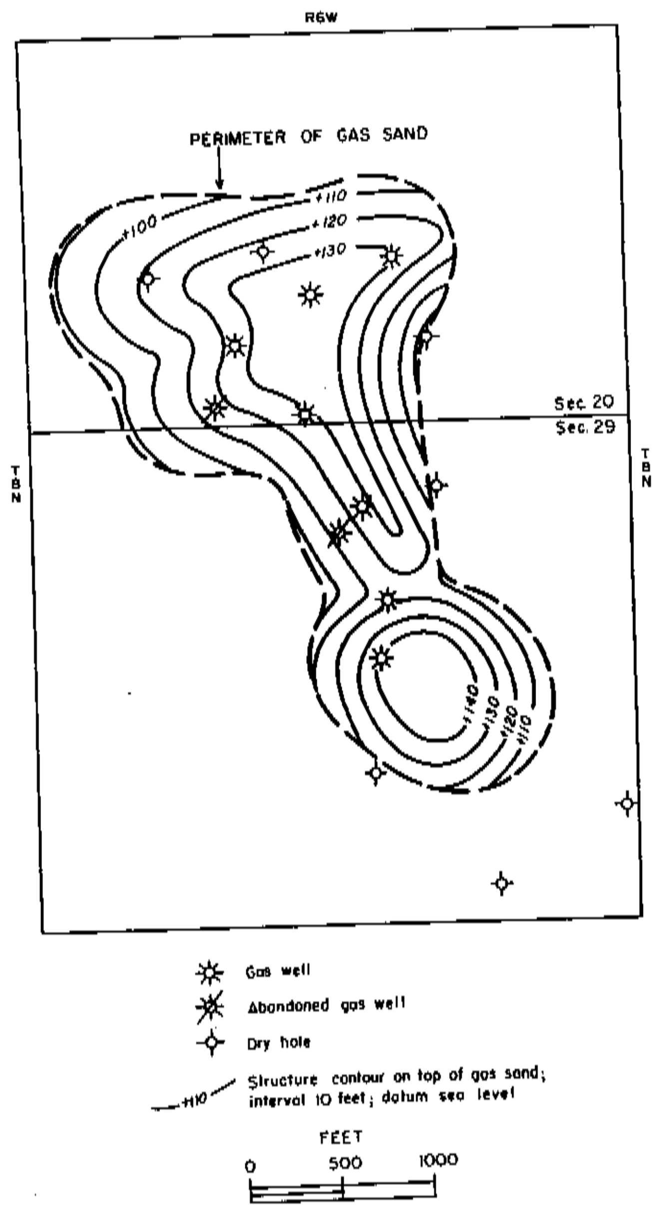


Figure 15 - Top of Pennsylvanian gas sand at Gillespie-Benld, Macoupin County (Illinois Power Co.).

low the surface and has an estimated ultimate capacity of 9 billion cubic feet of gas.

Wells were completed by drilling 450 feet of 8 5/8-inch hole to the middle of the Burlington Limestone, then decreasing to a $5\frac{1}{2}$-inch hole down into the Devonian at a depth of about 750 feet. The storage zone was reached by cable tool to total depth. Twelve observation wells monitor gas movement in the field.

Normal injection pressure is 350 psig. Open-flow potential of wells ranged from 4 to 25 MMcf per day, with an average of 8. Recent treatment of the wells with acid resulted in considerably enhanced deliverabilities, which now average 20 MMcf per day for the seven operational wells.

Gas was first injected at Glasford in 1964, with only minor withdrawals in 1964 and 1965 (table 9). On February 24, 1967, a daily high of over 45 million cubic feet of gas was withdrawn.

TABLE 9 - INJECTION AND WITHDRAWAL HISTORY OF GLASFORD PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	1,745	55	2,963	—
1966	611	574	3,000	30

Herscher Project

Operator: Natural Gas Pipeline Company of America

Location: Half a mile south of the village of Herscher, T. 30 N., R. 10 E., Kankakee County

Gas for the Herscher project comes from the Gulf Coast System line of the Natural Gas Pipeline Company of America by way of a 30-inch pipeline between Dwight and Herscher. The gas is consumed in Chicago and vicinity.

The Herscher Anticline was indicated on a structure map of the St. Peter Sandstone drawn by D. J. Fisher (in Athy, 1928, p. 75). Several small oil wells had been drilled to the Galena (Trenton) Group in the early 1900's, but all were abandoned in less than a year. In 1952, Natural Gas Storage Company of Illinois drilled over 100 Galena structure tests to delineate the anticline. Four deep tests were drilled and cored to the Galesville Sandstone to determine the presence of a suitable reservoir and caprock.

Injection of gas into the Galesville Sandstone commenced in April 1953. During the last week in July 1953, four months after gas injection was started, one of the shallow water wells at Herscher began to bubble gas (Natural Gas Storage Co. of Illinois, 1957). Within a week, 33 water wells in the vicinity became active with gas. Gas injection was stopped, and a search for the cause of leakage was undertaken. To date, the cause has not been determined with certainty.

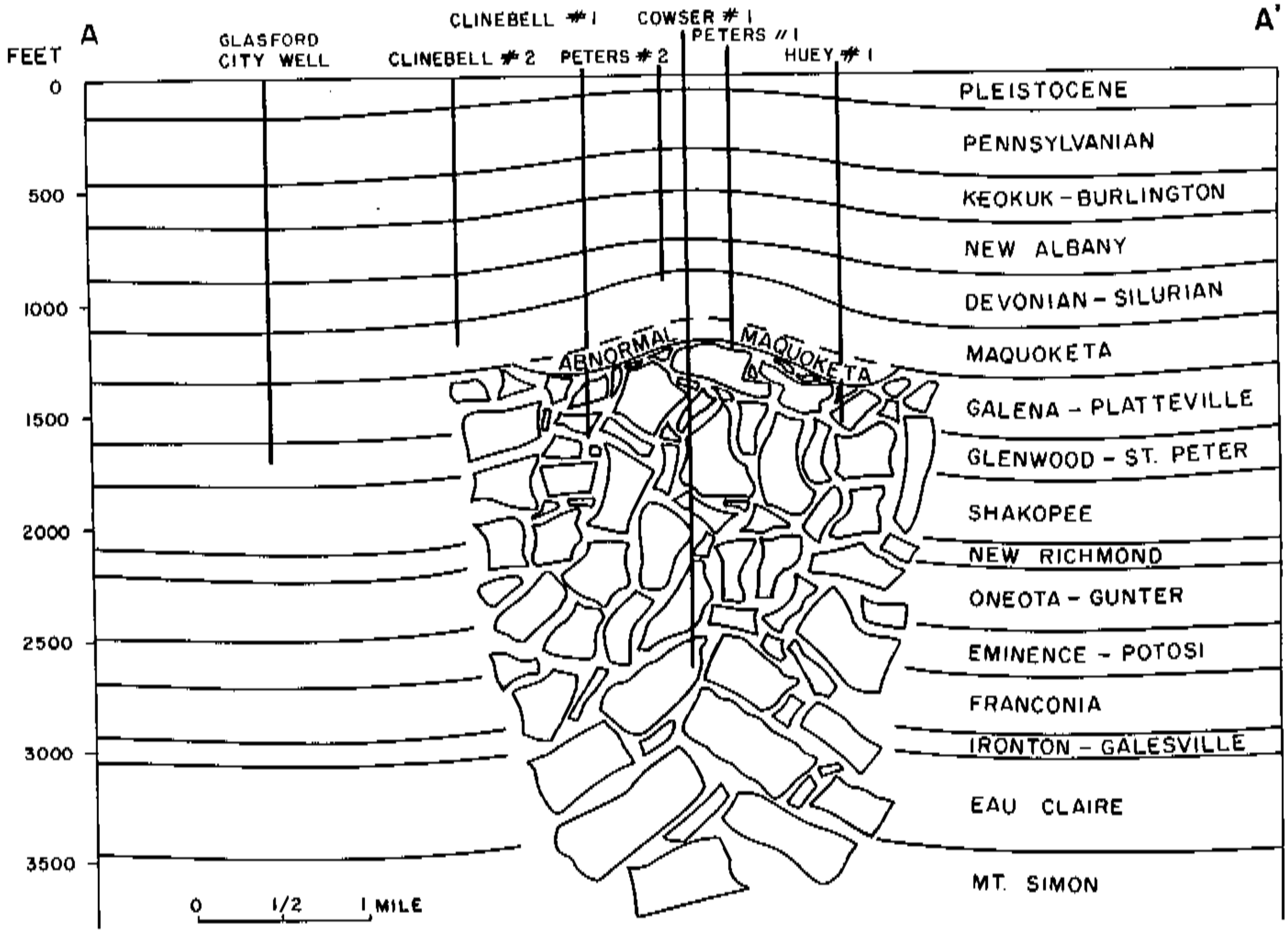
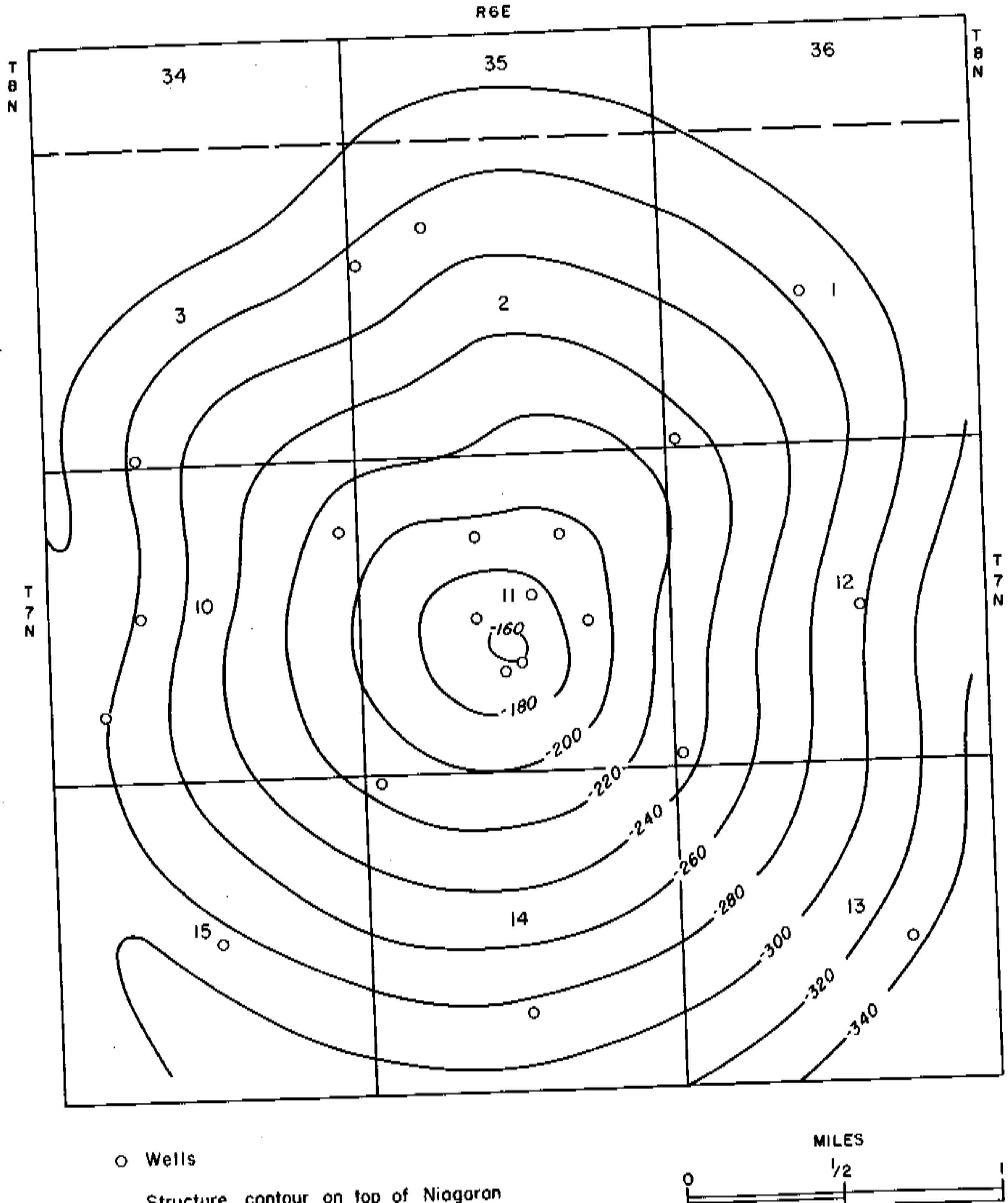


