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# Improved Storage Efficiency Through Geologic Modeling and Reservoir Simulation

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## Abstract

The U.S. Department of Energy (DOE), through partnerships with industry, is demonstrating the importance of geologic modeling and reservoir simulation for optimizing the development and operation of gas storage fields. The U.S. DOE has entered into Cooperative Research and Development Agreements (CRADAs) with National Fuel Gas Supply Corporation (NFGSC), Equitrans, Inc., and Northern Indiana Public Service Company (NIPSCO). The geologic modeling and reservoir simulation study for the NFGSC CRADA was completed in September 1995. The results of this study<sup>1</sup> were presented at the 1995 Society of Petroleum Engineers' (SPE) Eastern Regional Meeting. Although there has been no field verification of the modeling results, the study has shown the potential advantages and cost savings opportunities of using horizontal wells for storage enhancement. The geologic modeling<sup>2</sup> for the Equitrans' CRADA was completed in September 1995 and was also presented at the 1995 SPE Eastern Regional Meeting. The reservoir modeling of past field performance was completed in November 1996 and predictions runs are currently being made to investigate the potential of offering either a 10-day or 30-day peaking service in addition to the existing 110-day base load service. Initial results have shown that peaking services can be provided through remediation of well damage and by drilling either several new vertical wells or one new horizontal well. The geologic modeling for the NIPSCO CRADA was completed in November 1996. This was a coordinated effort between the U.S. DOE, NIPSCO, and the Gas Research Institute subcontractors through integration of geologic modeling and geophysics (seismic surveys). NIPSCO completed a horizontal well in January 1997. Based on well test results, the well will significantly enhance gas deliverability from the field and will allow the utilization of gas from an area of the storage field that was not accessible from their existing vertical wells.

## Introduction

A more efficient natural gas storage system will be essential for supporting the expected growth in U.S. gas demand. A strategy of the U.S. DOE Gas Storage Program<sup>3</sup> is to assist industry, through cooperative demonstration studies of selected storage fields, to increase storage efficiency, i.e., increase deliverability and capacity, and reduce development costs. A promising technology for increasing storage efficiency is horizontal wells. Thousands of horizontal wells have been drilled for exploration and production with great success, yet the application of this technology in the storage industry has been very limited. Several horizontal wells that have been drilled in gas storage fields,

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for which the results have been reported<sup>4,5,6</sup>, have shown deliverability increases of 4-7 times over vertical wells.

Horizontal wells, however, must be carefully studied to determine their usefulness and profitability. Thus, a second objective of the cooperative efforts between the U.S. DOE and industry is to show the cost benefit of using geologic modeling and reservoir simulation to "optimize" field development strategies. Three case studies are presented: a fairly homogeneous, depleted gas sandstone reservoir (NFGSC); a heterogeneous, depleted gas sandstone reservoir (Equitrans); and a fractured, carbonate aquifer (NIPSCO).

## **National Fuel Gas Supply Corporation**

**Field History.** The field was discovered in 1955 with an original recorded flow of 7 MMcfd. Original gas-in-place was estimated to be 18.6 Bcf at a discovery pressure of 2,240 psia. Drilling for production ended in 1966 with a total of eleven wells completed and stimulated. In June 1970, after producing 14 Bcf, the field was converted to storage to supply an ammonia plant. Following conversion to storage, three additional wells were drilled to enhance storage performance (Figure 1). However, since the requirements of the ammonia facility were limited, the field never turned more than 1.1 Bcf in a cycle, averaging about 400 MMcf per year for withdrawal and 470 MMcf per year for injection through 1990.

In April 1990, NFGSC purchased the field and began operations to test and define the potential for storage development. NFGSC storage operations through April 1995 have included four full injection cycles and four full withdrawal cycles. The maximum volume injected and withdrawn in one cycle has been 1.52 Bcf and 1.43 Bcf, respectively. The existing gathering lines, backbone line and compressor station have limited the seasonal deliverability and injectability. Maximum historical withdrawal was about 20.6 MMcfd.

**Geologic Setting.** The field lies along the northwest margin of the Oriskany sandstone at an average depth of about 4,000 feet. There is a uniform southeast dip of about 60 feet per mile. The Oriskany consists of light to medium gray, medium-grained quartzose sandstone that occasionally becomes limey due to fossil inclusions. The trap is bounded on the north, west, and east by the pinchout of the Oriskany sandstone. The Oriskany thins to the south and is accompanied by loss of permeability.

**History Match.** The history matching effort was separated into two different time periods: (1) the "early" history, from field discovery in 1955 through February 28, 1991, and (2) the "late" history, from March 1, 1991, through July 31, 1993. Although monthly gas production and injection volumes were available for each well for the early history, very limited pressure data were available between 1955 and 1991. Shut-in pressures were recorded between 1964 and 1970 during a 4-7 month summer shut-in period or for well testing. After 1970, the next available pressure data were from well test data in 1988. After 1988, bimonthly, shut-in wellhead pressures for each well were available for January and February, 1991. Table 1 shows a comparison of the simulator predicted and actual bottomhole pressures between 1964 and 1991. The number of wells with available pressure data and the shut-in period prior to the measurement are also presented. Except for 1965, the deviation of the average pressures is less than 4 percent.

The late history, which represents 2.5 injection/withdrawal cycles, was the main focus of the history matching effort since daily gas rates and flowing wellhead pressures were available for all

wells (except for February 1992 through November 1992 where weekly average rates and pressures were available). During the late history period, the field was shut in for 1 week for inventory verification in November 1991, April 1992, November 1992, and April 1993. Table 2 shows a comparison of the shut-in wellhead pressures for each well for the four different inventory periods. The average deviation for the four periods were between 1.8 and 3.4 percent, with only five match points having a deviation greater than 5 percent. Figures 2 and 3 show typical matches of simulator predicted flowing wellhead pressure and measured flowing wellhead pressures for two wells. Skin factors of -4.5 were used for each well. These values are consistent with the skin factors calculated during two separate well tests. The matches were considered to be very good because of the many uncertainties leading to a non-unique match. These uncertainties include: (1) the uncertainty of reservoir properties (permeability, thickness, and porosity) away from the center of the field; (2) the location of reservoir boundaries; (3) the accuracy of data measurements; and (4) the inability of the simulator to model water drop out.

**Field Development Forecasts.** NFGSC's proposed plans are to drill up to 16 new wells (14 active and 2 observation) and to inject additional base gas as required to expand the current working gas capacity. New well deliverability and injectability have been projected as a percentage of the average for existing wells to allow a conservative estimate. Proposed total storage capacity at a maximum bottomhole pressure of 2,240 psia is 17.6 Bcf. This volume is lower than original gas-in-place because of the compositional differences between the original gas and the pipeline quality gas to be injected for storage.

The rate schedule developed for modeling forecasts represents a mix of 60-day and 100-day service levels under a scenario that maximizes the withdrawal requirements at the latest point in the season. Different scenarios, which do not represent the maximum capability of the field, were investigated to increase working gas to 5 Bcf and to increase maximum deliverability to 55 MMcfd. Wellhead pressure was limited to 2,200 psia during injection and 400 psia during withdrawal.

