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RESOURCE AND EXPLORATION ASSESSMENT OF THE OIL AND GAS POTENTIAL IN THE DEVONIAN GAS SHALES OF THE APPALACHIAN BASIN

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EXECUTIVE SUMMARY

This report represents a detailed summary of the data from a complete suite of organic geochemical analyses performed on more than 2000 individual core samples as well as several hundred cuttings samples from Devonian Shale wells drilled in the Appalachian Basin. After the data were verified, plotted, mapped, and correlated with known production in the basin, the following conclusions became apparent:

Three parameters, two organic geochemical and one palynological, are the most diagnostic in describing the source potential of the shales. These reveal the quantity of hydrocarbon generated by the source, and whether the hydrocarbon is more likely to be gas or liquid. These three key parameters are:

1. The quantity of total organic carbon, determined by combustion of the carbonate-free rock.

2. The origin of that organic matter, determined by palynology, which identified three major sources in the basin:

   a. Normal marine life, i.e., the remains of algae, worms, and other life forms that have been found in Devonian rocks elsewhere,

   b. An unusually abundant form of the green algae, Tasmanites, which flourished to such an extent that in some rocks, it obscured all the other forms,

   c. Organic matter derived from plant life growing on a land mass. Some of this terrestrial material, the woody type, was carried into the basin by streams; some other types, plant spores and pollen-like material, were apparently borne by the wind, and are found to some extent in virtually all the samples.

3. The extent to which the above organic matter had been cracked by the heat from the surrounding rock. This is called the thermal alteration index.

By generally accepted geochemical criteria, the quantities of organic matter in the rocks in approximately the western half of the Appalachian Basin qualify many of the rocks as exceptional potential sources of petroleum hydrocarbons. In any given unit in the basin, the quantities decrease to the east.

It is very important to realize that the potential of any rock organic matter to generate hydrocarbons is not realized until it experiences moderate thermal alteration. In this basin, the rocks in the west have experienced only slight thermal modification and have realized only a fraction of their significant potential. In the deepest parts of the basin, the rocks have experienced too much heat, i.e., the organic matter has been completely cracked and virtually no potential remains.

The abundance of marine algae, including Tasmanites, would suggest that the Upper Devonian is potentially an oil province. This interpretation is supported by a host of other geochemical data, particularly the heavy hydrocarbon and other bitumen contents, and the proportion of ethane and heavier components in the gas evolved from the cores.

However, the abundance of gas and the relative paucity of liquid hydrocarbons, i.e., oil, in the basin, demanded that organic geochemical criteria had to be modified for application in this basin. Empirically, it can be seen that the rocks have to be at a Thermal Alteration Index of 3 or more (rather than values of 2 or more, usually applicable in other basins) in order to have cracked off enough liquid hycrocarbons to allow migration to have taken place.

This modification made it necessary to propose a mechanism to account for the retardation of the formation of liquid hydrocarbons from their precursors. The answer lay in the nature of the rocks themselves. The distinctive feature of these shales is their unusually low permeabilities. Apparently because of this exceptionally low permeability, the hydrocarbon gases which are formed early in the generation sequence, initially from microbial action on the rock organic matter, and then the very first gas cracked off by heat, are retained in the pores by the very tiny pore throats. Internal pressures build faster than in a more permeable shale, and retard the reactions which are responsible for the formation of the liquids. Under the influence of these elevated pressures, it takes greater thermal stress to generate liquids than ordinarily observed. Liquid hydrocarbons are formed in the basin, but further to the east than previously anticipated.

The oil-favoring limit was mapped as part of this study; the area that favors liquids is smaller than it otherwise would have been because the higher temperatures are generally displaced toward the leaner rocks, and away from the more marine, i.e., more oily, types of organic matter.

The distribution of amounts and types of organic matter, together with the location of the areas with more or less thermal alteration, also made it possible to re-assess the magnitude of the resource contained in the Eastern Gas Shales. As part of the study, improved methods were developed for determining the amounts of gas in place in individual core samples. Controlled off-gassing, calibrated with data on absolute quantities of gas-in-place in cores taken with the pressure-retaining core barrel, allowed algorithms to be developed for relating the amount of gas to the values of the three aforementioned geochemical variables obtained on the same cores. The gas-in-place values were calculated.

$2,549 \times 10^{12}$

The geochemical data and the algorithms produced a value of 2579 TCF for all the gas contained by all the Upper Devonian Rocks in the study portion of the Appalachian Basin.

In an attempt to define recoverable resources two recent studies were reviewed and while these studies appeared inadequate in addressing recoverable resource, sufficient data were not available to substantially improve the confidence level of a new value. If shot-well technology is used, it appears that the production would be diffusion controlled and the range of recoverable resource would fall between 30 and 50 TCF collectively for the states of West Virginia, Ohio and Kentucky. No data were available that would allow estimates to be made for Pennsylvania, New York and Virginia.

These estimates were made for shot wells on 160 acre spacings. Because of the diffusion-controlled production, closer well spacings can significantly improve these recoverable values. Locating naturally fractured reservoirs and improving stimulation technologies can also markedly improve the recovery rate.

The structural evolution of the basin was also studied. Originally it was hoped that this study would provide clues to the control of the distribution and localization of the marine, the Tasmanites, and the terrestrial types of organic matter. This evidence of a more local structural control of organic facies was not apparent on the regional scale at which it was sought; however, the structural information, as well as the data derived from the porosity and porosity determinations for the cores, and data on fracture descriptions in cores, were used to delineate, on a regional basis, those areas which should favor the occurrence of fracture porosity, which is essential to create natural reservoirs in these rock units with their virtual absence of coarse clastics.

Complete sets of maps and cross sections are provided to assist the explorationist to determine the probable regional favorability of the geochemistry in his area of interest. However, because of the wide spacing of the data points in this regional study, it is advisable to determine whether the favorable facies exist in the more geographically restricted area of interest. This project shows that this can be done with only two or three geochemical determinations.

INTRODUCTION

The major objectives of the U.S. Department of Energy's (DOE) Eastern Gas Shale Project (EGSP) are to accurately estimate both the gas in place and the economically recoverable resources contained in the Upper Devonian Shales of the Eastern Interior Basins. One of the tasks designed to meet this need was a comprehensive organic geochemical program. The purpose of this task was to subject a geographically representative suite of samples from across the basin to the same geochemical analyses that are used widely in the petroleum industry to identify source potential. Results of these tests were expected to reveal what the original potential of the dark shales was, how much of that potential has been realized, and the nature of the product, i.e., dry gas, wet gas, oil, or any combination of these, that has been generated regionally and locally within the potential source rock.

Of course, the fact that a rock has hydrocarbon source potential does not necessarily mean that contiguous reservoirs will contain any oil or gas, but does show that the rock satisfies one of the three major requirements for the presence of pooled hydrocarbons. In addition to the necessity for source rocks, the other requirements are the occurrence of some type of porous volume to serve as the reservoir, and the presence of some type of seal to confine the resource. These requirements being met, migration of the hydrocarbons from the sources to the reservoirs must also take place. In some instances hydrocarbons may migrate many miles; but in the case of the dark shales, the same rock that generates the bulk of the gas can also serve as the reservoir, i.e., where it is fractured or interbedded with thin silt stringers.

For these reasons, the first phase of this project was to study the distribution and the interrelationships of the organic geochemical data and determine which parameters had exploration significance and which could be used in an assessment of gas in place.

The second phase of the study was to map the diagnostic parameters. The richest sediment wedges, located areally and stratigraphically, could be pinpointed for industry's future exploration in the basins, as well as serving as a guide to those areas which should be targeted for future research on stimulation methods.

The next phase of the study was to use the geochemical parameters to calculate an estimate of the overall resource of the basin, and estimate how much of that resource is recoverable by existing technology, and how much might be recovered by technology of the future.

The last part of the geochemical study was to interpret the structural evolution of the basin in light of plate tectonics and continental drift, and see if there might be some tectonic control of the shifting locus of abundant Tasmanites in the unusual marine setting from which the Eastern Gas Shales were deposited. At the same time, possible relationships of the fracture

orientation in the cores with basin tectonics and structure were to be studied with the goal of identifying areas where reservoirs might be favored, or where stimulation projects might be most effective. Finally, the fracture and structural data were to be superimposed on the geochemical maps to locate the best trends for exploration for reservoired gas (and possibly, oil) that could be recovered by existing and by future technology.

This report concentrates on the Appalachian Basin, which is the largest of the Eastern Interior Basins.

GEOCHEMISTRY

Background

As the name implies, geochemistry (and more specifically in the context of this report, organic or petroleum geochemistry) is the combined science of organic chemistry and geology. Even more specifically, it is the application of chemical principles and procedures to the investigation of the composition and distribution of organic-carbon-containing components of subsurface rocks. In recent years, petroleum geochemistry has come to mean the use of chemical principles, methods and data to elucidate the processes of origin, migration, accumulation, and alteration of oil and gas.

The resulting understanding of some of these processes has made organic geochemistry an important adjunct to more classical geological and geophysical methods in the exploration for oil and gas.

It was for this reason that in the early stages of the Eastern Gas Shale Program the decision was made to bring the full complement of organic geochemical technology to bear on the problem of the relatively low realization of gas and oil from the dark Devonian shales that have for decades been known to be organic-rich.

With the exception of a small amount of hydrocarbons produced by living organisms and buried with sediments, and relatively small but commercially important amounts of methane gas produced by microbes in shallowly buried sediments, the consensus of opinion of organic geochemists is that the great majority of hydrocarbons found in sedimentary rocks is the result of the thermal conversion of part of the more complex kerogenous organic matter (1,2). This kerogen is a product of the remains of whatever organisms, plant or animal, that lived at the time of deposition of the sediments, that survived the destructive processes which ordinarily break down the organisms and recycle their organic carbon, and that were incorporated into the sediment at or near the time of deposition.

When a living organism dies, its remains are immediately subjected to microbial, chemical and physical attack and change. Generally the severe effects of oxidation from exposure to the elements, or the destructive effects of aerobic or anerobic bacteria convert the bulk of the organic remains to gases or water-soluble products that are quickly dispersed. Particles or molecules suspended in the water column or attached to settling mineral particles that do survive and mix with other particulate mineral matter at sites of deposition under water, are also subjected to digestive destruction by benthic and bottom organisms.

In spite of all these destructive mechanisms, a small fraction of the original biomass is incorporated into most sediments, particularly those deposited in stagnant ocean basins or lakes. Because of the wide variety in the original composition of the many different types of organisms, and the wide range of destructive influences they may experience, the amount and type of organic matter that is preserved in rocks varies greatly.

In the field of geochemistry, the details of the composition of all the components of this organic matter are elucidated. At the same time some of the associated inorganic matter of the rock is also studied and is correlated with the organic parameters. Different parameters appear to be more closely related to overall hydrocarbon potential in different basins. For that reason, in a comprehensive basin assessment, as complete as possible a suite of analyses is usually run. The variables are cross correlated and are also correlated with known production and shows, subsequently only the more diagnostic criteria are utilized to complete the assessment.

Experimental Program

Over 2000 core and cuttings samples from wells drilled as part of the Eastern Gas Shale Program were subjected to geochemical analyses. Most of these were selected at 30 or 10 foot intervals from the cored sections of wells in the Appalachian Basin. After the overall core was examined, its lithology described and fracture distribution noted, and its gamma radiation measured, a 3 to 6inch cylinder of core was broken from the core and was sealed in a gas-tight container to retain the released gas while the sample was transported to the laboratory for analyses.

A flow chart of the scheme of analyses is given in Figures 1 and 2. Generally, at any level of the chart, the determination on the left was the first one performed.

Gas volume and composition in the free-gas space was determined first, with a correction for the gas pressure in the container. Then, the volume and composition of the gas still retained in the core was measured, and total gas calculated. The sample was then dried and its detailed lithology described before division into the appropriate number of samples for the determinations scheduled for that specific sample. The analyses were performed using standard organic geochemical procedures which are widely used industry.

From regional plots and cross correlations of the various parameters, it became apparent that the most useful ones for geochemical assessment of the Eastern Gas Shale basins were the amount of total organic carbon, the nature of the organic matter as described in the biofacies determinations, and the degree of thermal alteration as described by the visual thermal alteration index. These three could be combined for an estimate of maximum indigenous gas expected in a zero-permeability shale. Another supporting parameter, but of more limited utility, was the residual gas determined in the initial screening analysis of the overall analytical scheme. However, since the gas measurements are more useful in assessing the total resource in the shale unit, gas determinations and distributions will be considered in a separate section of this report.

FLOW DIAGRAM FOR PHYSIOCHEMICAL CHARACTERIZATION ANALYSIS

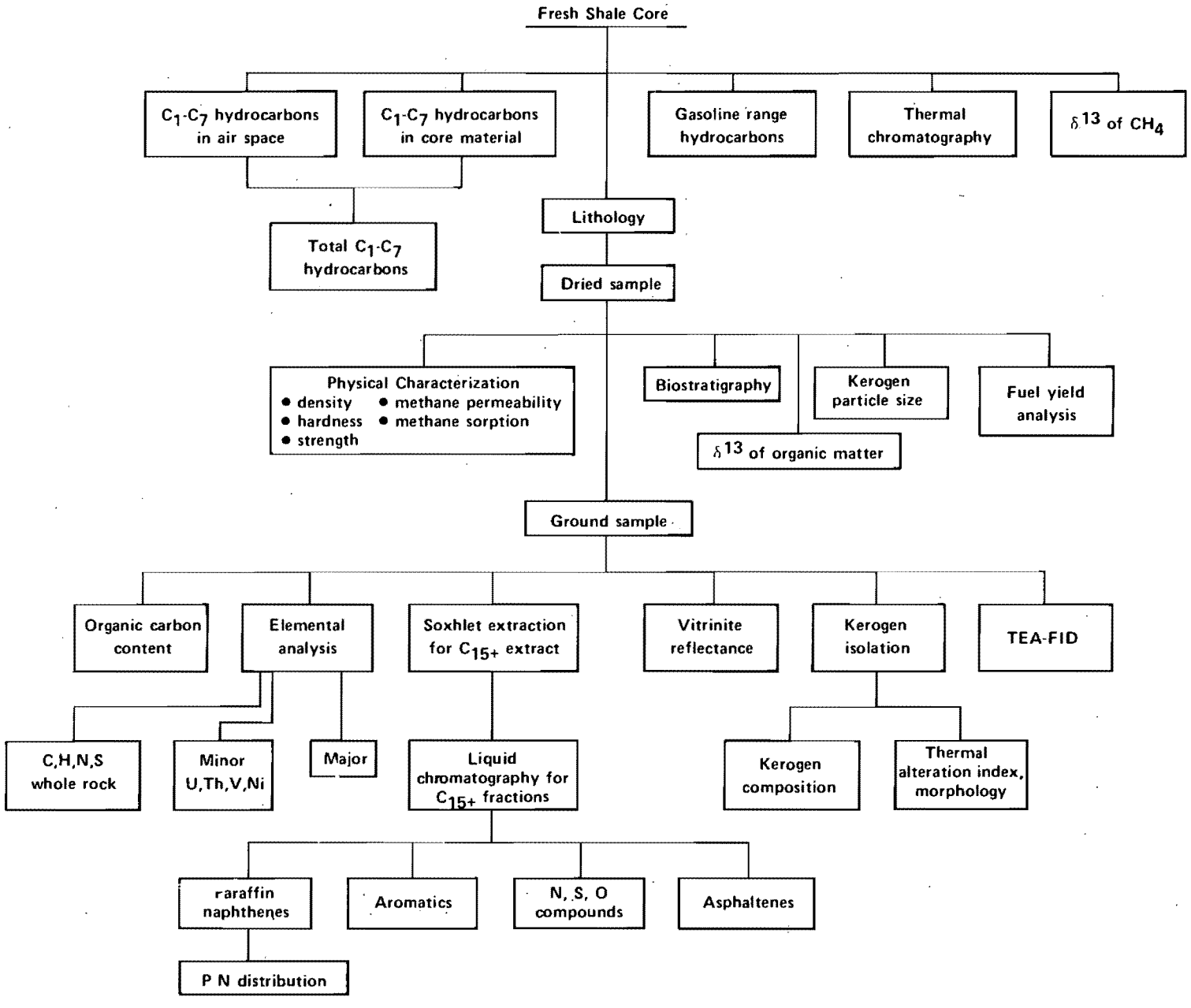

FIGURE 1

FLOW DIAGRAM FOR FUEL YIELD ANALYSIS

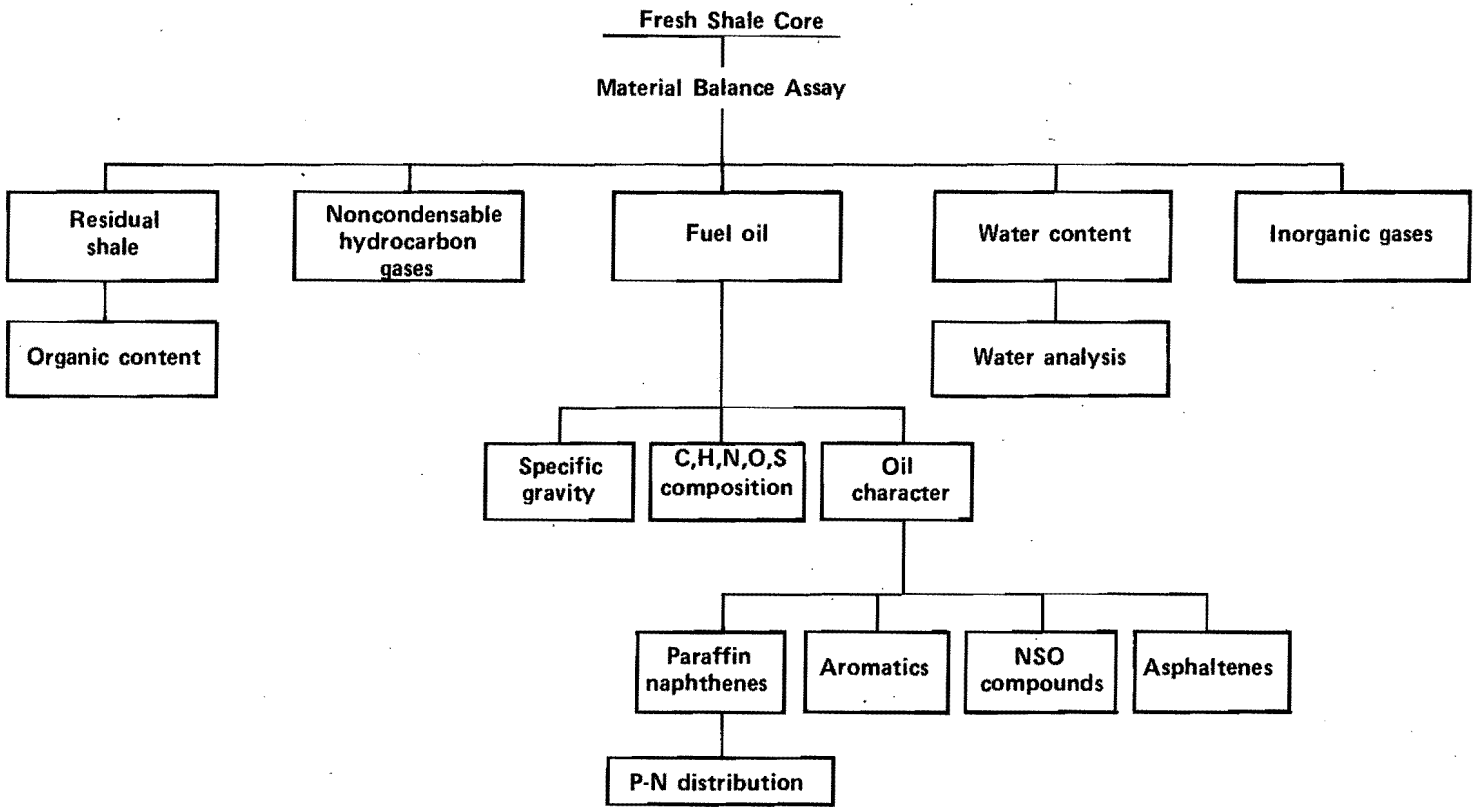

FIGURE 2

Total Organic Carbon

Because the source of virtually all the petroleum in all the sedimentary basins of the world is the remains of living organisms incorporated in the fine-grained rocks of those basins at the time they were deposited (1,2), the primary criteria in any basin assessment should be the amount and distribution of this material which is called "organic matter". The amount of this primary source material would be diminished by the fraction converted to mobile products that have moved or have been displaced from the rock by physico-chemical processes, called migration, but fortunately, the majority of the organic matter deposited in petroleum source rocks still remains in the mineral matrix, i.e., rock, with which it was deposited.

It is estimated both empirically and in laboratory experiments that less than a third of the original organic carbon is converted to mobile products, oil and gas (3), and only a portion of this can move from the rock. Therefore, a measurement of the amount of organic matter in an unmetamorphosed sedimentary rock is a semiquantitative indicator of the amount of organic matter that was originally present.

Geochemists estimate the organic matter contents of rocks by determing the amount of organic carbon they contain. Organic carbon is defined as the carbon incorporated into the carbon-carbon and carbon-hydrogen structures of organic molecules, and excludes the carbon in mineral carbonates. These latter forms, which may be the remains of skeletons or protective shells of living organisms, are technically "organic", but are not so labeled by petroleum geochemists because they do not enter into the oil or gas-forming processes. In many studies, the amount of organic matter was calculated from organic carbon contents, but the conversion factor varied so greatly from rock to rock (about 1.07 to 1.40) in the few rocks in which the detailed composition of the organic matter was determined (4), that organic carbon became the accepted reporting parameter.

As a first step in an exploration or basin assessment program, organic carbon data provide a means of high-grading the more favorable petroleum areas within the basin. Ronov (5) was the first to map organic contents regionally, and showed that on the Russian Platform, excellent potential reservoirs were filled or partially filled with oil and gas only if the nearby Devonian shales contained greater than 0.5 percent organic carbon. Large areas of the province were barren, and in all of these the organic carbon contents were beneath the minimum value.

Ronov's research also revealed that the amount of organic carbon was controlled to a large degree by the environment of deposition in various parts of the basin, but the major conclusion was that there was a minimum content of organic carbon that had to be exceeded before a rock could be a source, i.e., deliver commercial volumes of oil or gas to reservoirs, in any geological setting.

Subsequent studies of petroleum source relationships (6,7,8) confirmed this concept, that the organic carbon contents of rocks must exceed some threshold amount before they can begin to act as significant sources of petroleum hydrocarbons. Some geochemists feel that 0.4 percent represents the cutoff for shales. Others prefer 1.0 percent. For carbonates rocks, a lower

limit was established, i.e., about 0.3 percent organic carbon (9). Beyond these lower limits, the general rule is, "other things equal, the greater the organic carbon content, the greater the potential a rock has to act as a petroleum source rock."

In many cases, organic carbon determinations are made on rocks extracted exhaustively with organic solvents to remove the soluble organic matter, called "bitumen". The values, thus determined will be as much as 17 percent low (10). Nevertheless, the geographic and stratigraphic contrasts in the amounts of organic carbon are extremely useful in exploration. The residual organic matter that cannot be extracted has been labeled "kerogen" by petroleum geochemists. This term expands the earlier definition in which the term only included those kinds of organic matter which gave up significant quantities of liquid hydrocarbons upon heating. Under the new usage, the term includes more inert forms.

In the Eastern Gas Shale Program, total organic carbon analysis was run on 2000 core and cuttings samples. From the beginning it was apparent that the organic carbon content varied widely from one ten-foot interval to the next in many of the wells. This was not surprising considering that the environment of deposition of sediments may change abruptly with changes in sea level, with tectonism, with circulation, etc., and that a ten-foot section of the Devonian shale might represent the sediments deposited over 5,000 to 10,000 years. n 100,000

The distribution of organic carbon in the samples analyzed is shown in histogram form in Figure 3. The range of values measured was from less than 0.10 to greater than 27 percent, with a mean value of 2.13 percent. Superimposed on the data from the Eastern Gas Shale samples are the data from various source shales from around the world, and the generally accepted source potential rating associated with various ranges. It is obvious that, based on this criterion alone, much of the dark Devonian shale must be considered an exceptional potential source of hydrocarbons.

Originally it was intended to map the values of organic carbon to show the regional trends. However, with the rapidly changing values, the average value for a unit was misleading, particularly if there were only a few analyses in a thick section, therefore, it was decided to supplement the mapping with a series of cross sections on which the stratigraphic and regional distribution of the organic carbon would be illustrated.

These cross sections were prepared for each of the lines of wells shown on the map in Figure 4. The wells in each cross section are as follows:

Section A - A':

KY - 2	OH - 8
KY - 4	OH - 3
OH - 6 - 4	OH - 5

Section B - B':

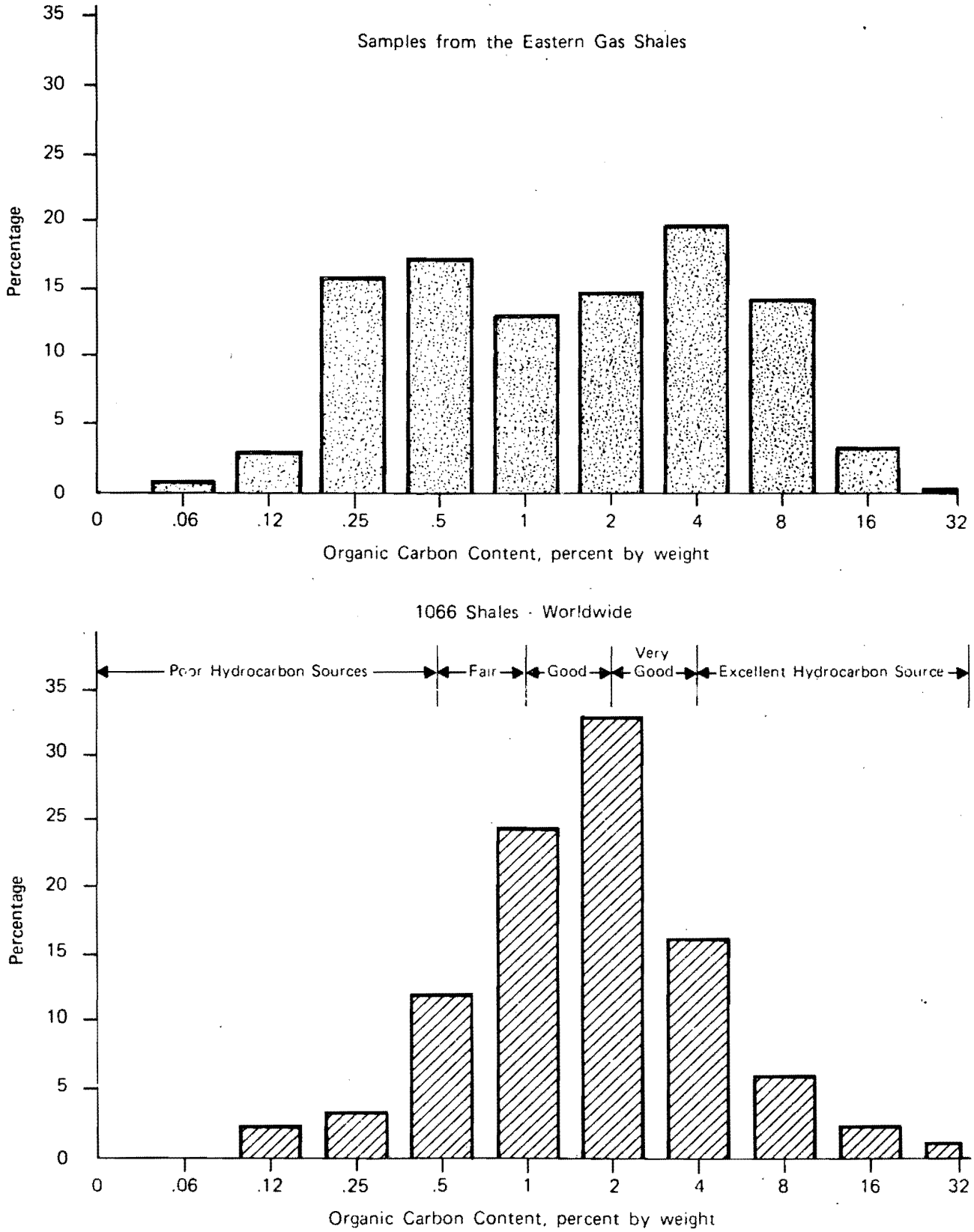

FIGURE 3 Organic Carbon Content of the Eastern Devonian Shales from the Appalachian Basin Compared with Other Shales.

LOCATION OF LINES OF SECTION

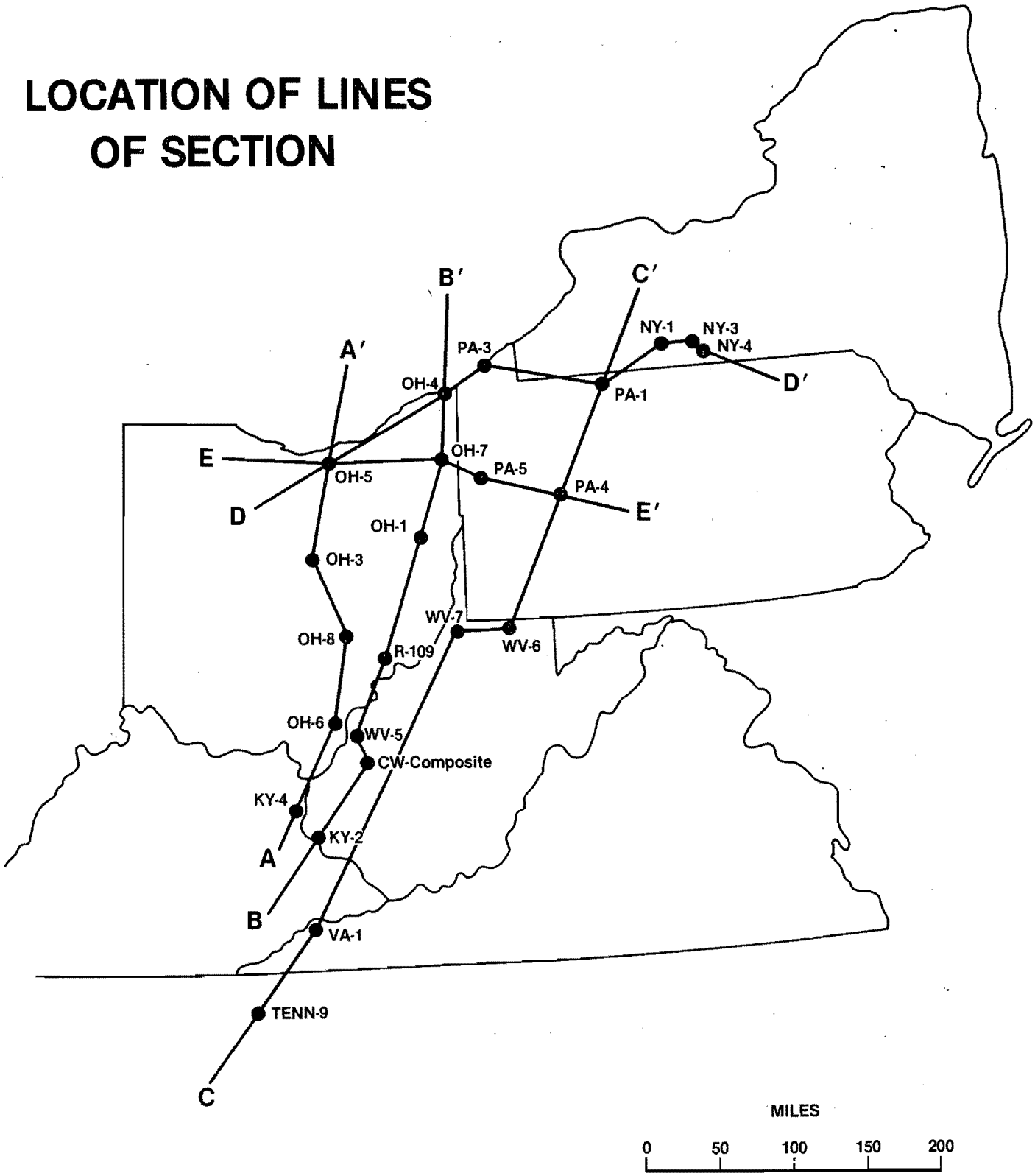

FIGURE 4

MOUND

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KY - 2	OH - 1
Cottageville wells (Composite)	OH - 7
WV - 5	OH - 4

Section C - C':

TENN - 9	WV - 6
VA - 1	PA - 4
WV - 7	PA - 1

Section D - D':

OH - 5	PA - 5
OH - 7	PA - 4

Section E - E':

OH - 5	NY - 1
OH - 4	NY - 3
PA - 3	NY - 4
PA - 1	

Detailed locations of each of the wells is given in Appendix A of this report. The cross sections are shown in Figures 5 through 9. To prepare them, strip logs of total organic carbon vs depth were prepared for each well in the program. The appropriate value of organic carbon was plotted at the appropriate sampling depth. The tops of stratigraphic intervals identified from well logs or palynology were also recorded on each of the strip logs. Then each of these logs were positioned so that some stratigraphic marker common to two neighboring logs was aligned horizontally.

Because the data were so highly variable, it was not possible to correlate the detailed layers of alternating rich and lean organic carbon; however, general wedges of rich and very rich potential source rocks were outlined on each of the sections.

The rich organic carbon wedges bear a striking resemblance to the dark shale zones delineated in the stratigraphic column shown in Figure 10 and with the dark shale units presented in summary form in Potter's summary report (11). This correspondence was anticipated. However, the organic carbon data show that the "dark shale zones" are not necessarily uniformly dark they just contain more consistent and more closely spaced layers rich in organic carbon.