Figure 16 - Cross section through Glasford structure (Buschbach and Ryan, 1963).

Early in 1956, efforts were made to utilize the Galesville reservoir to its maximum limit with safety. Wells were drilled into the reservoir to remove water from the periphery of the bubble, thereby facilitating injection of gas without significant pressure change. Water from the peripheral wells in the Galesville was injected into the Potosi Dolomite (Trempealeau); this had the effect of pressurizing the formations above the reservoir. Thus, by careful regulation of differential pressures, and by recycling gas from vent wells in the Galena and St. Peter, the Galesville Sandstone at Herscher has become a successful storage reservoir.

Test drilling was done in 1957 to determine the feasibility of deeper gas storage to supplement the Galesville reservoir. The information obtained indicated that the Mt. Simon Sandstone had the requirements of a good storage zone. Gas was injected into the Mt. Simon late in 1957 and withdrawals began in 1958. No leakage of gas from the Mt. Simon has been observed.

The Herscher structure is an asymmetrical, doubly plunging anticline that trends generally north-south. Both reservoirs are aquifers. The Galesville has a porosity of 18 percent, and the Mt. Simon has a porosity of 12 percent. The Galesville is 80 to 100 feet thick in the area and its caprock is 125 feet of sandstone and dolomite of the Ironton Formation. The Mt. Simon is over 2500 feet thick (Buschbach, 1964), but gas is stored only in its uppermost part and in the Elmhurst Sandstone Member of the overlying Eau Claire Formation. Caprock for this reservoir is 200 feet of shale and dolomite assigned to the Lombard Member of the Eau Claire.



○ Wells

-200 Structure contour on top of Niagaran Series; interval 20 feet; datum sea level

Figure 17 - Top of Niagaran Series at Glasford, Peoria County (Central Illinois Light Co.).

The Galesville is 1750 feet deep and the Mt. Simon is 2450 feet deep. Closure totals almost 200 feet on the Galena, a little over 100 feet on top of the Galesville, and 80 feet on top of the Mt. Simon (fig. 18). Closure is lost with depth, due to northward thinning (convergence) of most beds. The storage area covers about 8000 acres. The ultimate capacity of the Galesville reservoir is estimated to be 75 billion cubic feet. The capacity of the Mt. Simon is about 67 billion cubic feet.

In the Herscher project, 120 wells are used for injection and withdrawal of gas and 85 are used for observation. A total of 42 wells are used for recycling leakage gas from the Galena and St. Peter to the Galesville, and 14 wells are used to withdraw water from the Galesville at the perimeter of the bubble. Some of the Galesville wells are completed open hole and some have been cased and perforated. All Mt. Simon wells are cased through the upper part of the formation and perforated.

Normal injection pressures are 680 psig for the Galesville and 1180 psig for the Mt. Simon. Open-flow potential of the wells is not available, but in 1966, over 1 billion cubic feet of gas was withdrawn from the Galesville and 148 million cubic feet was withdrawn from the Mt. Simon (table 10) in one day.

TABLE 10 - INJECTION AND WITHDRAWAL HISTORY OF HERSCHER PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
		Galesville Sandstone		
1953	11,885	99	11,984	61
1954	6,178	340	17,822	158
1955	4,338	1,865	20,295	368
1956	6,491	1,539	25,247	415
1957	7,041	2,997	29,291	291
1958	9,124	8,529	29,887	411
1959	9,698	6,051	33,534	430
1960	7,826	7,166	34,195	473
1961	7,561	7,160	34,596	495
1962	12,381	11,547	35,430	634
1963	16,185	17,693	33,922	702
1964	16,809	11,956	38,776	705
1965	18,149	15,488	41,436	771
1966	16,064	16,336	41,163	1,054
		Mt. Simon Sandstone		
1957	22	0	22	0
1958	3,750	88	3,684	25
1959	6,034	364	9,354	52
1960	7,456	734	16,076	65
1961	7,636	1,626	22,087	81
1962	8,678	4,293	26,472	97
1963	10,856	4,147	33,181	97
1964	10,325	7,976	35,529	142
1965	11,759	3,797	43,492	145
1966	11,293	8,300	47,894	148

Herscher-Northwest Project

Operator: Natural Gas Pipeline Company of America

Location: T. 31 N., R. 9 and 10 E., Kankakee County

Gas for the Herscher-Northwest project will come from the Gulf Coast System line of Natural Gas Pipeline Company of America. The gas will be supplied by a 6-inch pipeline between Herscher-Northwest and the 36-inch pipeline between the original Herscher project and the Natural Gas Pipeline Company-Chicago District facilities at Joliet. The gas will be consumed in Chicago and vicinity.

The Herscher-Northwest project is now being developed; injection and withdrawal wells are being drilled, but as yet no gas has been injected. It is anticipated that injection will begin late in the summer of 1967 or early in the summer of 1968.

The trap is a doubly plunging anticline that trends slightly west of north (fig. 19). Gas will be stored in the Mt. Simon Sandstone, an aquifer with a porosity of 15 percent, and in the overlying Elmhurst Sandstone Member of the Eau Claire Formation. The Elmhurst is only 12 feet thick and consists of sandstone with a few interbeds of shale. The caprock is 161 feet of shale, dolomite, and siltstone assigned to the Lombard Member of the Eau Claire.

The Herscher-Northwest structure has 58 feet of closure on top of the Mt. Simon. The reservoir is 2200 feet deep and covers over 3000 acres. Ultimate capacity of the project is estimated to be 20 billion cubic feet of gas.

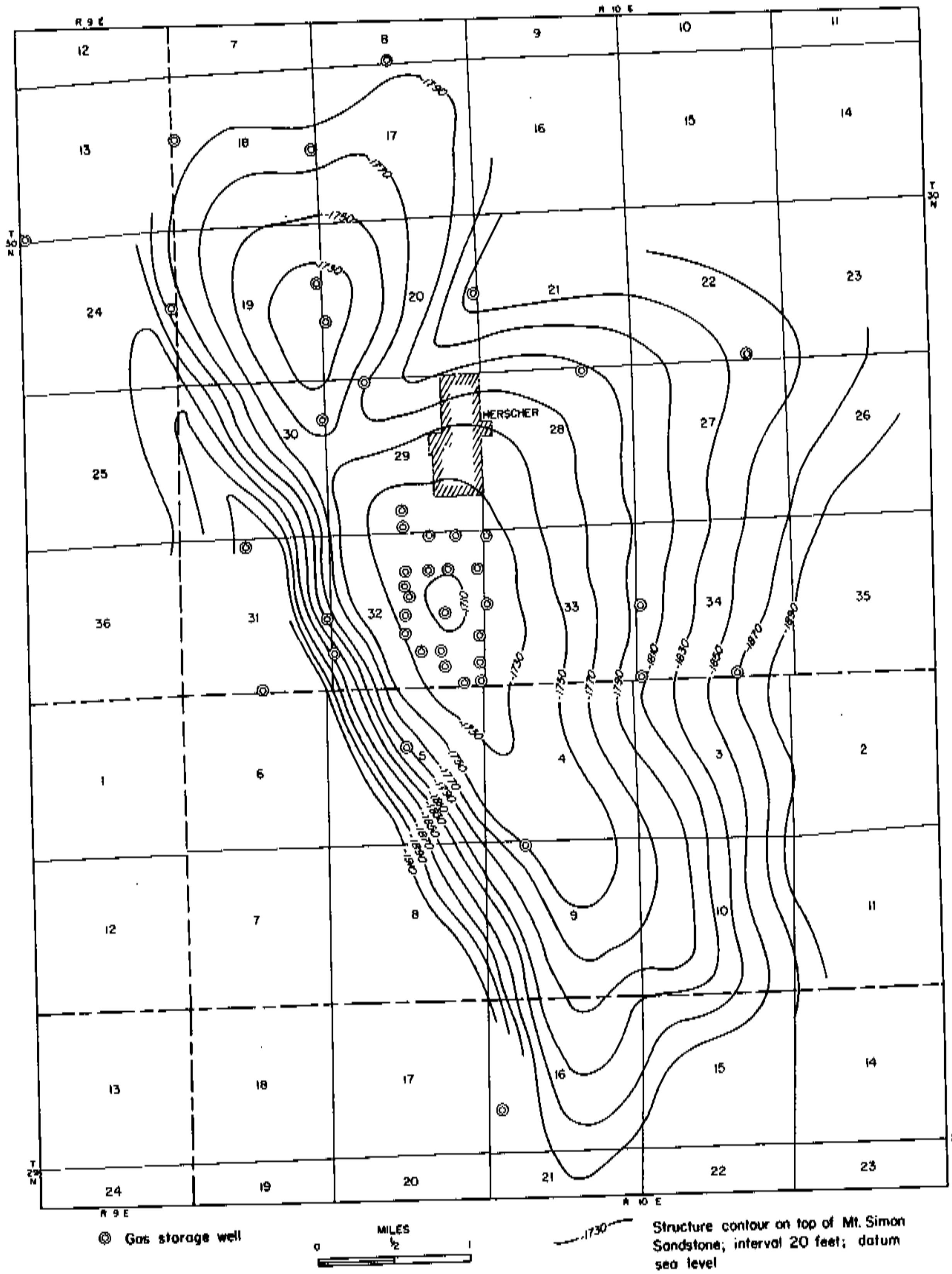


Figure 18 - Top of Mt. Simon Sandstone at Herscher, Kankakee County (Natural Gas Pipeline Co. of America).