Several cases have been simulated to compare the storage efficiency using both horizontal and vertical wells. The base case was set up such that a direct comparison of the extra working gas and deliverability obtained using different well configurations could be made. The injection and withdrawal pressures required to meet the designed rate schedule for the base case were forecasted and these pressures were then used in subsequent cases.

The base case included 11 existing vertical wells (Wells 1 - 11) and 14 new vertical wells proposed by NFGSC as shown in Figure 1. The skin factors for the new vertical wells were set at -4.5, the same as the existing wells as determined from the history match. Three other well configurations were compared to the base case. For Case A, the well locations of the 14 proposed vertical wells were moved closer to the center of the field. For Case B, the 14 proposed vertical wells were replaced with four, 2,000-foot horizontal wells as shown in Figure 1. The skin factors of the horizontal wells were set to zero. Because of the uncertainty of reservoir properties away from the center of the field, additional data will probably be obtained before proceeding with full field development, especially with horizontal wells. Hence, four vertical step-out wells have been proposed to provide this data. Once this data is processed, refinements to the geologic model will be made and new forecasts for the vertical and horizontal well scenarios will be conducted. Hence, Case C was set up with 4 vertical step-out wells (P1-P4) and three, 2,000-foot horizontal wells, HW1, HW2, and HW4 (see Figure 1).

Table 3 compares the injection and withdrawal volumes for two storage cycles and the contribution of the different well groups for the base case, Cases A, B, and C. The first injection cycle of 7.5 Bcf includes the injection of additional base gas to bring the total gas volume to 15 Bcf. The second cycle represents a typical storage cycle 5 Bcf per year. Table 3 shows that an additional 260 MMcf can be cycled by better well placement (Case A) and that an additional 460 MMcf can be cycled by using horizontal wells (Case B). Four, 2,000-foot horizontal wells performed better than 14 vertical wells. Case C showed that replacing one horizontal well (HW3) with 4 vertical step-out wells had only a small impact on the amount of gas cycled.

**Cost Benefit Analysis.** An analysis was conducted to determine the cost benefit of using geologic modeling and reservoir simulation for "optimizing" development strategies. The net present value (NPV) of the additional gas cycled was calculated for Cases A, B, and C assuming a 10 percent rate of return and a 10-year contract length. The annual income for each case was calculated using the additional volume of gas cycled during the second cycle (Table 3) and a cost-of-storage service of \$1/Mcf. Using a vertical well cost of \$300,000 and a horizontal well cost of \$600,000, additional cost savings of \$1.8 million and \$1.2 million are obtained for Case B and Case C, respectively. Assuming a cost of \$250,000 for the geologic modeling and reservoir simulation study, NPVs of \$1.2 million, \$4.1 million, and \$2.9 million were calculated for Cases A, B, and C, respectively. These NPV calculations show a significant cost benefit, however, are not reflective of the NPV for the overall storage development project.

**Discussion of Results.** Although there has been no field verification of the modeling results, the results of the study have shown that geologic modeling and reservoir simulation can be very important to the efficient development of a storage reservoir. The cost benefit analysis showed that the additional gas cycled and well saving costs identified through the modeling effort provided NPVs that were 5-16 times that of the initial investment of the simulation study. The modeling results have shown the potential advantages of using horizontal wells, four horizontal wells performed equal to or better than 14 vertical wells, and have also focused efforts to gather additional data necessary to make the final decision on a field development strategy. While cost savings opportunities have been identified through this modeling effort with NFGSC, the need for additional reservoir description will require three to four vertical step-out wells before proceeding with full field development, especially with horizontal wells.

### **Equitrans, Inc.**

**Field History.** The field was discovered in 1889 and developed through 1930. Conversion of the field to storage began in 1947. The first storage pool was comprised of six wells completed in the Fifth sandstone. While studies and tests were being performed in this area, the possibilities of using a nearby Fifth sandstone pool for storage were explored. From 1950 through 1952, an intensive program was carried out in reconditioning, drilling, and inserting new casing and tubing in wells. By January 1953, the storage field was comprised of these two pools and had a total of 33 wells. Obvious communication existed between the two pools, but the mechanism for communication was poorly understood.

As part of a 1992 study, the field was divided into three areas of distinct reservoir performance (designated as West, Main, and East) based on the high- and low-end inventory pressures

recorded from 1987 through 1992. In general, the West and East areas operated in a narrower pressure range than the Main area, which implies that these portions of the field were not operating at their fullest potential. Both volumetric and material balance calculations were used in quantifying the volumetric increase that would result from operating the West area under the same pressure conditions as the Main area. The results indicated that 400 to 700 MMcf of storage potential was not being utilized in the West area due to an insufficient number of wells. Thus, four new wells were drilled in 1992 to efficiently cycle this area and to increase field deliverability. These wells increased field deliverability by approximately 16 MMcfd and field capacity by 250 MMcf at 600 psig. Over the last three years, Equitrans has cycled about 2.1 Bcf per year with a maximum field deliverability of over 40 MMcfd.

**Geologic Setting.** The storage field is located in the Fifth sandstone within the historic shallow gas belt of the Appalachian basin. This region is characterized by numerous overlapping stratigraphic traps within highly lenticular sandstones of the Upper Devonian Catskill Delta complex. The name Fifth sandstone is an unofficial term coined by drillers and used widely by petroleum geologists to denote a thin package of multiple, locally amalgamated sands at the base of the Upper Devonian Venango Formation. Although it is difficult to track informal drillers' names across the basin, the Fifth interval in southwestern Pennsylvania closely correlates with the Fourth sandstone of northern West Virginia and the Third Venango sandstone of the historic oil fields of Venango County, Pennsylvania.

Regional correlations by numerous authors have shown that the primary gas reservoirs of the shallow gas belt generally occur within a sandstone-rich facies that grades westward into marine shales and siltstones and eastward into non-marine red shales and fluvial sandstones. Harper and Laughrey<sup>7</sup> confirmed the marginal-marine origin of lower Venango sandstones through analysis of nearby outcrops. A sandstone isolith of the lower Venango Formation<sup>8</sup> (Figure 4), including both the Fifth sandstone as well as the subjacent Bayard sandstone, shows a well-developed belt of sandstone with a north-south strike trend that is interpreted to mark the approximate paleoshoreline position. Dip-trending units are common to the east of the strike trend, and are interpreted as fluvial/distributary feeder channels. The western edge of the strike trend is regular and abrupt, suggesting efficient redistribution of sediment along the shoreline by wave action. An understanding of these general characteristics of Venango sandstones was an important guide to the interpretation of sandstone geometry within the subject gas storage field.

**Geologic Analysis.** Geophysical well logs from over 100 gas wells completed in or around the field between 1902 and 1992 were used to perform the analysis. Since the majority of the logs were run in the 1950's, the suite generally consisted of only gamma ray, caliper, and temperature logs. Neutron-density and induction logs were available for only seven to eight of the newer wells. After studying the gamma ray logs, it was apparent that correlating the logs would be difficult due to problems that existed involving vertical scaling and the units in which the data were recorded. To overcome these problems the log traces were digitized and replayed in cross-sections using a consistent scale. Prior to digitizing, the units were normalized by setting up a 0-200 scale such that no sands would be less than zero API units and only the most radioactive shales in the section would approach 200 API units.