Section A - A' Figure 5, the westernmost South - North line, shows the variations in organic carbon content from eastern Kentucky to north central

Gas Potential
Based on Organic Carbon Content
Section A-A′

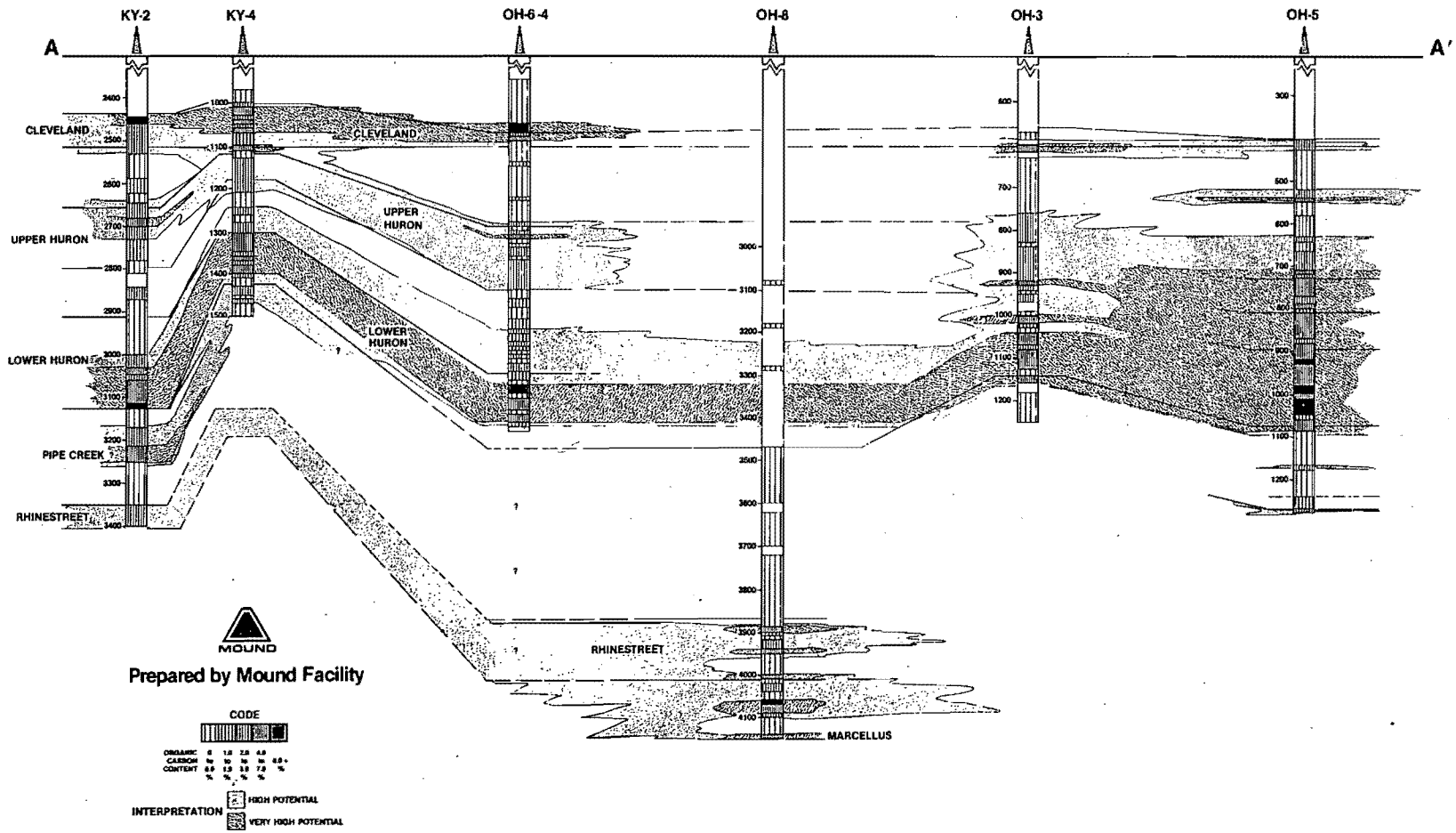

FIGURE 5

Ohio. In the two Kentucky wells, the Cleveland Member and the Upper and Lower Huron members or equivalent (Chagrin-Chemung and Dunkirk, respectively) of the Ohio Shale both are represented with organic-rich zones. The organic-rich zone in the Lower Huron Member is particularly well developed; it is about 100 feet thick in both Kentucky wells. The samples from the KY - 2 well also showed the thinner and less widely developed organic-rich intervals of the Cleveland Shale (above the Huron) and the Pipe Creek Shale, equivalent to the Olentangy Shale of Ohio which is older than the Huron Shale.

The Upper Huron shales do contain some organic-rich rich layers, but this unit is more heterogeneous, i.e., with more alternating lean- and rich interbedding, through the first three wells of the section.

The Lower Huron rich zone also becomes more interbedded with less-rich layers in OH - 6 - 4. In OH - 8, sampling was only done in the intervals older than the Ohio formation, thus we see the development of the organic-rich interval in the lowermost Upper Devonian Rhinestreet Shale, and the Middle Devonian Marcellus of the Hamilton Group, both of which appear to be represented by interbedded sections of alternately rich and lean shale.

In the OH - 3 well, the organic-rich Cleveland zone is still present, but it is only represented by one sample. The Ohio Shale is now much more rich overall, and particularly in the lower 150 feet. At OH - 5, the Upper and Lower Huron are both very rich organically. Again, the richest section is in the lowermost Lower Huron, but both of them, combined, make up about 400 feet of rich shale, most with over 4 percent organic carbon, and over 50 feet with greater than 8 percent.

The area of OH - 5 and OH - 3, where the shallow Ohio Shale laps up on the Cincinnati Arch, is the site of the thickest continuous section of organic-rich shale revealed by organic carbon analyses. There are many other distinct organic-rich intervals, i.e., the Rhinestreet or its equivalent, but they are invariably more interbedded than the Huron of north-central Ohio. While this is the thickest continuous section of organic-rich shale revealed by organic studies, that does not necessarily make it the best source rock. There are other factors that also play primary roles in determining the overall potential and how much of that potential has been realized. The type of organic matter is one of these, the degree of thermal diagenesis is the other. Both of these controls will be discussed in later sections of the report. It appears that any sediment layer with greater than 2 percent organic carbon, and of the order of twenty-five to thirty or more feet in thickness would be considered a good potential source of gas. Where there are thicker sequences the prospects would be increased even more.

In section B - B' (Figure 6), the interbedded, relatively richer Lower Huron zone can be traced from eastern Kentucky northward to extreme northeast Ohio. The "rich" Rhinestreet becomes more interbedded from KY - 2 to WV - 5, but becomes richer in organic carbon overall. About 150 feet of primarily rich Rhinestreet also appear in the northernmost two wells. A 30 - 40 foot section of the relatively organic-rich Marcellus zone was also penetrated in these latter two wells.

Gas Potential
Based on Organic Carbon Content
Section B-B′

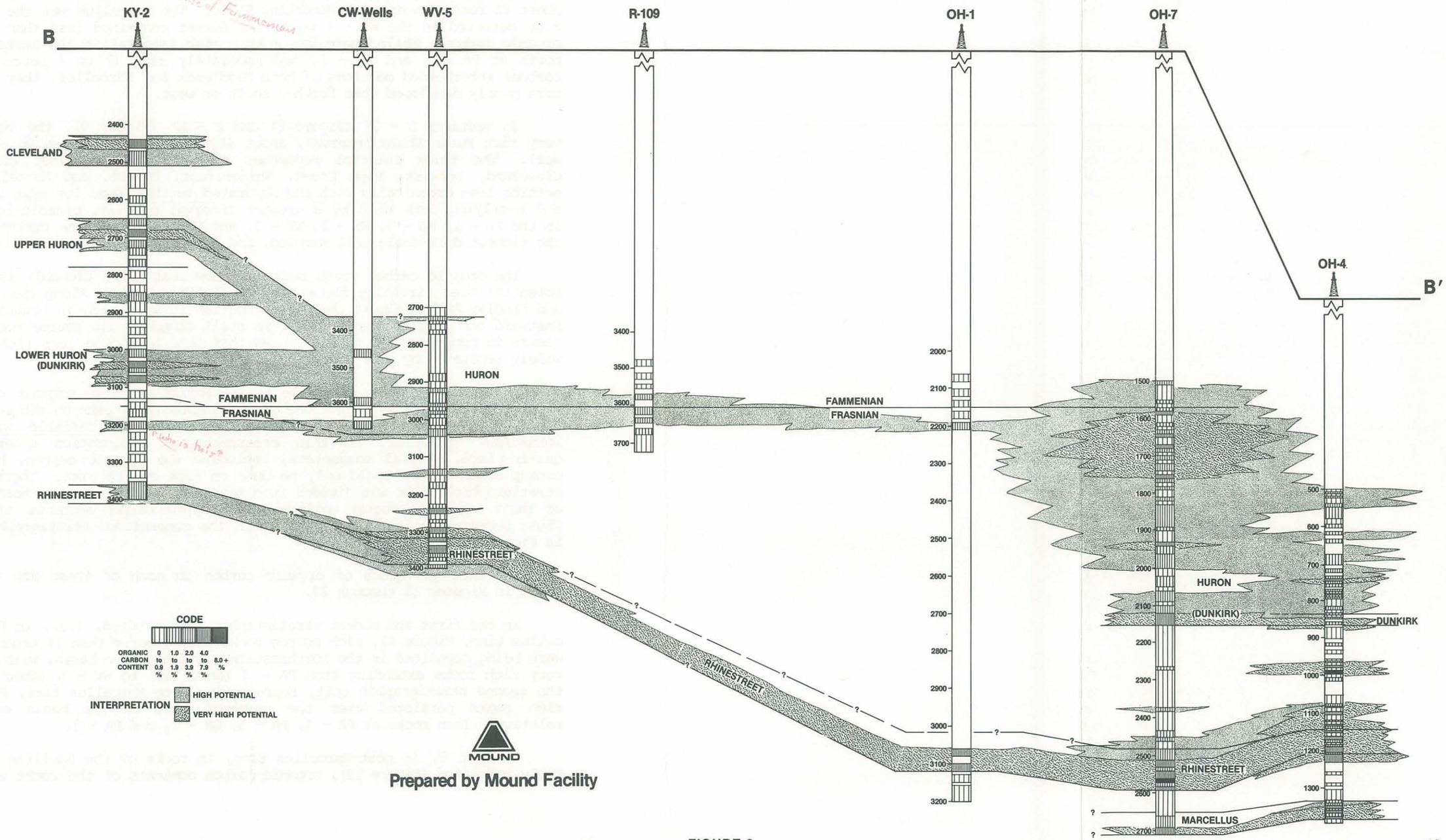

FIGURE 6

Section C - C' (Figure 7), shows a rapid diminution of organic contents in the Lower Huron from about 100 feet of rocks with more than 4 percent organic carbon in the TENN - 9 well to a section of about the same thickness but with about half the organic carbon in the VA - 1 well. This section was not penetrated in the rest of the wells in this cross-section. The WV - 7 well penetrated poorly developed Rhinestreet and Burket dark shales, and about 40 feet of very rich Marcellus Shale. The Marcellus was the only rich zone detected in the WV - 6 well, the Burket contained less than 4 percent organic carbon. While there was a thin rich interval in the Burket further north at PA - 4 and PA - 1, and moderately rich (2 to 4 percent organic carbon) interbedded sections of both Middlesex and Marcellus, they were much more poorly developed than further south or west.

In sections D - D' (Figure 8) and E - E' (Figure 9), the very thick, very rich Huron Shale interval, about 400 feet thick is seen in the OH - 5 well. The thick interval separates eastward into distinct groups the Cleveland, Dunkirk, Pipe Creek, Rhinestreet, Burket, and Marcellus, each getting less organically rich and separated further from its next underlying and overlying dark unit by a greater interval of gray, organic-lean shale. In the PA - 1, PA - 3, NY - 1, NY - 3, and NY - 4 wells, the Burket Shale is the richest dark shale unit sampled, and is about 50 to 60 feet thick.

The organic carbon cross sections show that there probably is rich gas potential over virtually the entire Appalachian Basin. Along the Cincinnati and Findlay Arches almost the entire section is very rich in organic carbon. Eastward and southeastward, there is still abundant gas source rock, but it occurs in progressively thinner zones that tend to become less rich and more widely separated by poor source quality intervals.

It is difficult to summarize the potential based on organic carbon and show it geographically on but one map of the basin or even on single maps for single formations if the organic carbon is quite variable within the formation. Moreover, in this assessment of exploration potential and gas-in-place, several parameters, including the organic carbon, had to be crossplotted. This could only be done on maps of the area. Therefore, the stratigraphic column was divided into seventeen separate units chosen because of their somewhat greater uniformity in organic carbon contents throughout. These seventeen units are identified on the generalized stratigraphic column in Figure 10.

The average values of organic carbon in each of these map units are shown in Figures 11 through 27.

In the first and oldest stratigraphic unit studied, i.e., in Early Marcellus time, Figure 11, rich source rocks with greater than 1% organic carbon were being deposited in the northeastern portion of the basin, with a belt of very rich rocks extending from PA - 3 (about 4%) to WV - 6 (about 6%). In the second stratigraphic unit, representing Late Marcellus time, Figure 12, rich rocks persisted over the northern part of the basin except for relatively lean rocks at PA - 4, PA - 5, OH - 7, and PA - 1.

In unit 3, in post-Marcellus time, in rocks of the Hamilton Group and Tully Formation (Figure 13), organic carbon contents of the rocks were lower

Gas Potential
Based on Organic Carbon Content
Section C-C′

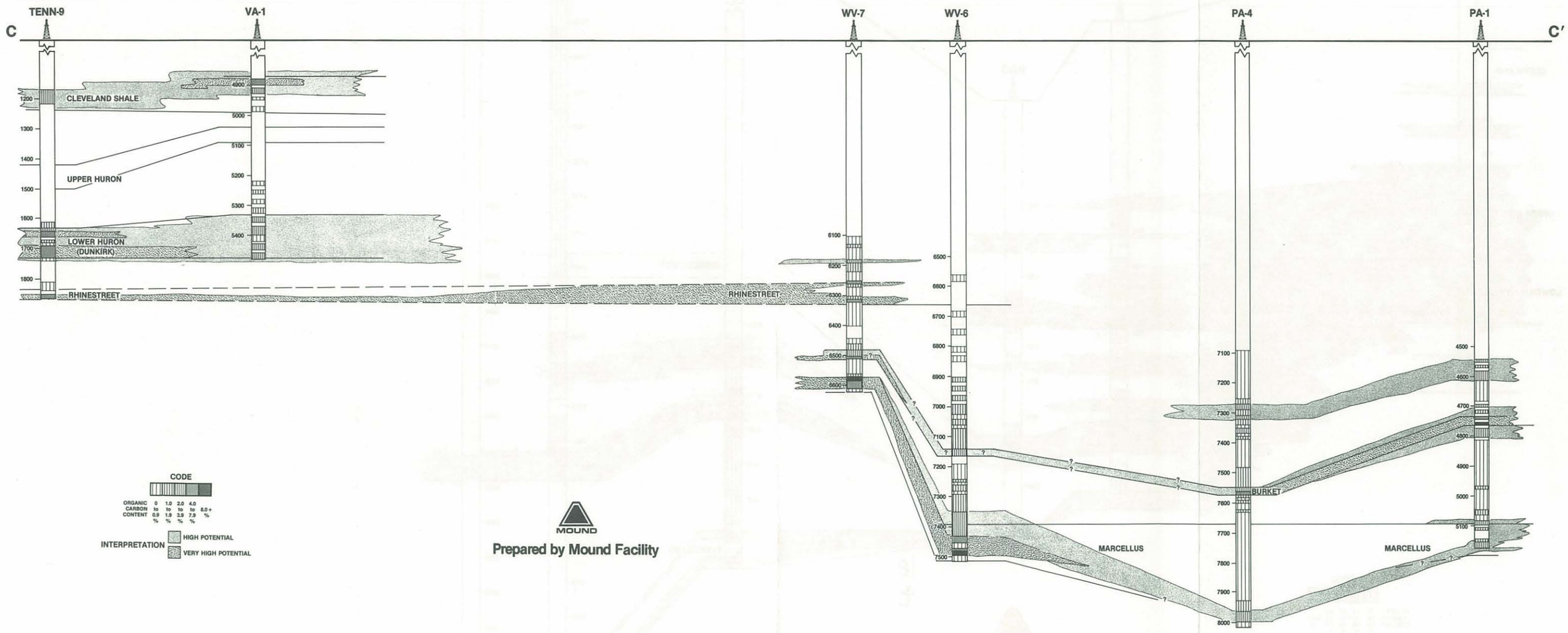

FIGURE 7

Gas Potential
Based on Organic Carbon Content
Section D-D′

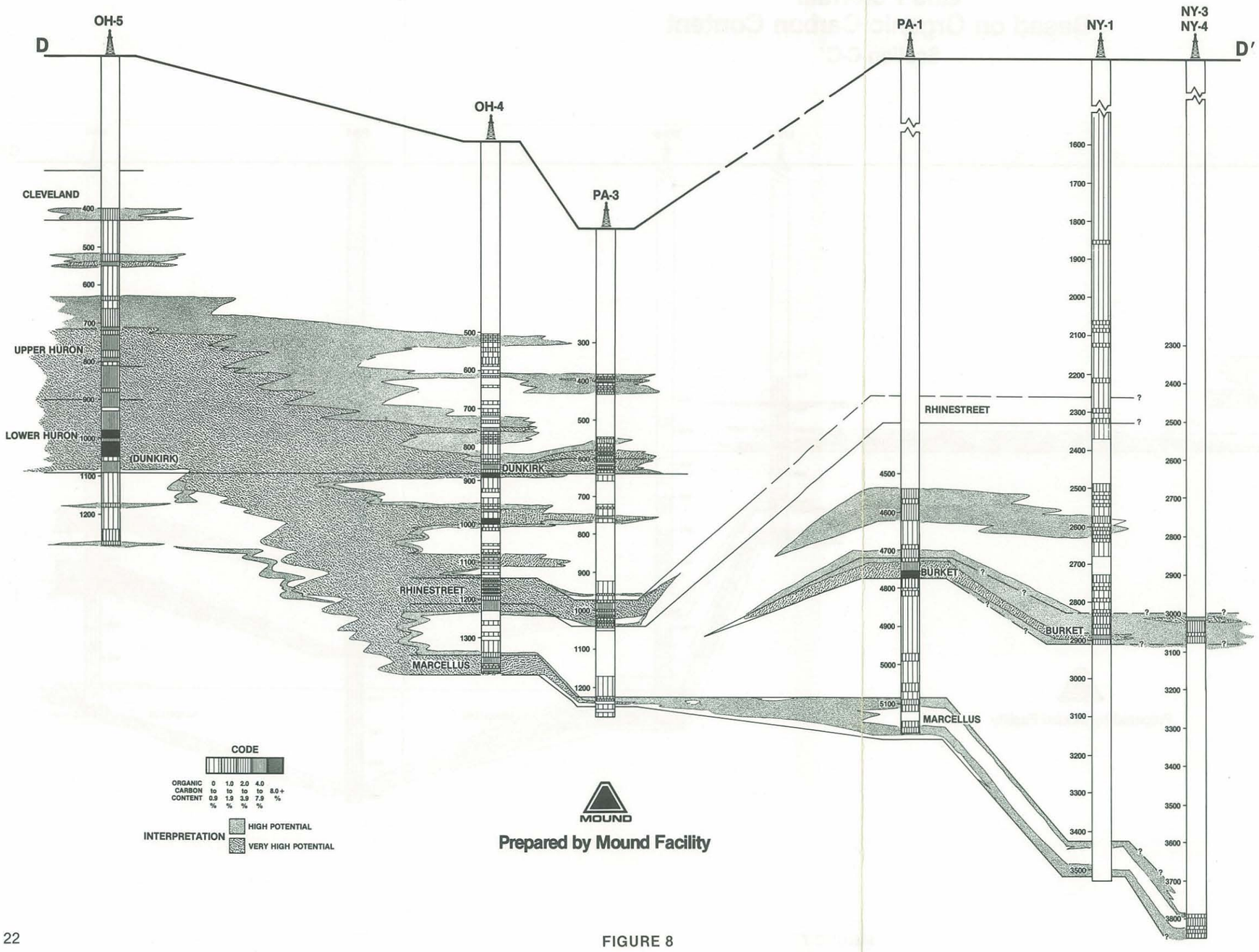

FIGURE 8

Gas Potential
Based on Organic Carbon Content
Section E-E′

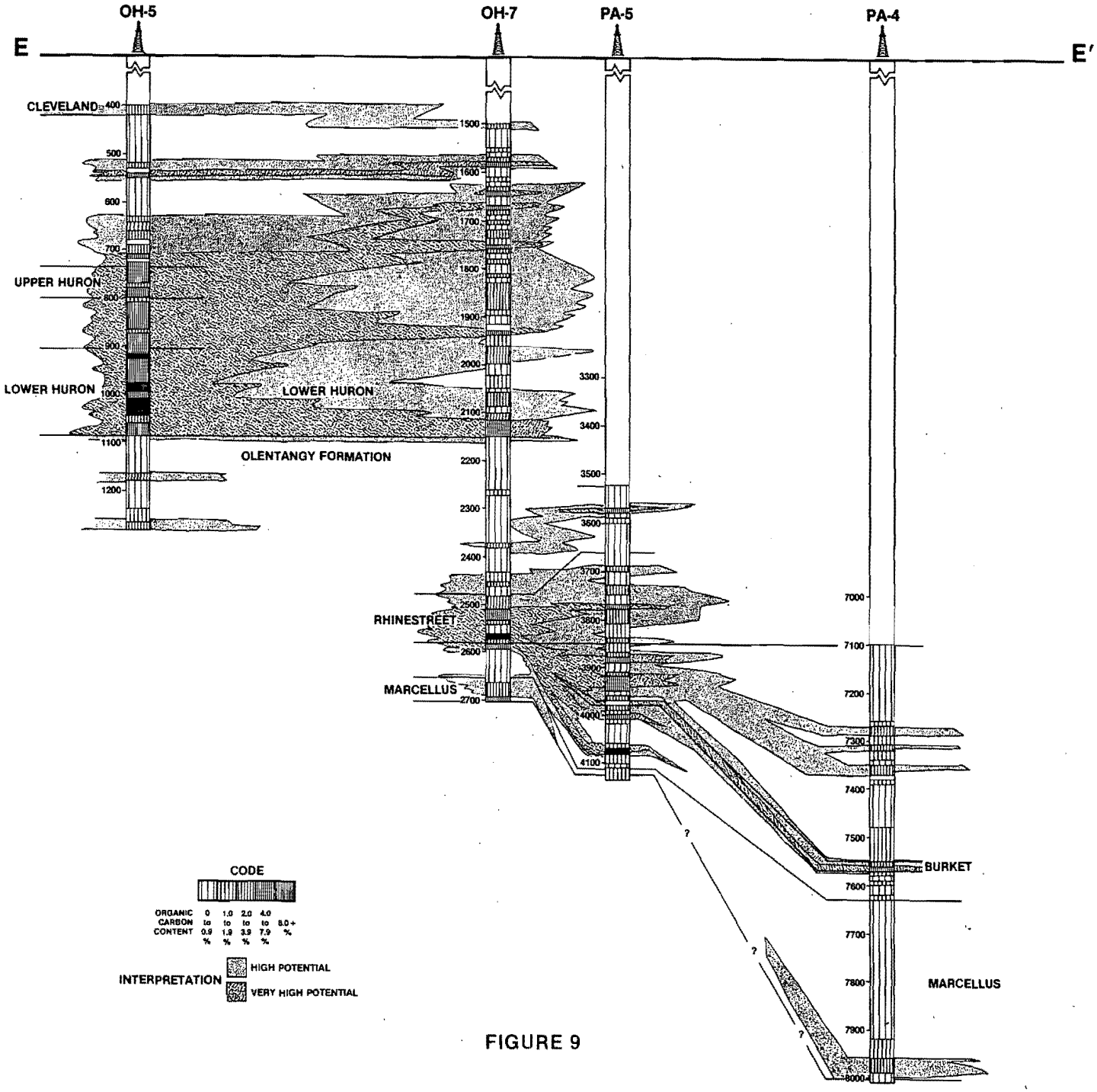

FIGURE 9

IDENTIFICATION OF SUBDIVISIONS USED IN ORGANIC GEOCHEMICAL ASSESSMENT MAPPING

WEST			EAST	
APPALACHIAN BASIN				
OHIO		PENN.	NEW YORK	
				ASSESSMENT MAP NUMBER
BEDFORD SH.		POCONO FM.	KNAPP FM.	
CLEVELAND SH.		CATSKILL	CATTARAUGUS FM.	17
CHAGRIN SH.			CHADAKOIN FM.	16
OHIO SHALE	UPPER HURON SHALE M.		CANADAWAY GROUP	15
				14
	MIDDLE HURON SHALE M.			13
				12
	LOWER HURON SHALE M.			11
		DUNKIRK SH.	DUNKIRK SH. M.	10
UPPER OLENTANGY SHALE		JAVA FM. (HANOVER SH.)	JAVA FM. (HANOVER SH.)	9
MIDDLE OLEN.			WEST FALLS FM. ANGOLA SH. M.	8
LOWER OLENTANGY SH.		RHINESTREET SH.	RHINESTREET SH.	7
				6
ONONDAGA LS.		MIDDLESEX SH.	SONYEA GROUP MIDDLESEX SH.	5
		HARRELL SH.	GENESEE GROUP GENESEO SHALE	4
		TULLY FM.	TULLY FM.	3
		MAHANTANGO FM.	HAMILTON GROUP	
			MARCELLUS	2
				1

FIGURE 10

ORGANIC CARBON CONTENT
(In Percent)

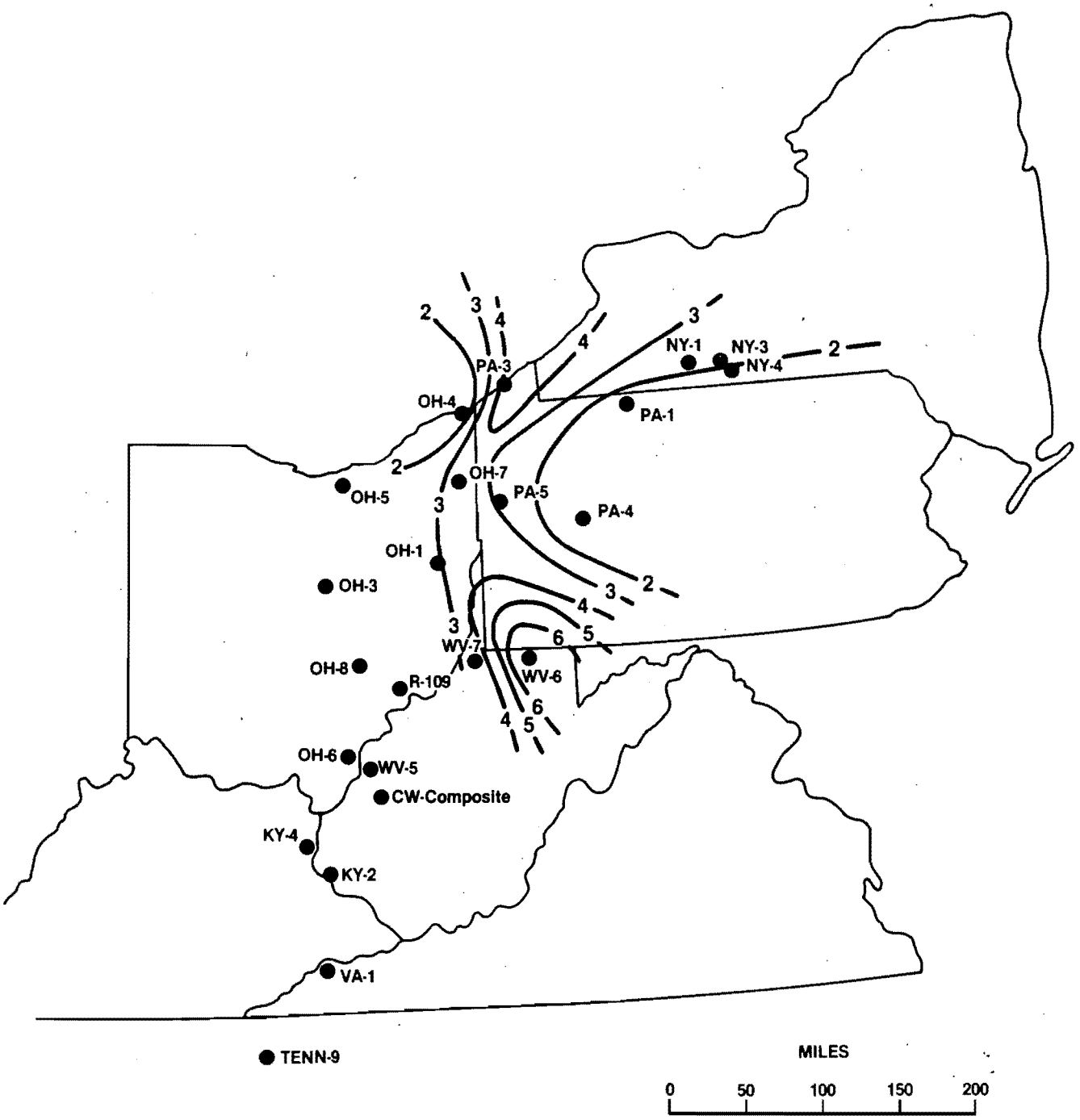

FIGURE 11

EARLY MARCELLUS TIME
MAP UNIT 1

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

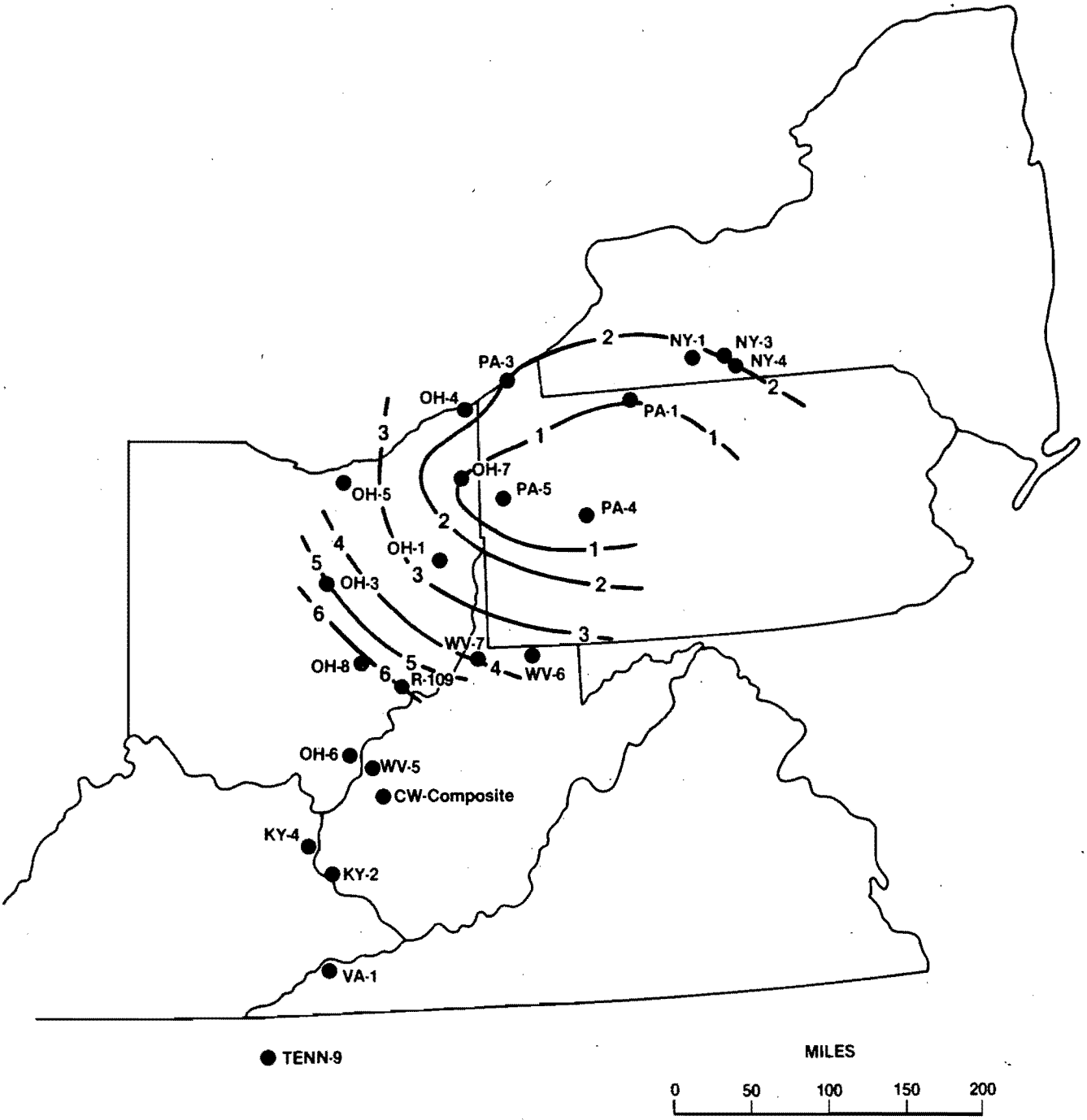

FIGURE 12

LATE MARCELLUS TIME
MAP UNIT 2

MOUND

Prepared by Mound Facility

than in Marcellus time, but still sufficient to rate as fair sources in a band along the northwestern edge of the basin and swinging around through R - 109 to WV - 6 (Figure 13).

In unit 4, i.e., Genessee/Geneseo (Harrell Shale) time, Figure 14, the rocks became relatively richer in organic carbon to the south and east but a band of low potential rocks persisted along OH - 1, OH - 5, PA - 5, and PA - 3.

The Middlesex Shale and other rocks of the Sonyea group of unit 5, Figure 15, are moderately rich (1% to 3%) over most of the basin, except for an east-west band through OH - 3, OH - 1, and PA - 4.

In Early Rhinestreet time or unit 6, shown in Figure 16, rich source rocks were deposited over virtually the entire basin, except for the extreme northeast and at OH - 3. Later in Rhinestreet time, in unit 7, Figure 17, the organic-rich rocks persisted down the center of the basin, but the rocks to the east and to the west had less than one percent organic carbon.

Following the Rhinestreet deposition, the organic carbon contents of unit 8, or Middle Olentangy/Angola Shale time, were much lower, except very locally, as shown in Figure 18. This poor source character persisted through unit 9, i.e., the Upper Olentangy/Java Formation (Hanover Shale) time, as shown in Figure 19.

In Huron time, the amount of organic carbon deposited increased and the patterns of organic carbon changed, with the shales along the western edges of the basin tending to be richest. In Lower Huron time, the patterns of organic carbon are different in the earlier section of shale of unit 10, (Figure 20) than they are in the later Lower Huron Shales of unit 11 (Figure 21). In units 12 and 13 of Middle Huron time, (Figures 22 and 23), the shales tend to be more gray, and less rich in organic carbon, but still capable of sourcing significant quantities of gas. Upper Huron shales of units 14 and 15 (Figures 24 and 25) have organic carbon contents that qualify them as good potential sources of gas, particularly along the extreme eastern margins of the basin.

The Chagrin unit, (Figure 26) has enough organic matter to qualify as a fair-to-good source in areas around OH - 5 and KY - 4, but could not be considered in a class with the other units which contain the dark shale facies. The Cleveland unit, Figure 27, is much richer ranging from 3% to greater than 7.5% in the southern reaches of the basin. This, of course, is part of the oil-shale facies of Kentucky and southwestern West Virginia.