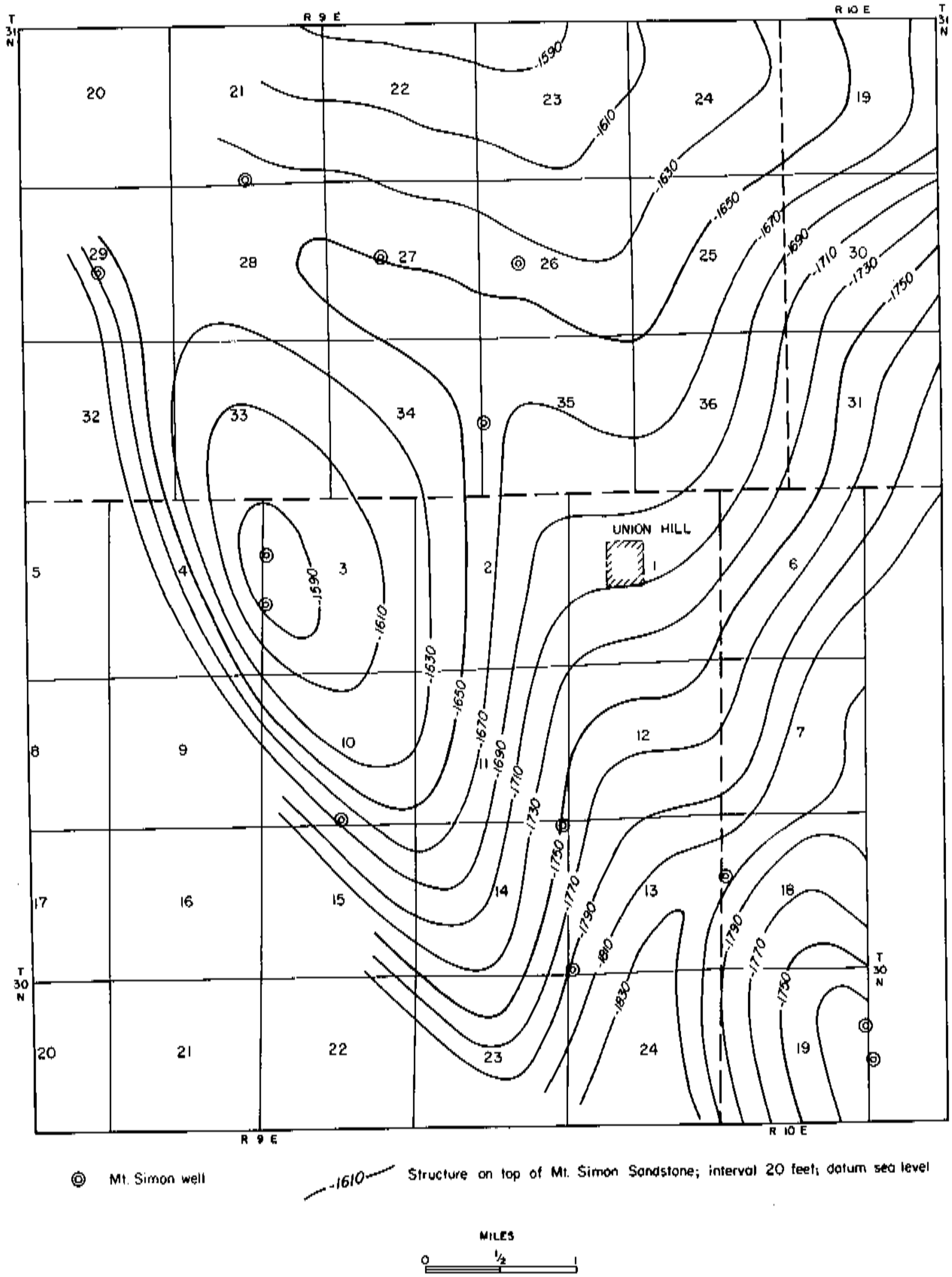


Figure 19 - Top of Mt. Simon Sandstone at Herscher-Northwest, Kankakee County (Natural Gas Pipeline Co. of America).

Hookdale Project

Operator: Illinois Power Company
Location: 7 miles south and 2 miles east of Greenville, T. 4 N., R. 2 W., Bond County

Gas for the Hookdale project is purchased from Natural Gas Pipeline Company of America and is consumed in the area east of East St. Louis.

This reservoir is a former gas field, discovered in 1961. It was acquired and developed for gas storage in 1962 and 1963, with injections and withdrawals beginning in 1963. The reservoir is a combination structural and stratigraphic trap in the Yankeetown ("Benoist") Sandstone of Mississippian age. The sandstone has an average porosity of 20.3 percent and is 1125 feet deep. The reservoir has 28 feet of closure and covers 414 acres (fig. 20).

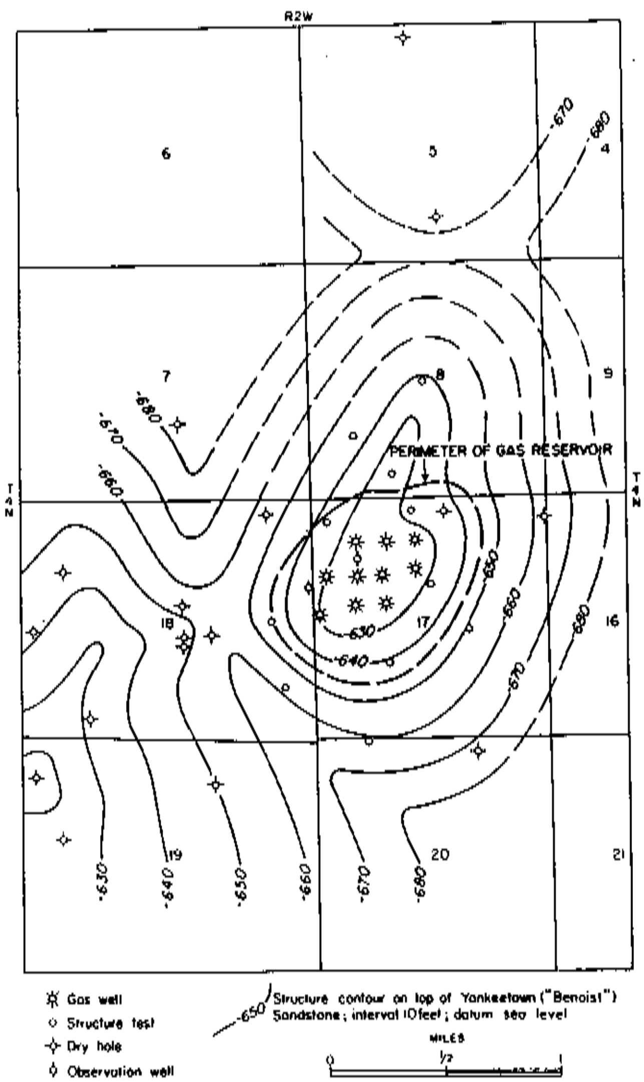


Figure 20 - Top of Yankeetown ("Benoist") Sandstone at Hookdale, Bond County (Illinois Power Co.).

At the end of 1966, the reservoir contained 512 million cubic feet of working gas (table 11). Ten wells are used for injection and withdrawal of gas, and two wells are used for observation.

TABLE 11 - INJECTION AND WITHDRAWAL HISTORY OF HOOKDALE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1963	83	109	46	29
1964	638	610	513	23
1965	596	596	513	26
1966	629	756	512	30

*Working gas

Wells were drilled to about 40 feet below the gas-water contact. Production casing, $4\frac{1}{2}$ or $5\frac{1}{2}$ inches in diameter, was cemented from total depth to surface and perforated opposite the producing zone with four shots per foot.

Normal injection pressure is 300 to 450 psig. Open-flow potential of the wells ranges from 2.5 to 32 MMcf per day with an average of 13.8 MMcf per day.

Mahomet Project

Operator: Peoples Gas, Light and Coke Company
Location: 5 miles north of Mahomet, T. 21 N., R. 7 E., Champaign County

Gas for the Mahomet project is supplied by Natural Gas Pipeline Company of America through 7 miles of 12-inch pipeline. The gas is consumed in Chicago.

During a detailed exploration program along the LaSalle Anticline, the Union Hill Gas Storage Company, a subsidiary of Peoples Gas, Light and Coke Company, confirmed the presence of a domal structure in the northwestern corner of Champaign County. A total of 24 structure tests were drilled to the top of the Galena Group in 1959 and 1960. Injection into the St. Peter Sandstone began in 1961. In early August 1961, gas was discovered migrating from the St. Peter to the glacial drift south of the crest of the structure.

Gas injection into the St. Peter was discontinued on August 21, 1961.

Shallow vent wells were drilled in the area of leakage to prevent the accumulation of gas. Test holes were drilled within the bubble area in an attempt to locate the source of leakage. The cement job on each injection well was tested, and tracers were injected into selected wells to determine areas of leakage. All of the tests and remedial measures were inconclusive; the location and nature of the leakage have not been determined.

In 1963, gas containing propylene as a tracer was injected into the Galesville Sandstone. After one month of injection, it was apparent that the gas was migrating upward into the St. Peter Sandstone. At about the same time, water analyses and pumping tests indicated a lack of communication between the Mt. Simon Sandstone and strata overlying the Eau Claire caprock. The Mt. Simon, therefore, was chosen as the ultimate reservoir.

The trap is a structural dome 6 miles long and 4 miles wide (fig. 21). It is elongated in a north-south direction. The reservoir is in the Mt. Simon Sandstone, an aquifer with an average porosity of 11 percent. The caprock is 100 feet of shaly beds in the overlying Eau Claire Formation.

The structure has 116 feet of closure on top of the Mt. Simon. The reservoir is 3950 feet deep and covers 13,370 acres within the last closing contour. The ultimate capacity of the reservoir is 30 billion cubic feet of gas. In early 1967, more than 14 billion cubic feet of gas was in storage.

Fifteen wells are used for injection and withdrawal from the Mt. Simon at Mahomet and 10 for observation. In the operational wells, 7-inch casing was set and cemented 500 feet into the Mt. Simon. The casing was perforated opposite the storage zone. Injection pressure is 1650 psig. Maximum daily withdrawal has been almost 22 million cubic feet of gas (table 12).