Initially, 50 percent clean sandstone was used to indicate potential pay zones for each of the three sandstone units. However, it was apparent that the zones where a neutron-density crossover occurred (indicative of the presence of gas) correlated only with the good permeability and porosity

measurements from sidewall cores, and that these zones correlated well with 75 percent clean sandstone. Zones with gamma ray readings between 50 to 75 percent clean sandstone showed little to no crossover on the neutron-density logs and very low permeability and porosity from sidewall core measurements. Therefore, a 75 percent clean sandstone cutoff was used to represent the pay interval in all wells. The amount of 75 percent clean sandstone in each of the three sandstone units of the Fifth was then determined and mapped across the field to evaluate reservoir pay/permeability trends.

The thickest (middle) unit in the area of interest is herein called Zone 2. The isopach map of net sandstone in Figure 5 reveals two primary trends in sandstone development. A prominent thick trend (located at the west side of the field) is oriented roughly north-south, parallel to regional depositional strike and most likely was deposited along a paleoshoreline. This thick trend thins both to the south and to the north from a maximum of over 30 feet to less than 15 feet at the field margins. The thickening in this strike-trend coincides with a major east-west dip-trend accumulation (located at the east side of the field). This second trend may represent channelized deposition simultaneous to the shoreline unit as a distributary channel with the thickening in the strike-trend marking the distributary mouth bar. Alternately, the dip-trending portion of Zone 2 may be a slightly younger fluvial system. These trends are comparable to the Fifth sandstone mapped in the McDonald field<sup>9</sup> to the north as shown in Figure 6.

**History match.** Data available for the history match began with the injection cycle in 1987 and ended with the withdrawal cycle in 1996. Only total field volumes and biannual inventory pressure (shut-in wellhead pressure) data were available between 1987 and 1993. Starting with the injection cycle in 1993, flowing rates and wellhead pressures, averaged over 1 to 3 week periods, were available for 20 of the 28 injection/withdrawal wells. In 1995, pressure transient tests were conducted on 15 of the injection/withdrawal wells. These well tests showed a very wide range of transmissibility and a high degree of damage for most wells. Permeability calculated from well test data and permeability based on flow rate data from the metered wells were used as a starting point in the history match.

The average of the difference between actual inventory pressure and simulator predicted pressure for the 28 injection/withdrawal wells and 3 observation wells over the 10 year period was about 10.5 percent. This match was reasonable since individual well rates were dependent on permeability and skin factor (and no well treatment history was available to provide skin factor over the ten year period), and porosity and water saturation data were available for only 7 wells. The results of the history match indicated that (1) gas-in-place was lower than expected or was not effectively being cycled due to low permeability areas and the shorter withdrawal season with respect to the injection season, and (2) although connected, there were several very high permeability areas that appeared to be acting as localized pools (there are several areas of the field where active wells are separated by 4,000 to 6,500 feet).

**Field Development Forecasts.** One of the field operations scenarios that Equitrans wanted to explore was offering a 10-day or 30-day peaking service in addition to the baseload service already provided. A base case run was set up using the results from the history match, i.e., existing wells and damage (skin factor), to turn 2 Bcf annually. An additional 200 MMcf was injected during the first cycle to account for the difference between actual and history matched gas-in-place. Even with the additional gas, the prediction runs were considered very conservative.

The forecast runs consisted on either a 10-day peaking service of 10 MMcfd offered March 1st through March 10th, or a 30-day peaking service of 10 MMcfd offered February 15th through March 16th. This represented a worst case scenario where the peaking service was offered near the end of the withdrawal season when reservoir pressure was at its lowest. Several runs were made to investigate the effect of well remediation and well remediation with either new vertical or new horizontal wells.

The well remediation only forecast assumed that skin damage on 7 wells could be reduced from +20 (or higher) to +2. For this prediction run, wellhead pressures fell below minimum level during the peaking service. Thus, 4 new vertical wells were placed in areas of low well density. The results of this run were good, with the wellhead pressures remaining slightly above minimum level. The 4 new vertical wells were then replaced by one 1,500 foot horizontal well, which performed as well as the 4 new vertical wells. An additional run was made to determine the affect of when the peaking service was offered. For this run, the 30-day peaking service was offered January 1st through January 30th. Wellhead pressures remained almost 70 psi higher during the peaking service compared to earlier runs, indicating that higher rates could be met if the peaking service was offered earlier in the withdrawal season.

**Discussion of Results.** Results of this study have shown that a thorough understanding of the paleo-depositional environment is necessary to develop a good geologic model. In areas where data are scarce, an understanding of the regional geology is important for extrapolation into undrilled areas. Normalizing the gamma ray units, digitizing and replaying on a consistent scale allows the use of well logs spanning nearly five decades to be utilized in geologic modeling and reservoir analysis. This is critical in Appalachian fields where pre-1960 gamma rays may be the only data available. Permeability and porosity measured from sidewall cores and neutron-density crossover correlated well with the 75 percent clean sandstone from gamma ray logs. The 75 percent clean sandstone cutoff appears to be a good representation of the pay interval. Simulator predictions have shown that 10-day and 30-day peaking services can be provided in addition to the 110-day base load service. These services can be met through well remediation and by drilling either 1 new horizontal or 4 new vertical wells. Also, higher peaking rates can be offered if the peaking service is offered earlier in the withdrawal season.

### **Northern Indiana Public Service Company**

**Field History.** The Royal Center storage field, located 15 miles north of Logansport, Indiana, was developed in 1963. There are two aquifer reservoirs used for storage at the Royal Center field: the Trenton Dolomite at 950 feet (the focus of the CRADA study) and the Mt. Simon Sandstone at 2,950 feet. The Trenton reservoir was developed into a 15 Bcf field with a working gas capacity of 4.5 Bcf. Design capacity is 150 MMcfd.

Although a material balance verified the inventory, a 1980's reservoir study determined that the mapped gas/water contact did not represent enough acreage to contain the total inventory. Thus, a drilling program was planned to redefine the structure by drilling inside the locations of existing water observation wells. Full field pressure was discovered in three wells drilled in 1984, indicating that gas was accumulating beyond the reach of the established gathering system. Gas has been withdrawn each season since 1990 when two of the wells were tied into the gathering system. Although this has helped to control the expanded gas bubble, there remains an estimated 300 to 500 MMcf of



recoverable gas beyond the reach of the present wells. Hence, a more detailed study of the Trenton was required to determine the best method of recovering this gas.

**Geologic Setting.** The Trenton is a very geologically complex reservoir. The Trenton storage reservoir of the Royal Center field is a southwest-northeast trending anticline with a parallel fault on the southeast side. The dip to the southeast is very steep while the dip to the northwest is gentle. The Trenton is a dolomitized limestone which has had subaerial erosion, fracturing, leaching, and secondary calcite filling of some vugs. This results in some wells with cavernous porosity and others which have little to no porosity. Individual well deliverability varies greatly within the Trenton. However, most of the good wells tend to be grouped along perceived fracture systems.