ORGANIC CARBON CONTENT
(In Percent)

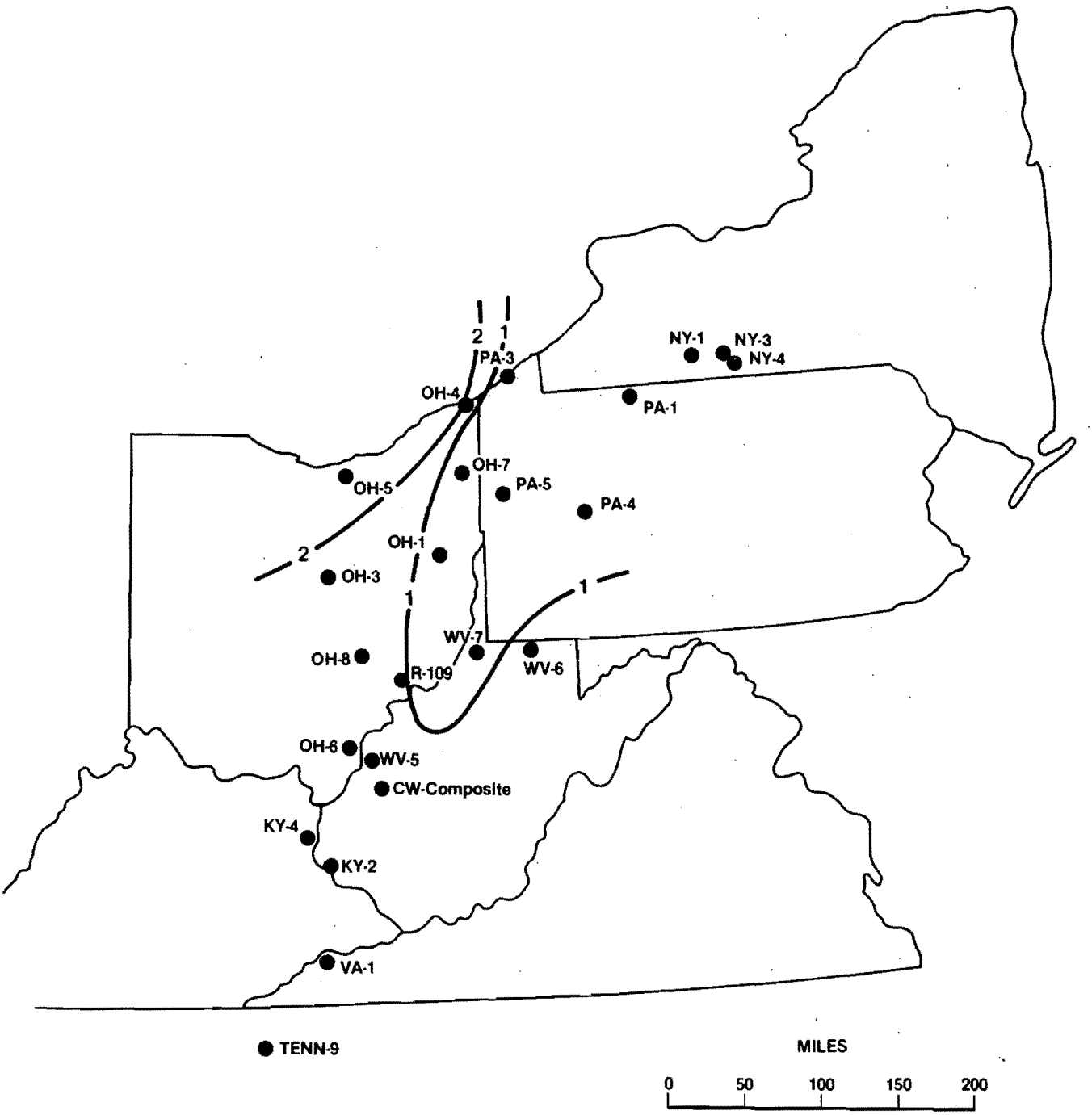

FIGURE 13

HAMILTON GROUP / POST-MARCELLUS TIME
MAP UNIT 3

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

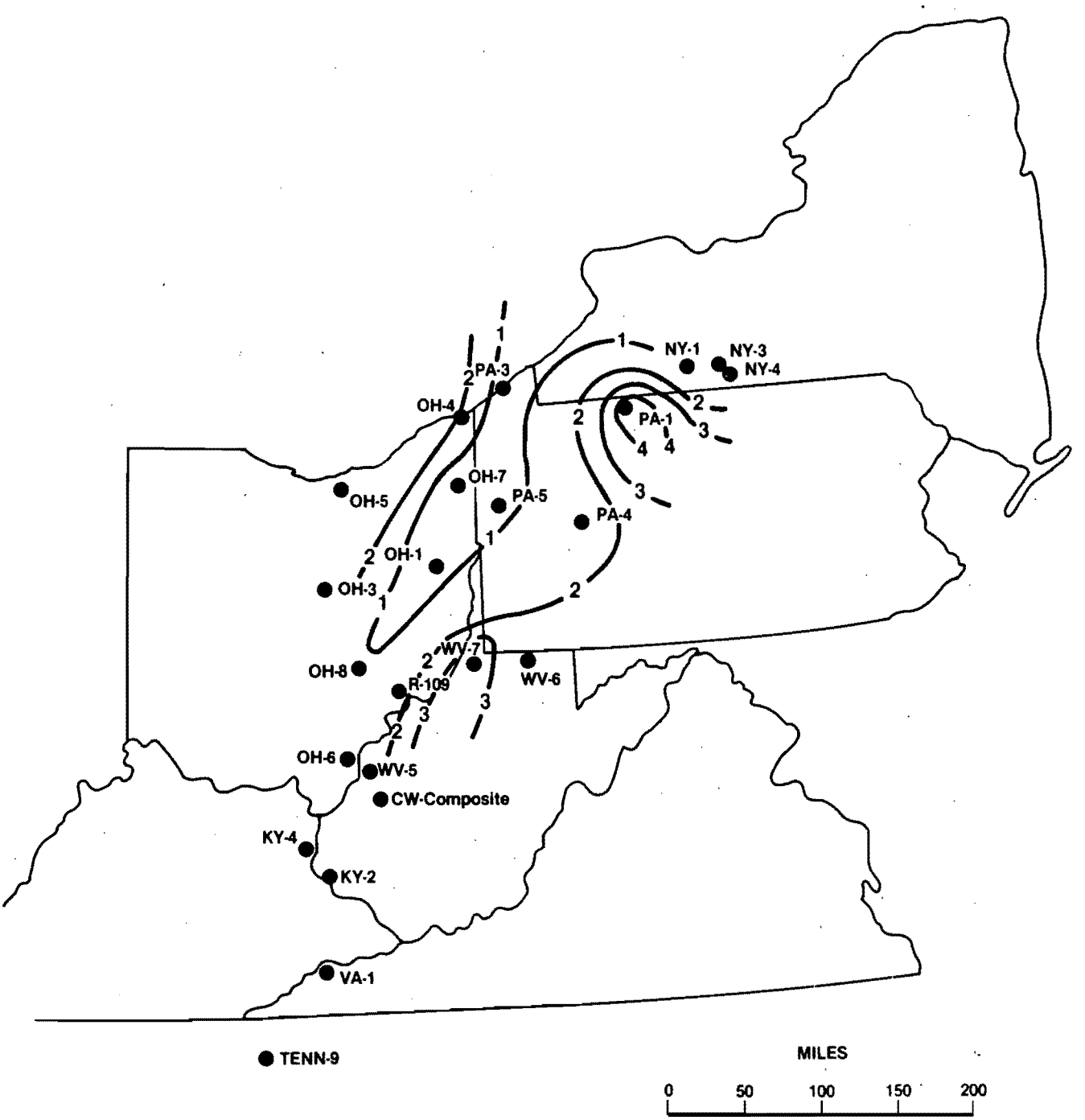

FIGURE 14

GENESEE / GENESEO TIME
MAP UNIT 4

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

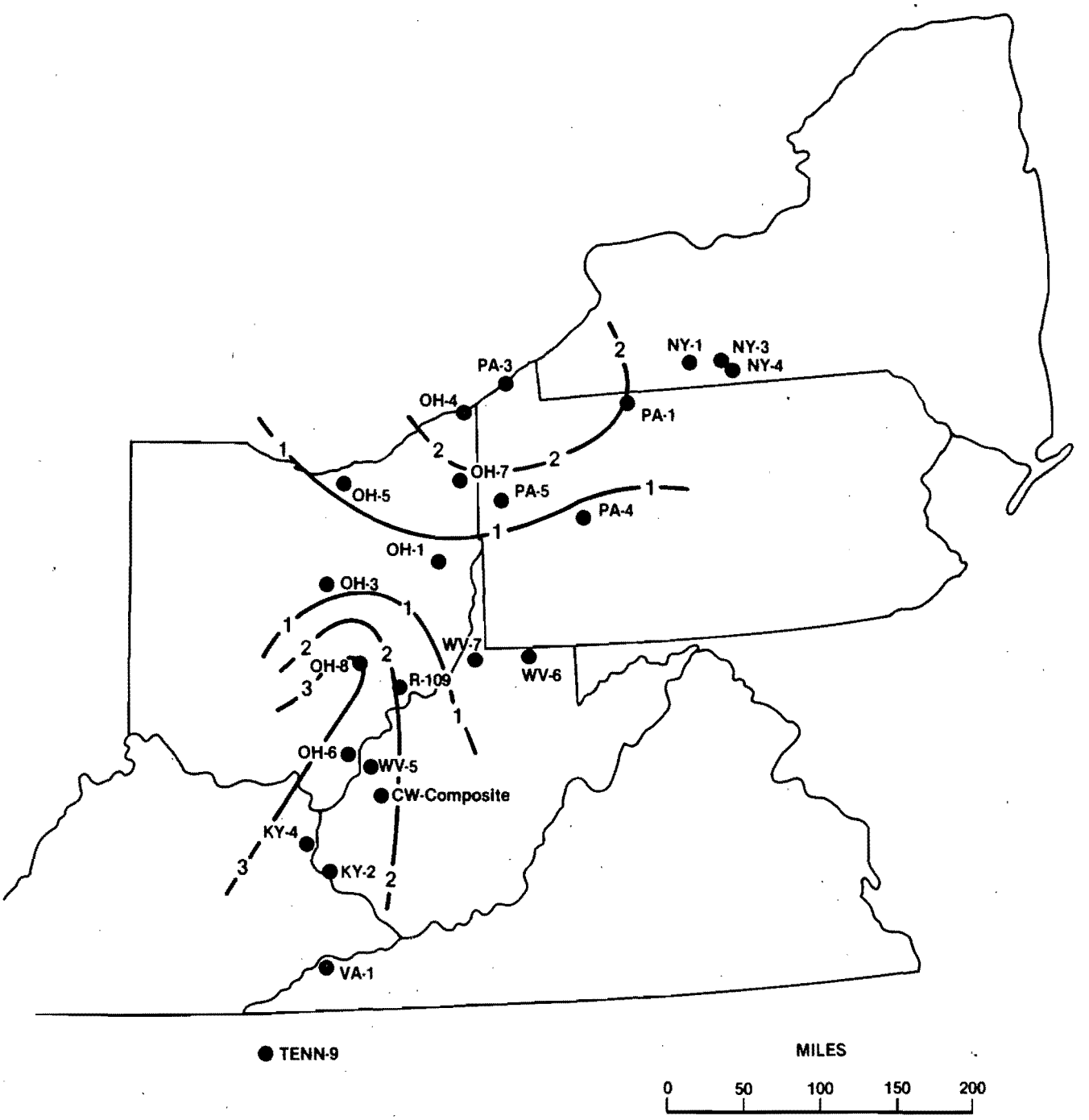

FIGURE 15

SONYEA / MIDDLESEX TIME
MAP UNIT 5

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

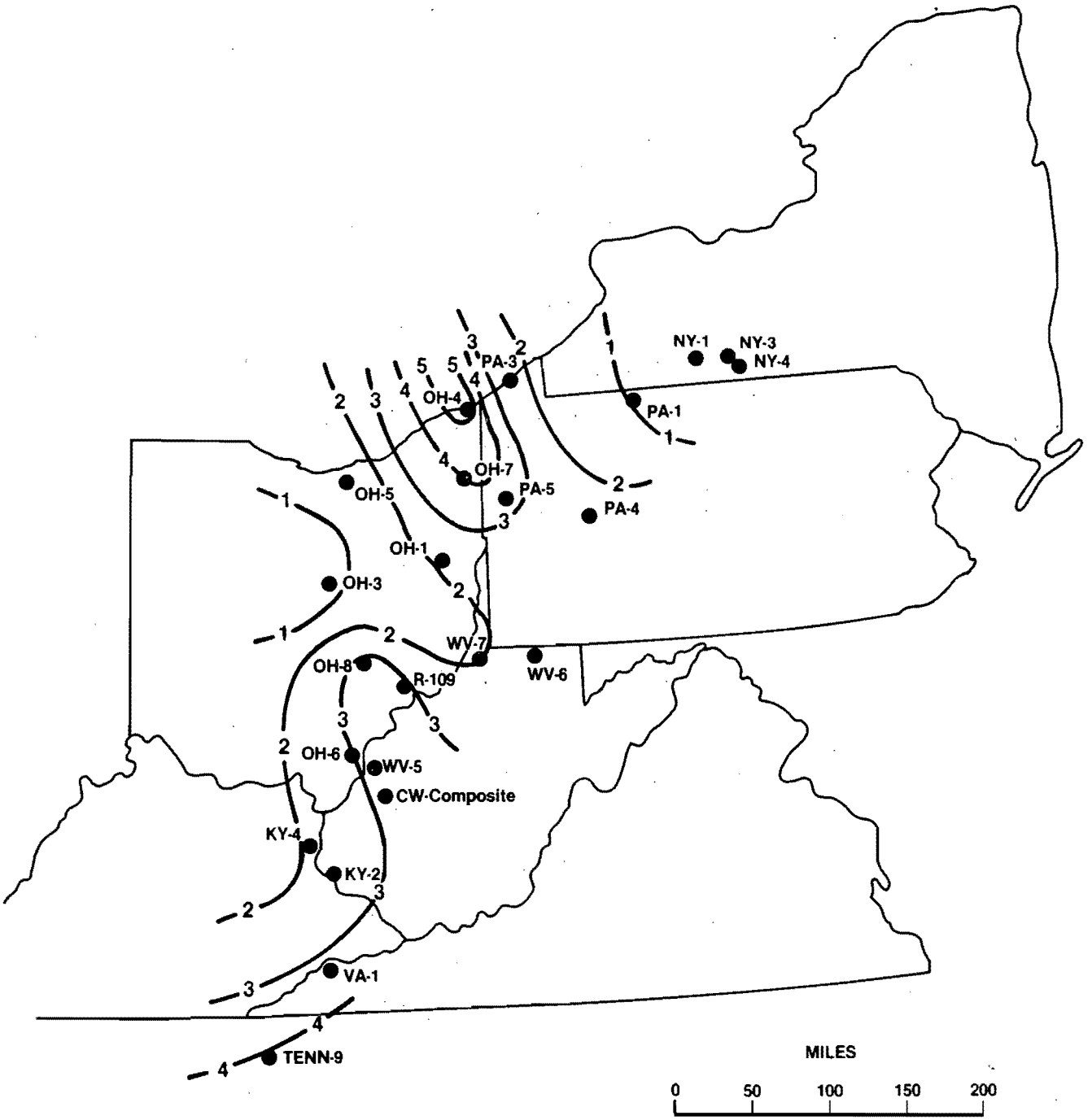

FIGURE 16

EARLY LOWER OLENTANGY / EARLY RHINESTREET TIME

MAP UNIT 6

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

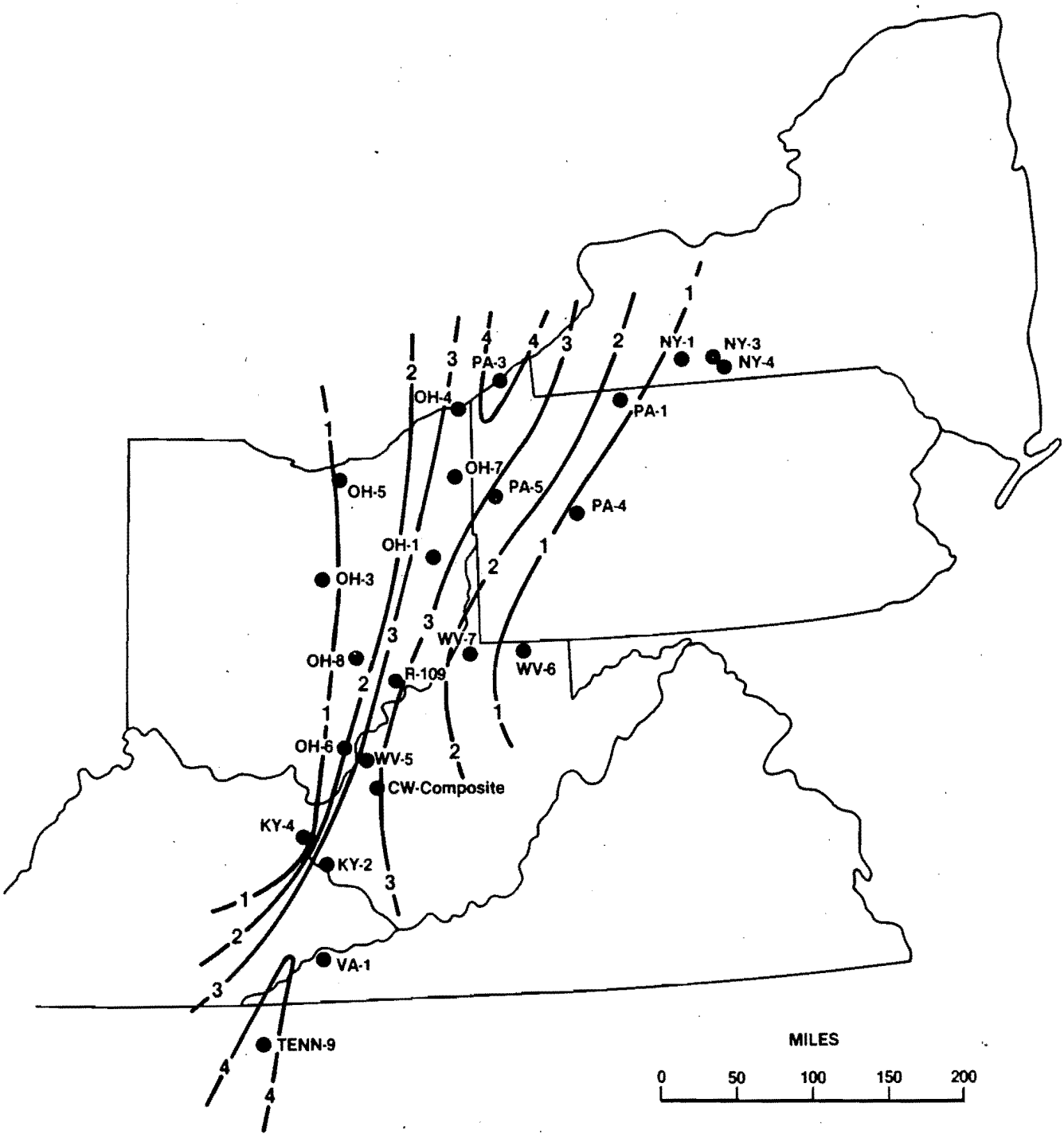

FIGURE 17

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

MAP UNIT 7

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

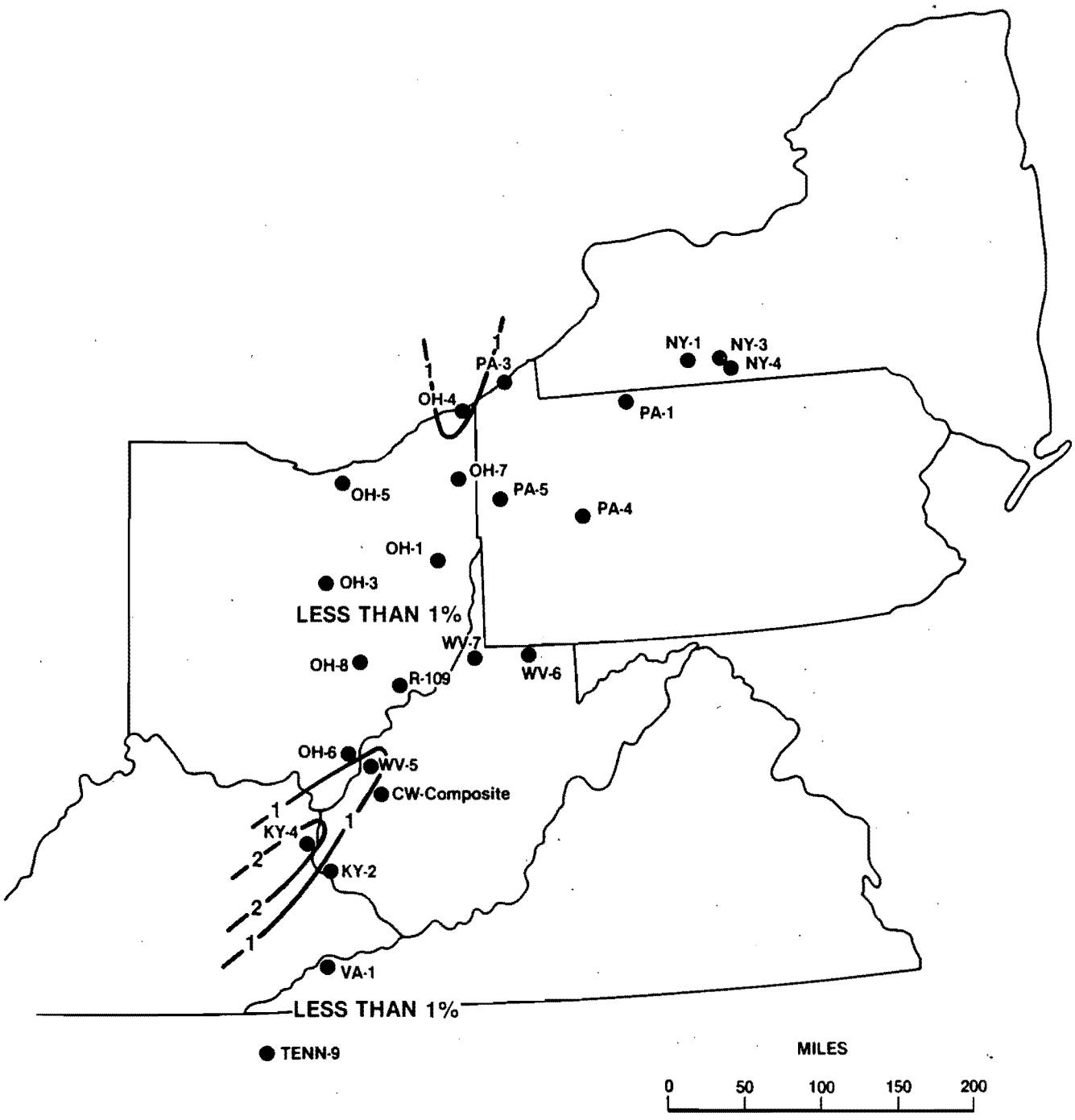

FIGURE 18

MIDDLE OLENTANGY / ANGOLA SHALE TIME

MAP UNIT 8

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

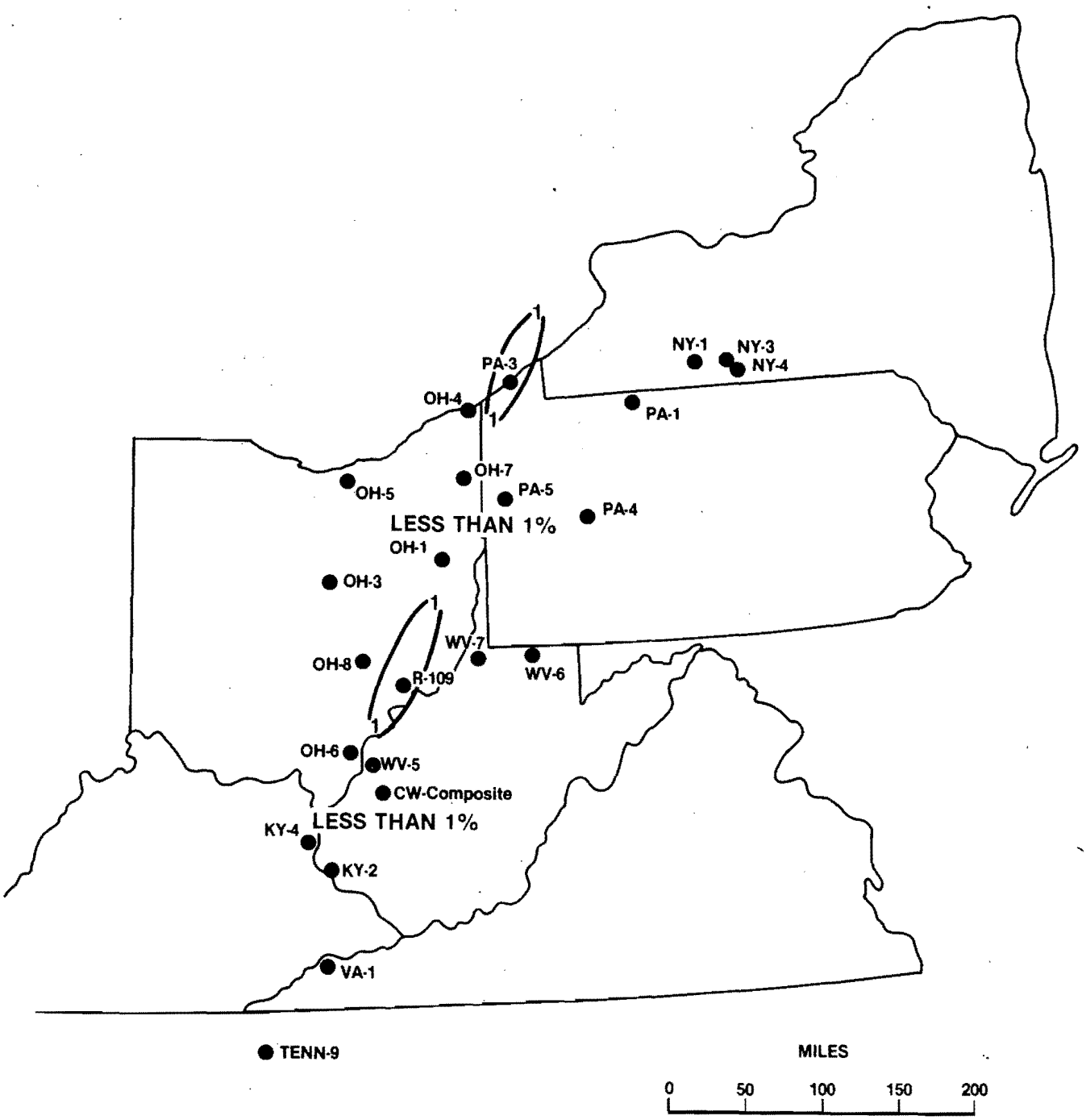

FIGURE 19

UPPER OLENTANGY / JAVA FM.
HANOVER SHALE TIME
MAP UNIT 9

MOUND

Prepared by Mound Facility

ORGANIC CARBON CONTENT
(In Percent)

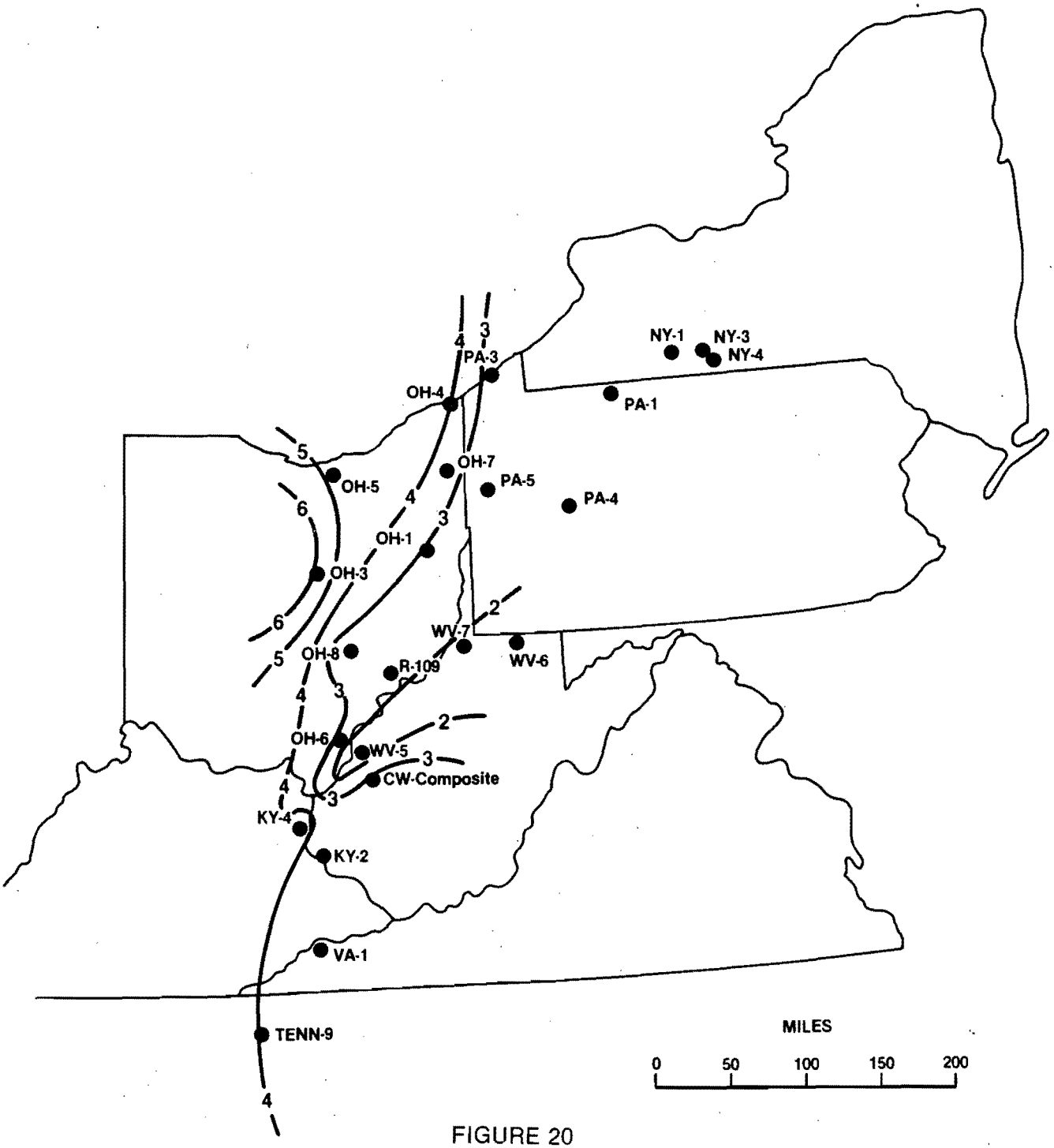

FIGURE 20

EARLY LOWER HURON / EARLY DUNKIRK TIME

MAP UNIT 10

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ORGANIC CARBON CONTENT
(In Percent)