TABLE 12 - INJECTION AND WITHDRAWAL HISTORY IN THE MT. SIMON SANDSTONE OF MAHOMET PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	3,158	0	3,158	0
1966	8,945	178	12,249	21.7

Nevins Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 and 13 N., R. 11 W., Edgar County

Gas for the Nevins project comes from Midwestern Gas Transmission Company's 30-inch line through the Elbridge storage project. A 10-inch feeder line connects the Nevins project to the Elbridge project. The line serves for both injection and withdrawal of gas.

The Nevins Dome was discovered during exploration for oil. Structure tests were drilled in 1961 and 1962, and injection of gas began in 1965. The first withdrawals were made in 1966 (table 13).

TABLE 13 - INJECTION AND WITHDRAWAL HISTORY OF NEVINS PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1965	1,682	0	1,682	—
1966	1,452	210	2,924*	10

*Estimate - structure presently being tested

Gas is stored in porous dolomite and dolomitic limestone beds of the Grand Tower Formation (Devonian). The trap is a structural dome caused by draping of Devonian and younger strata over a Silurian reef (fig. 22). Similar structures are present at the Elbridge and State Line storage projects. The caprock is 90 feet of shale of the New Albany Group, which overlies the dolomite and limestone reservoir.

The Nevins Dome has 105 feet of closure on top of the Grand Tower and covers 1650 acres (fig. 23). The reservoir has an average porosity of 16.5 percent and is 1975 feet deep. The ultimate capacity of the Nevins project is estimated to be 3.5 billion cubic feet of gas, about half of which will be cushion gas.

Nevins has seven injection and withdrawal wells and seven observation wells. The operational wells have $4\frac{1}{2}$-inch casing set and cemented 30 feet into the storage formation. The casings are perforated with four shots per foot opposite the top 25 feet of porosity. Packers are run on $2\frac{3}{8}$-inch tubing and are set about 50 feet above the perforations. Gas is injected and withdrawn through the $2\frac{3}{8}$-inch tubing.

Normal injection pressure is 1100 psig. Open-flow potentials of the wells range from 8.5 to 28 MMcf per day and average 15.2.

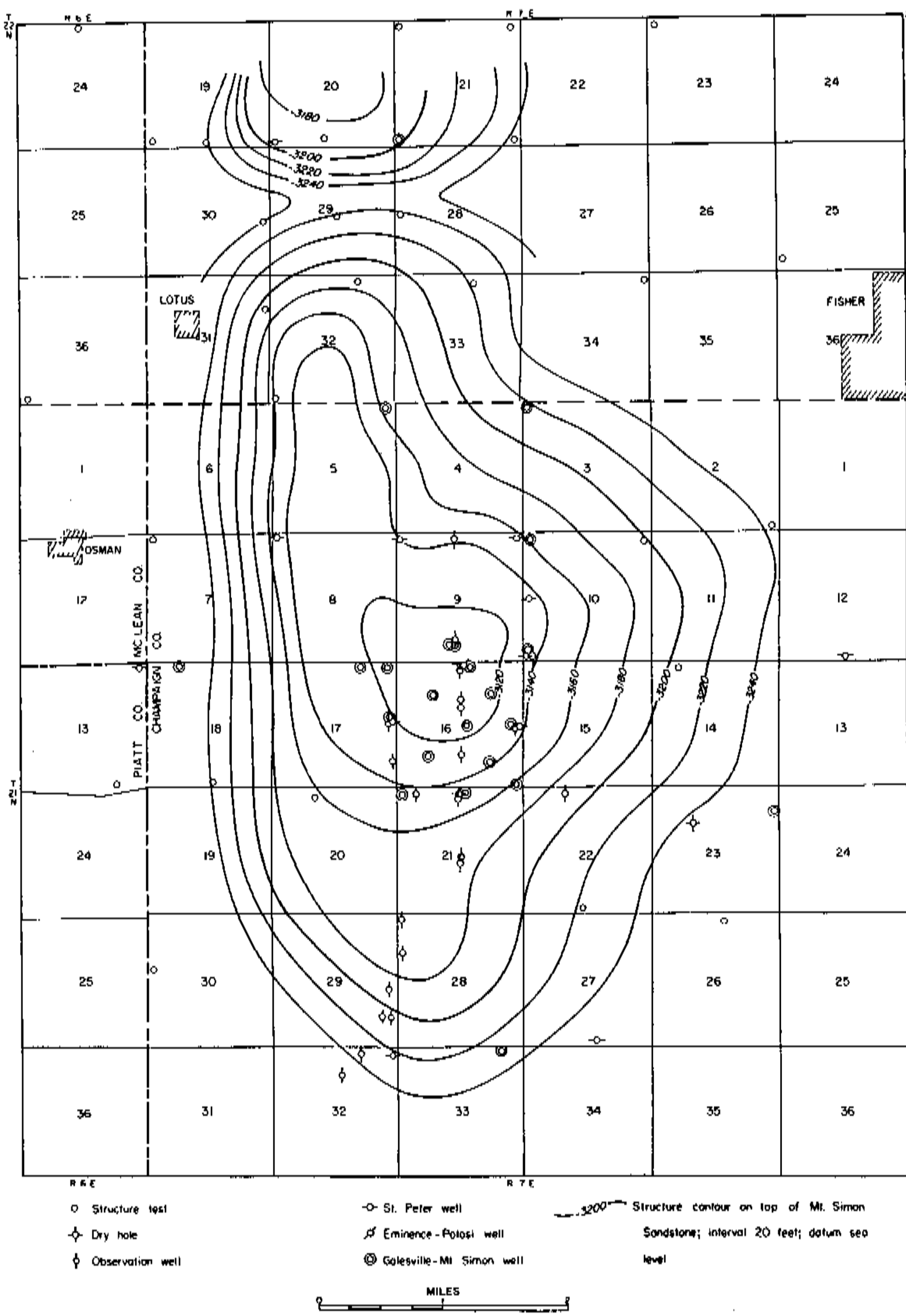


Figure 21 - Top of Mt. Simon Sandstone at Mahomet, Champaign County (Peoples Gas, Light and Coke Co.).

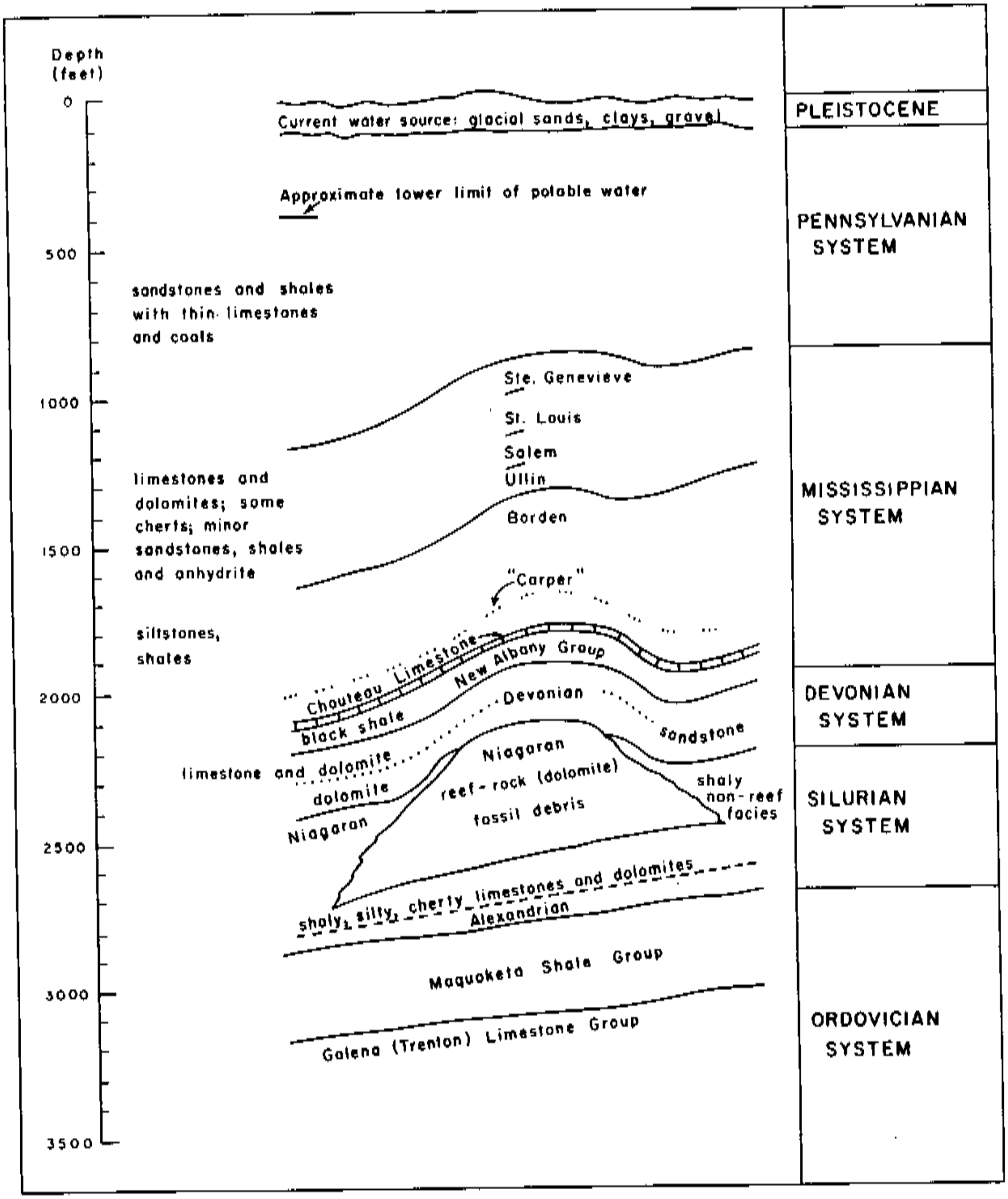


Figure 22 - Generalized cross section showing draping of strata over a Silurian reef at Nevins (after a drawing prepared by E. N. Wilson for testimony presented to Illinois Commerce Commission, Docket No. 48793).