**Geologic/Geophysical Analysis .** In the spring of 1994, NIPSCO entered into a co-funded project with the Gas Research Institute to determine if a limited 2-D seismic survey over the western area of the Trenton could map the fracture system and identify the presence of gas or gas filled porosity. The results were so successful in locating areas where wells would likely be productive that the co-funded project was continued with a major seismic survey of the entire Trenton in early 1996. The objectives of this larger survey were to locate the ideal drilling sites for wells and to confirm the location of the western boundaries of the reservoir. Finding the suspected fractures would be more difficult using 2-D seismic, compared to 3-D, but by extending the survey across the main field it was hoped to identify signatures in areas of perceived cavernous fracture systems that could be identified in the areas of interest to the west.

In an effort to thoroughly evaluate the potential drilling sites, NIPSCO also entered into a CRADA with the U.S. DOE in early 1996. Detailed cross-sections and 3-D gas saturation and porosity maps were constructed from Epilogs over the entire Trenton reservoir. The 3-D gas saturation map (Figure 7) showed areas of localized gas which supports the withdrawal behavior of the reservoir. The cross-sections showed areas of gas saturation above the developed porosity zones and above perforated intervals, as seen in Figure 8, supporting the possibility of vertical fracture systems. This interpretation is also supported by the evaluation of core descriptions from early reservoir characterization activities by NIPSCO. The cores indicate a fieldwide distribution of both open and cemented fractures near the top of the Trenton.

The geologic data was then compared to the seismic amplitude for the Trenton limestone interpreted by Polaris Energy under the GRI effort. A 2-D map was compiled (Figure 9) and anomalous amplitudes trends were highlighted for correlation. The trends show a dominant northwest trend and a northeast component. These orientations are consistent with the geometry of the monoclinial structure. The new structure maps and some earlier reservoir work by Core Laboratories also indicate a north to south orientation to faults coming off of the primary northeast fault on the southeast side of the structure. The geometry of these reservoir characteristics and the primary intersection of two amplitude anomalies were used to determine the location, depth and orientation of the horizontal well.

**Drilling Results.** NIPSCO drilled a horizontal well in January 1997. The well was completed in the Trenton at a depth of approximately 1,060 feet with a 360 foot horizontal offset. The planned 1,500 foot offset could not be completed due to the loss of about 33,000 barrels of drilling fluid into the highly fractured, cavernous reservoir. After the drilling fluid was unloaded from the well with coiled tubing, a well test was conducted. The results of the well test indicated that the horizontal well will

significantly increase the deliverability from the field and will allow NIPSCO to cycle gas from an area of the field that was not accessible from the existing vertical wells.

**Discussion of Results.** The integration of geologic and geophysics data lead to the successful location of a horizontal well in a very complex gas storage reservoir. The horizontal well will significantly increase the deliverability from the field and will allow NIPSCO to cycle gas from an area of the field that was not accessible from the existing vertical wells. The correlations of anomalous amplitudes trends and geologic mappings of gas saturation and porosity indicate other potential (vertical or horizontal) well locations. Analysis of the cross sections indicate that re-perforating the upper part of the Trenton in certain wells would allow access to gas in fractures above the main porosity mapped from the well logs, possibly increasing field deliverability and working gas capacity.

**Conclusions.** Results from the three case studies presented show the importance of geologic modeling and reservoir simulation with respect to gas storage field enhancement strategies. A cost benefit analysis conducted for the NFGSC study showed that the additional gas cycled and well saving costs identified through the modeling effort provided NPVs that were 5-16 times that of the initial investment of the simulation study. Simulation results showed that 4 new horizontal wells would perform better than 14 new vertical wells. Results of the Equitrans study have shown that a thorough understanding of the paleodepositional environment is necessary to develop a good geologic model. In areas where data are scarce, an understanding of the regional geology is important for extrapolation into undrilled areas. Normalizing the gamma ray units, digitizing and replaying on a consistent scale allows the use of well logs spanning nearly five decades to be utilized in geologic modeling and reservoir analysis. This is critical in Appalachian fields where pre-1960 gamma rays may be the only data available. Simulator predictions have shown that 10-day and 30-day peaking services can be provided in addition to the 110-day base load service. These services can be met through well remediation and by drilling either 1 new horizontal or 4 new vertical wells. Also, higher peaking rates can be offered if the peaking service is offered earlier in the withdrawal season. The integration of geologic and geophysics data in the NIPSCO study lead to the successful location of a horizontal well in a very complex gas storage reservoir. The horizontal well will significantly increase the deliverability from the field and will allow NIPSCO to cycle gas from an area of the field that was not accessible from the existing vertical wells.

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**Table 1. Comparison of Shut-In Pressures for Early History Match**

Date	Actual BHP (psia)	Simulated BHP (psia)	Percent Deviation (%)	Number of Wells	Shut-In Period (Days)
12/64	1247	1220	2.2	3	230
07/65	1182	1085	8.9	3	60
06/66	1214	1172	3.6	4	395
07/67	1053	1014	3.8	8	46
08/69	580	567	2.3	8	30
09/69	635	619	2.6	8	60
10/69	670	653	2.6	8	90
07/70	525	532	-1.3	8	10
08/88	1214	1207	0.6	10	90
02/91	1040	1023	1.7	8	210

**Table 2. Comparison of Shut-In Wellhead Pressures (psia) for Late History Match**

Well	11/20/91			04/13/92			11/03/92			04/11/93		
	Actual	Simulated	% Dev	Actual	Simulated	% Dev	Actual	Simulated	% Dev	Actual	Simulated	% Dev
1	1288	1280	-0.6	958	989	3.2	1273	1253	-1.6	844	816	-3.3
2	1310	1293	-1.3	916	921	0.6	1290	1258	-2.5	793	785	-1.0
3	1241	1275	2.7	1048	1061	1.2	1235	1233	-0.2	947	897	-5.3
4	1313	1286	-2.1	956	932	-2.5	1302	1242	-4.6	843	826	-2.0
5	1316	1297	-1.4	934	894	-4.3	1300	1264	-2.8	822	796	-3.2
6	1311	1298	-1.0	936	899	-4.0	1295	1251	-3.4	821	794	-3.3
7	1316	1297	-1.4	914	838	-8.3	1299	1248	-3.9	795	781	-1.8
8	1302	1243	-4.5	984	961	-2.3	1299	1228	-5.6	878	860	-2.1
9	1314	1280	-2.6	907	914	0.8	1295	1236	-4.6	788	833	5.7
10	1314	1305	-0.7	918	878	-4.4	1303	1267	-2.8	798	775	-2.9
11	1317	1301	-1.2	918	866	-5.7	1298	1257	-3.2	789	778	-1.4

**Table 3. Comparison of Development Strategies**

Case	First Cycle		Second Cycle		Percentage Contribution		
	Injection (bcf)	Withdrawal (bcf)	Injection (bcf)	Withdrawal (bcf)	Existing Wells	New Vertical	New Horizontal
Base	7.45	5.00	4.90	5.00	67.9	32.1	—
A	7.20	5.21	5.20	5.26	61.6	38.4	—
B	7.31	5.43	5.36	5.46	61.8	—	38.2
C	7.25	5.34	5.26	5.37	62.2	8.4	29.4