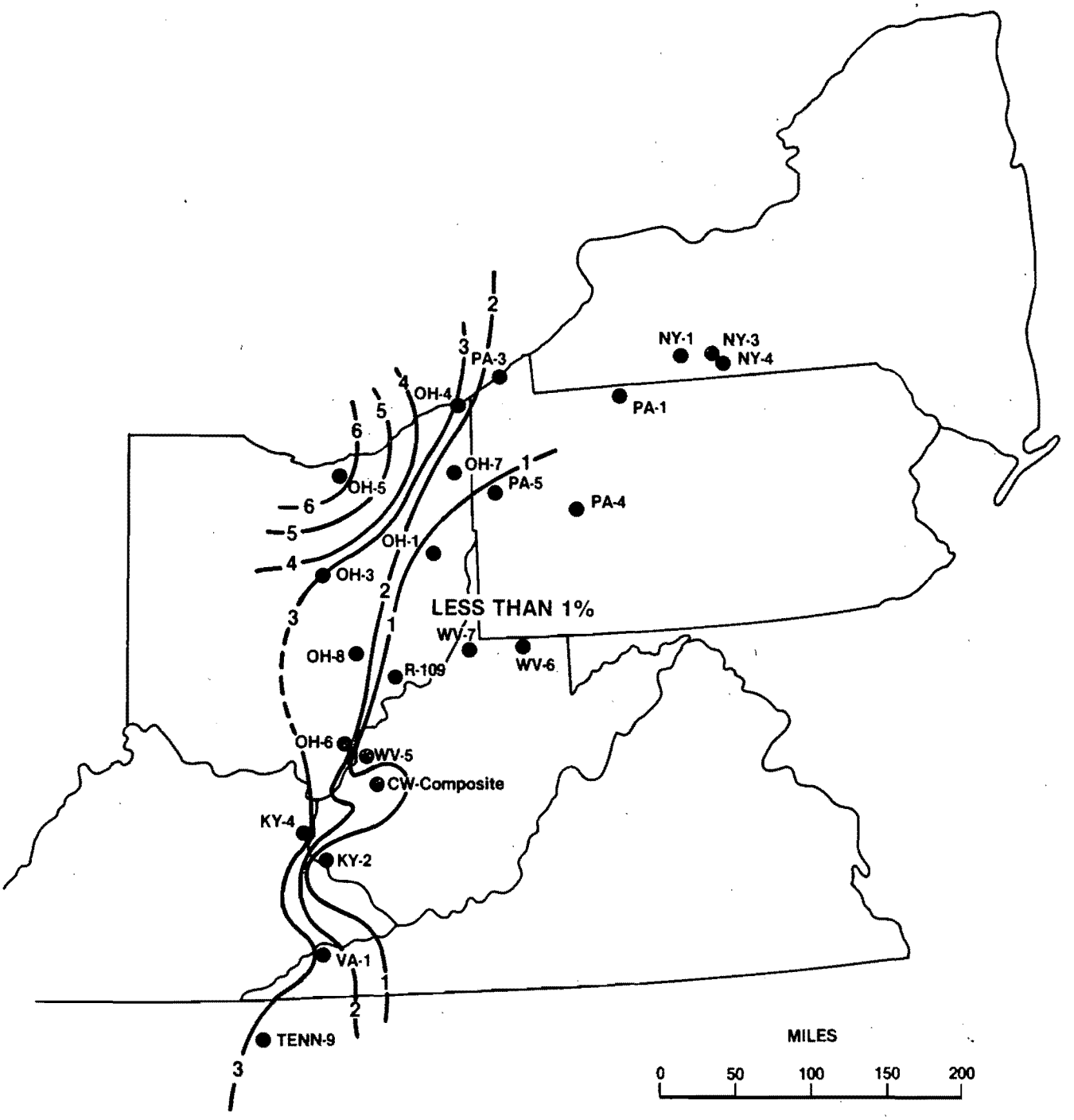

FIGURE 21

LATE LOWER HURON / LATE DUNKIRK TIME

MAP UNIT 11

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

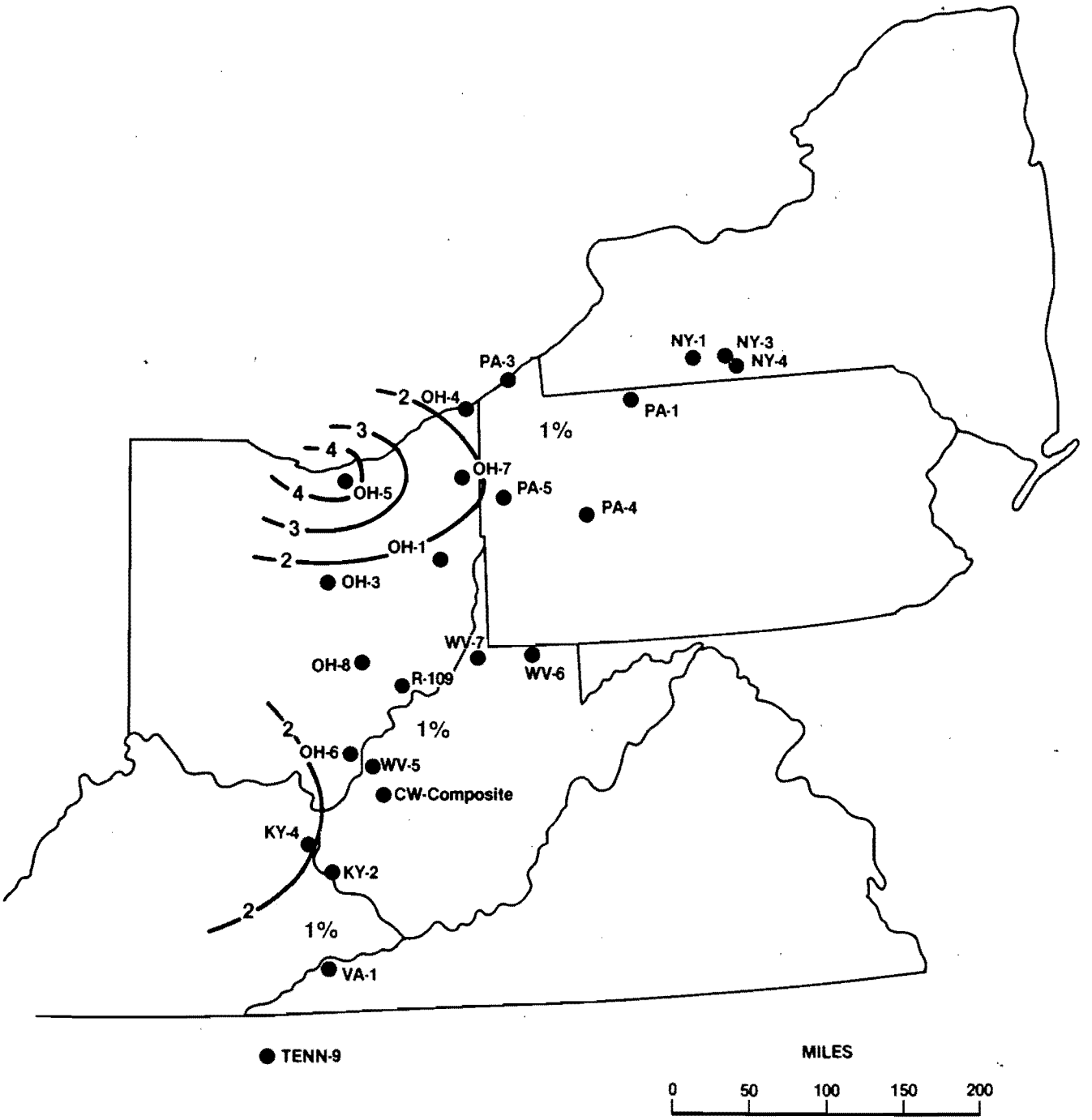

FIGURE 22

EARLY MIDDLE HURON TIME
MAP UNIT 12

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

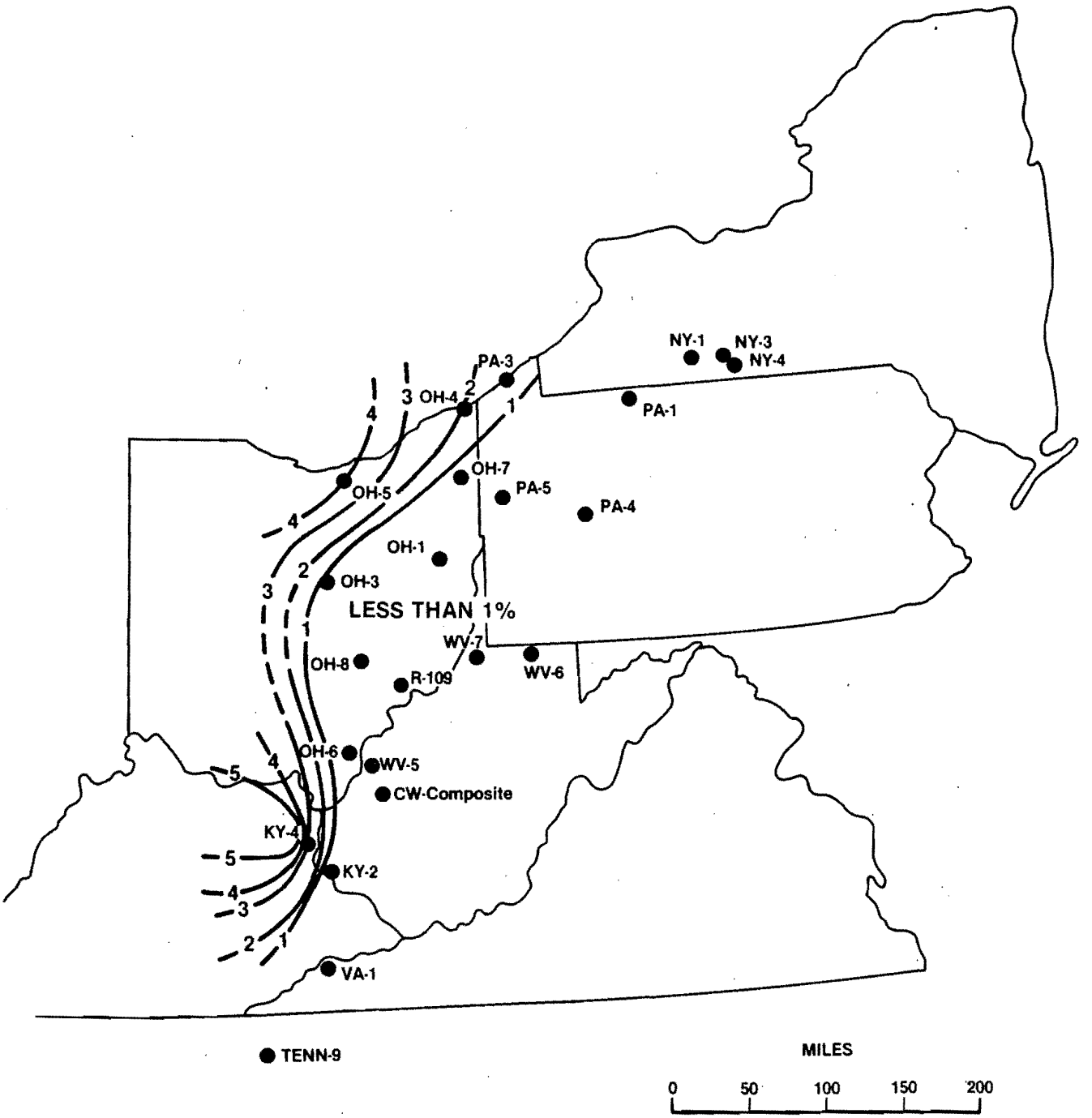

FIGURE 23

LATE MIDDLE HURON TIME
MAP UNIT 13

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

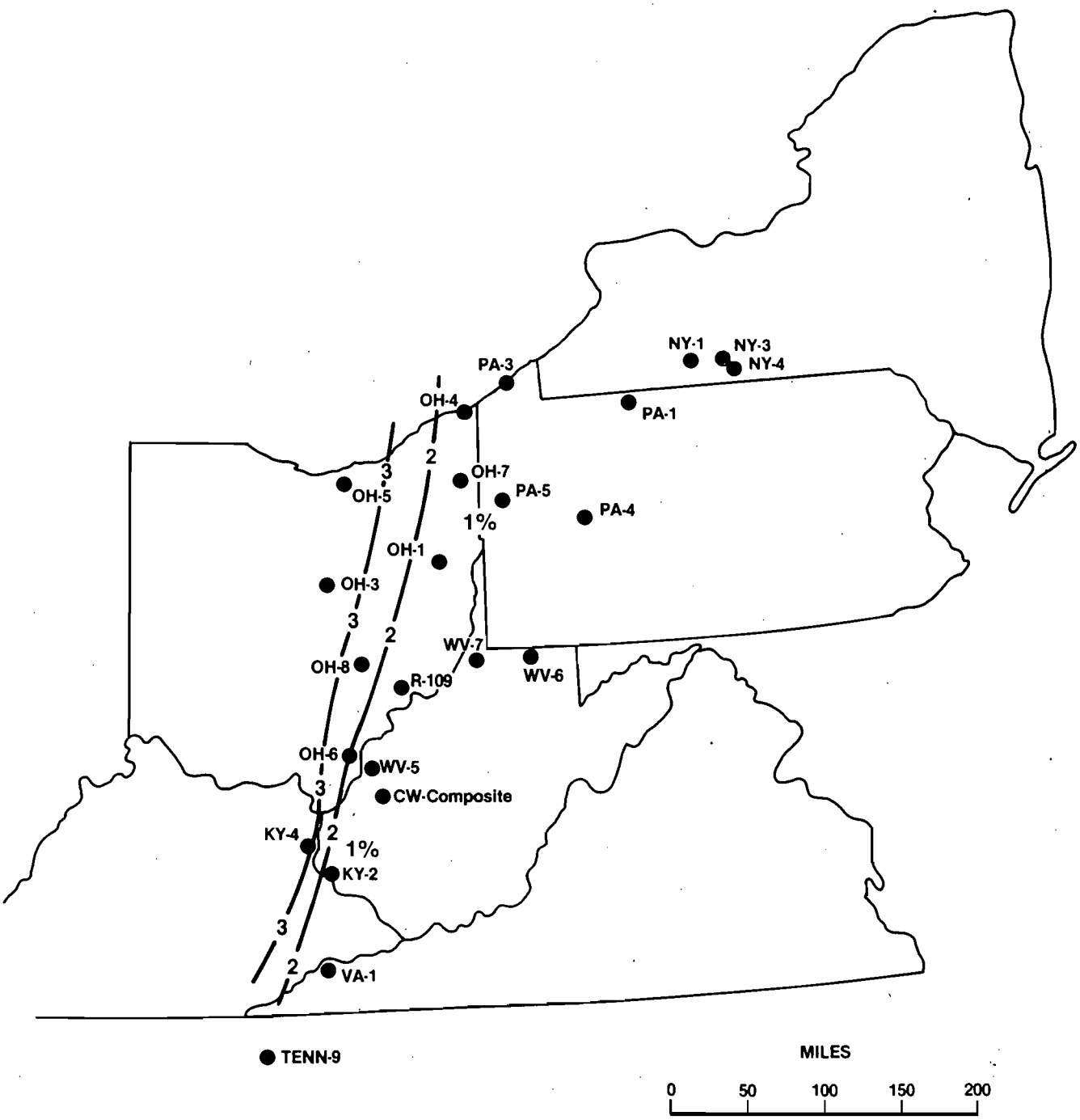

FIGURE 24

EARLY UPPER HURON TIME

MAP UNIT 14

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

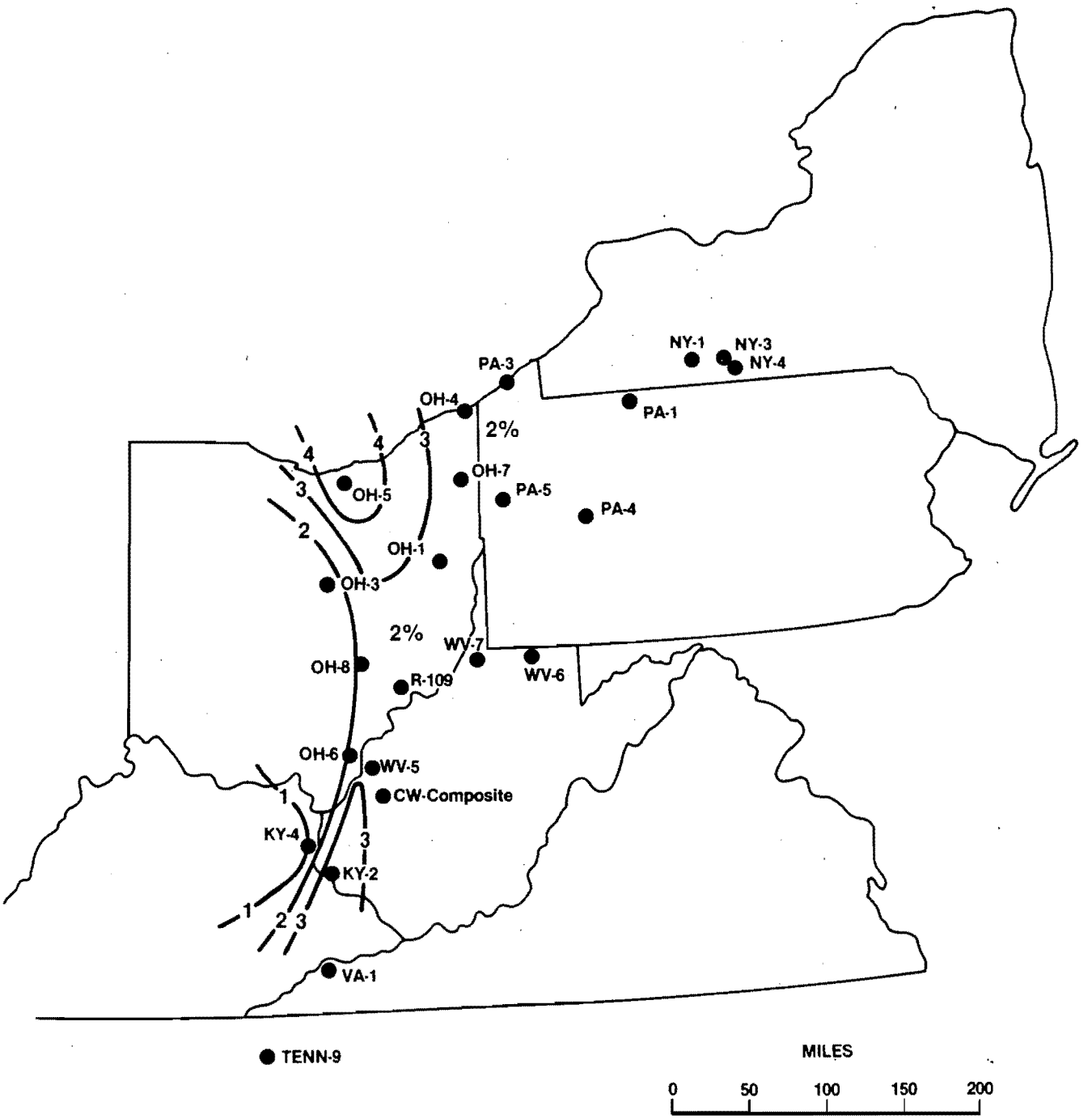

FIGURE 25

LATE UPPER HURON TIME
MAP UNIT 15

MOUND

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ORGANIC CARBON CONTENT
(In Percent)

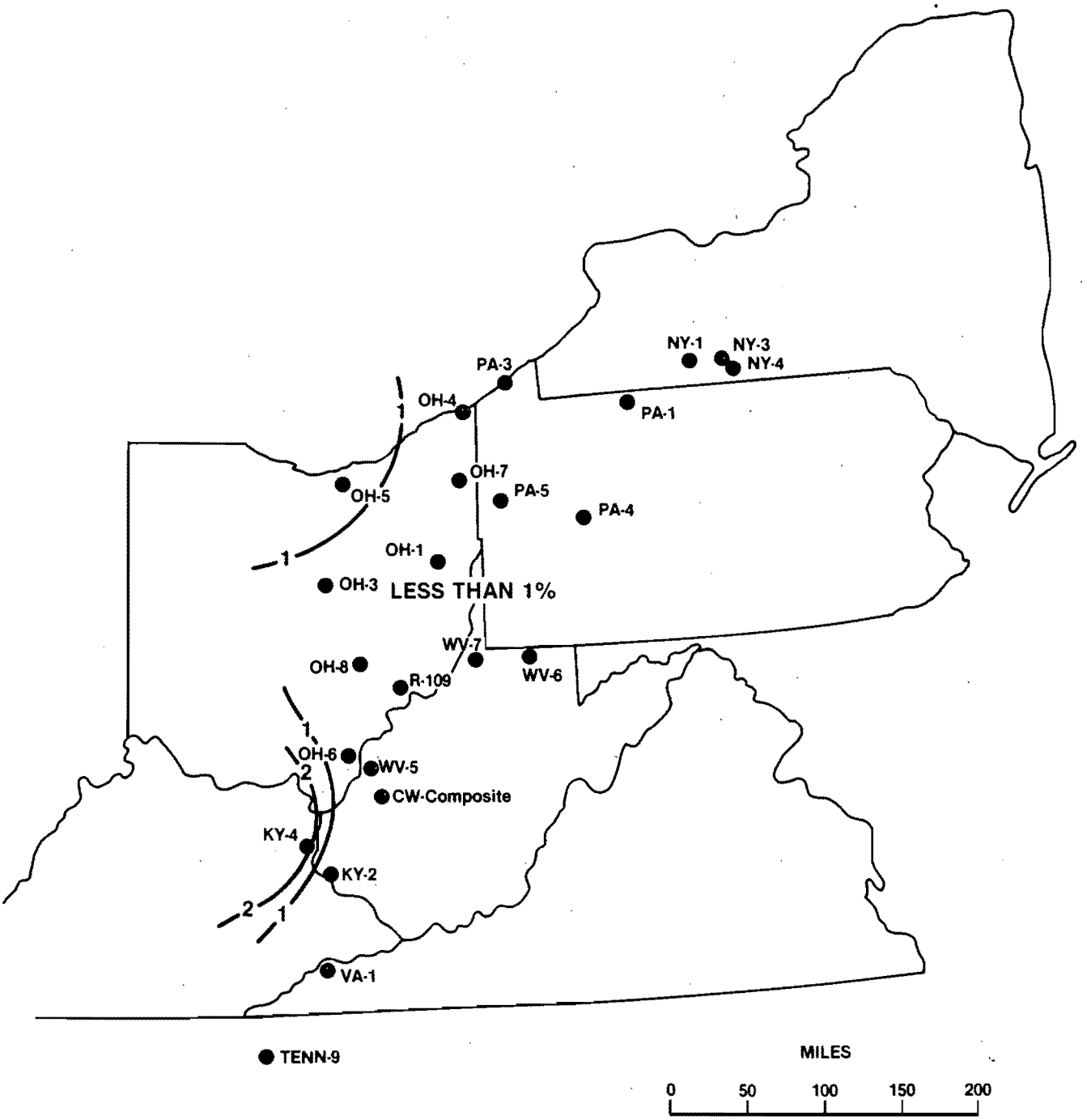

FIGURE 26

CHAGRIN TIME
MAP UNIT 16

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ORGANIC CARBON CONTENT
(In Percent)

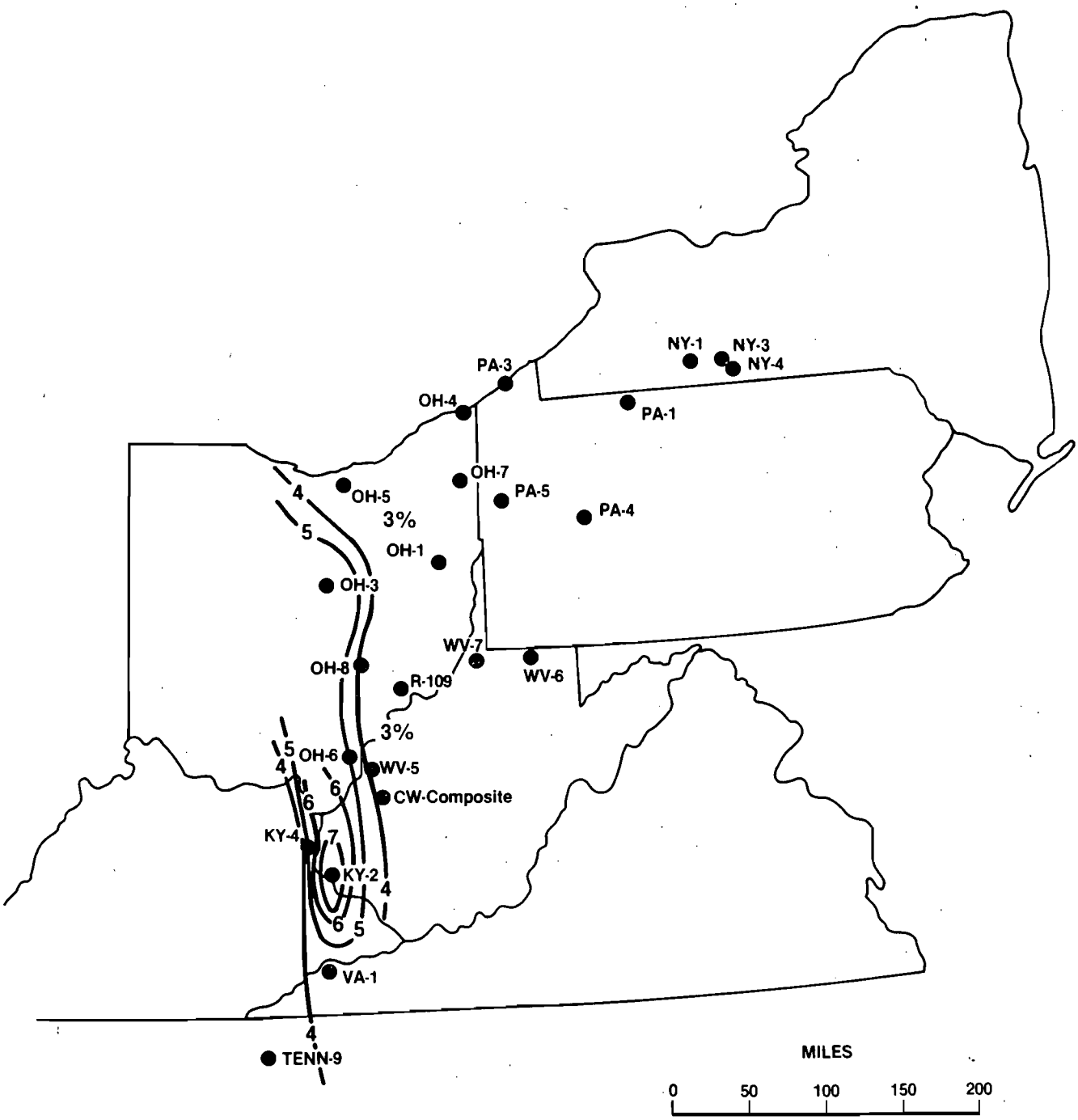

FIGURE 27

CLEVELAND TIME
MAP UNIT 17

MOUND

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Biofacies

Organic carbon is usually the first parameter determined in a geochemical evaluation of the oil and gas potential of a basin, play, or formation. It is often used as a screening step because it gives a relative picture of the potential of a rock, and it is inexpensive and rapid. The next step is usually to determine whether that organic matter is of the correct type to produce gas and/ or oil under subsurface conditions.

Very early in the development of organic geochemistry as a powerful tool in petroleum exploration, the nature of the organic matter was recognized as being equally as important as the amount. It was obvious from coal chemistry that bituminous coal contained more liquid hydrocarbons, and would produce more on heating, than anthracite coal (12).

The organic matter of fine-grained rocks, i.e., the kerogen, could be similarly divided into more and less bituminous types, which have been called sapropelic and humic, respectively (13). With time, these types have been further subdivided and defined so that current descriptions include identification and estimation of relative proportions of structured or cellular material, called "woody", or shiny, angular opaque material, called "coaly", or spores, pollen, plant cuticle fragments, and other membraneous plant remains all described by the term "herbaceous", remains of algae, called "algal", and nondescript, fluffy material, called "amorphous". These distinctions are made by examination, under the microscope, of mineral acid-insoluble residues from fine-grained rocks being studied for their source potential.

Organic matter of the algal and amorphous types has a greater potential to generate hydrocarbons than that derived from plants which grow in the shallow water near the shore line or on land masses surrounding the seas and lakes where the host rocks are deposited (14). And, of that material from plants, the herbaceous type has greater potential to generate gas than does the woody-coaly types. Not only does the potential quantity of associated hydrocarbon decrease in order from the amorphous type, through the algal, herbaceous, and woody varieties, to the coaly types, but the tendency to generate liquid hydrocarbons (oil) also decreases in the same sequence, i.e., the amorphous kerogen has the greatest tendency to generate hydrocarbons, the coaly types, virtually none. Moreover, oil derived from these kerogen types tends to be more naphtenic with algal, amorphous kerogen, more paraffinic with herbaceous-woody types, and more aromatic with coaly types.

This section infers the 'amorphous type' is marine

Suggest amorphous material produces liquid HC (oil). Oil is naphthenic from amorphous kerogen, paraffinic from herb-woody kerogen

SUMMARY Amorphous kerogen = marine origin and oil according to Z + M

Another method of classifying sediments according to their relative hydrocarbon potential and their relative oil vs gas-generating potential is provided by the palynologist. Palynology is the study of pollen, spores and other microfossils in the acid-insoluble rock residues. Microfossils exist in many different shapes and forms (called their morphology) which have been classified and cataloged, they are so different and distinctive that they can be used for age determination, for stratigraphic correlation, and for identifying the nature of the environment of deposition that existed at the time the host rock was deposited. This environmental interpretation is called the paleoenvironmental analysis. The determination of the most abundant type of organic matter is known as biofacies analysis.

In the Eastern Gas Shale geochemical study, it was found that the kerogen was made up of more of the algal forms west of the Appalachian Basin axis, and more of the woody/coaly forms east of that axis. Herbaceous matter was ubiquitous. The relative quantities of the major kerogen types varied so widely from sample to sample within single rock units, that average composition of thick sequences of rock was obviously not a useful parameter for showing regional contrasts in organic contents or sequence potential.

In this study, the most useful method for showing regional and stratigraphic contrasts was the palynology. Although this technique revealed four distinctly different assemblages, or facies, of acid-resistant microfossils (15), the three major ones were selected as the primary parameters to be used for the assessment phase of the project.

The most important facies that emerged from palynological examination was one labeled "Tasmanites". It is characterized by very large numbers of the green algae, Tasmanites, in many cases to the exclusion of other marine forms such as acritarchs (algal origin), scolecodonts (polychaete worm teeth), and chitinozoans (flask-shaped forms of indeterminate origin). Because in many of the samples the distribution of palymorphs was limited, or restricted, entirely or almost entirely to Tasmanites, the term "restricted marine" was also used to describe this facies. This was intended to imply only that the kerogen forms were restricted to Tasmanites. However, since the term restricted marine has other connotations in consideration of the environment of deposition, namely in referring to depositional areas or basins with restricted water circulation, that term was dropped in favor of the more descriptive term, Tasmanites facies.

Tasmanites obviously were deposited in a marine environment, but their presence apparently hindered or even prevented the growth of other marine algae. Perhaps like present-day red tides, their metabolism may have produced toxic products that were lethal to other life forms. Meanwhile, detrital material such as the herbaceous matter, particularly saccate and zonate spores, were transported to the area by prevailing winds, were dropped on the surface of the sea, sank, and were incorporated into the sediment.

The second major facies is a "marine" facies, which implies a normal assemblage of marine microfossils that are found in marine Devonian shales elsewhere in the world. Among the forms found in sediments deposited in this environment in the Eastern Gas Shale basins are chitinozoans (which became extinct in the Upper Devonian), acritarchs, scolecodonts, leisospheres and sphaeromorphs (distinctive, thin-walled spherical palynomorphs), a few Tasmanites, and the usual herbaceous material.

The third major facies is labeled "terrestrial" because of the predominance of nonmarine or terrestrial debris and a very small or insignificant contribution of marine palynomorphs to the organic matter. The terrestrial kerogen is made up of both fresh woody debris and oxidized and reworked woody material. There are also small quantities of normal marine forms, as well as the ever-present herbaceous kerogen.

The description as terrestrial refers to the predominant source of the organic material deposited with the mineral matter in these rocks, and not to be environment of deposition.

There is little question but that all of the Upper Devonian sediments of the Appalachian Basin were deposited in a normal, albeit relatively shallow marine environment. However, the organic matter varied in both biological and geographic origin. There were times and areas where normal marine forms grew, died, and their remains were incorporated into the sediments. There were other times when the green algae, Tasmanites, flourished and at periods of maximum growth, actually crowded out other marine organisms. When erosional slopes of the emergent land masses and their stream gradients were steep enough, large quantities of particulate woody material from primitive forests would flood portions of the basin, particularly the eastern parts, to such an extent that the marine forms were virtually obscured. And, superimposed on all possible combinations of these organic-matter types, herbaceous material, primarily in the form of saccate and zonate spores, was transported, probably wind-borne, across the entire basin.

As in the case of the organic carbon, the facies changed so rapidly from formation to formation, and within single formations that the first analysis was done on cross sections the same ones on which organic carbon was presented. To assist in plotting the facies, each sample was labeled depending on its position on a triangular diagram (Figure 28) corresponding to its relative content of each of the three major facies types of organic matter.

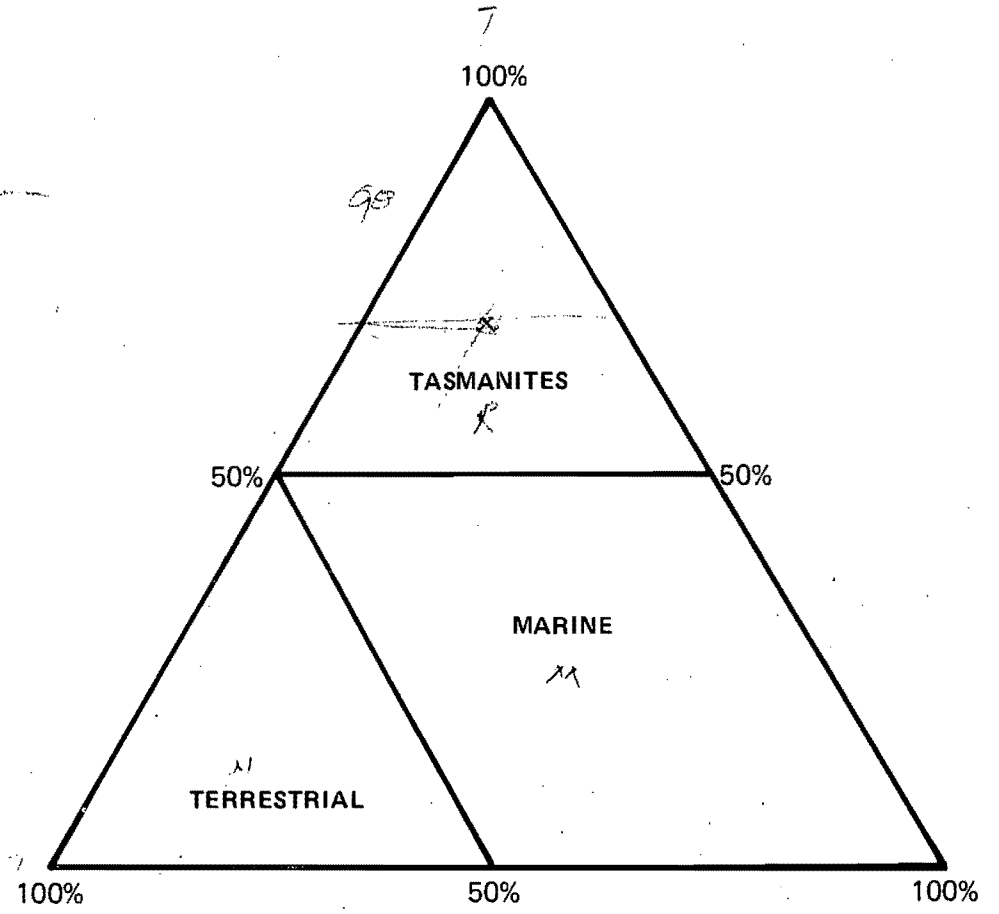
The five cross sections (Figures 29 through 33) are included in this report.

Cross section A - A', (Figure 29), the most westerly South - North line, shows the variations in facies from eastern Kentucky to north central Ohio. In the area of the KY - 2 well, the Rhinestreet was initially receiving large quantities of terrestrial or nonmarine material probably from the east. In late Rhinestreet time, there was a period when Tasmanites flourished in the marine setting and then died out. In Middle Olentangy time, the palynomorphs were normal marine, probably reflecting the connection of the basin to open marine sea, known as the Ouachita Sea, to the south.

In Olentangy time, Tasmanites again flourished, and persisted for about two-thirds of Lower Huron or Dunkirk time, after which they again died out, leaving the normal marine setting until Upper Huron time when the area was flooded for a time with nonmarine, terrestrial material from a southeastern source. Throughout the remainder of the Huron and through Cleveland time there were several alternations of terrestrial and restricted or Tasmanites facies.

At KY - 4, about 25 miles northwest of KY - 2, there are no data on the Rhinestreet, but in Olentangy time, large quantities of nonmarine organic matter poured into the basin. The Tasmanites at KY - 2 to the southeast suggests that the Cincinnati Arch may have been emergent at this time, and may have been a source area for the nonmarine organic matter flooding the area of KY - 4.

In Lower Huron time, Tasmanites began to fluorish, and persisted through most of the rest of the Upper Devonian, except intermittently when nonmarine material was dumped in the basin, either from brief periods of emergence of the Cincinnati Arch or from periodic tectonic events during which relatively



Subdivision of Biofacies Data For
Paleo-Environmental Interpretation

FIGURE 28

Biofacies Distribution
Section A-A′

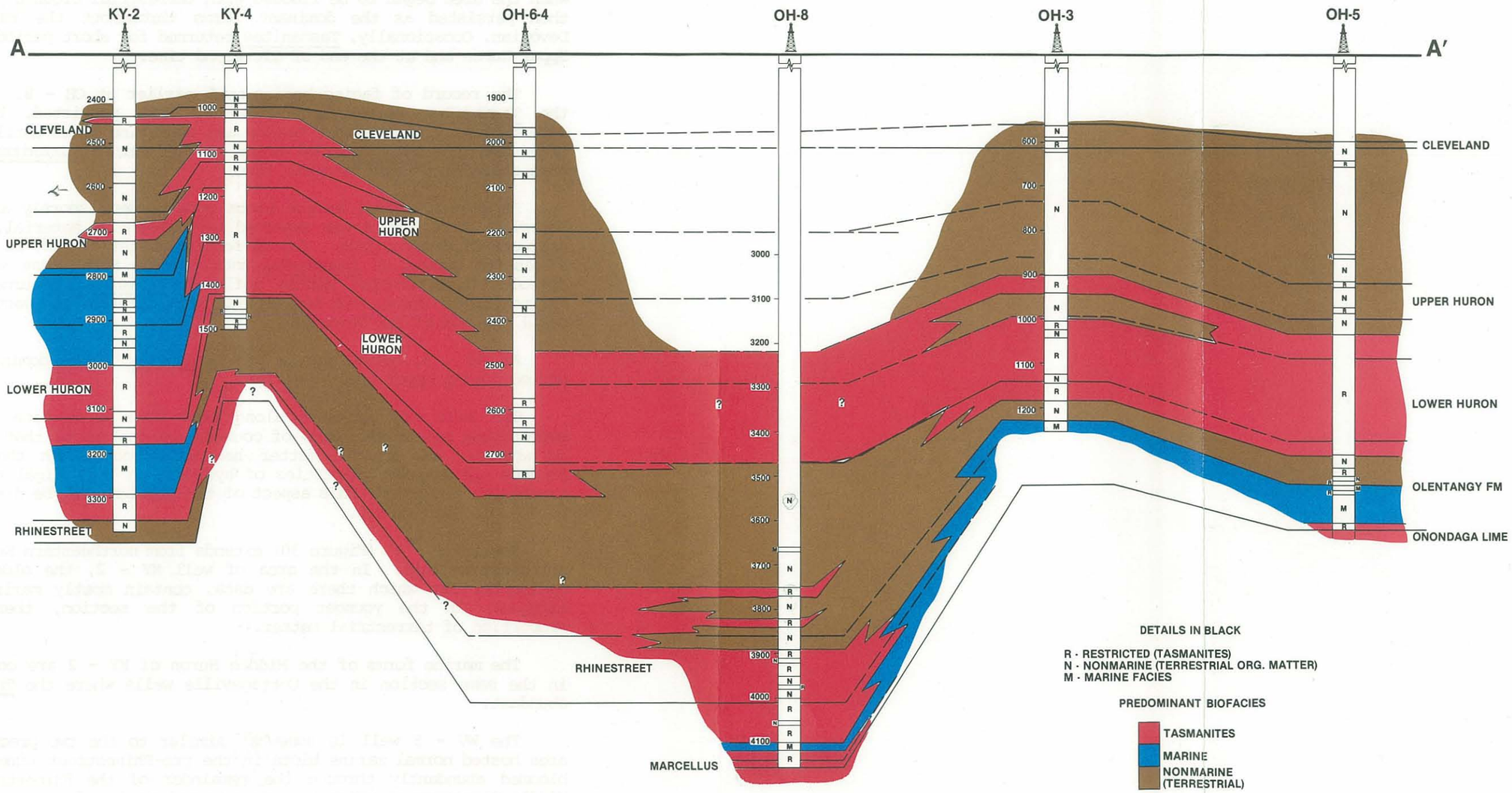


FIGURE 29

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why?

small local segments of the basin subsided more rapidly relative to the rest of the basin and to the bordering highlands on the southeast.