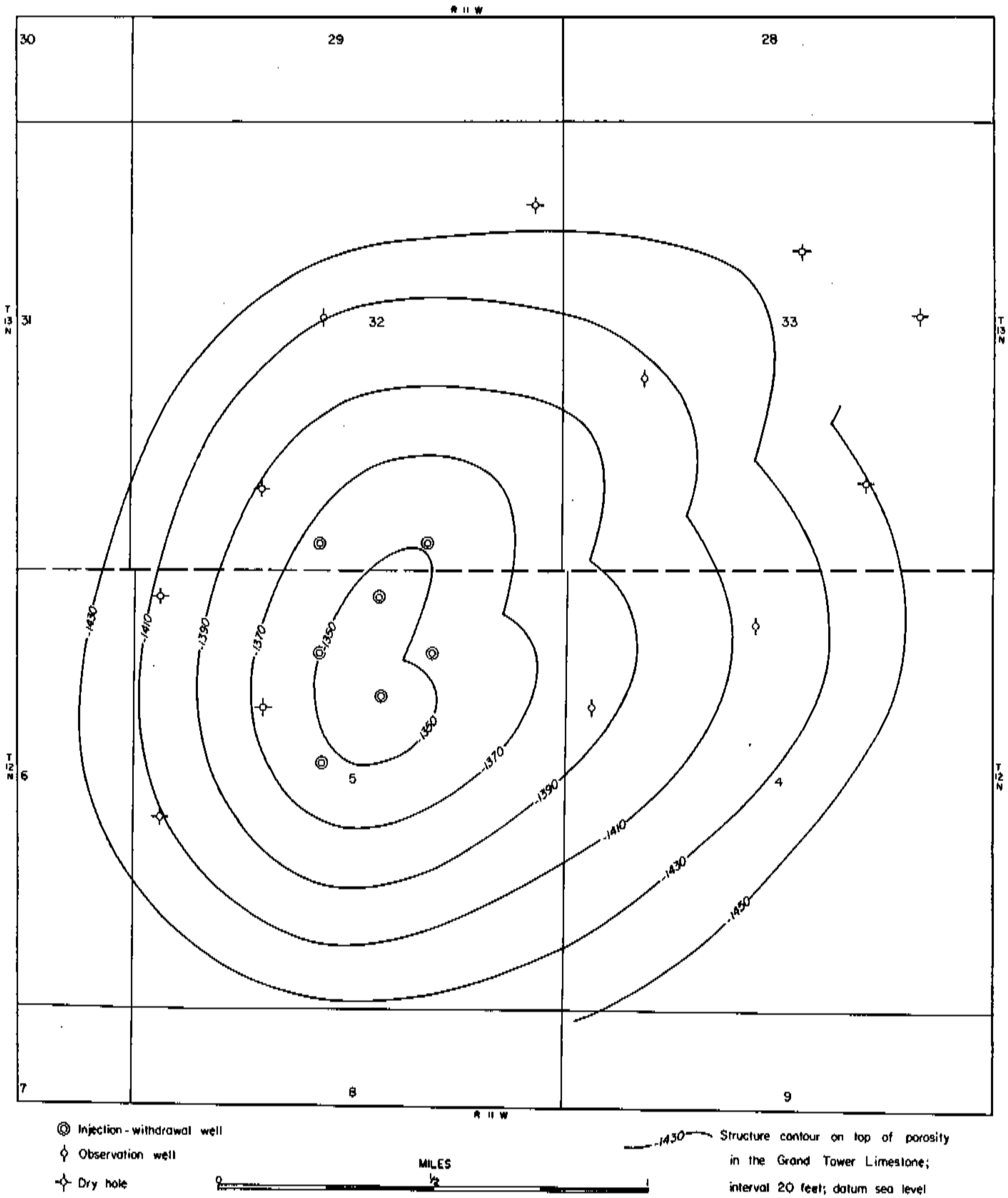


Figure 23 - Top of porosity in the Grand Tower (Jeffersonville) Limestone at Nevins, Edgar County (Midwestern Gas Transmission Co.).

Pontiac Project

Operator: Northern Illinois Gas Company
Location: Approximately 5 miles southeast of Pontiac, T. 27 and 28 N., R. 6 E., Livingston County

Gas for the Pontiac project comes from the trunkline of Natural Gas Pipeline Company of America through a 12-inch pipeline to the storage project. The gas will be used in suburban Chicago areas.

Preliminary geologic exploration in the Pontiac area began in 1963. Northern Illinois Gas Company drilled 10 deep wells below the Ironton Sandstone and 86 structure tests to determine suitability for gas storage and structural configuration. Most of the structure tests were drilled to the Fort Atkinson (middle Maquoketa), although 25 wells in the area reached the top of the Galena Group. Three experimental seismic profiles were run across the structure to aid structural mapping and to evaluate seismic methods for future exploration. The results were favorable.

The Pontiac project is in early stages of development. Gas injection began in 1966, with a total of 543 million cubic feet injected during the year.

The trap is an anticline, 3 miles wide and, 5 miles long, that trends north-south (fig. 24). The reservoir is in the Mt. Simon Sandstone, an aquifer with 10 percent porosity. The Mt. Simon is estimated to be over 2000 feet thick, but only the upper 465 feet have been tested for storage purposes. The caprock is 125 feet of shale and thin dolomite lenses assigned to the Lombard Member of the Eau Claire Formation. Between the Mt. Simon reservoir and the Lombard Member is the Elmhurst Member of the Eau Claire, 50 feet of shaly and silty sandstone. Any gas that migrates into the Elmhurst presumably will be trapped by the overlying shale, and it will become part of the cushion gas inventory.

The Pontiac structure has 100 feet of closure on top of the Mt. Simon. The reservoir is 3000 feet deep and covers about 3500 acres within the last closing contour. The leased area covers 10,690 acres. Ultimate capacity of the project is estimated to be 50 billion cubic feet of gas.

Five wells are completed for injection and withdrawal, and 11 wells are completed for observation. The wells were completed by casing to total depth with $5\frac{1}{2}$- or 7-inch production casing, which was perforated opposite the storage zone.

Richwoods Project

Operator: Gas Utilities Company, Robinson, Illinois
Location: T. 6 N., R. 11 W., Crawford County

Gas for the Richwoods project is supplied by Texas Gas Transmission Corporation through a $2\frac{1}{2}$-inch supply line about 2 miles long. A 4-inch line carries the storage gas to Palestine, Illinois.

The Richwoods project is a former gas field that produced 28 million cubic feet of gas before it began to produce water. The gas was produced from a sandstone of Pennsylvanian age, which is about 700 feet below surface. The one operating well was reworked in 1966, and during that year, 26 million cubic feet of gas was injected. Four million cubic feet of gas was vented to the atmosphere to test output capacity.

In addition to the operating well, there are 2 observation wells. The peak daily withdrawal in 1966 was one-half million cubic feet. Total withdrawals for the year were almost 5 million cubic feet.

St. Jacob Project

Operator: Mississippi River Fuel Corporation
Location: At St. Jacob, 6 miles east of Granite City, T. 3 N., R. 6 W., Madison County

Gas for the St. Jacob project is supplied by an 18-inch pipeline owned by Mississippi River Fuel Corporation. The gas is consumed in the St. Louis area.

The St. Jacob oil pool was discovered in 1942. Production is from the Galena (Trenton) Limestone Group. A total of 55 oil wells have been drilled on the structure, and the pool had produced 3,540,000 barrels of oil to the end of 1966. At that date, the Galena was being waterflooded, and there were 29 producing wells. Production of oil from the Galena and storage of gas in the underlying St. Peter Sandstone have been carried out contemporaneously since 1963. Withdrawals of storage gas began in 1965 (table 14). The project is being expanded, with development expected to be completed in 1967.

The St. Jacob structure is a double-domed anticline with 100 feet of closure on top of the Galena (fig. 25). Gas is stored in the north dome in the St. Peter Sandstone, an aquifer with a porosity of 14 percent. The reservoir is 2860 feet

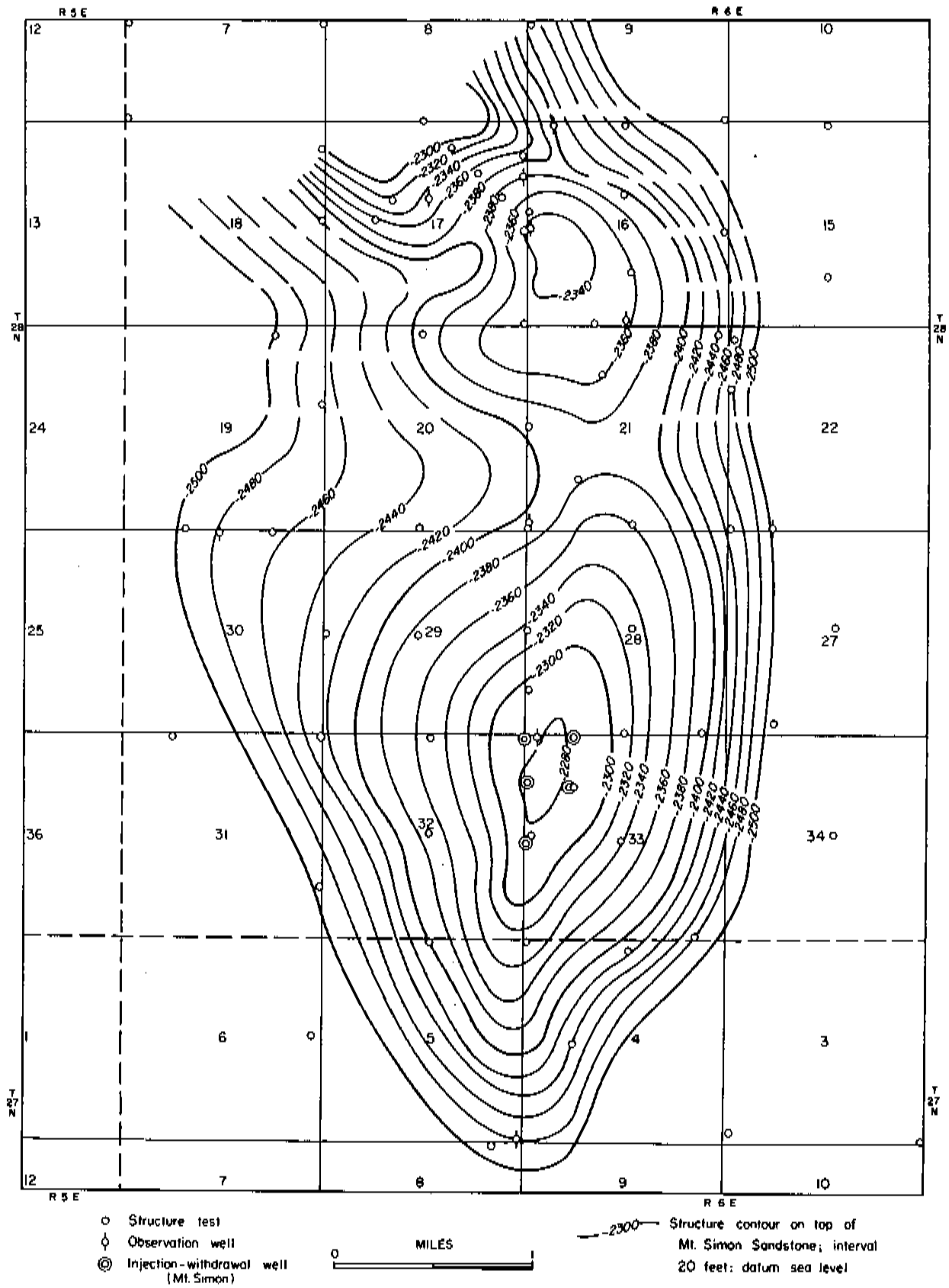


Figure 24 - Top of Mt. Simon Sandstone at Pontiac, Livingston County (Northern Illinois Gas Co.).