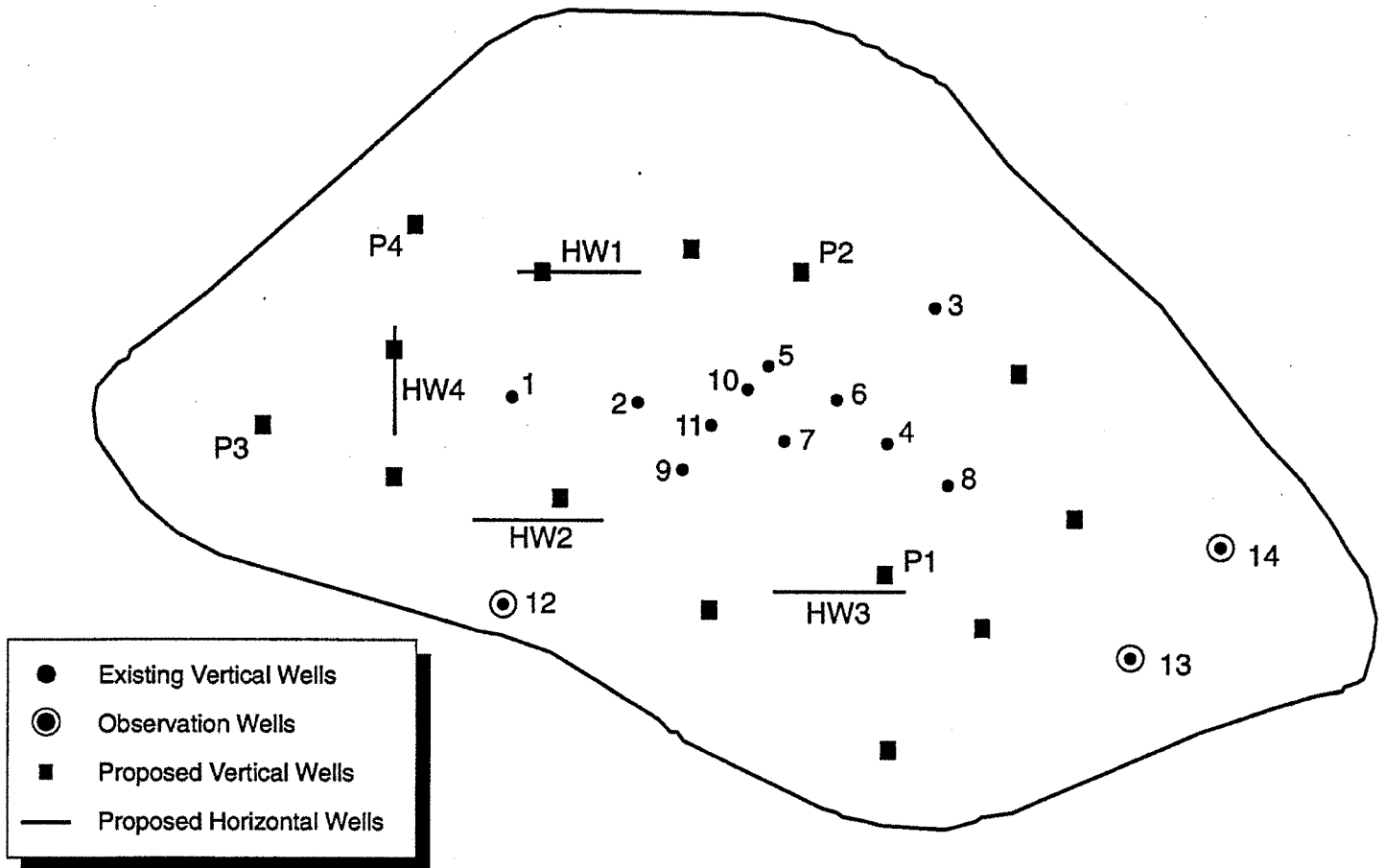


Figure 1. Location Map, NFGSC Field

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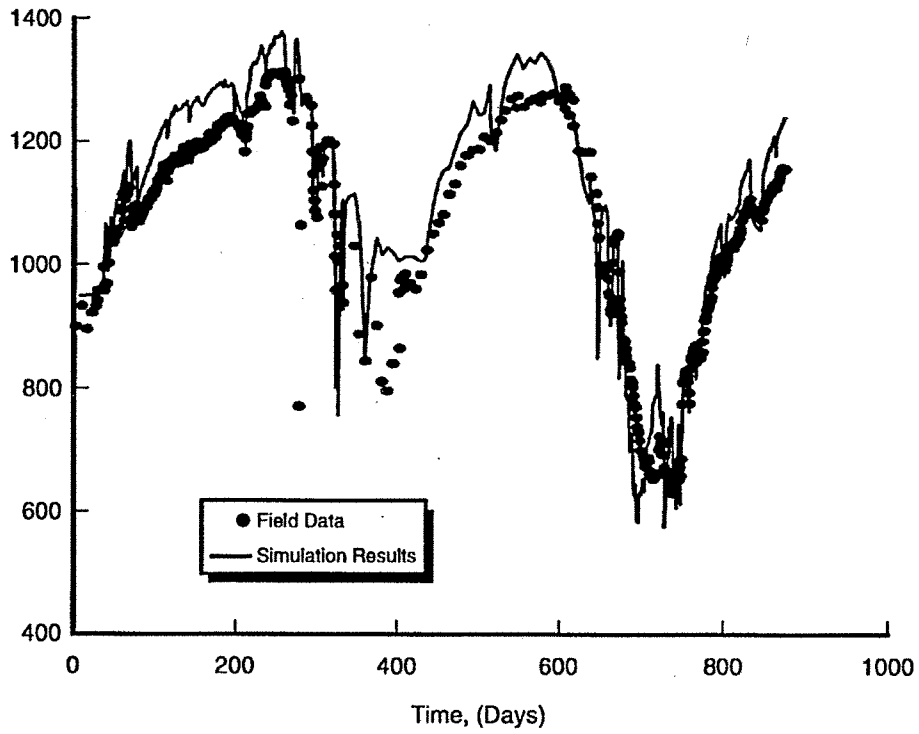