At OH - 6, the record of events begins with Tasmanites in abundance in Middle Olentangy time. This facies persisted until late Middle Huron time when the area began to be flooded with terrestrial organic palynomorphs which then persisted as the dominant forms throughout the rest of the Upper Devonian. Occasionally, Tasmanites returned for short periods, such as in the Upper Huron and at the end of Cleveland time.

The record of facies begins much earlier at OH - 8. In Marcellus time the Tasmanites facies was present. This persisted, but was replaced intermittently with either marine and nonmarine forms until late Rhinestreet time when nonmarine material began to dominate. Tasmanites are inferred to have again flourished in Huron time.

At OH - 3, normal marine biota were present shortly after the close of Marcellus time. This was replaced by terrestrial material, probably from an emergent Cincinnati Arch. The terrestrial material was, in turn, replaced by a massive growth of Tasmanites until Middle Huron time when there was an episode of terrestrial matter influx. Tasmanites returned one more time during Middle Huron, but terrestrial material from the west flooded the area until the end of the Devonian.

what evidence demonstrates the "terrestrial" material came from the west??

At OH - 5, normal marine and Tasmanites facies dominated except for a period during Upper Olentangy time.

The belt of sediments along this line of section have an enormous hydrocarbon potential. But, of course, realization of that potential depends on whether the organic matter has undergone enough thermal cracking to produce the massive quantities of hydrocarbon that algal organic matter is capable of producing. This aspect of the problem will be discussed in a later portion of this report.

Section B - B' (Figure 30) extends from northeastern Kentucky to extreme northeastern Ohio. In the area of well KY - 2, the older Upper Devonian sediments, for which there are data, contain mostly marine and Tasmanites kerogen. In the younger portion of the section, there is a greater proportion of terrestrial matter.

The marine forms of the Middle Huron of KY - 2 are completely obscured in the same section in the Cottageville wells where the Tasmanites are more abundant.

The WV - 5 well is somewhat similar to the two preceding wells. The area hosted normal marine biota in the pre-Rhinestreet time, then Tasmanites bloomed abundantly through the remainder of the Rhinestreet and into the Middle Olentangy at which time more normal marine forms returned. There was an abrupt change to terrestrial organic matter in Upper Olentangy time. This nonmarine material flooded into the area at the same time all of the contemporaneous sediments in the other wells in the central and northeastern portions of the basin were receiving similar material from the eastern source provenance.

Biofacies Distribution
Section B-B′

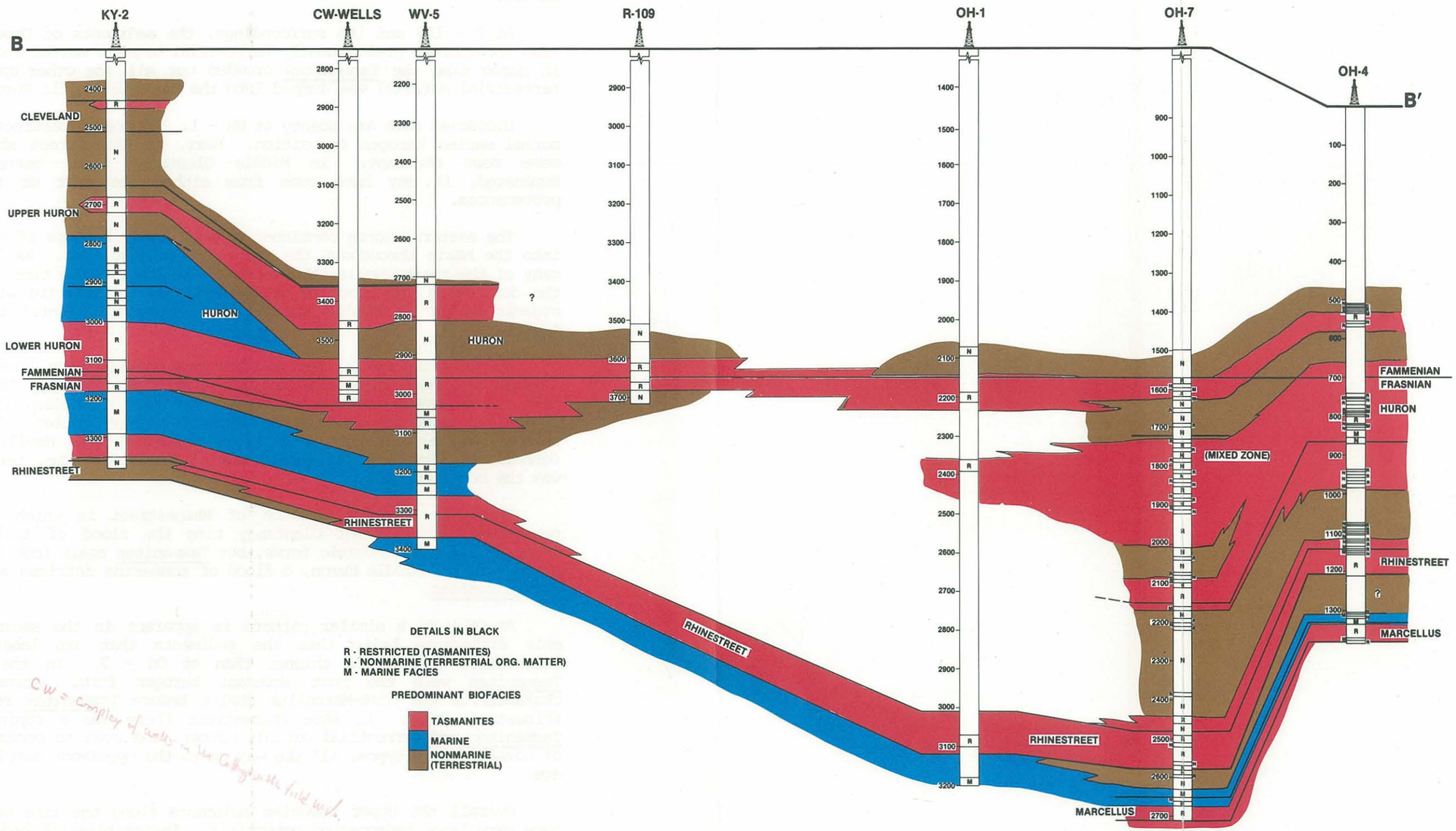

FIGURE 30

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In Huron time, Tasmanites again became predominant, and remained so until the Middle Huron when the eastern terrestrial source again poured nonmarine kerogen into the basin. Tasmanites flourished again in Upper Huron time, only to be replaced again in Cleveland time with terrestrial organic matter.

At R - 109 and its surroundings, the sediments of Upper Olentangy time also incorporate predominantly terrestrial organic matter and, as at WV - 5, in Huron time the Tasmanites crowded out all the other marine forms until terrestrial material was dumped into the basin in Middle Huron time.

Biofacies data are scanty at OH - 1. In pre-Rhinestreet time, there was normal marine kerogen deposition. Next, in Rhinestreet shales, Tasmanites were most abundant. In Middle Olentangy time, terrestrial material dominated, it may have come from either the east or the west source provenances.

The eastern source continued to pump large amounts of nonmarine kerogen into the basin throughout the rest of Olentangy time. As is the case in so many of the nearby wells, the sediments of Lower Huron time in this well show the dominating influence of Tasmanites, which then give way to terrestrial organic matter in Middle Huron time. It persists until the close of the Devonian.

The last two wells, the northernmost ones on this line of section, are located in areas where the Tasmanites persisted for the longest periods of time in the basin. At the onset of the Upper Devonian, in the Marcellus, Tasmanites were the predominant form of organic matter. This gave way to normal marine biota in the late Marcellus and Hamilton and Genesee formations. For a brief period during Middlesex time, terrestrial kerogen was the most abundant.

There is a thick section of Rhinestreet in which Tasmanites again persisted. During Upper Olentangy time the flood of terrestrial kerogen obscured all other organic forms, but Tasmanites again took over in the Lower Huron. In the Middle Huron, a flood of nonmarine detritus again crowded out the Tasmanites.

At OH - 4, a similar pattern is apparent in the sediment column, the only difference being that the sediments that are labeled as being of terrestrial facies are thinner than at OH - 7. In the Marcellus, the Tasmanites were the most abundant kerogen form. Normal marine forms characterize the post-Marcellus shales before Tasmanites returned again in Rhinestreet time. In late Rhinestreet there was a rapid alternation of Tasmanites and terrestrial organic matter, and even an occasional appearance of normal marine types, all the way up to the uppermost sample of Upper Huron age.

Overall the Upper Devonian sediments along the line of section B - B' have very large hydrocarbon potentials. Tasmanites-rich beds are present at one time or another, and usually are the most abundant, throughout the entire sampled section. Had these sediments been subjected to sufficient thermal alteration, and were reservoir rocks abundant, this would be one of the great oil and gas-producing provinces of the world.

Line C - C' is the easternmost South - North line of section, and the longest one also. At TENN - 9, only the Rhinestreet, Lower Huron, and Cleveland shales were sampled. The first two units are classified as Tasmanites facies, the last one, terrestrial. This is important because it shows that, at its greatest geographical extent, the Tasmanites bloom extended another 70 miles toward the opening to the Devonian Ouachita Sea which bounded the North American plate on the south during the Devonian.

The facies of the VA - 1 well stand out in sharp contrast to the TENN - 9 well - the facies are all terrestrial except for one sample (which is now suspect) toward the base of the Lower Huron. This well is different in that it is located to the east of the basin axis, which places it closer to the intermittently growing Appalachian mountains which were shedding enormous volumes of clastics and terrestrial organic matter into the basin.

Much further to the north-northeast, the sediments of the WV - 7 well also testify to the prolific nature of the eastern terrestrial source. In Marcellus time, the terrestrial facies appears first. In Upper Marcellus shales, the Tasmanites take over but are quickly flooded out by terrestrial kerogen, except for two short appearances of Tasmanites in Burket and Rhinestreet times.

Further to the east, and closer to the basin axis where the formations are a little thicker, in the shales at WV - 6, the Marcellus facies begins with the Tasmanites type, but are soon replaced by terrestrial facies. Immediately above the Marcellus, the data reveal a period in which Tasmanites are again very abundant, but the powerful influence of the growing Appalachians with its abundant flora soon controls the facies.

The sediments around well PA - 4 must be relatively close to a prolific source of terrestrial organic matter with a major river system. This system poured particulate terrestrial remains into the basin from the beginning of the Upper Devonian at least through Rhinestreet time. The organic matter of every sample taken from over a one-thousand foot section was classified as belonging to the terrestrial facies.

PA - 1, almost 100 miles to the north-northeast, showed the Tasmanites facies in the Marcellus shale and again in the Genesee formation.

This line of section (Figure 31) reveals that the original hydrocarbon potential of the sediments of the Appalachian Basin are significantly reduced in the area of the basin axis, and to the east of that axis, because the organic matter becomes more and more terrestrial in nature. According to the general relationships pointed out earlier, this means that a unit volume of organic matter will generate less hydrocarbon when undergoing normal diagenesis. Also, since the general trend is for organic carbon contents to decrease toward the east as well, the potential is doubly diminished.

On the other hand, it must be stressed that the direction of diminishing original source potential is in direct opposition to the trend of increasing thermal alteration. This means that the decreasingly rich potential source rocks may have had increasingly greater proportions of their organic matter converted to gas and/or oil. Therefore, they key to exploration success in the basin probably lies in the ability of geologists and geochemists to

Biofacies Distribution
Section C-C′

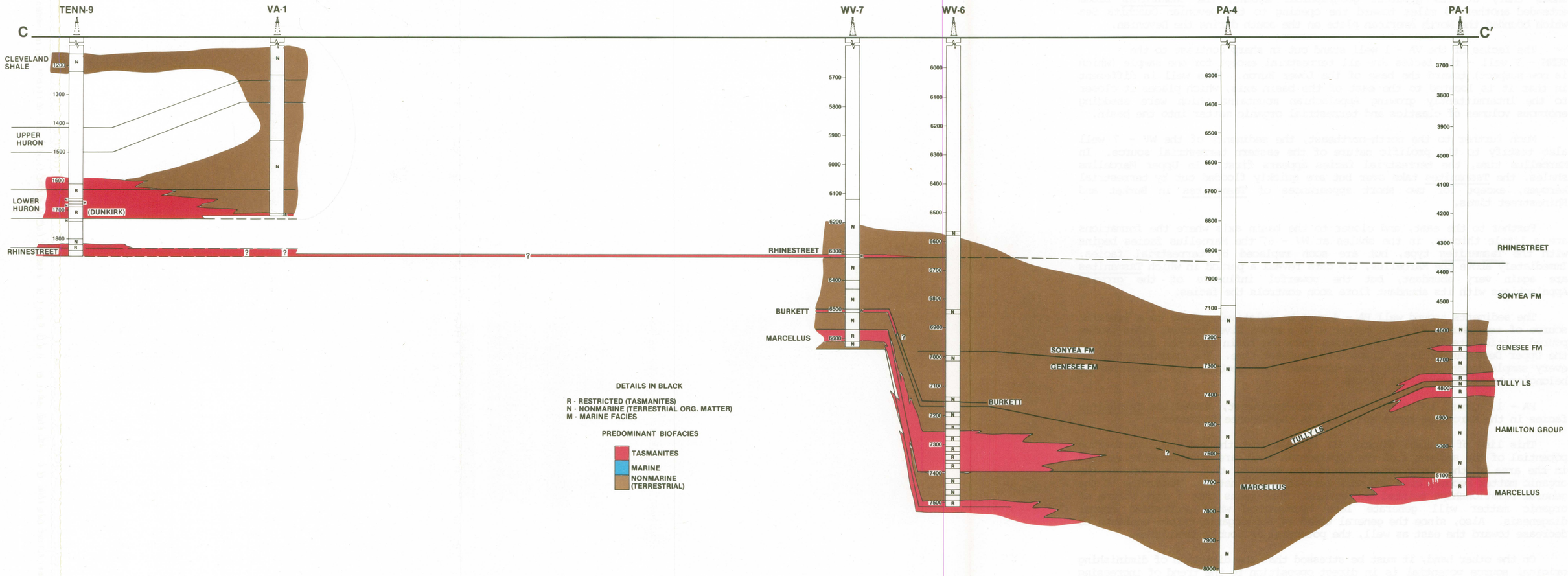

FIGURE 31

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locate those areas where facies with enough original source potential persist far enough to the east (or are buried deeply enough) to have been subjected to enough thermal stress. This thermal exposure is necessary in order for a rock to have realized enough of that potential and to have generated enough hydrocarbons to enable the host rock to have become a source of commercial quantities of reservoired gas or oil. Should there not be any contiguous reservoirs, or sufficient permeability for much of this hydrocarbon to migrate from the rich source rock, they may be preferred sites for stimulation projects with the greatest chance of tapping commercial quantities of hydrocarbon tightly held in the shale itself.

Section D - D', Figure 32, is a line along the northern end of the Appalachian Basin. At the western end of that line of section, well OH - 5 has sediments that incorporated alternating types of organic matter prior to the onset of the Huron. The largest of these facies is a marine type, followed by a section which represents a period of predominantly terrestrial deposition. In the Huron, the facies become Tasmanites-rich, and that type persists until the very late Lower Huron at which time, terrestrial organic matter dominantes until Cleveland time.

The Tasmanites-rich section is expanded in the next well, OH - 4, which is characterized by numerous alternations of the various facies, over half of which are of the restricted Tasmanites type.

Further east, at PA - 3, a deeper facies of marine organic matter begins in the Marcellus shales and persists up to the Rhinestreet. Above this, the Tasmanites facies persists, but an intervening wedge of terrestrial facies characterizes the interval between the Rhinestreet and the Huron.

At PA - 1, the section below the Rhinestreet is much deeper and thicker. While some Tasmanites-rich intervals are present, the strong influence of the eastern source of terrestrial organic matter is evident throughout the pre-Rhinestreet section. The New York wells also have the tremendous thicknesses of terrestrially derived kerogen from the eastern source provenance, although thin layers of Tasmanites facies occasionally extend even this far east, e.g., in the Burket and Marcellus shales.

This section clearly shows the thickening and coalescing of the Tasmanites facies in the northwest portions of the Appalachian Basin, and the increasing contribution of the prolific eastern source of nonmarine organic matter. However, the infrequency of samples and the occasional appearance of Tasmanites among these, suggests that there may be some significantly thick (greater than 25 to 30 feet) Tasmanites source intervals as far east as the New York wells.

Section E - E', Figure 33, cuts through the heart of the Tasmanites deposition at OH - 7 and probably PA - 5. Between PA - 5 and PA - 4, the terrestrial organic matter derived from the east completely obscures all other organic facies types. This parallels the general trend of Section D - D'.

In order to present the biofacies data in map form, the appropriate data for each of the seventeen units chosen for presentation of the organic carbon data (discussed earlier in the report), were placed on separate maps. These

Biofacies Distribution
Section D-D′

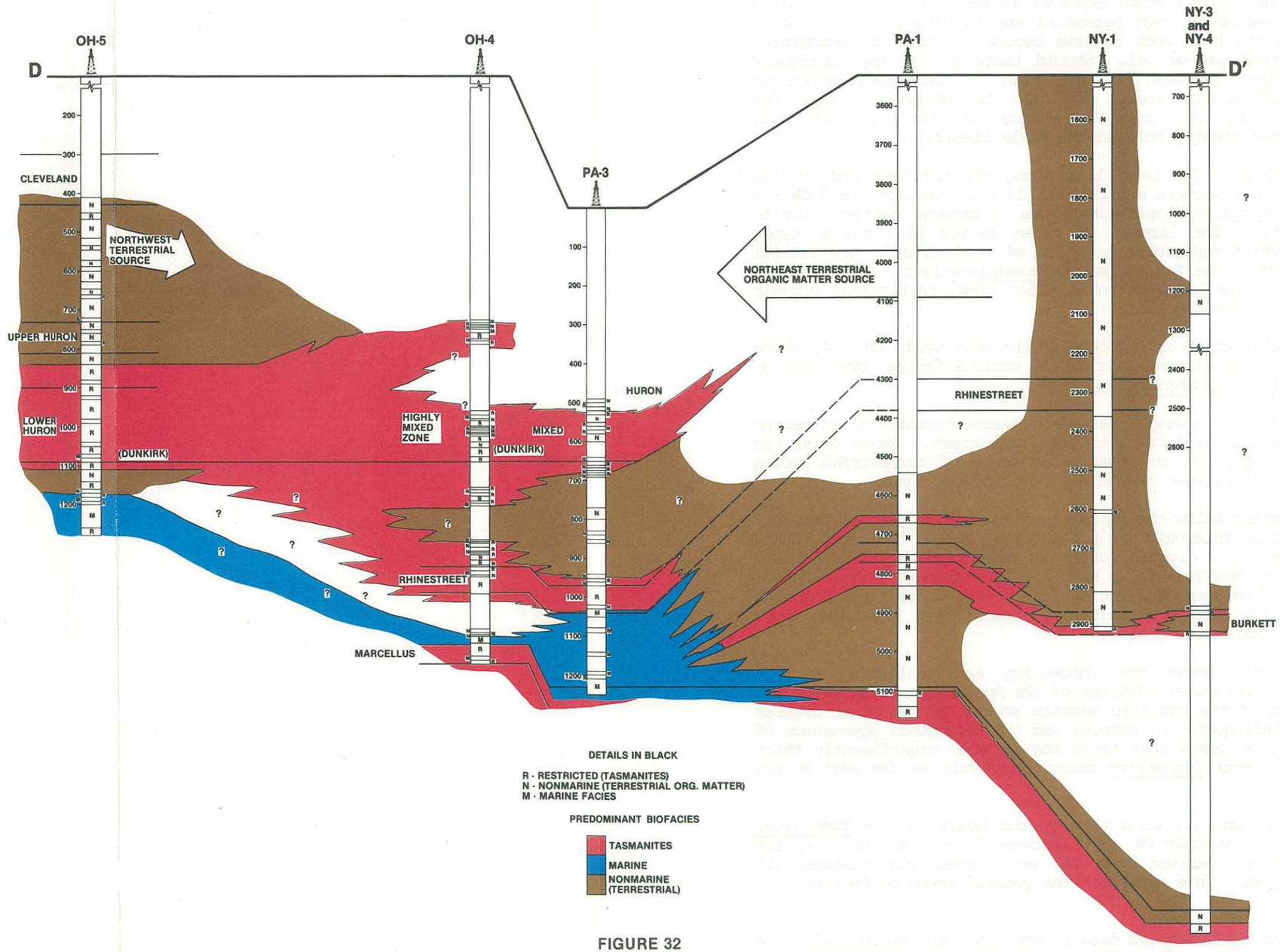

FIGURE 32

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Biofacies Distribution
Section E-E′

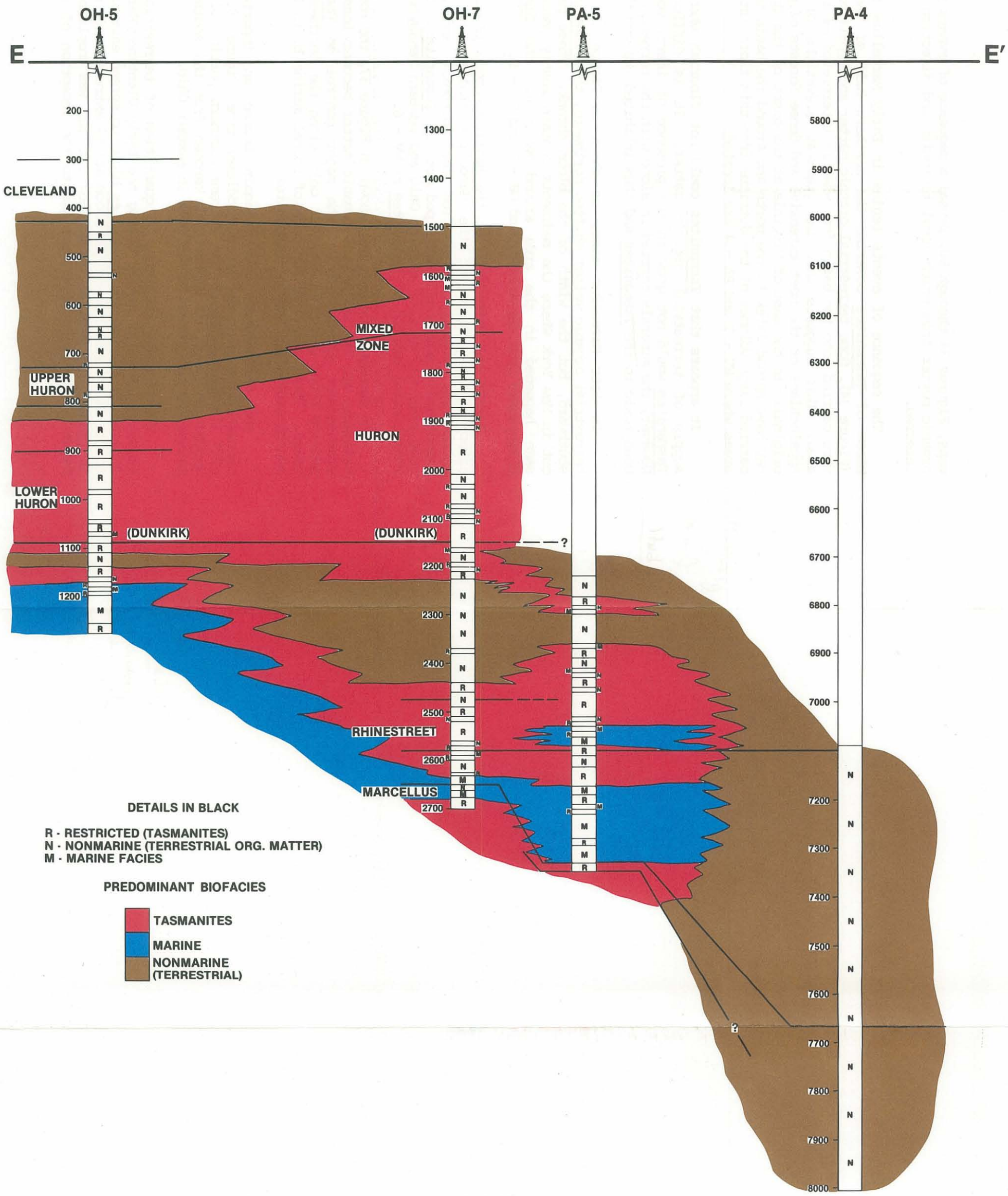

FIGURE 33

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maps, Figures 34 through 50, reveal a sequence of events in the deposition of organic matter from which local tectonism and direction of drainage can be inferred.

The sequence of events begins in Early Marcellus time with a massive bloom of Tasmanites covering the northern half of the Appalachian Basin (Figure 34). Some terrestrial organic matter and Appalachian-derived sediment were carried into the basin from what is interpreted as a southeastern source area. This suggests that the greatest elevations of the newly forming Appalachians or the most extensive and dense forests of primitive trees were originally to the east of Virginia at the onset of the Upper Devonian. They may have spread later to the north and around the basin to the west. Streams carried large volumes of the detritus from this flora into the basins in the areas where WV - 7 and PA - 4 are located.

preservation? vs? flourish? bad!

It appears that Tasmanites could not flourish when there was a large supply of terrestrial organic matter. It is difficult to imagine why Tasmanites would not grow in the presence of inert, woody organic matter. However, the minerals carried in along with the terrestrial material may have been toxic to the Tasmanites and thus inhibited its growth.

In late Marcellus time, as shown in Figure 35, the source of the terrestrial organic matter shifted northward, the Tasmanites extended further southward, but the width of the bloom shrank. These particular algae died out in New York where the sediments contain mostly nonmarine kerogen. The same happened in the area around WV - 6. The Tasmanites bloom also disappeared from the area around OH - 7 and PA - 5.

During the deposition of the Hamilton Group (Figure 36), immediately after the deposition of the Marcellus shales, the massive influx of terrestrial organic matter from the northeast and southeast, and the associated minerals all but wiped out the Tasmanites. Normal marine biota grew over the area of eastern Ohio and western Pennsylvania. There is one long-lasting remnant of Tasmanites at WV - 6.

In Genesee/Geneseo time, shown in Figure 37, the northeastern source of sediments and of terrestrial organic matter becomes less important, and the southeastern source becomes the major control on Tasmanites growth. A massive bloom was restored, but only along the northwestern margin of the basin. There was a buffer zone of normal marine biota between the sediment source provenance and the Tasmanites.

The northeastern source again became an important contributor of terrestrial organic matter in Middlesex time (Figure 38) and began to "kill off" the Tasmanites of the extreme northern portion of the basin, while a continuing supply of terrestrial kerogen from the southeastern source area maintained the marine buffer zone in eastern Ohio.

Early Olentangy vs Muhontango M. Dev. Not U Dev.

The apparent reduction in quantities of terrestrial material and its associated mineral matter during the Early Olentangy/Early Rhinestreet time (Figure 39) allowed the Tasmanites bloom to spread eastward across the basin. At the same time, some of the bloom at the extreme western part of the basin, in present day central Ohio, died out and was replaced by normal marine forms. This might have been due to the inception of a western source of