TABLE 14 – INJECTION AND WITHDRAWAL HISTORY OF ST. JACOB PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	400	0	400	0
1964	1,273	0	1,673	0
1965	2,063	932	3,300	30
1966	2,237	1,708	3,800	41

TABLE 15 – INJECTION AND WITHDRAWAL HISTORY OF STATE LINE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1963	97	10	87	4
1964	764	74	777	11
1965	553	277	1,053	4
1966	1,015	653	1,415	13

deep, has a thickness of 100 feet, and covers 650 acres. Ultimate practical capacity of the reservoir has been estimated to be 4.8 billion cubic feet. The caprock is 400 feet of very fine-grained limestone of the Platteville Group. The south dome is being tested for possible storage in the Mt. Simon Sandstone.

Nine wells are used for injection and withdrawal of gas, and three wells are used for observation in the north dome of the St. Jacob structure. Normal injection pressure is 1260 psig. Maximum open-flow potential of all withdrawal wells is at least 41 MMcf per day. The production wells were cased to the top of the reservoir and completed open hole. Surface pipe, 13 3/8 inches in diameter, was set to 320 feet, 8 5/8-inch intermediate string was set to 2540 feet, and 5½-inch production casing was set to approximately 2860 feet.

State Line Project

Operator: Midwestern Gas Transmission Company
Location: T. 12 N., R. 10 W., Clark County, Illinois, and Vigo County, Indiana

Gas for the State Line project comes from Midwestern Gas Transmission Company's 30-inch line through a 10-inch feeder line. The line serves for both injection and withdrawal of gas.

State Line is a former oil field, which is located with about 85 percent of its area in Indiana and 15 percent in Illinois. Gas was first injected into the State Line project in 1963, and minor withdrawals were made during the same year (table 15). The station site is in Indiana, and the gas volumes are not separated by states; therefore, State Line is considered an Indiana storage project and its capacity is not included in the Illinois totals.

Gas is stored in porous dolomite and dolomitic limestone beds of the Grand Tower Formation (Devonian). The trap is a structural dome caused by draping of Devonian and younger strata over a Silurian reef. Similar structures are present at the Elbridge and Nevins storage projects. Caprock is about 90 feet of shale of the New Albany Group overlying the dolomite and limestone reservoir.

The State Line Dome has 91 feet of closure on top of the Grand Tower and covers 496 acres (fig. 26). The reservoir has an average porosity of 17.3 percent and is 1860 feet deep. The ultimate capacity of the project is estimated to be 2.3 billion cubic feet of gas. State Line has seven injection and withdrawal wells, which are all in Indiana, and seven observation wells, six of which are in Indiana and one in Illinois.

Normal injection pressure is 1000 psig. Open-flow potentials of the operating wells range from 6.5 to 12 MMcf per day, and average 9.1.

Tilden Project

Operator: Illinois Power Company
Location: 23 miles southeast of Belleville, T. 3 S., R. 5 and 6 W., St. Clair and Washington Counties

Gas for the Tilden project is purchased from Mississippi River Fuel Corporation. The gas is consumed in the East St. Louis area.

The reservoir is in a former gas field that was discovered in 1957. From 1957 to 1961, 21 core holes were drilled to determine the reservoir limits. Gas is stored in the Cypress Sandstone of Mississippian age. The sandstone has an average porosity of 20.8 percent and a maximum thickness of 33 feet. The reservoir is a monoclinal stratigraphic trap in which the sandstone dips generally eastward and grades to shale to the north, west, and south (fig. 27). The reservoir is 712 to 812 feet below surface and covers 1287 acres.

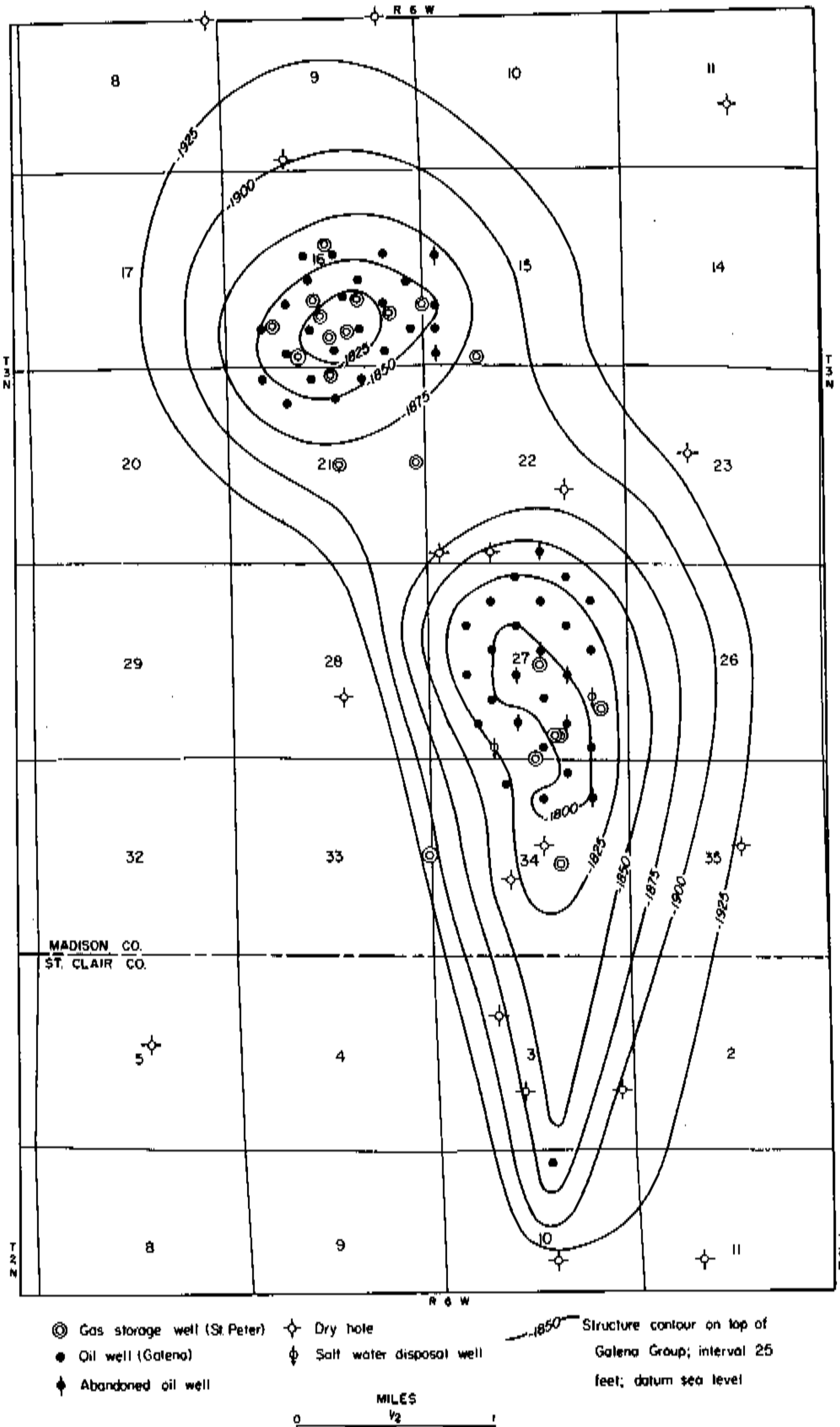


Figure 25 - Top of Galena Limestone Group at St. Jacob, Madison County (Mississippi River Fuel Corp.).

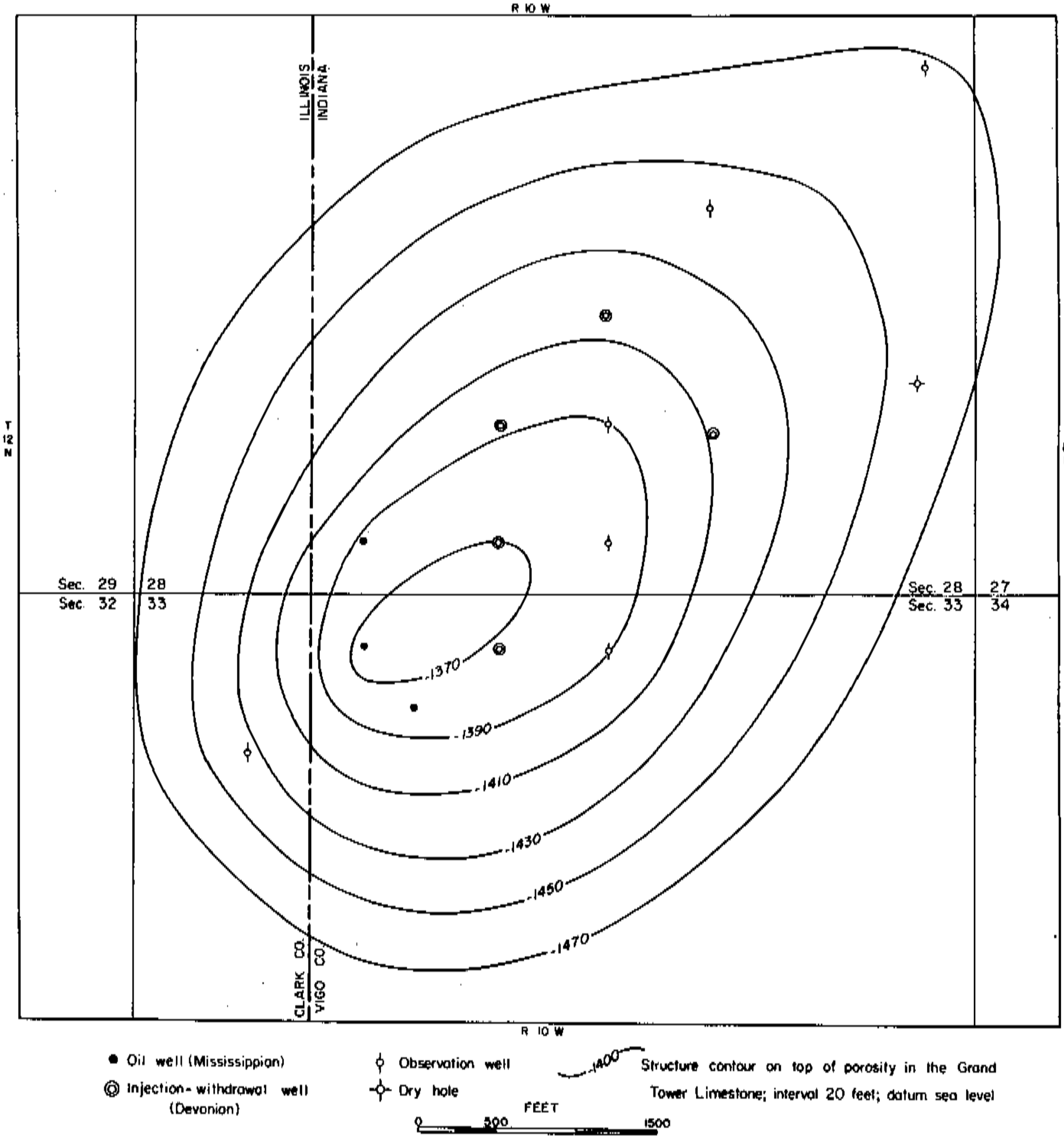


Figure 26 - Top of porosity in the Grand Tower (Jeffersonville) Limestone at State Line, Clark County, Illinois, and Vigo County, Indiana (Midwestern Gas Transmission Co.).