Figure 2. History Match of Well 01, NFGSC Field

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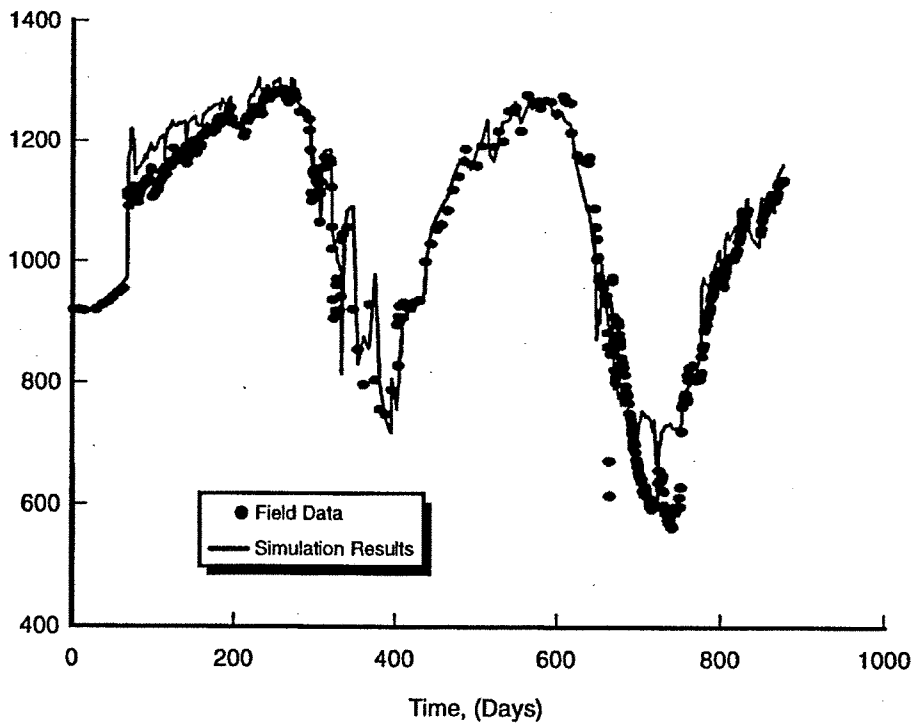


Figure 3. History Match of Well 05, NFGSC Field

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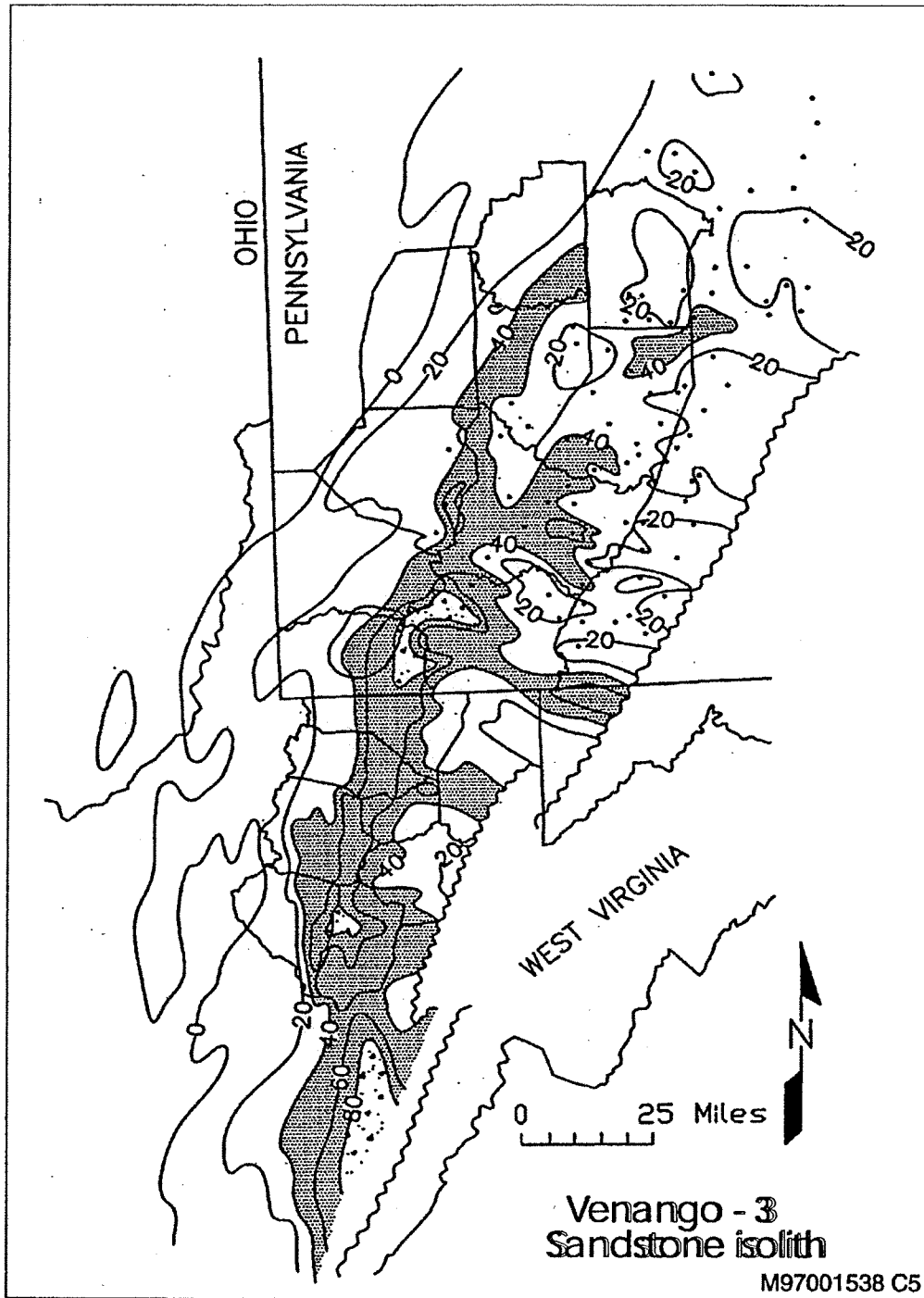