BIOFACIES DISTRIBUTION

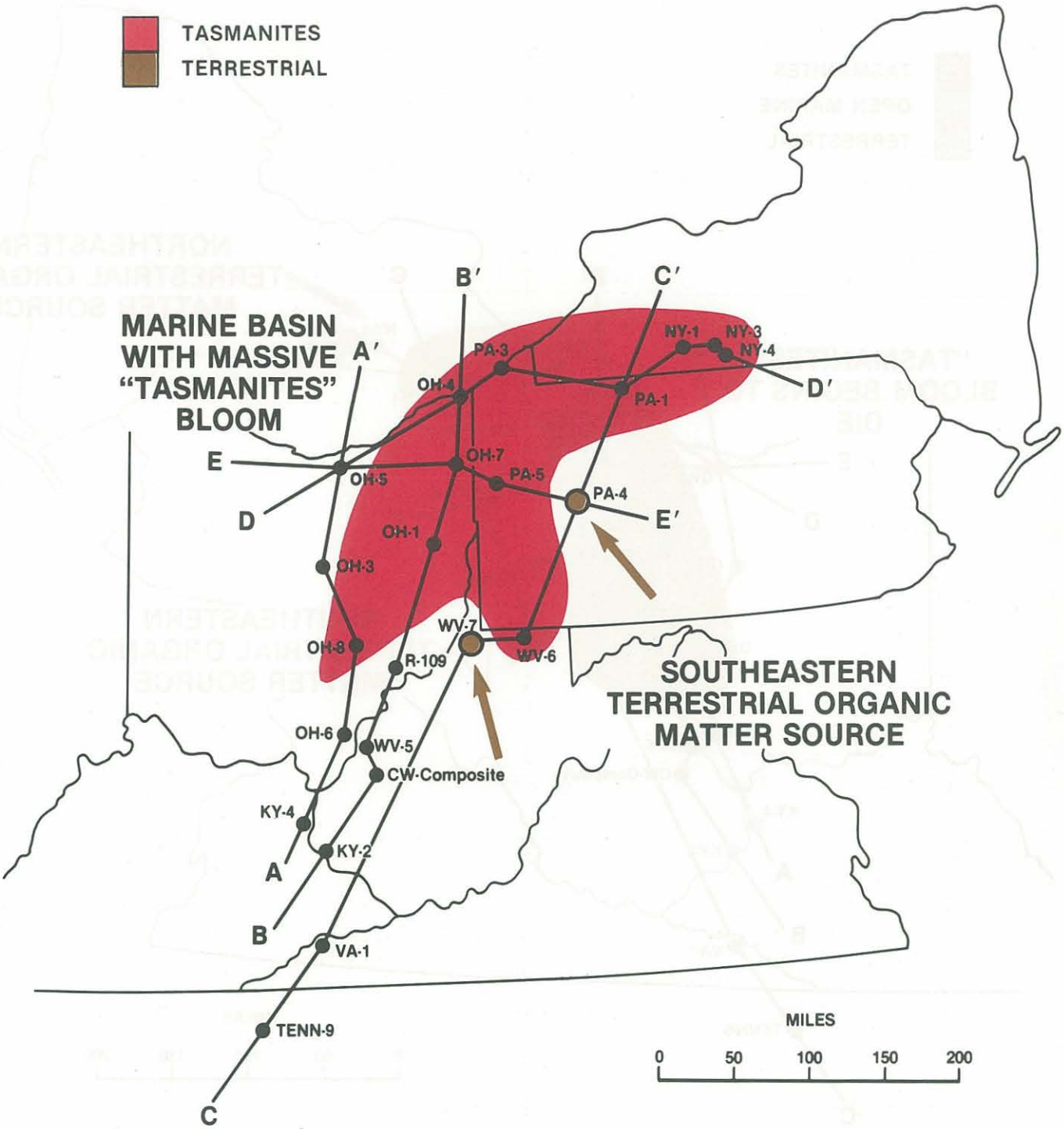


FIGURE 34

EARLY MARCELLUS TIME

BIOFACIES DISTRIBUTION

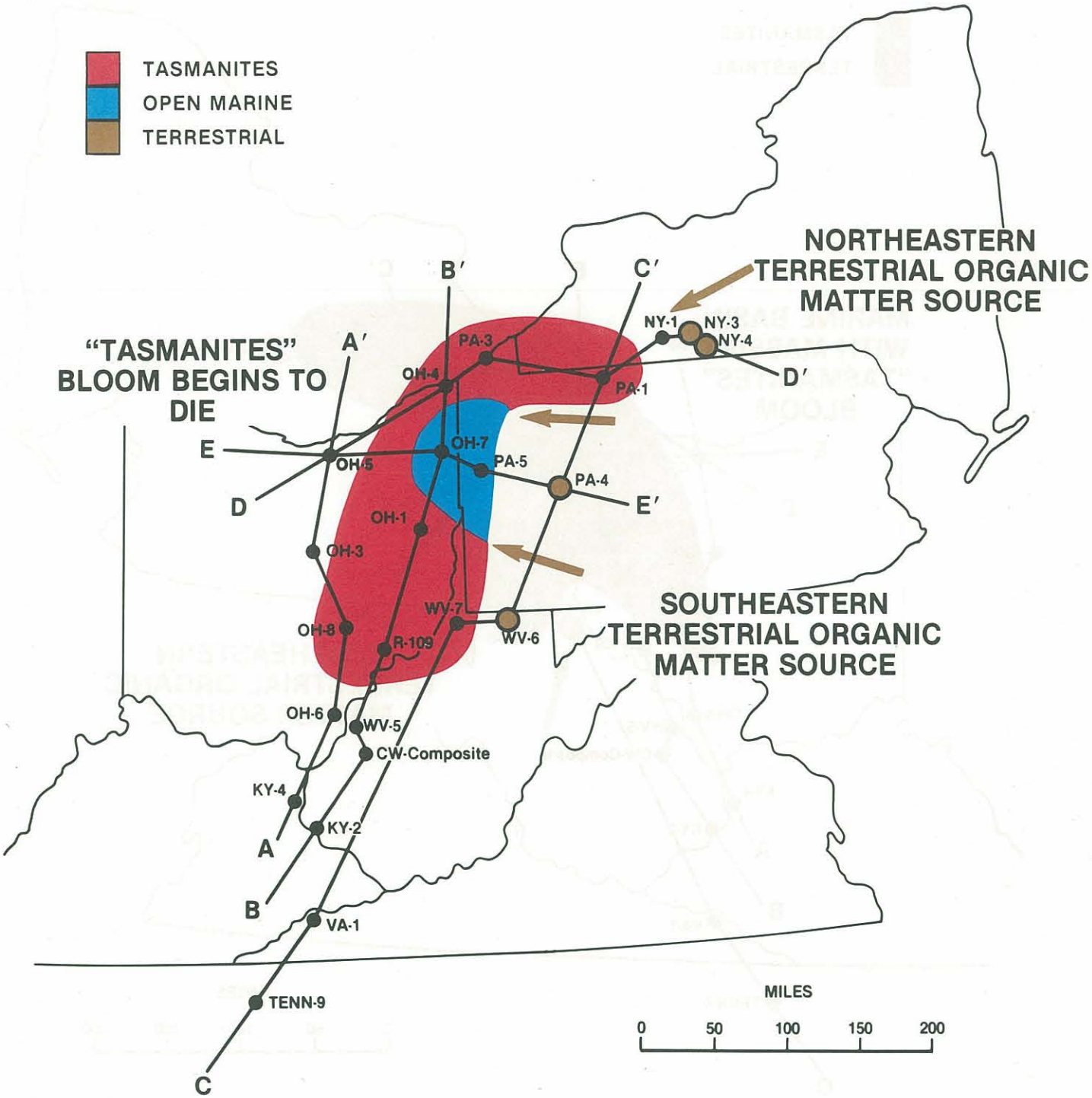


FIGURE 35

LATE MARCELLUS TIME

BIOFACIES DISTRIBUTION

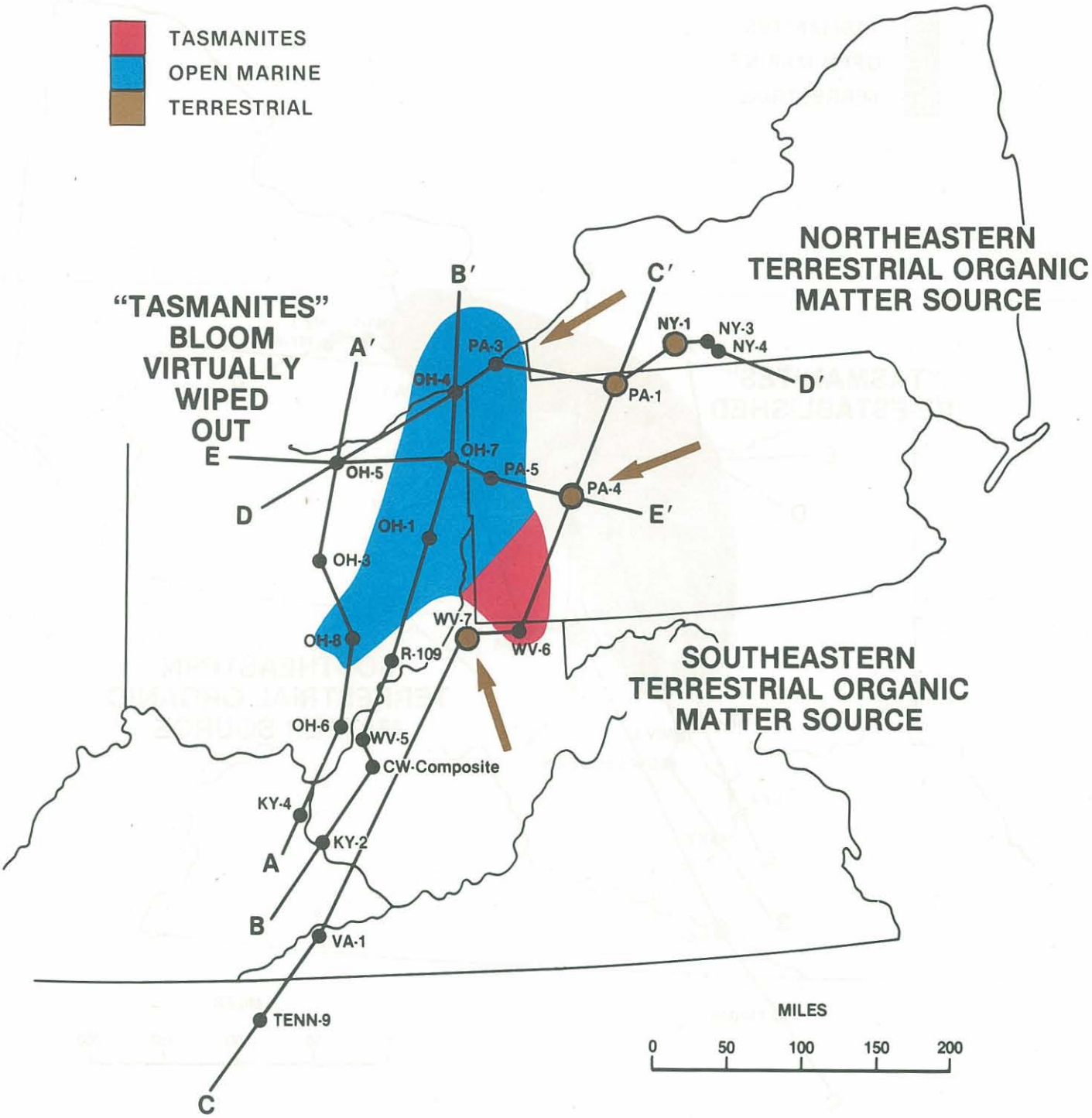


FIGURE 36

HAMILTON GROUP/POST-MARCELLUS TIME

BIOFACIES DISTRIBUTION

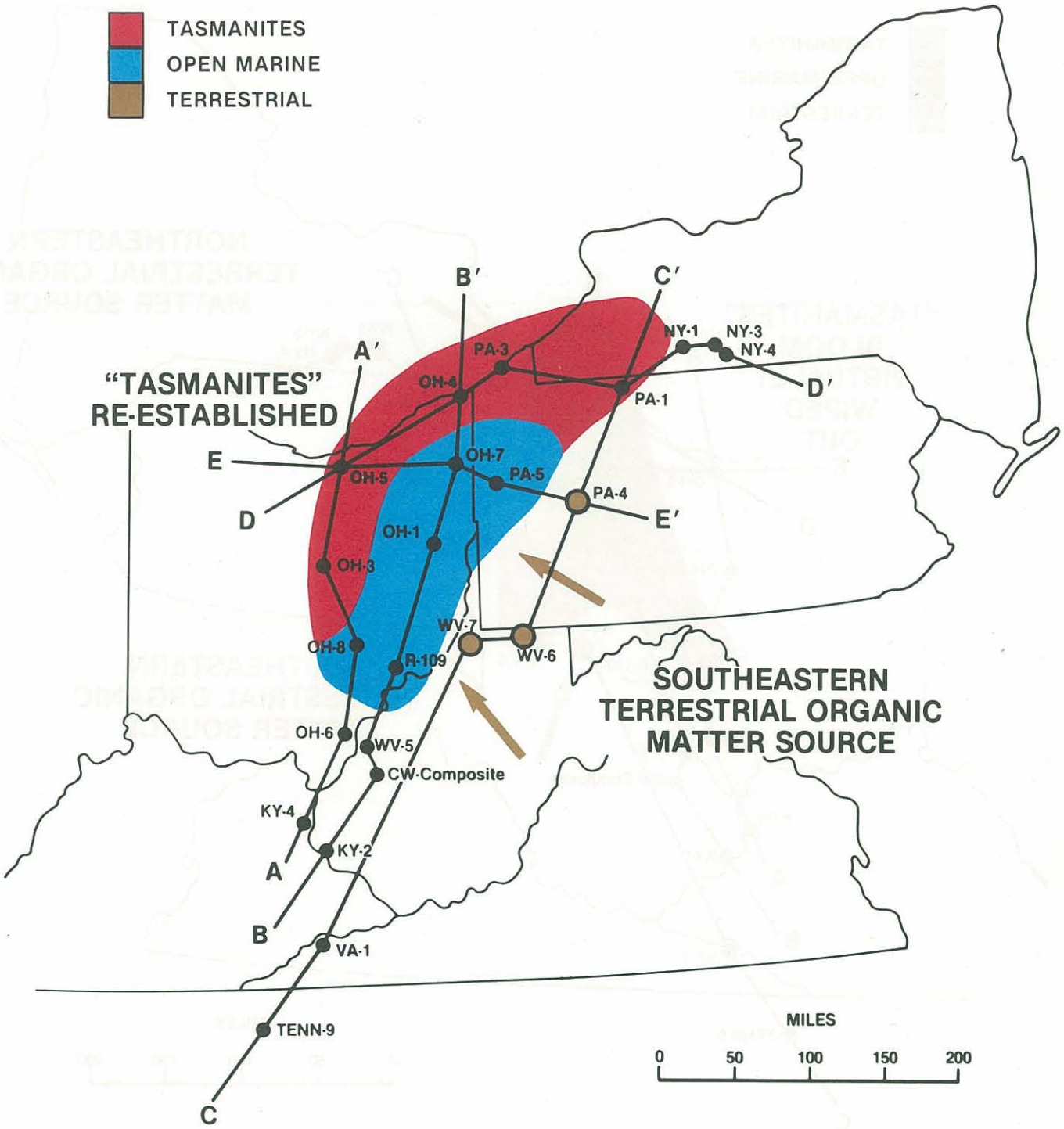


FIGURE 37

GENESEE / GENESEO TIME

BIOFACIES DISTRIBUTION

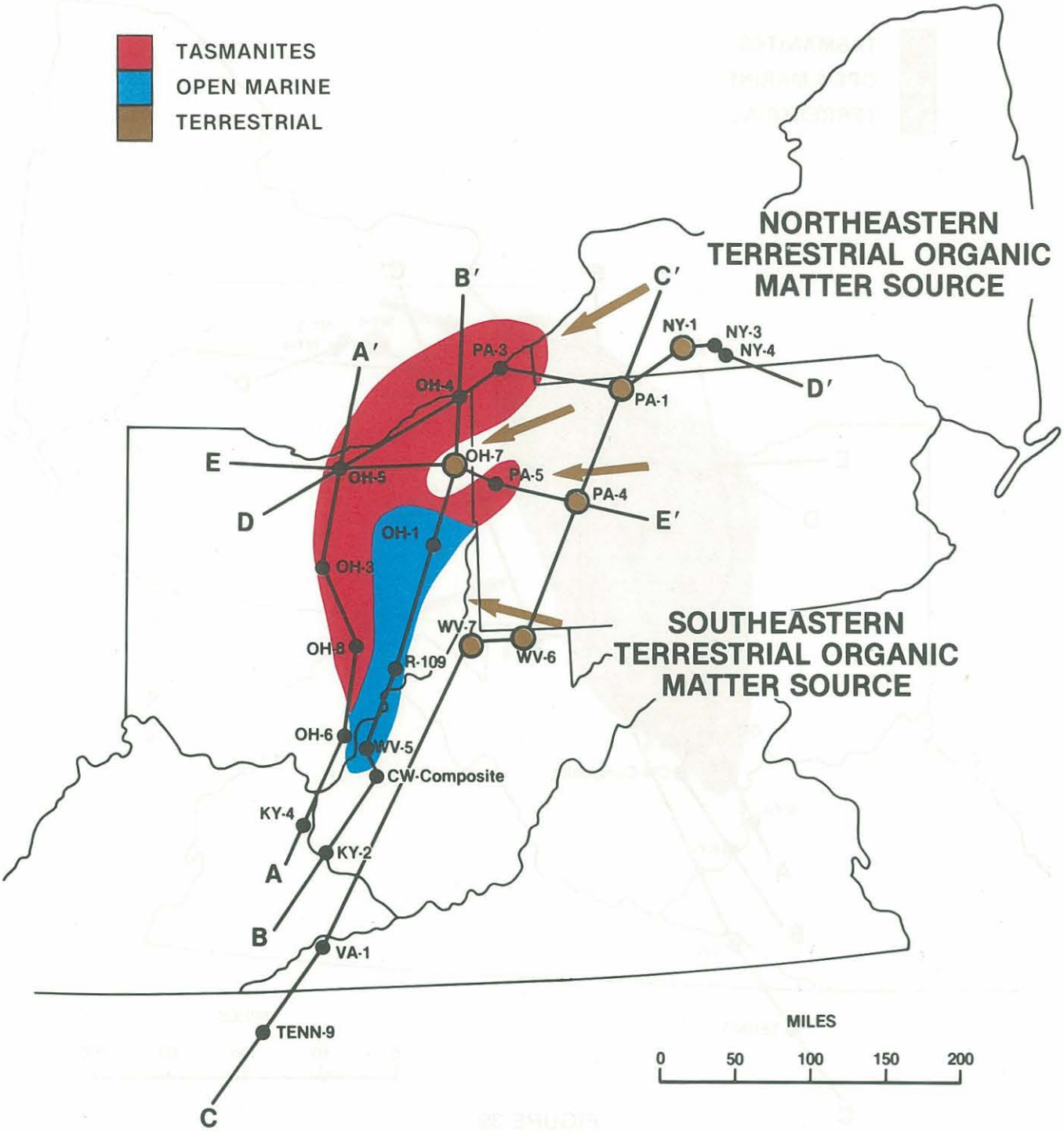


FIGURE 38

SONYEA / MIDDLESEX TIME

BIOFACIES DISTRIBUTION

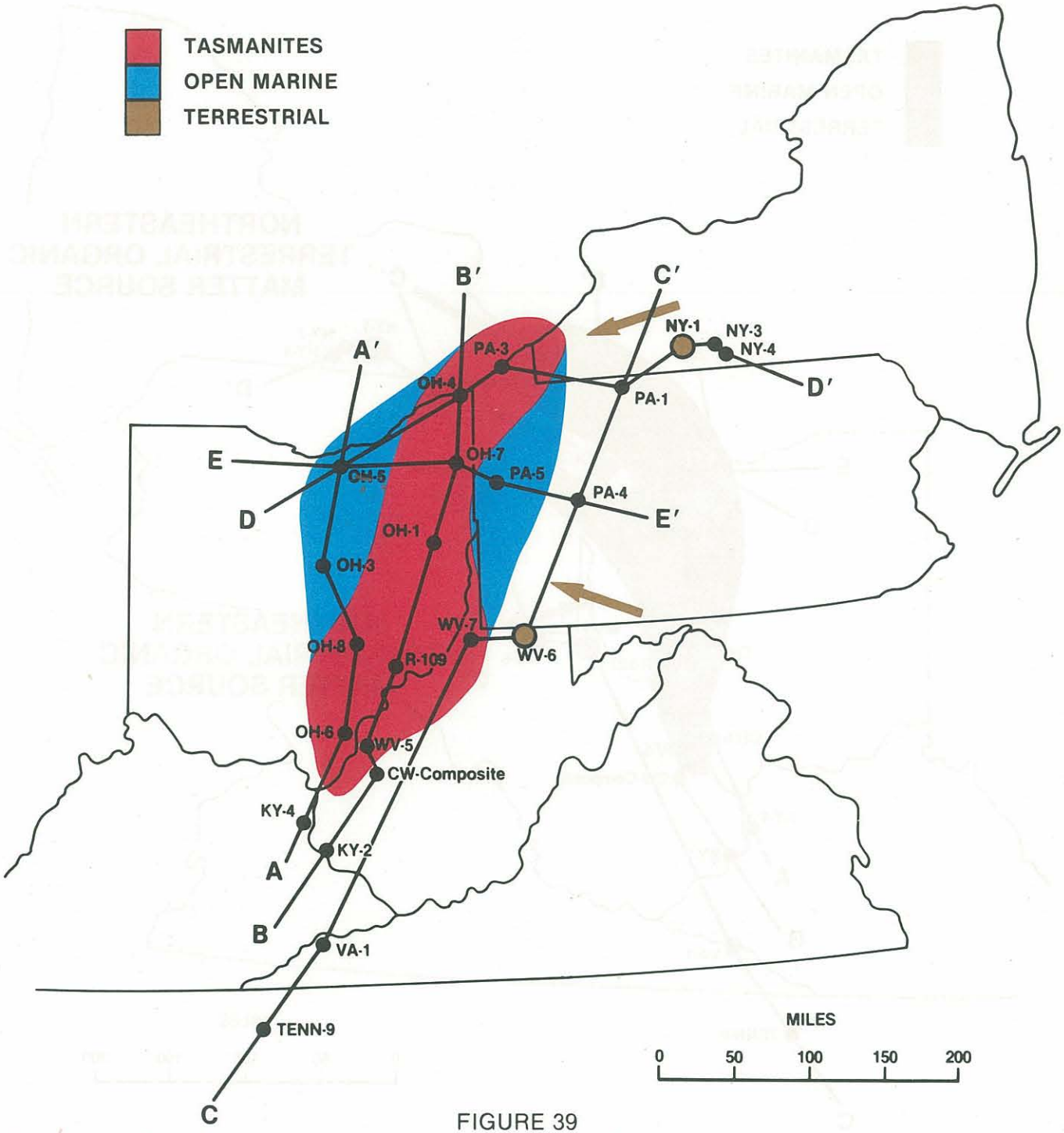


FIGURE 39

Early lower Olentangy = Post-Marcellus - Pre Centerfield Hamilton - NOT Rhinestreet

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

MOUND

Prepared by Mound Facility

terrestrial organic matter and of minerals or nutrients that were also toxic to the very unusual algae, Tasmanites.

There is a stronger evidence for a western source of terrestrial kerogen and associated mineral matter in late Rhinestreet Shales (Figure 40). The Tasmanites bloom is "held" as an elongate mass parallel to, but distant from, the western edge of the basin, and parallel to, but west of, the basin axis. The southernmost occurrence of Tasmanites is also seen in this unit, i.e., in the TENN - 9 well.

In Middle Olentangy time, shown in Figure 41, terrestrial material was being dumped in from practically the entire circumference of the basin. The Tasmanites bloom began to shrink, and only two pods of this very rich hydrocarbon source facies remained.

Later in Middle Olentangy time (Figure 42) the northwestern source of terrestrial organic matter became inactive and the Tasmanites bloom rapidly grew to the basin margin in that area; while the active eastern sources kept the bloom pinned to the western margin of the basin.

At the beginning of Huron time, the western sources of nonmarine kerogen were inactive, and the eastern ones diminished. As a result, as Figures 43 and 44 show, the Tasmanites flourished and spread widely over practically the entire basin west of the basin axis, and as far south as TENN - 9.

In Middle Huron time, the eastern sources again became very active contributors of terrestrial organic matter, and the Tasmanites bloom shrank, first along its entire length (Figure 45), and then at both ends (Figure 46).

From that time on, the rejuvenation of the southwestern terrestrial source and slight variations in the eastern sources first killed the Tasmanites in one area while it expanded to others (Figures 47), then wiped out the northern "pod" (Figure 48), and finally shrank the southern pod to but a tiny area (Figures 49 and 50) at the close of the Upper Devonian.

This dynamic growth and decline of the Tasmanites bloom, and its shift from area to area, in response to the influx of some unknown chemical material from the basin margins holds clues to the tectonics which were important in the evolution of the Appalachian Basin. The shifting patterns were the justification for a cursory look at the structural reconstruction based on new concepts of plate tectonics and continental drift which will be presented later in this report.