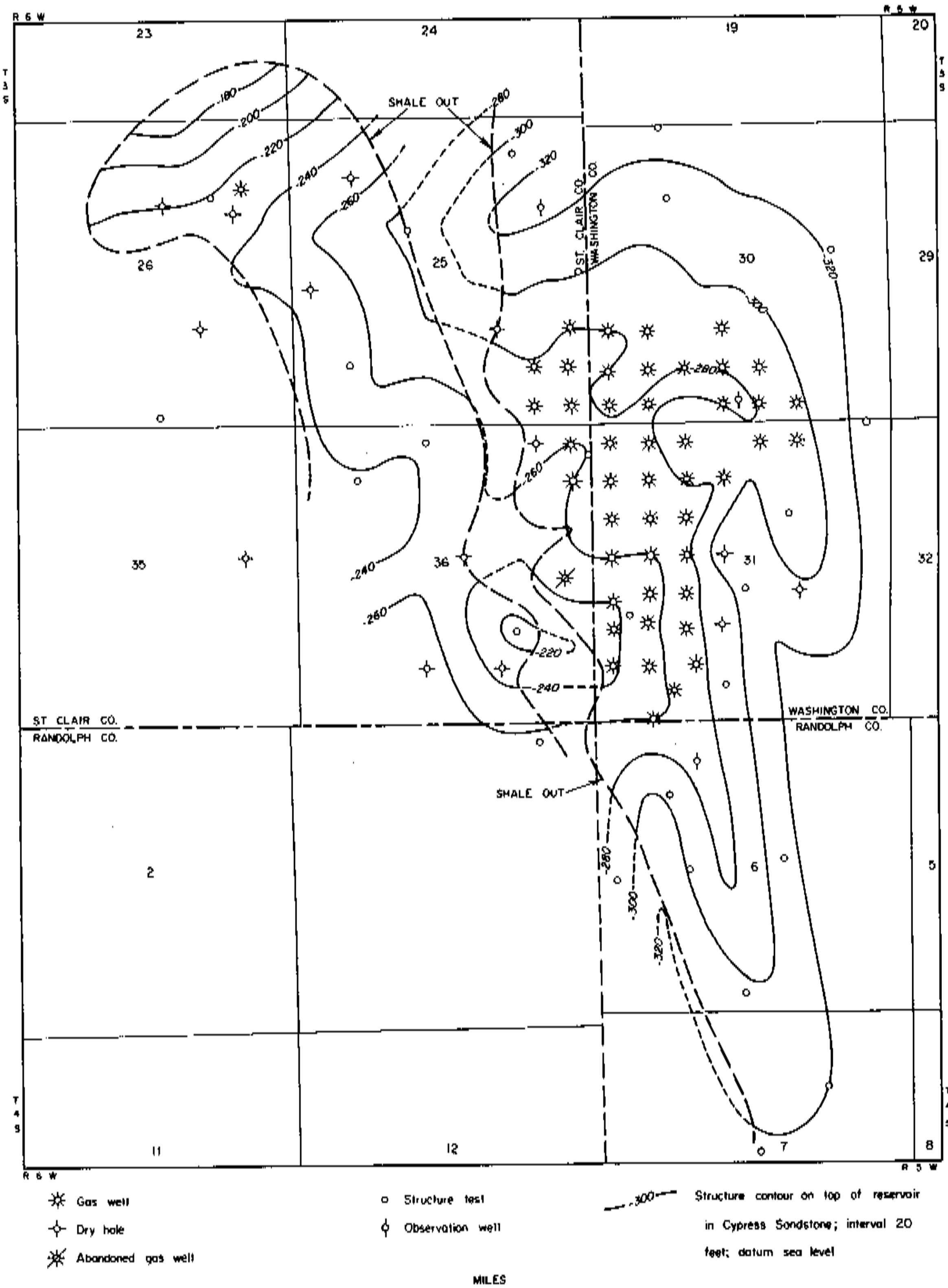


Figure 27 - Top of reservoir in Cypress Sandstone at Tilden, St. Clair, Washington, and Randolph Counties (Illinois Power Co.).

At the end of 1966, the reservoir contained 869 MMcf of working gas (table 16). The project has 45 injection and withdrawal wells and 4 observation wells.

TABLE 16 – INJECTION AND WITHDRAWAL HISTORY OF TILDEN PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory* (end of year)	Peak daily withdrawal
1961	327	330	810	24
1962	1,017	1,014	749	42
1963	708	857	560	41
1964	392	112	831	17
1965	313	267	868	20
1966	941	1,193	869	43

*Working gas

In the part of the reservoir underlain by water, the wells were drilled and cased through the sandstone. The casing was perforated above the gas-water contact. In these wells, where water production was anticipated, 1-inch siphon strings were installed. All other wells were cased to the top of the Cypress Sandstone and completed open hole into the reservoir. Casing, $5\frac{1}{2}$ inches in diameter, was used in all wells.

Normal injection pressure is 250 to 360 psig. Open-flow potential of the wells ranges from 230 to 16,500 Mcf per day, with an average of 5234.

Troy Grove Project

Operator: Northern Illinois Gas Company
Location: Midway between Mendota and LaSalle, near Troy Grove, T. 34 and 35 N., R. 1 E., LaSalle County

Gas for the Troy Grove project comes from the Amarillo trunkline of Natural Gas Pipeline Company of America by way of a 16-inch pipeline. The gas is used in the suburban Chicago area.

Basic geologic studies were carried out in 1957, and by 1958 Northern Illinois Gas Company had drilled 56 structure tests in the Troy Grove area. Currently, over 200 test holes have been drilled to delineate the structure. Deep holes were drilled and cored to determine caprock and reservoir qualities of the Eau Claire Formation and the upper part of the Mt. Simon Sandstone. One well reached the Precambrian after penetrating over 2000 feet of Mt. Simon.

The Troy Grove structure is an east-west elongated dome on the LaSalle Anticline. The structure is 5 miles long and 3 miles wide. It is intersected by four faults, one of which has 180 feet of vertical displacement (fig. 28). The primary reservoir is in the Mt. Simon Sandstone, an aquifer with 17 percent porosity. Gas has also been injected into two sandstones in the lower part of the overlying Eau Claire Formation. Gas migrates between the Mt. Simon and the sandstones of the lower Eau Claire. Excessive pressure buildup in the uppermost sands of the Eau Claire has been controlled by producing gas from these zones. The caprock is 180 feet of shale and siltstone in the upper part of the Eau Claire. Although the area is cut by faults, the caprock has prevented upward migration of gas above the Eau Claire.

The Troy Grove structure has slightly over 100 feet of closure on top of the Mt. Simon Sandstone (fig. 28). The reservoir is about 1400 feet below surface and covers 9600 acres within the leased area. The capacity of the reservoir is estimated to be 64 billion cubic feet of gas. About 55 percent of the total is considered working gas.

Troy Grove has 84 injection and withdrawal wells and 27 observation wells. Normal injection pressure is 740 psig. During a single day in 1966, 650 MMcf of gas was withdrawn from storage (table 17).

TABLE 17 – INJECTION AND WITHDRAWAL HISTORY OF TROY GROVE PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1958	707	0	707	0
1959	4,138	65	4,780	20
1960	6,930	528	11,182	50
1961	9,649	1,081	19,751	100
1962	12,670	3,042	29,408	250
1963	20,749	12,940	37,218	400
1964	16,070	8,372	44,916	500
1965	28,069	24,342	48,643	580
1966	26,700	22,762	46,447	650

The operational wells are cased with 7-inch production casing through the storage zone. The casing was perforated adjacent to the reservoir.