Figure 4. Regional Distribution of the 5th Through Bayard Sandstone Isolith

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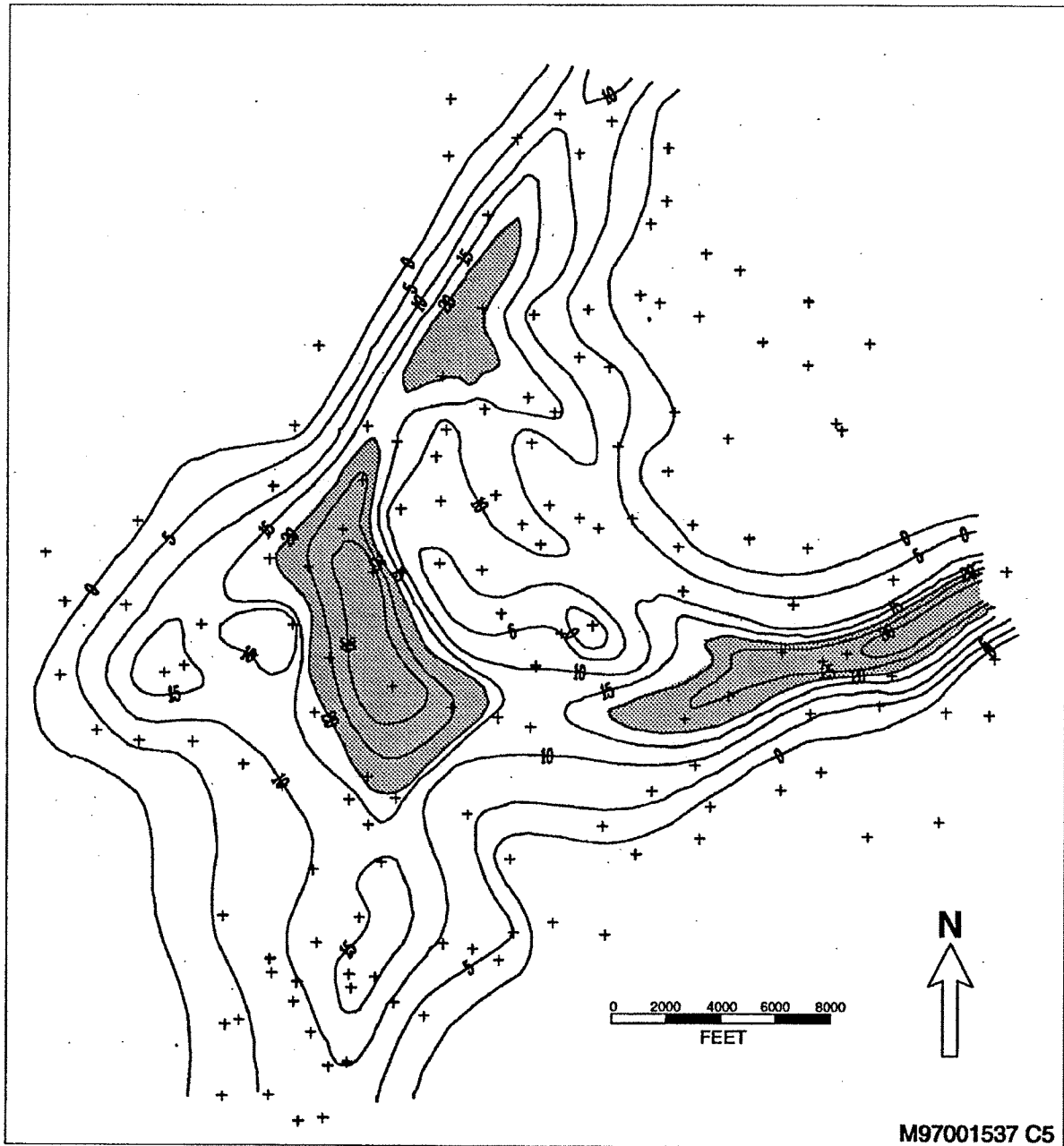


Figure 5. Isopach Map of 75% Clean Sand in Zone 2 of the 5th Sand Reservoir, Equitrans Field

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Figure 6. Isopach map of 5th Sand, McDonald Field

Units: percent

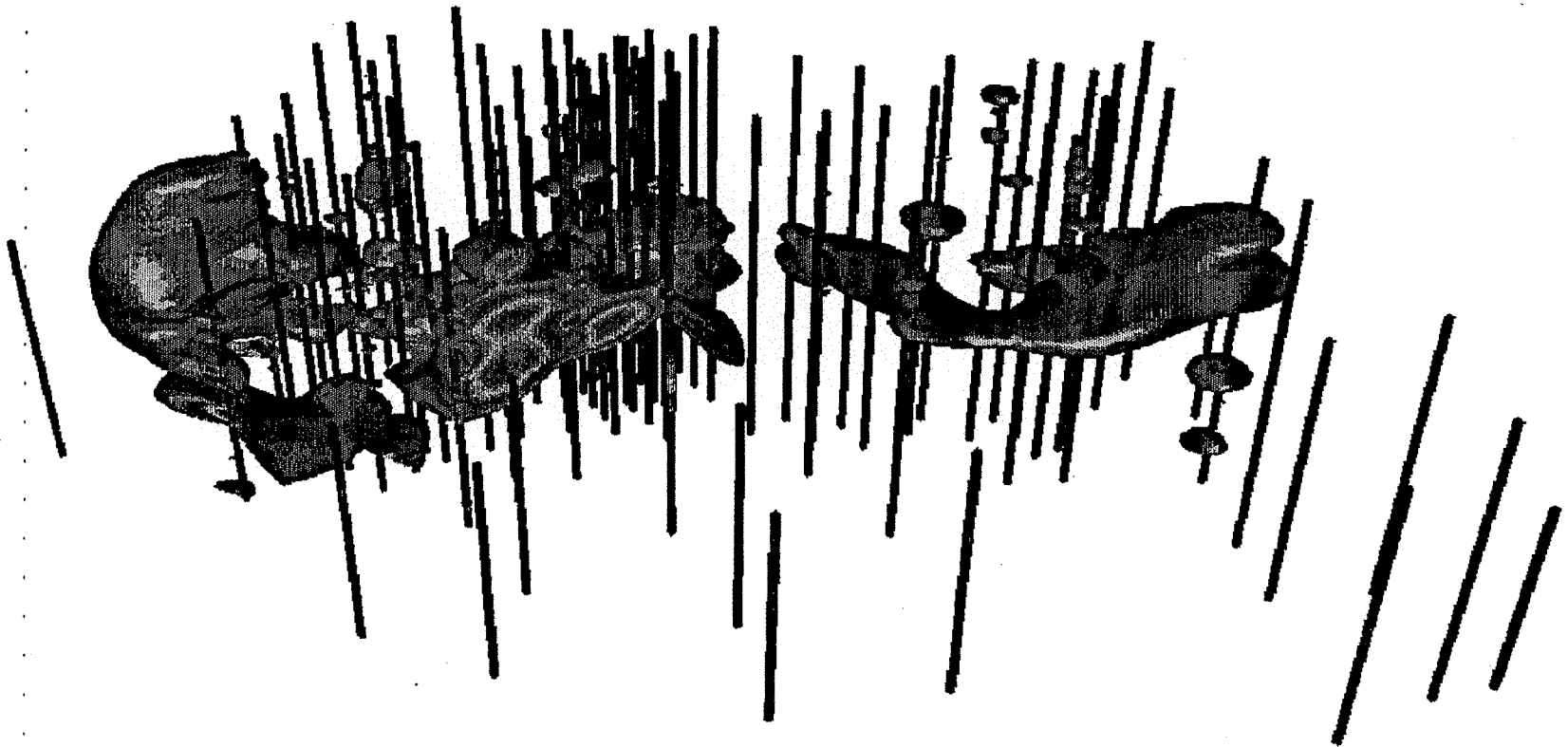
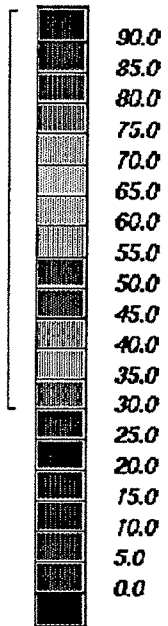
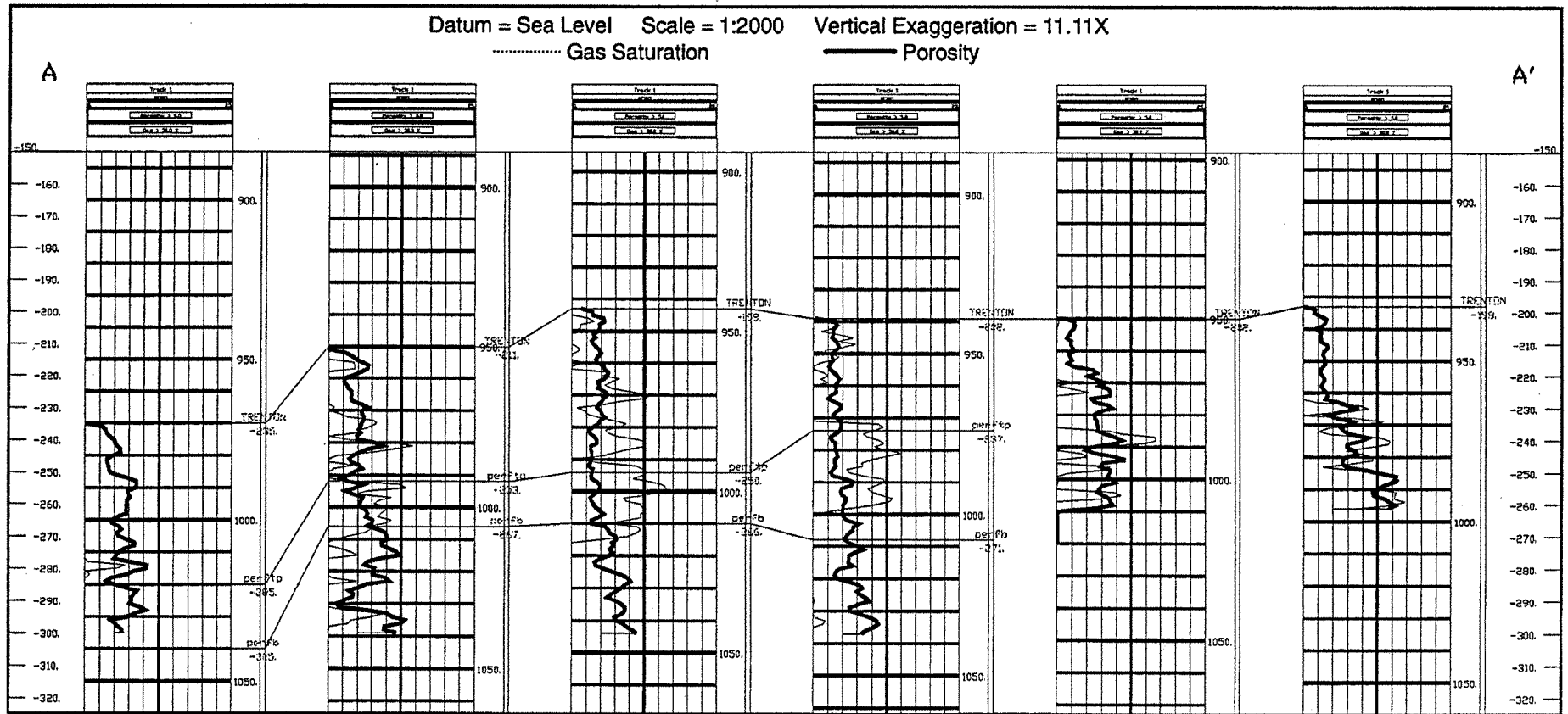