BIOFACIES DISTRIBUTION

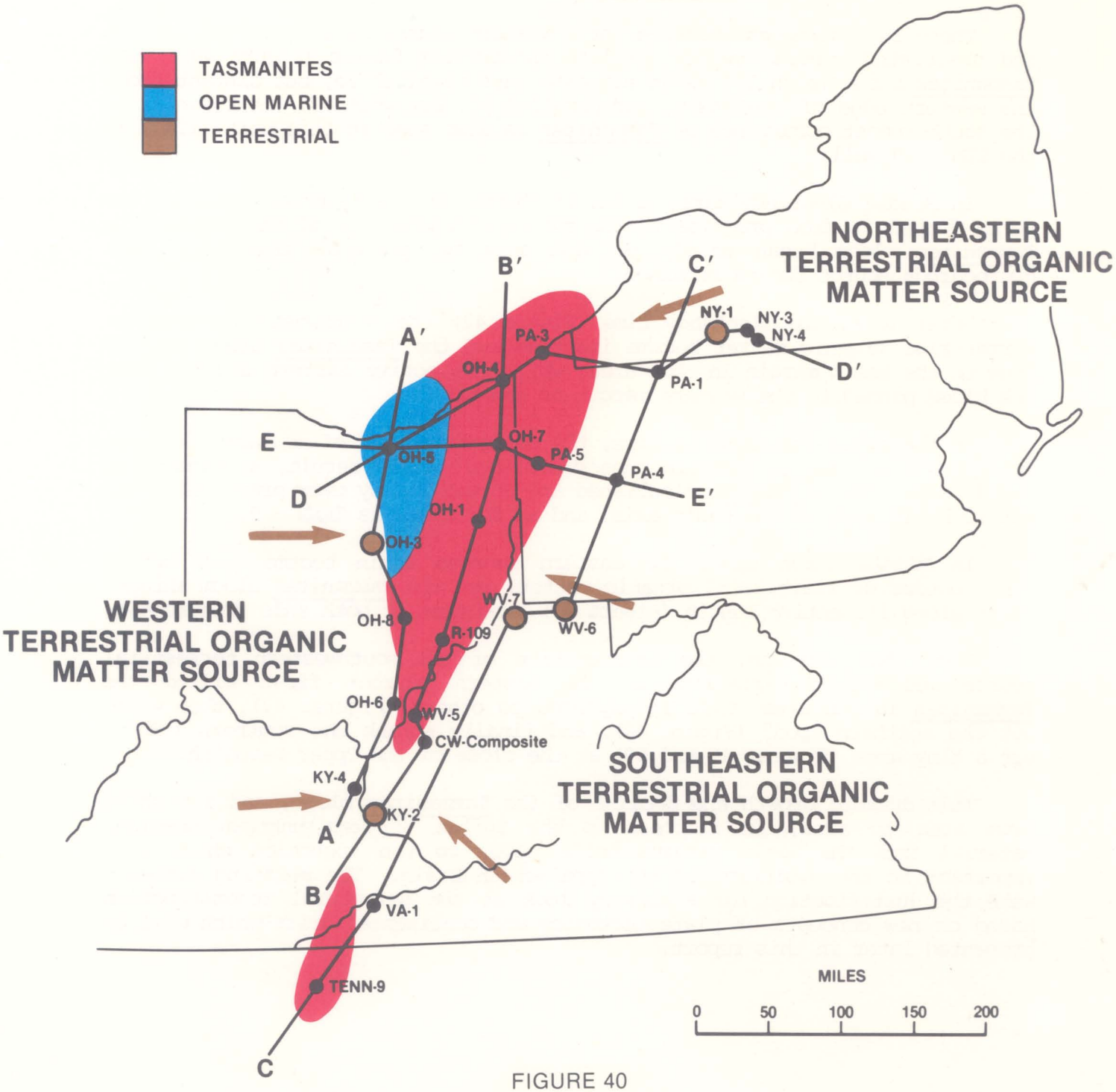


FIGURE 40

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

BIOFACIES DISTRIBUTION

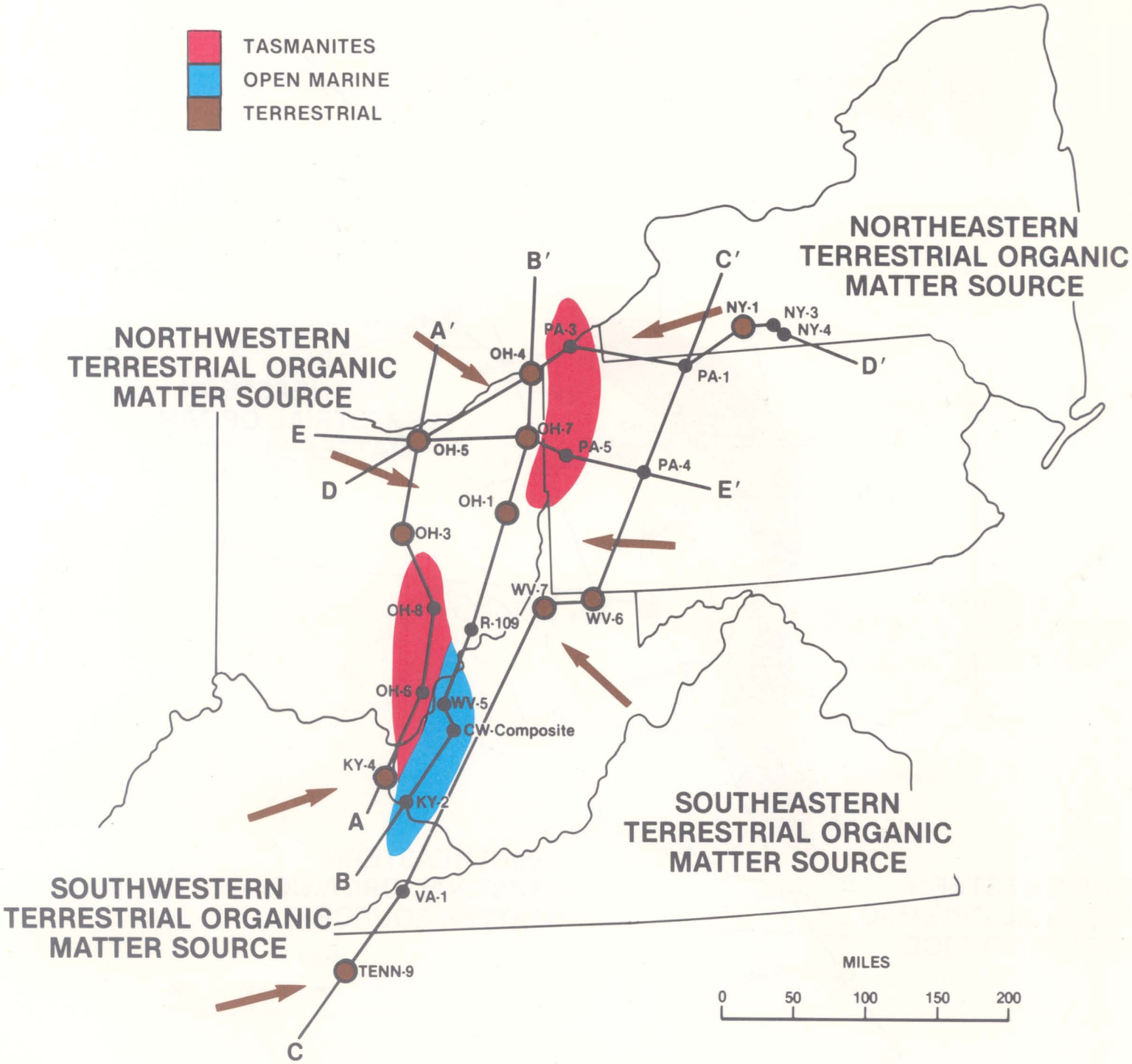


FIGURE 41

MIDDLE OLENTANGY/ANGOLA SHALE TIME

BIOFACIES DISTRIBUTION

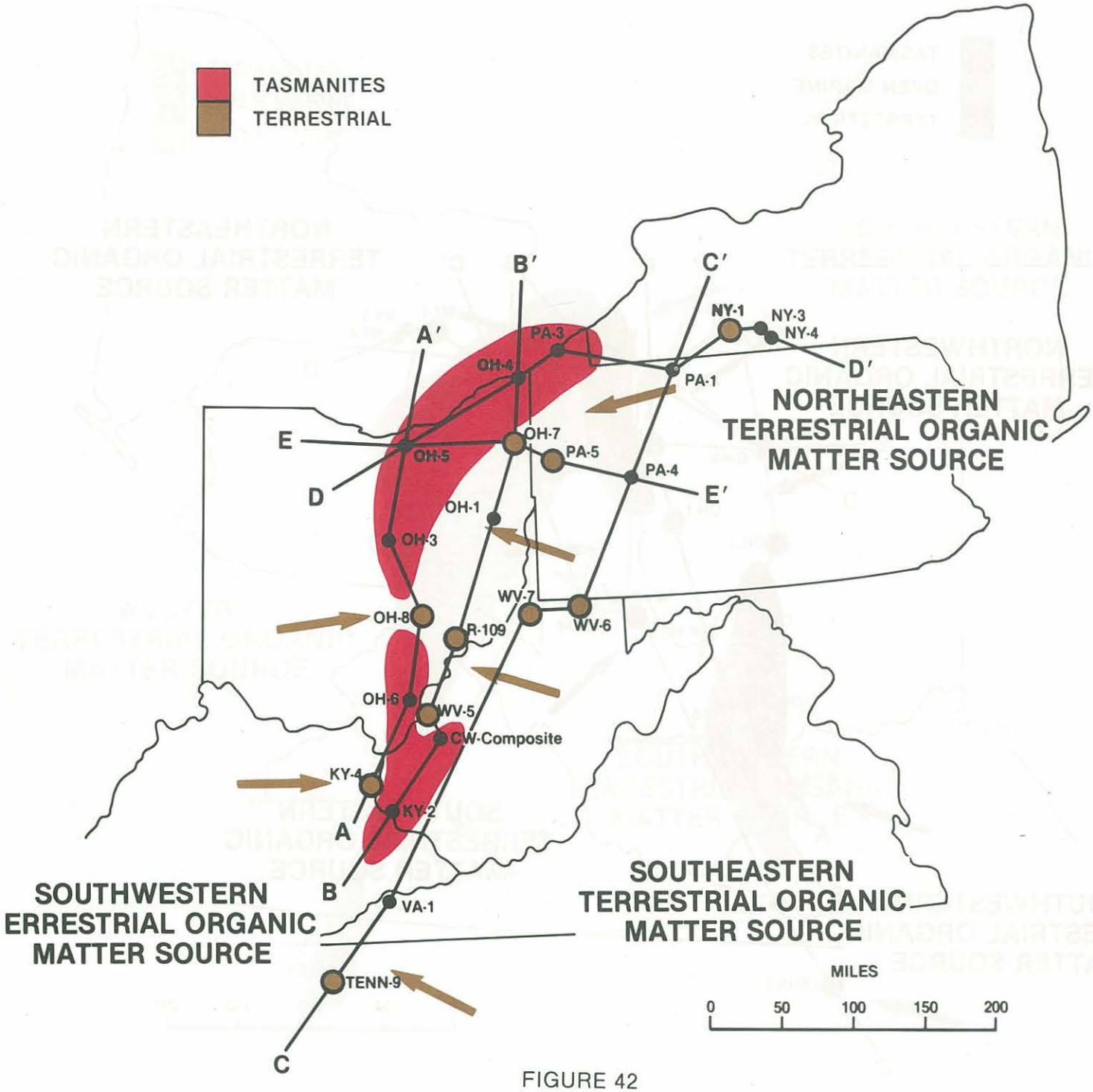


FIGURE 42

UPPER OLENTANGY/JAVA FM. HANOVER SHALE TIME

BIOFACIES DISTRIBUTION

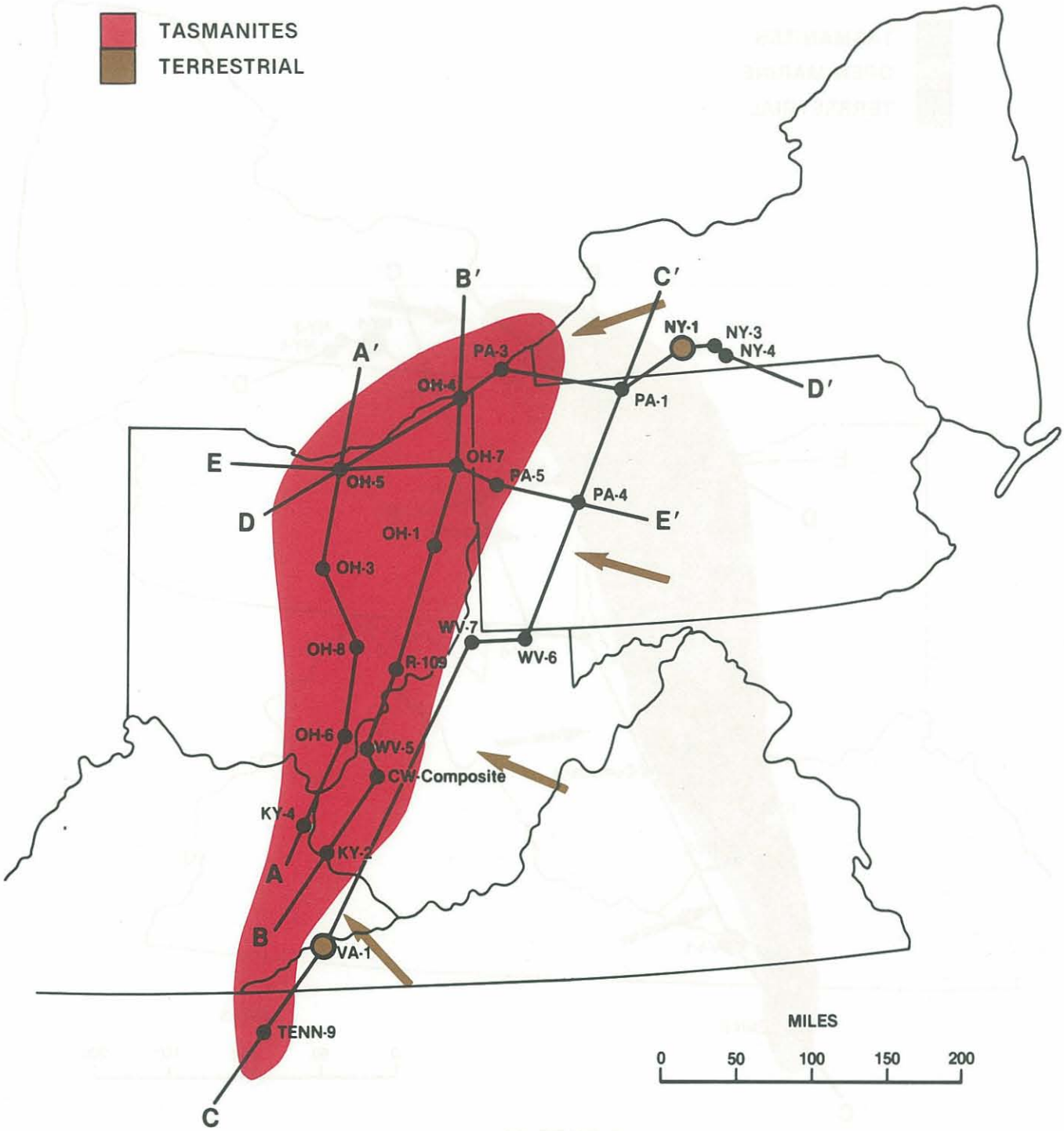


FIGURE 43

EARLY LOWER HURON/EARLY DUNKIRK TIME

MOUND
Prepared by Mound Facility

BIOFACIES DISTRIBUTION

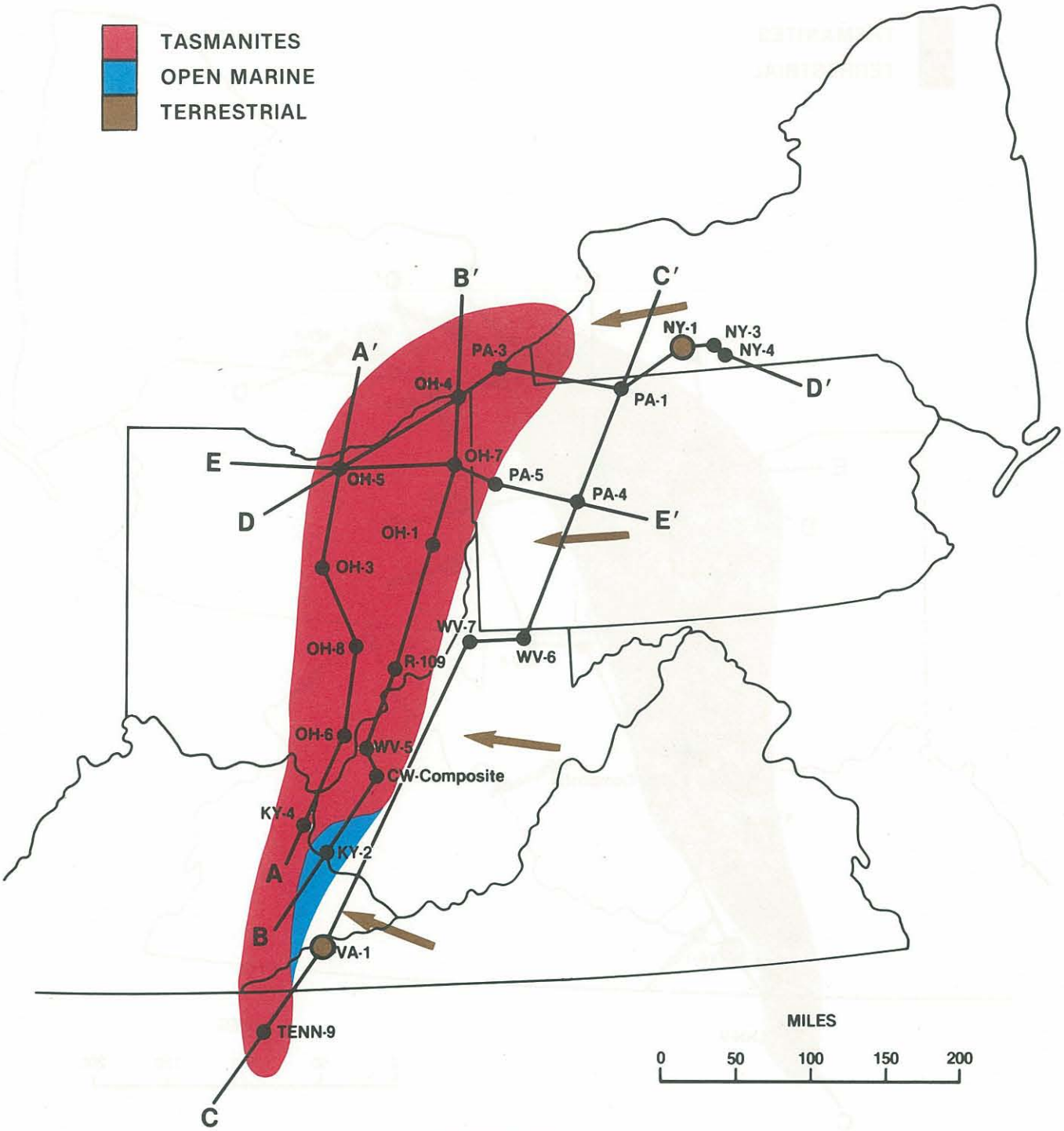


FIGURE 44

LATE LOWER HURON/LATE DUNKIRK TIME

BIOFACIES DISTRIBUTION

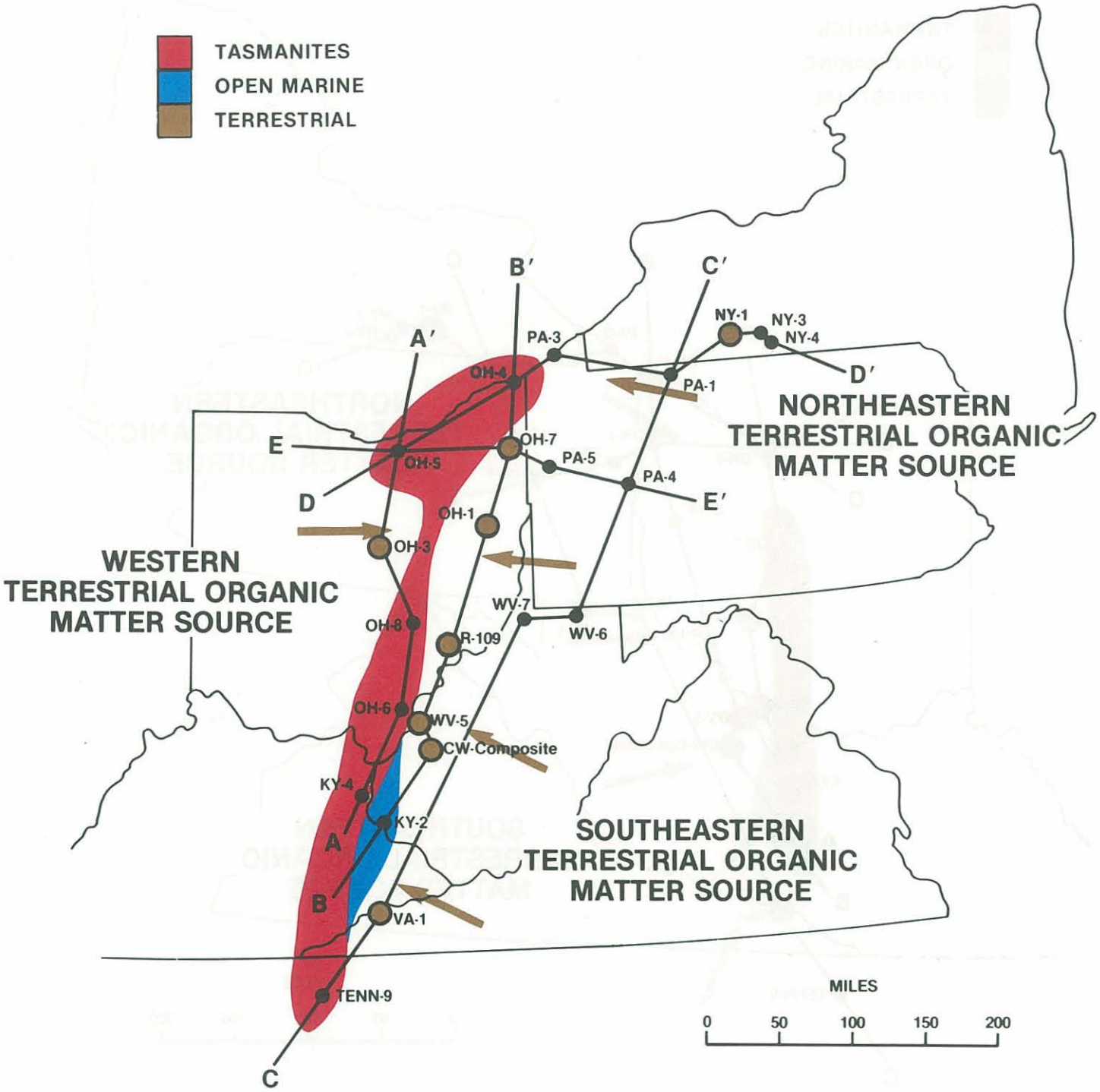


FIGURE 45

EARLY MIDDLE HURON TIME

BIOFACIES DISTRIBUTION

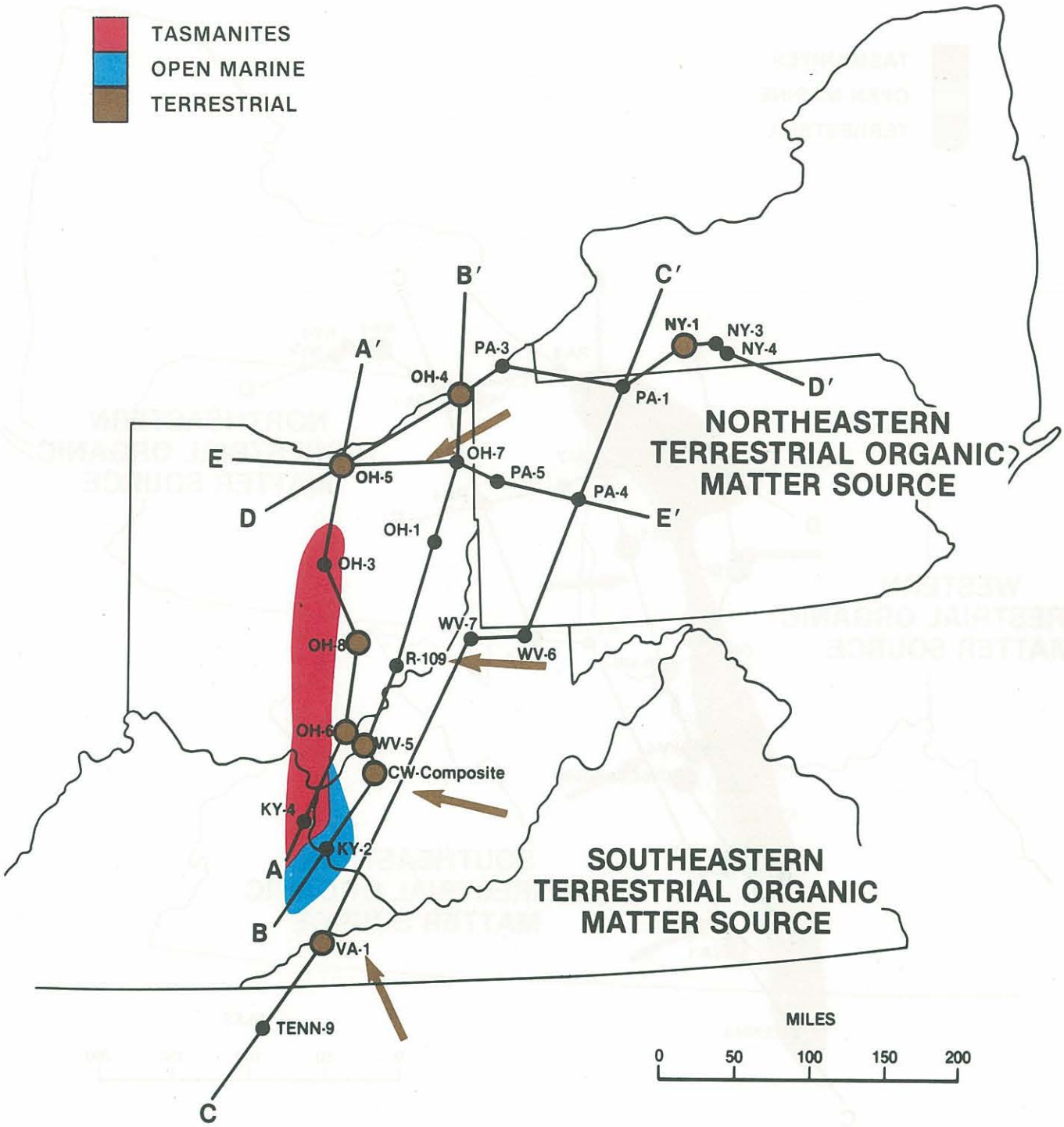


FIGURE 46

LATE MIDDLE HURON TIME

BIOFACIES DISTRIBUTION

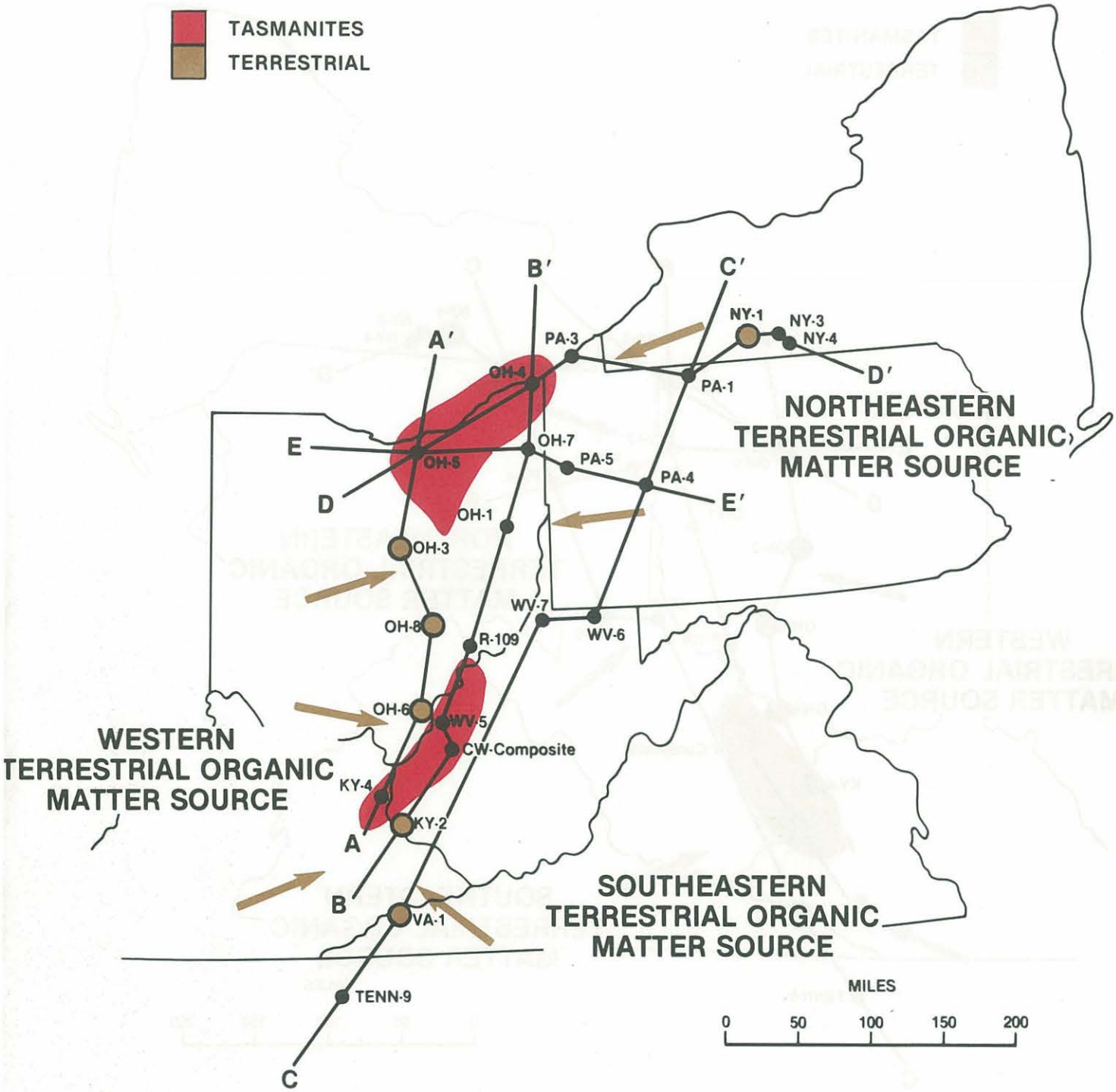


FIGURE 47

EARLY UPPER HURON TIME

BIOFACIES DISTRIBUTION

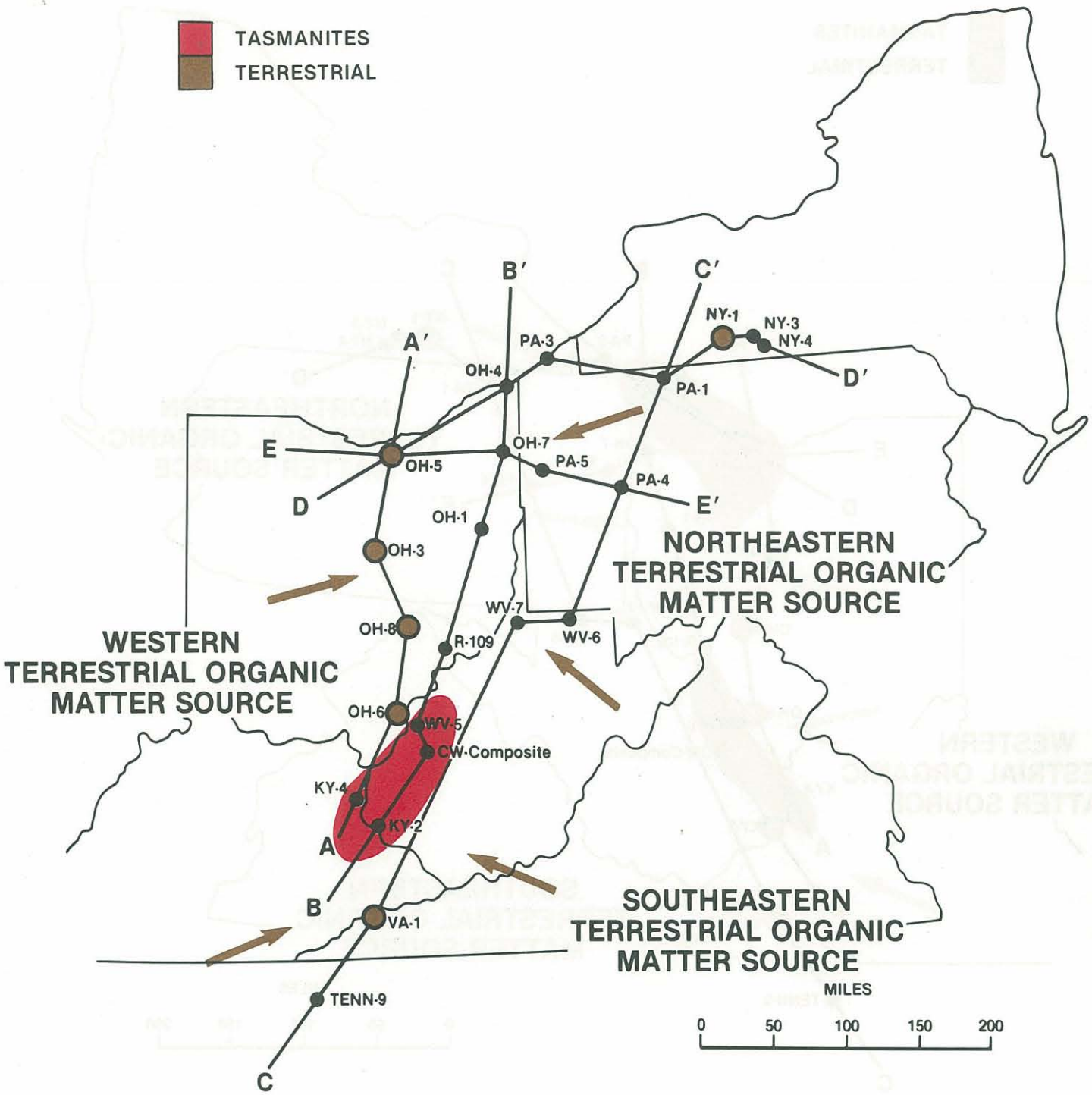


FIGURE 48

LATE UPPER HURON TIME

BIOFACIES DISTRIBUTION

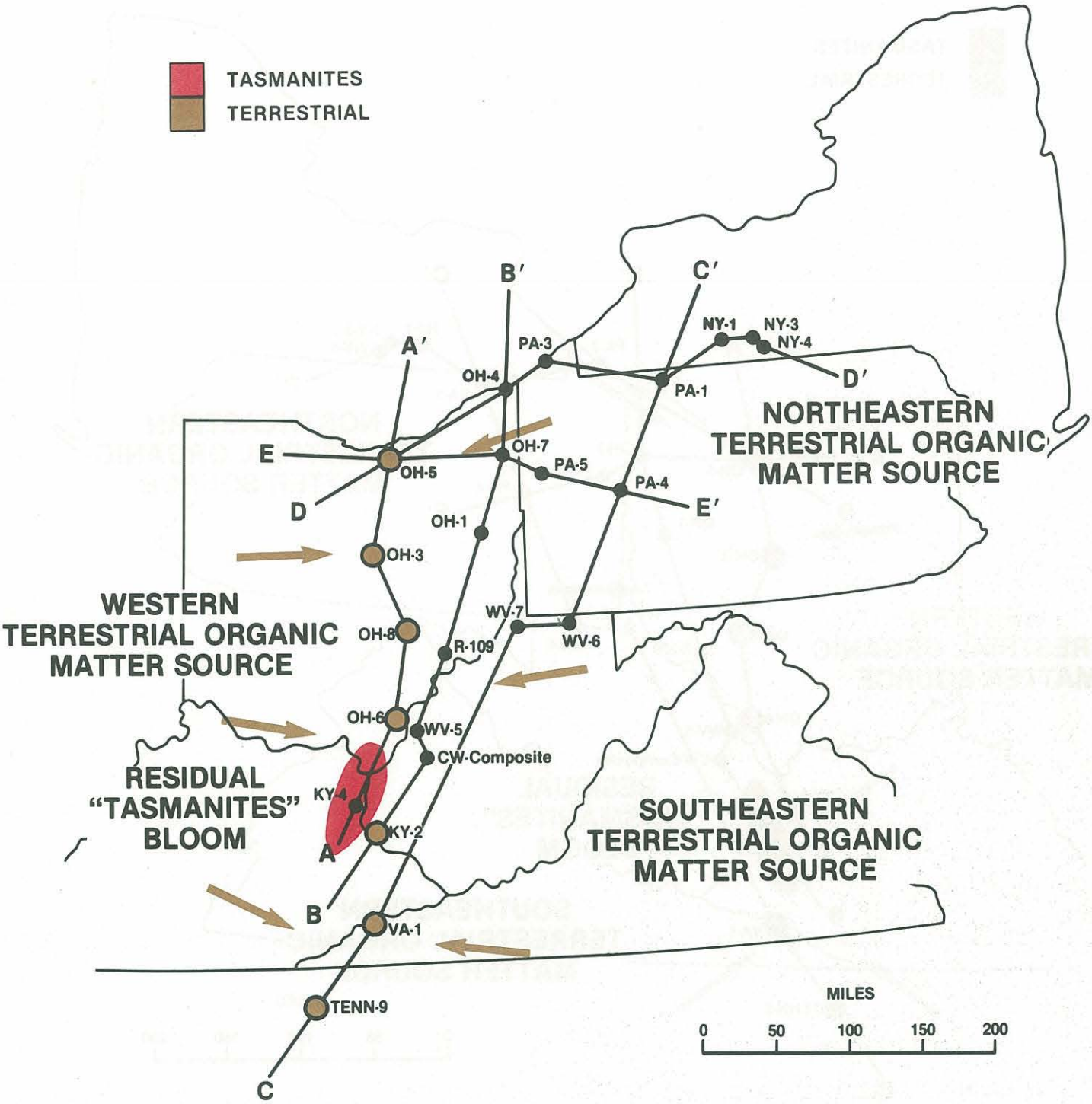


FIGURE 49

CHAGRIN TIME

MOUND
Prepared by Mound Facility

BIOFACIES DISTRIBUTION

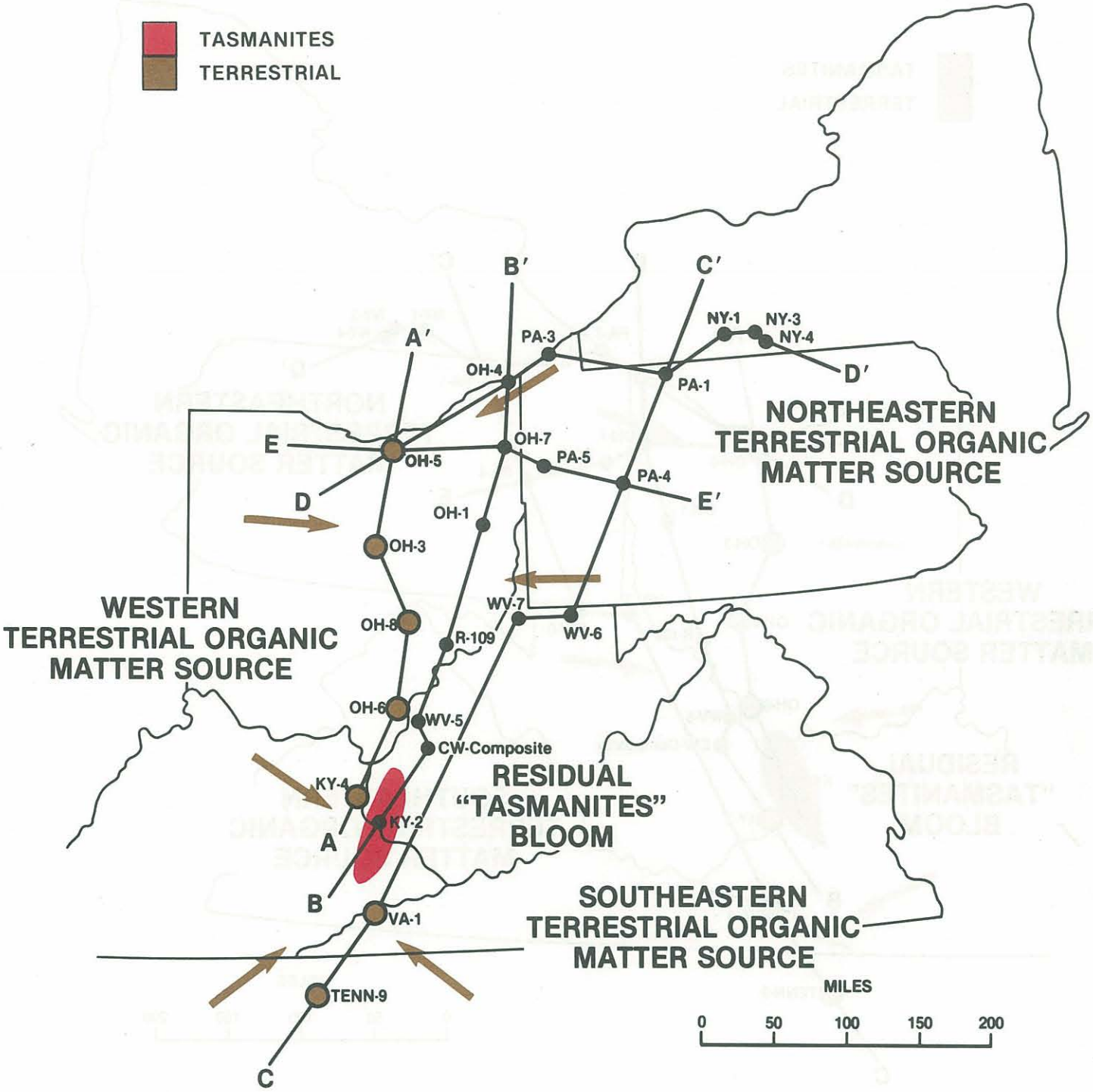


FIGURE 50

CLEVELAND TIME

Maturity

Organic matter laid down at the time of deposition contains only traces of free petroleum hydrocarbons, far too little for even an organic-rich rock to act as a source rock without further change. Some changes, such as oxidation destroy some or all of the source potential, but in a normal source-producing environment, the bulk of the organic matter is preserved because the conditions at or shortly after deposition are anerobic, or reducing.

Organic matter in potential source rocks undergoes a sequence of changes that converts as much as 30 to 35 percent of its original mass to petroleum hydrocarbons. The first process, a low temperature one, is called diagenesis. This term refers to the combined effects of biological, physical and chemical alteration before heat begins to "crack" the organic matter. The only potential petroleum-producing reaction operating during diagenesis is the microbial formation of methane, large quantities of which may form and be trapped in reservoirs that are formed early. It is estimated that 20% of the world's gas reserves are made up of this biogenic gas (16). This gas can be identified by its carbon isotopic composition (i.e., it is enriched in the lighter isotope).

When the temperature of a rock rises to above about 50°C, the chemical bonds of the contained organic matter begin to break in response to the heat, and the stage called thermal maturation or catagenesis begins. The great majority of the petroleum hydrocarbons of the world is formed by this process which continues until the temperature of the rock reaches about 150 to 200°C. At higher temperatures, the process, now called metamorphism, begins to destroy petroleum hydrocarbons.

Temperature estimates for the onset and completion of petroleum hydrocarbon production are only approximate because the rock organic matter system is so variable and complex. Moreover, because the organic matter is a chemical system, the rate of reactions must increase with temperature. Therefore, there should be a trade-off of temperature for time, i.e., rocks buried for longer periods at lower temperature should experience the same degree of catagenesis as those buried at higher temperatures for shorter periods of time.

In an exploration venture, it is important to know whether the organic matter has undergone sufficient catagenesis to produce commercial quantities of petroleum, but not so much alteration that the hydrocarbon has been destroyed. This is not always easy to determine from the present day geological setting of the rock or its present temperature because the rock may have had a complex history of several episodes of burial, uplift, and erosion of the overlying rocks.

Fortunately, the kerogen itself, immobilized in the rock matrix since deposition, carries a record of its own time-temperature history. The degree of thermal alteration, catagenesis, can be estimated from the color of spores, pollen, or plant cuticle fragments (13), or from the optical reflectivity of specific carbonized particles, called vitrinite (17).

H index
O index

Kerogen coloration is reported on a scale of from 1 to 5. These values are also called Thermal Alteration Index (TAI) values. Fresh, unaltered pollen, spores and cuticle fragments are light yellow or light greenish yellow, this unaltered kerogen is assigned a TAI of 1. Such a rating indicates that the rock has not been exposed to temperatures above 50°C. Rocks with this low a TAI are sometimes associated with methane gas of biogenic origin.

The onset of catagenesis, between 50 and 100°C, is detected by the loss of the greenish tinge and a slight intensification of the yellow coloration of the appropriate type of herbaceous kerogen. TAI's of rocks with kerogen exhibiting this coloration are rated at 1+. These rocks are associated with dry (methane only) gas and sometimes with heavy oil. Rocks with these very light colors are said to be "immature".

Orange colors indicate that the rock's organic matter is moderately altered, it has probably been exposed to temperatures in the range 100 to 150°C. Light orange kerogen (TAI = 2) is sometimes associated with gas with a large percentage of ethane, propane, the butanes and some light hydrocarbon liquids. TAI's of 2 generally indicate that the rock is in its most prolific oil generating stage.

Brown colors (TAI = 3) indicate that the organic fractions of the rock have been strongly altered, probably having experienced temperatures above 150°C. At these temperatures, kerogen has realized most of its potential to give up hydrocarbons, the free hydrocarbons have been converted to light liquid and gaseous hydrocarbons. Deep brown or brownish black (TAI = 4) coloration denotes severely altered kerogen with dry methane gas the only associated hydrocarbon.

When the kerogen is black (TAI = 5), the rock has been exposed to relatively high subsurface temperatures (200°C) and there is little possibility of associated hydrocarbon except for a small amount of methane.

These colorations are not always clear cut. Different spores and pollen grains from the same rock sample may have somewhat different colorations. Therefore, ratings should be made with other samples from the same well or outcrop so that subtle trends and relative colorations can be detected. The colors should be checked frequently against standard kerogen slides. Of course, the method is also somewhat subjective because of the different perception of color by different individuals, but it has the advantage of being rapid and requiring only a microscope.

Vitrinite reflectance is measured with a photomultiplier detector capable of accurately measuring the percent of a collimated beam light that is reflected from a polished surface of a minute vitrinite particle imbedded in a plastic matrix. While the measurement can be done accurately on a single particle, one of the drawbacks is that it is not always easy to recognize vitrinite. Other macerals, or kerogen types, that can be confused with vitrinite have quite different reflectance values at the same stage of thermal alteration. Another limitation is that even vitrinite particles that have experienced exactly the same histories may vary in reflectance because of small variations in the method of sample preparation, oxidation of the surface, texture, etc. Therefore the reflectance of a large number of

particles must be measured to derive a statistically significant estimate of alteration. In cases where the vitrinite is very uniform, this may require only 30 readings, in other cases, where the rock has a heterogeneous organic population, it may require over a hundred. In addition, the procedure is time-consuming and expensive relative to determination of TAI's.

Skillful interpretation of the data not only gives an estimate of extent of thermal maturation, but also may provide valuable information on possible unconformities in the section, on the amount of reworked kerogen introduced into the basins from eroding older rocks, and on the proportion of cavings in the well (14).

The TAI measurements on the samples form the Eastern Gas Shale Program appear to be more useful for the purposes of assessment than reflectance estimates. TAI data more closely parallel the geology and show trends from top to bottom in some wells in which reflectance values were inexplicably uniform from top to bottom. Therefore, in this geochemical assessment, the TAI's will be the factor used in the calculations and mapping.

To show regional trends in maturity, TAI values were spotted on the appropriate map (of the seventeen subdivisions selected for this study). Comparison of those maps showed that some of the TAI contours of adjacent intervals were identical and the maps could be combined into five maps.

The first such map, Figure 51, shows the TAI profiles for the lowermost Upper Devonian rock units. These values are applicable from the base of the Marcellus through the Genesee Group or its equivalent rocks. The alteration indices range from 2- in the extreme northwest portion of the basin (in the area around wells OH - 5, OH - 4, and PA - 3) to 4 at PA - 1.

Figure 52 shows the TAI's that apply for rocks of the Sonyea Group or its equivalents. These range from 2- in the northeastern extremity of the basin to 3+ at PA - 1 and PA - 4. The next map, Figure 53, gives the TAI values that describe the degree of alteration of the kerogen in the Olentangy Shales, including the Rhinestreet. The TAI's range from 2- in the shallow rocks in the northeast to 3+ in rocks in the area of WV - 5 and the Cottageville wells.

Figure 54 is a map of the degree of alteration of the organic matter in the Lower and Middle Huron shales and their equivalents. Immature kerogen with a TAI of 1+ is found in the PA - 3 well, and the values increase to 3 in the area of OH - 8 and R - 109. The last map, Figure 55, shows the less mature section including the Upper Huron, Chagrin, and Cleveland Shales and their equivalents. Values of 1+ are found in the northern and southwestern portions of the basin, and the values increase to 3 in the region of OH - 8 and R - 109.