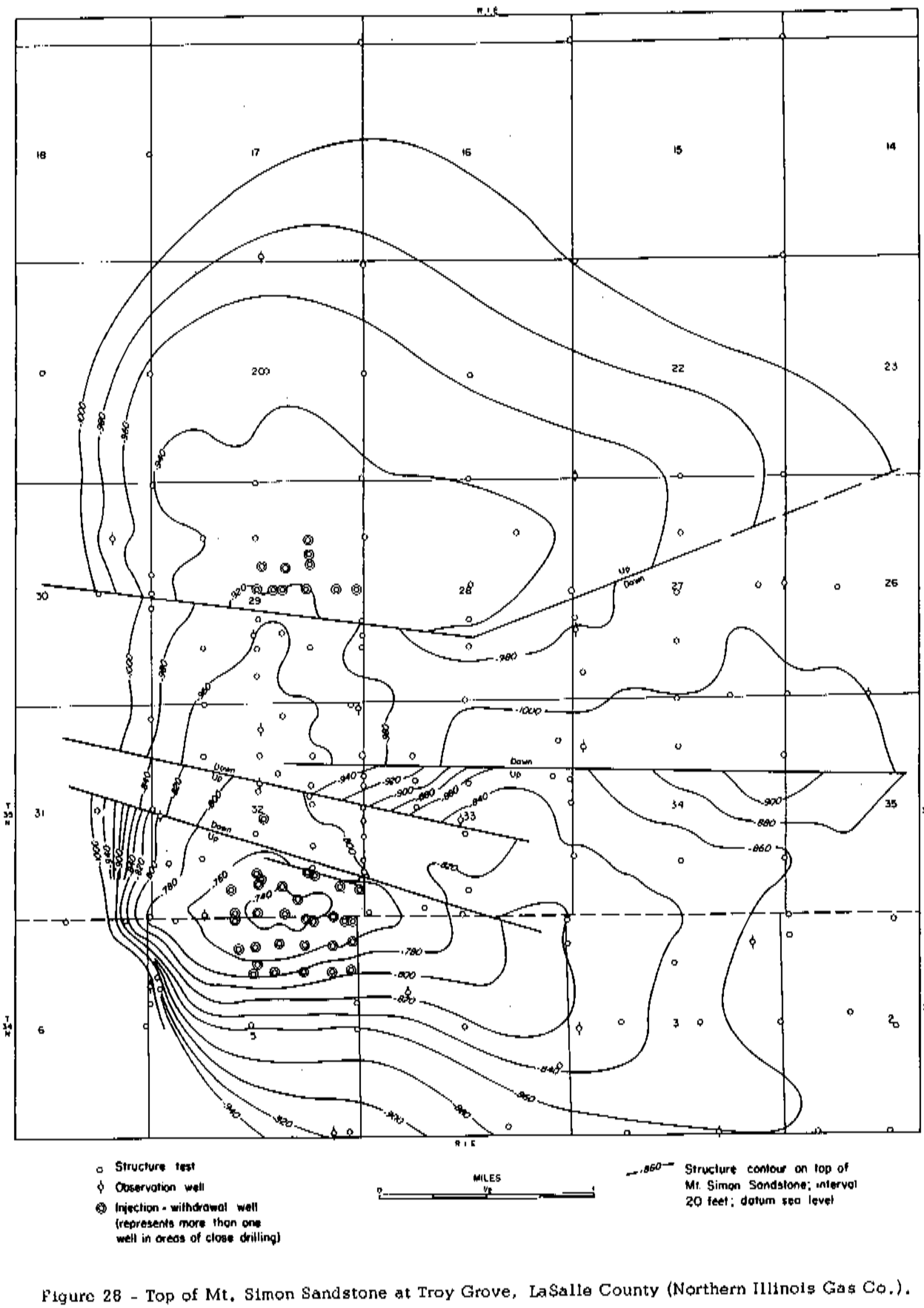


Figure 28 - Top of Mt. Simon Sandstone at Troy Grove, LaSalle County (Northern Illinois Gas Co.).

Waterloo Project

Operator: Mississippi River Fuel Corporation
Location: 15 miles south of East St. Louis, T. 1 and 2 S., R. 10 W., Monroe County

Gas for the Waterloo project comes from a 22-inch line of the Mississippi River Fuel Corporation by way of a 6-inch pipeline. Because of its relatively small size, the reservoir serves chiefly as a surge tank to compensate for diurnal variations in demand on the line that supplies gas for the St. Louis area.

The Waterloo oil pool was discovered in 1920, abandoned in 1930, revived in 1939, and converted to gas storage in 1951. About 238,000 barrels of oil were produced from the Galena (Trenton) Limestone Group at a depth of about 410 feet.

The Waterloo structure is an anticline that trends generally north-south with about 100 feet of closure on top of the Oneota Dolomite (fig. 29). Gas is stored in the St. Peter Sandstone and also in sandstones and dolomites of the New Richmond and Oneota Formations.

The maximum amount of gas known to have been stored in the reservoir is 450 MMcf in 1959. As much as 21 MMcf has been withdrawn in one day. In 1966, 250 MMcf was in storage, and the peak daily withdrawal during the year was 17.7 MMcf. Six wells are used for injection and withdrawal of gas and six are used for observation.

Waverly Project

Operator: Panhandle Eastern Pipeline Company
Location: 1 mile southwest of Waverly, T. 13 N., R. 8 W., Morgan County

Gas for the Waverly project comes through Panhandle Eastern Pipeline Company's trunklines from the Anadarko Basin. The gas is consumed in Illinois, Indiana, Ohio, and Michigan.

A structure map of the Pennsylvanian strata in the vicinity of Jacksonville (Collingwood, 1923, fig. 2, p. 21) shows an anticlinal nose trending northeast in T. 12 N., R. 7 and 8 W. Later drilling found oil shows and gas in the Devonian strata and helped to delineate the structure of the Waverly Dome. In the early 1950's, Panhandle Eastern Pipeline Company acquired gas storage rights in the area, and in 1954 they began injecting gas into the St. Peter Sandstone. Withdrawals were begun on a small scale in 1961 (table 18). The project has been fully active since 1962, but it is still being expanded.

The trap is a structural dome. The reservoir is in the St. Peter Sandstone, an aquifer with 18 percent porosity. The St. Peter is 250 to 300 feet thick in the area. Caprock is the lime-

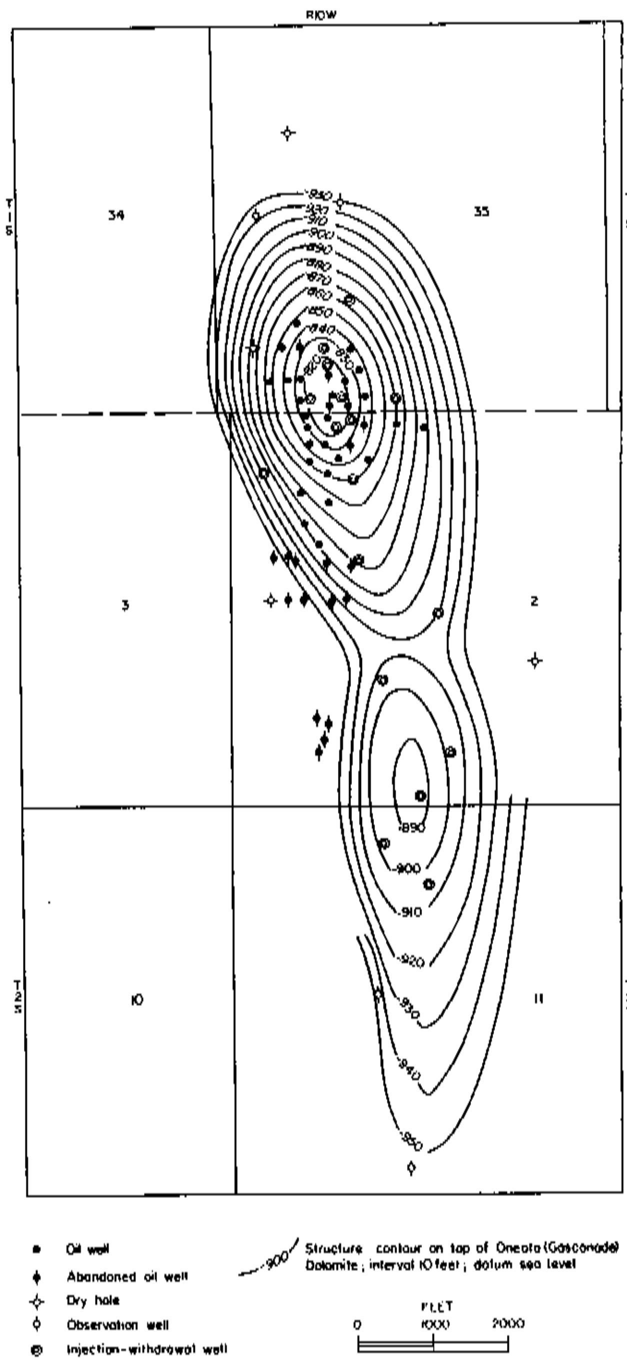


Figure 29 - Top of Oneota (Gasconade) Dolomite at Waterloo, Monroe County (Mississippi River Fuel Corp.).

TABLE 18 - INJECTION AND WITHDRAWAL HISTORY OF WAVERLY PROJECT (MMcf)

Year	Injection	Withdrawal	Inventory (end of year)	Peak daily withdrawal
1954–1960	10,708	—	—	—
1961	929	50	6,487	—
1962	2,666	834	8,319	71
1963	4,004	2,891	9,432	99
1964	5,838	3,553	11,201	154
1965	7,289	5,299	13,164	104
1966	8,250	6,636	18,000	142

stone and dolomite of the Platteville and Galena Groups, which total 320 feet thick. Overlying the Galena is the Maquoketa Shale Group, 200 feet thick. Some gas migrates upward from the St. Peter into porous zones in the Galena. The leakage gas is recycled into the St. Peter or produced. Recent drilling at Waverly suggests that the Mt. Simon Sandstone may also be a satisfactory reservoir for storage gas.

The Waverly structure has over 100 feet of closure (fig. 30). The reservoir is 1800 feet deep and covers about 7000 acres. The ultimate capacity of the project is estimated to be 150 billion cubic feet of gas.

Seventeen wells are used for injection and withdrawal, 19 wells are used for observation, and 10 additional wells are used for withdrawal only. Normal injection pressure is 845 psig. The operational wells are cased to total depth with 7-inch production casing. The casing is perforated opposite the St. Peter and the wells have been acidized.

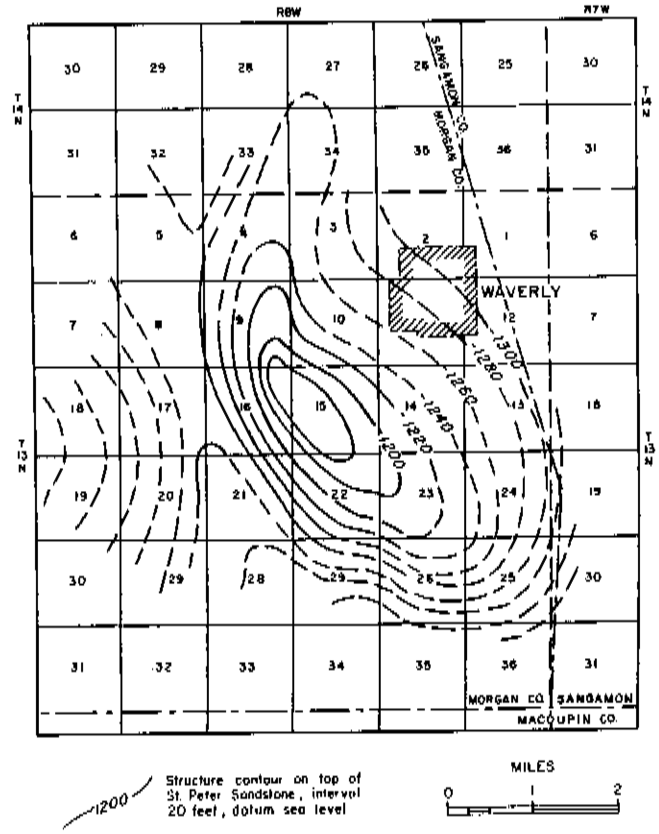


Figure 30 - Top of St. Peter Sandstone at Waverly, Morgan County (Panhandle Eastern Pipeline Co.).

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