Figure 7. 3-D Distribution of Gas Saturatiion from Well Logs, Royal Center Field

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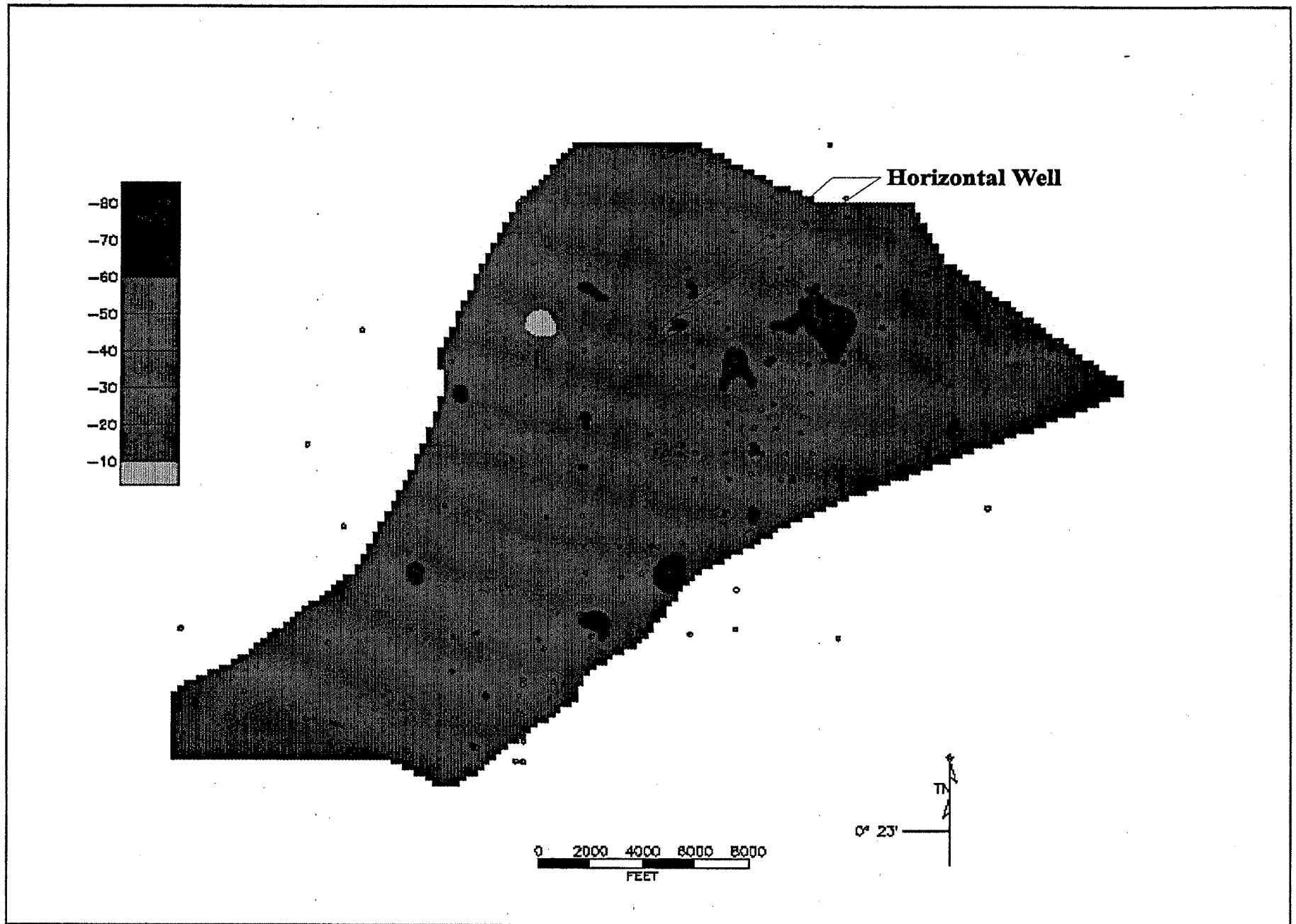
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Figure 8. Structural Cross-Section of the Trenton Reservoir, Royal Center Field

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**Figure 9. Amplitude Anomalies in Trenton Reservoir, Royal Center Field**

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(Ammer and others, 1997)

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