These maps reveal that not all portions of the basin are as favorable for the generation of hydrocarbons as others. Some sediments are too immature to have realized a significant fraction of their enormous potential and some have experienced such extensive thermal cracking that the hydrocarbon is probably destroyed. The former case probably applies to the extreme northwestern and western portions of the study area where TAI's are less than 2. In spite of thick sections rich in organic carbon, the rocks

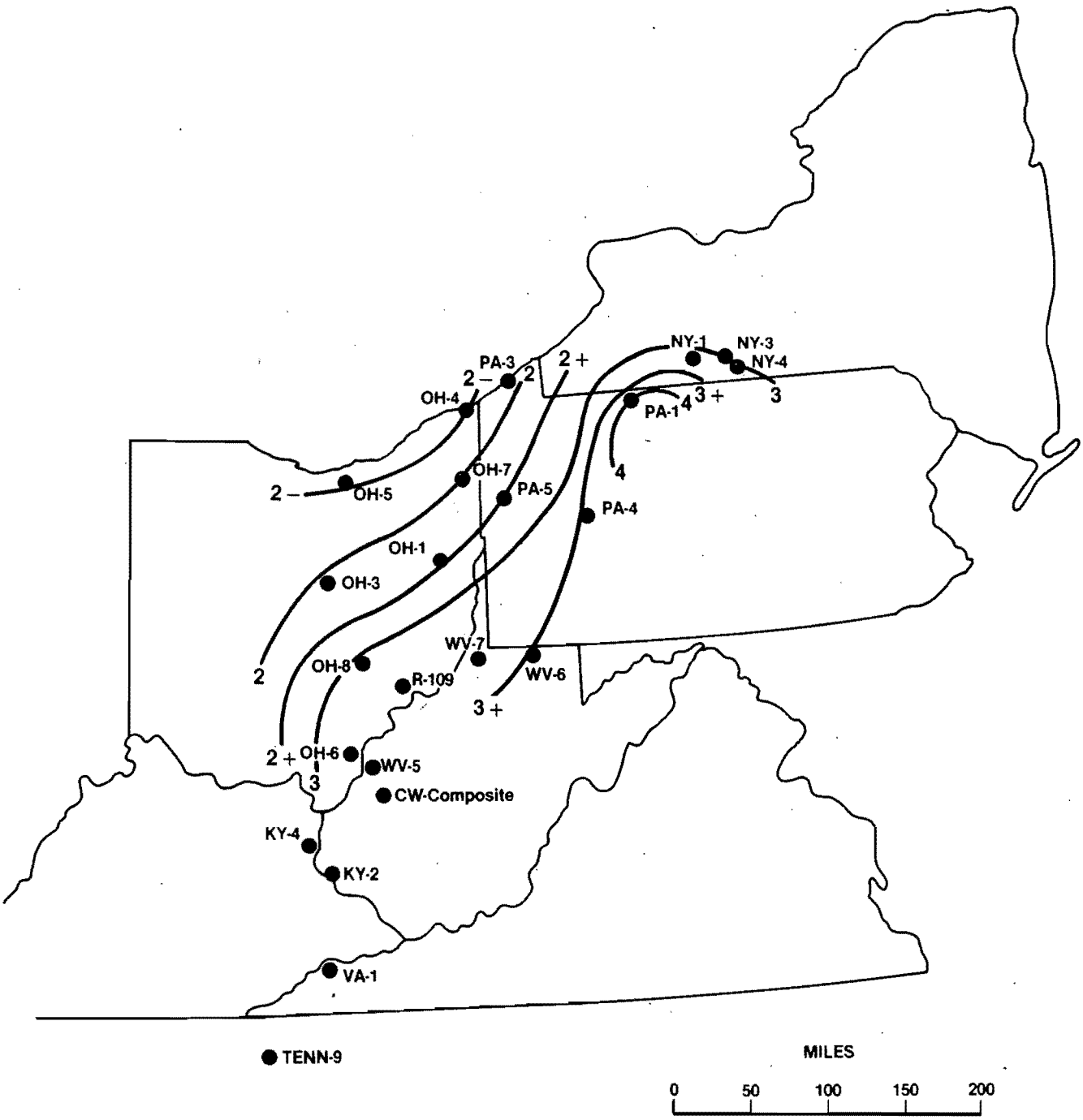


FIGURE 51

EARLY MARCELLUS THROUGH GENESEE / GENESEO TIME

MAP UNITS 1 THRU 4

MOUND

Prepared by Mound Facility

THERMAL ALTERATION INDEX PROFILES

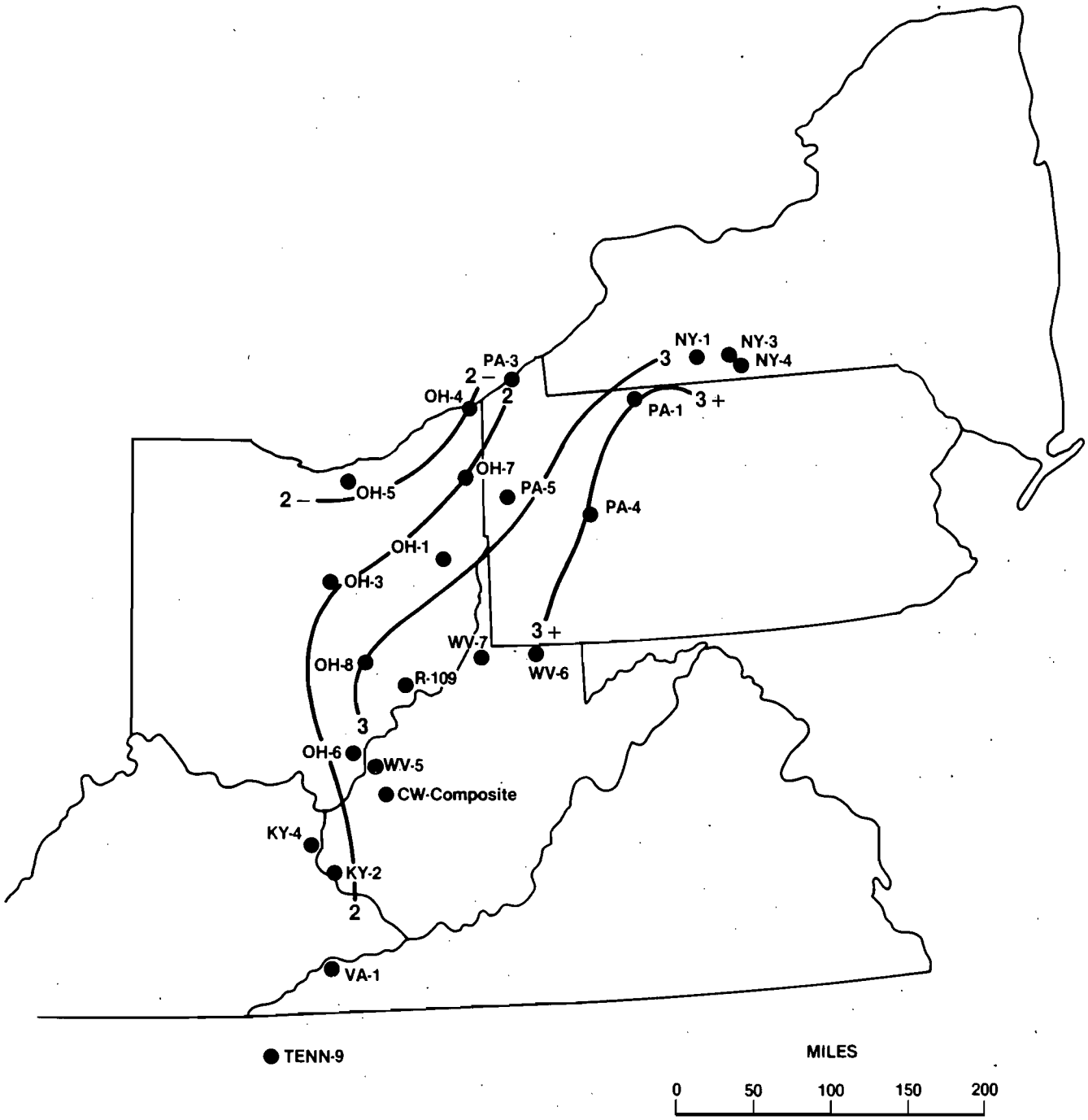


FIGURE 52

SONYEA / MIDDLESEX TIME

MAP UNIT 5

MOUND

Prepared by Mound Facility

THERMAL ALTERATION INDEX PROFILES

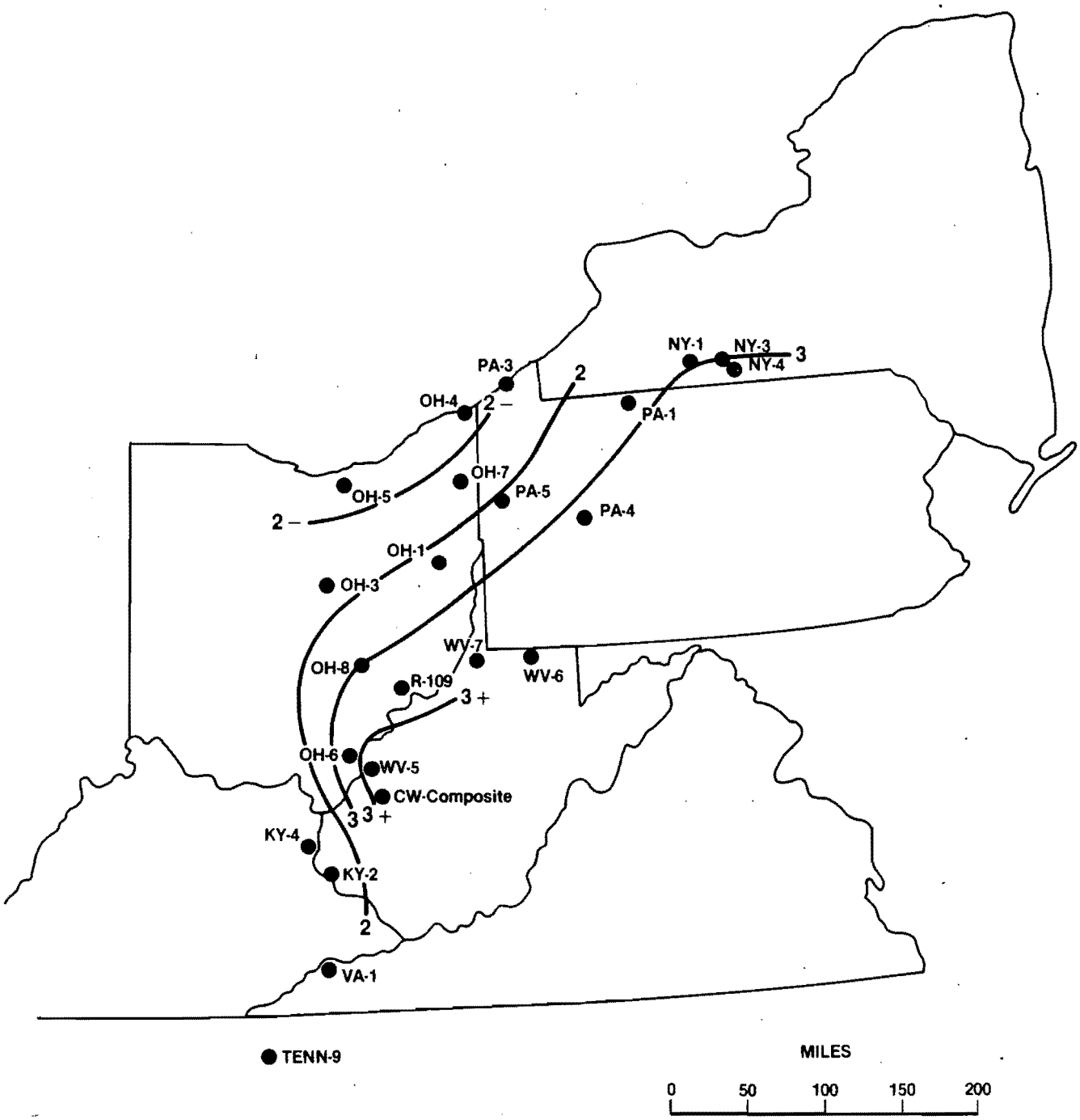


FIGURE 53

EARLY LOWER OLENTANGY THROUGH HANOVER SHALE TIME

MAP UNITS 6 THROUGH 9

MOUND

Prepared by Mound Facility

THERMAL ALTERATION INDEX PROFILES

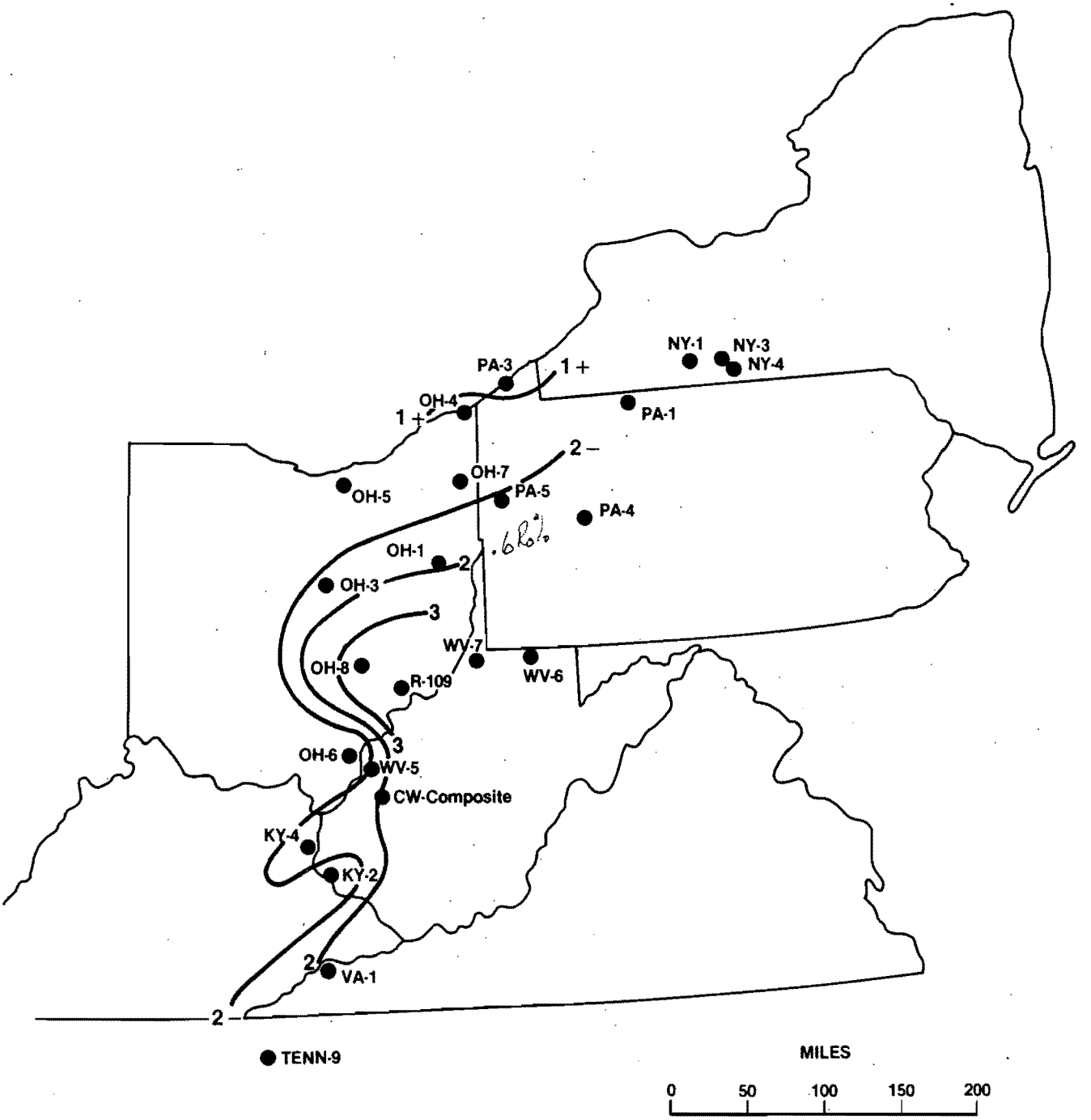


FIGURE 54

EARLY LOWER HURON THROUGH LATE MIDDLE HURON TIME

MAP UNITS 10 THROUGH 13

MOUND

Prepared by Mound Facility

THERMAL ALTERATION INDEX PROFILES

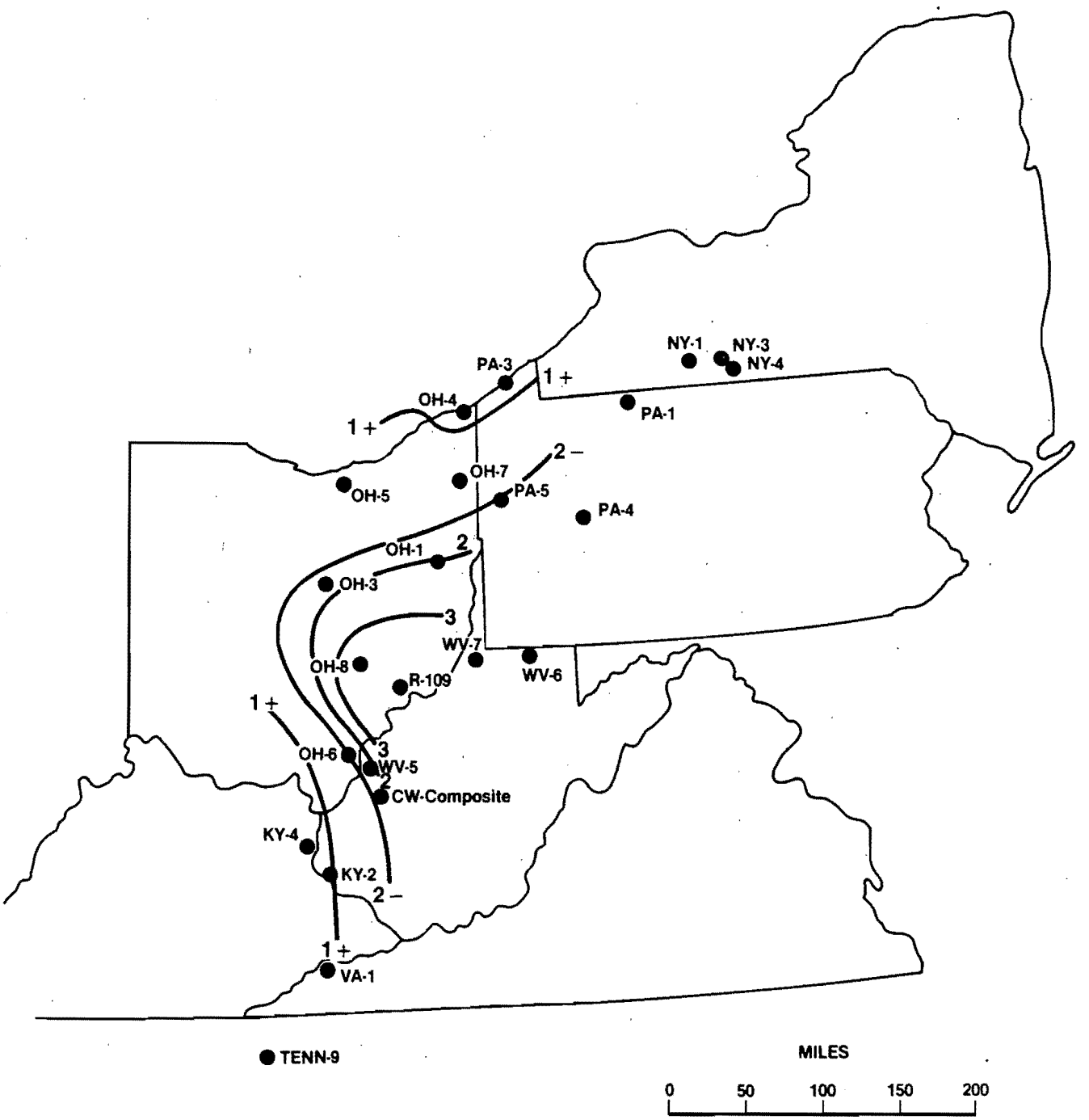


FIGURE 55

EARLY UPPER HURON THROUGH CLEVELAND TIME

MAP UNITS 14 THROUGH 17

MOUND

Prepared by Mound Facility

can only be considered poor to fair sources of gas, and much of this may be microbially, not thermally, produced.

Source shales located in the areas where TAI's are between 2 and 3+ are in the optimum range for hydrocarbon generation, and this will be reflected in the hydrocarbon potential maps that will be presented later. Rocks exposed to temperatures such that their TAI's are 3+ or greater, are considered too mature. Most of their hydrocarbon has probably been dissipated or destroyed.

Regional Hydrocarbon Source Potential

Geochemical Source Quality Maps

The next step of the assessment was to combine the data on the organic carbon content, the biofacies (organic) type, and the thermal alteration index into a rating system that showed the relative source character of each of the seventeen study intervals as well as for the Appalachian Basin as a whole. This then was combined with the thickness of each unit to give the source potential of each unit, and a combined potential for the entire Upper Devonian.

For this purpose an arbitrary rating system, shown in Table 1, was set up. In this chart, relative ratings of source and potential were assigned to various combinations of organic carbon contents and thermal alteration indices. The absolute values were based on petroleum geochemical considerations, biased somewhat by the observation that in this basin, the low permeability Devonian shales apparently retain most of the gas that they generate, and because of this, maximum generation of hydrocarbons, and particularly of liquid hydrocarbons (oil), is held back until higher temperatures are reached (i.e., at higher alteration indices).

The qualifying footnotes at the bottom of the Table are based on the facts that algal and amorphous kerogens begin to crack at lower temperatures than terrestrial organic matter, and that algal and amorphous kerogen gives up more hydrocarbon liquids (oil or condensate) than does the terrestrial types.

The set of source quality maps, Figures 56 through 72, were derived by first cross plotting TAI against organic carbon content to obtain a relative numerical ranking in each small uniform field (outlined area) on the map. This map was then superimposed on the biofacies map of the same interval, and the qualifying statements at the bottom of Table 1 were used to label the relative nature of the hydrocarbon expected from the kerogen in each field.

It is very important to note that the numerical values shown on this first set of maps is the potential per unit volume of sediment. Even with a very high relative potential, a ten foot section of rock would not produce enough hydrocarbons to be of commerial interest. On the other hand, a thick (e.g., 100 foot) section of rock with good relative quality could source commerical quantities of hydrocarbon. These maps are included to show the geochemical character of each of the units - a parameter that will be combined with thickness to produce exploration source potential maps later in this report.

Figure 56 shows the hydrocarbon source quality of the shale in Early Marcellus time. The rock is an excellent oil and gas source in many parts of the basin, particularly along a band extending from the boundary between West Virginia and Pennsylvania, along the Ohio-Pennsylvania border, to southwestern New York. Unfortunately, as will be shown later, the unit is relatively thin, so it does not have the exploration potential of other leaner but thicker units.

TABLE 1
RELATIVE SOURCE ROCK RATING OF DEVONIAN SHALES

Organic Carbon Content (percent)	THERMAL ALTERATION INDEX 1+ to 2	2 to 3	3 – 4	4 – 5
0–1	0	0	0	0
1–2	1	1	2	0
2–3	1	2	4	0
3–4	2	4	7	0
4+	2	6	10	0

0 - Little Potential

1 - Good Gas Potential only if organic matter is Tasmanites or Marine

2 - Excellent Gas Potential if OM is Tasmanites or Marine; Good Gas Potential if OM is Terrestrial

4 - Good Oil and Gas Potential if OM is Tasmanites or Marine; Good Gas Potential if OM is Terrestrial

6-7 - Excellent Oil and Gas Potential if OM is Tasmanites or Marine; Good Oil and Gas Potential if OM is Terrestrial

10 - Exceptional Oil and Gas Potential

OIL AND GAS SOURCE ROCK POTENTIAL

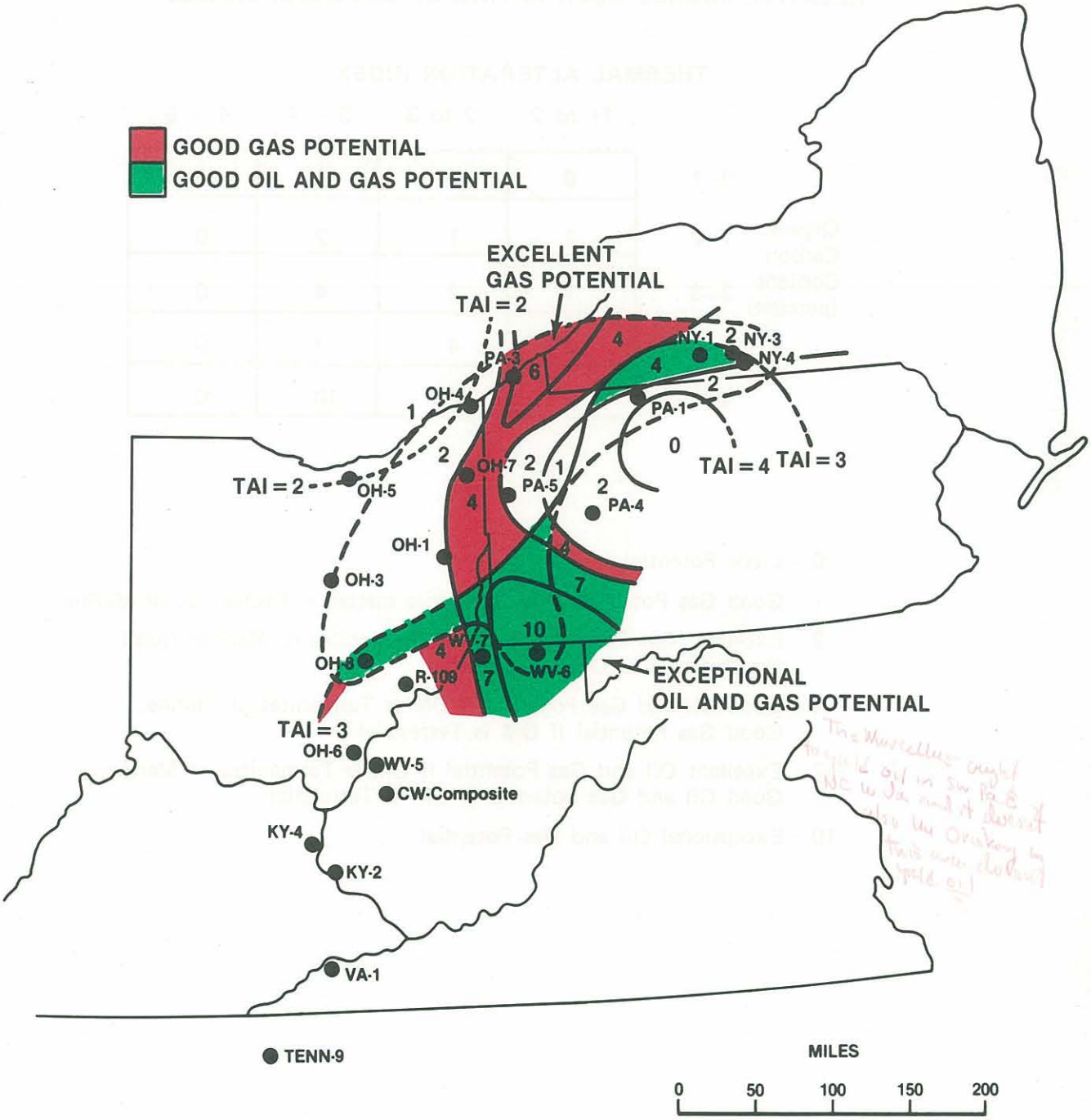


FIGURE 56

EARLY MARCELLUS TIME

MAP UNIT 1

MOUND

Prepared by Mound Facility

The upper Marcellus unit (Figure 57) also has an area of good source quality for oil and gas, but it is further southwest than in the unit below. The good source rocks are situated in a triangle whose apices are in north-central Ohio, south-central Ohio, and southwestern Pennsylvania. The exploration potential of this unit, too, is diminished because it is relatively thin over much of the basin.

The Hamilton Group and its equivalents generally have poor source rock as shown in Figure 58. The Genesee/Geneseo Group, Figure 59, and their equivalents have a thin meandering belt of good sources extending from northern West Virginia to southwestern New York.

The Sonyea/Middlesex unit and its equivalents shown in Figure 60 have two areas of good source quality - one small one in northwestern Pennsylvania and another in south-central Ohio.

The early Rhinestreet rocks shown in Figure 61 have excellent source quality in many parts of the basin, e.g. in northeastern Ohio and northwestern Pennsylvania, in southwestern Pennsylvania, along the Ohio-West Virginia boundary, and in the area of TENN - 9. The upper part of the Rhinestreet (Figure 62) has good-to-excellent source quality along a thin band stretching from TENN - 9 almost to OH - 4 and PA - 3.

The Middle Olentangy unit (Figure 63) is characterized as a poor source interval, as is the Upper Olentangy shale (Figure 64), except for one point, which must be suspect, in the area of OH - 3.

Figure 65 shows that the early Lower Huron shales have good-to-excellent source quality in central and southeastern Ohio and western West Virginia southward to Tennessee. The later Lower Huron shales also have somewhat poorer, but still good, potential in roughly the same areas as shown in Figure 66.

Middle Huron shales (Figures 67 and 68) have poorer source quality than the Huron shales above and below. The Upper Huron shales (Figures 69 and 70) have an area of good source rocks in southeastern Ohio. The Chagrin shale (Figure 71) has poor source quality.

Figure 72 shows that the Cleveland has good source rocks for gas generation in central Ohio, and for gas and oil further southeast in Ohio.

Next, to show overall source quality for gas and for oil in the basin, the numerical rating from each of the areas for each of the seventeen maps was transferred to a grid with lines spaced about 9 miles apart both north-south and east-west. The values at each grid coordinate on each map were totaled with those at the same grid point on all the other maps, and the total was placed on similar grid for the entire Upper Devonian section. This process was done individually for each grid point in an area identified as having gas potential, and again for each grid point in any area identified as having oil potential. The data on the composite grids were contoured, and the absolute values reduced by a factor of ten, to produce the two overall source quality maps shown in Figures 73 and 74.

OIL AND GAS SOURCE ROCK POTENTIAL

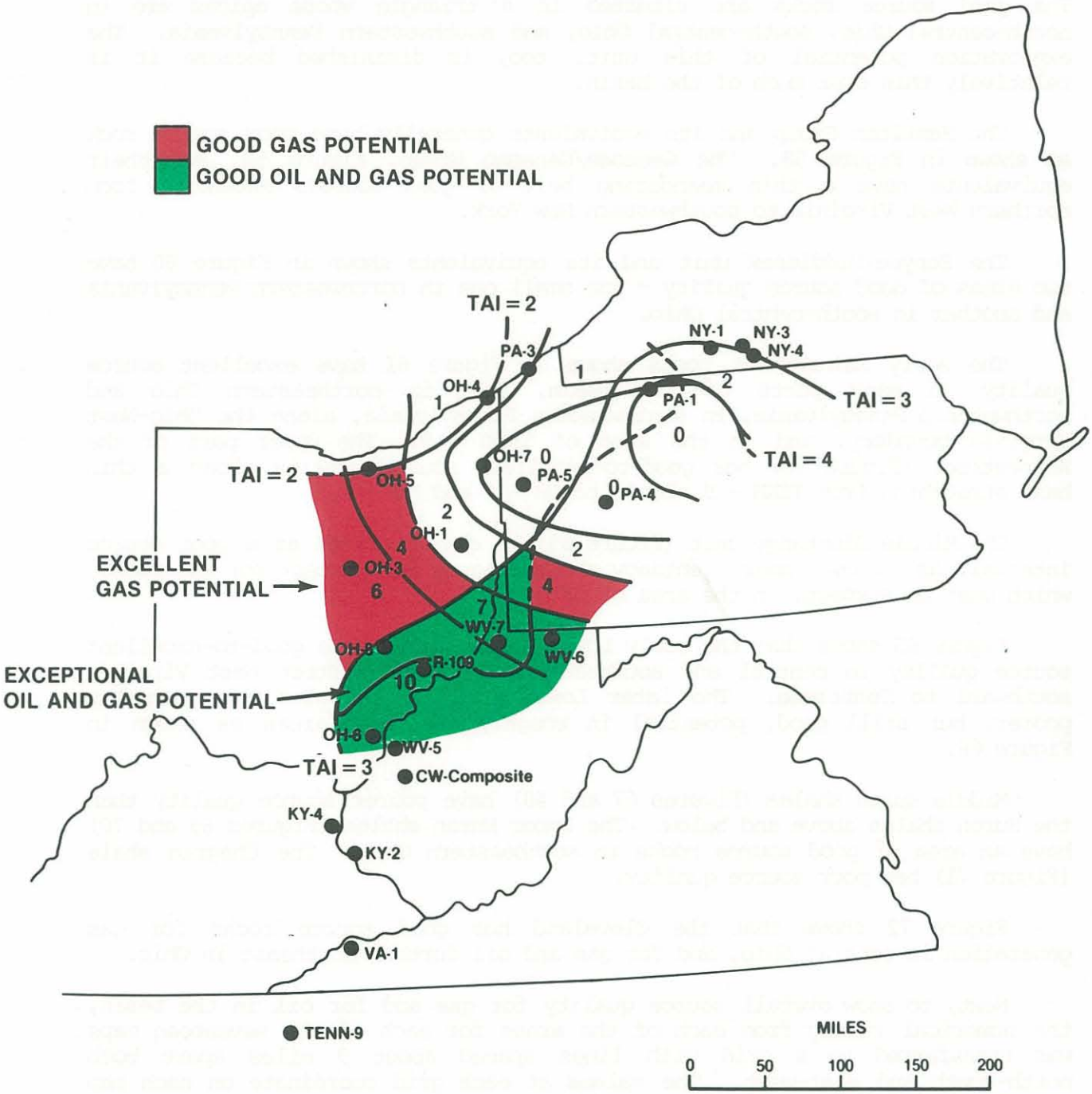


FIGURE 57

LATE MARCELLUS TIME

MAP UNIT 2

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

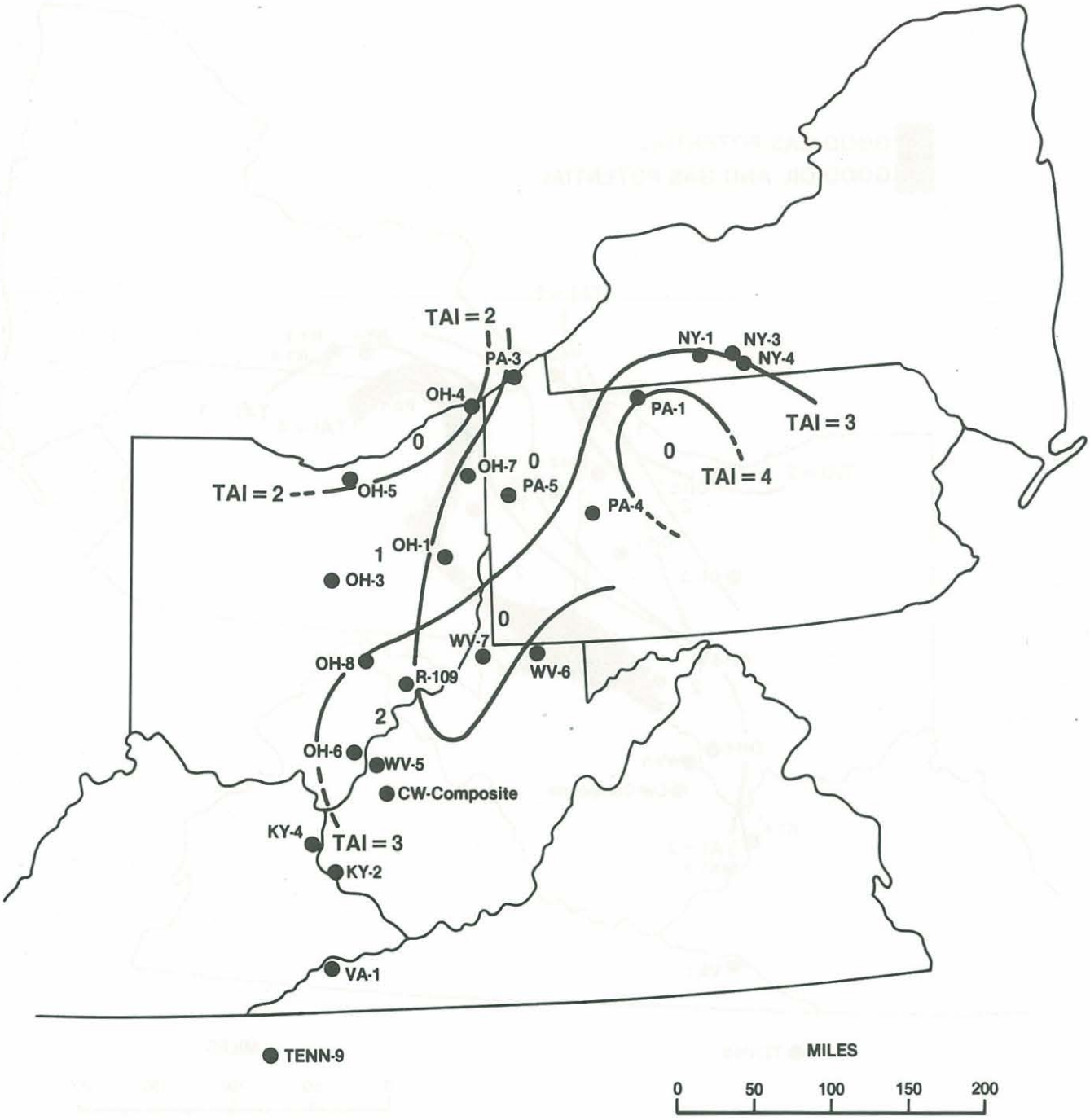


FIGURE 58

HAMILTON GROUP / POST-MARCELLUS TIME

MAP UNIT 3

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

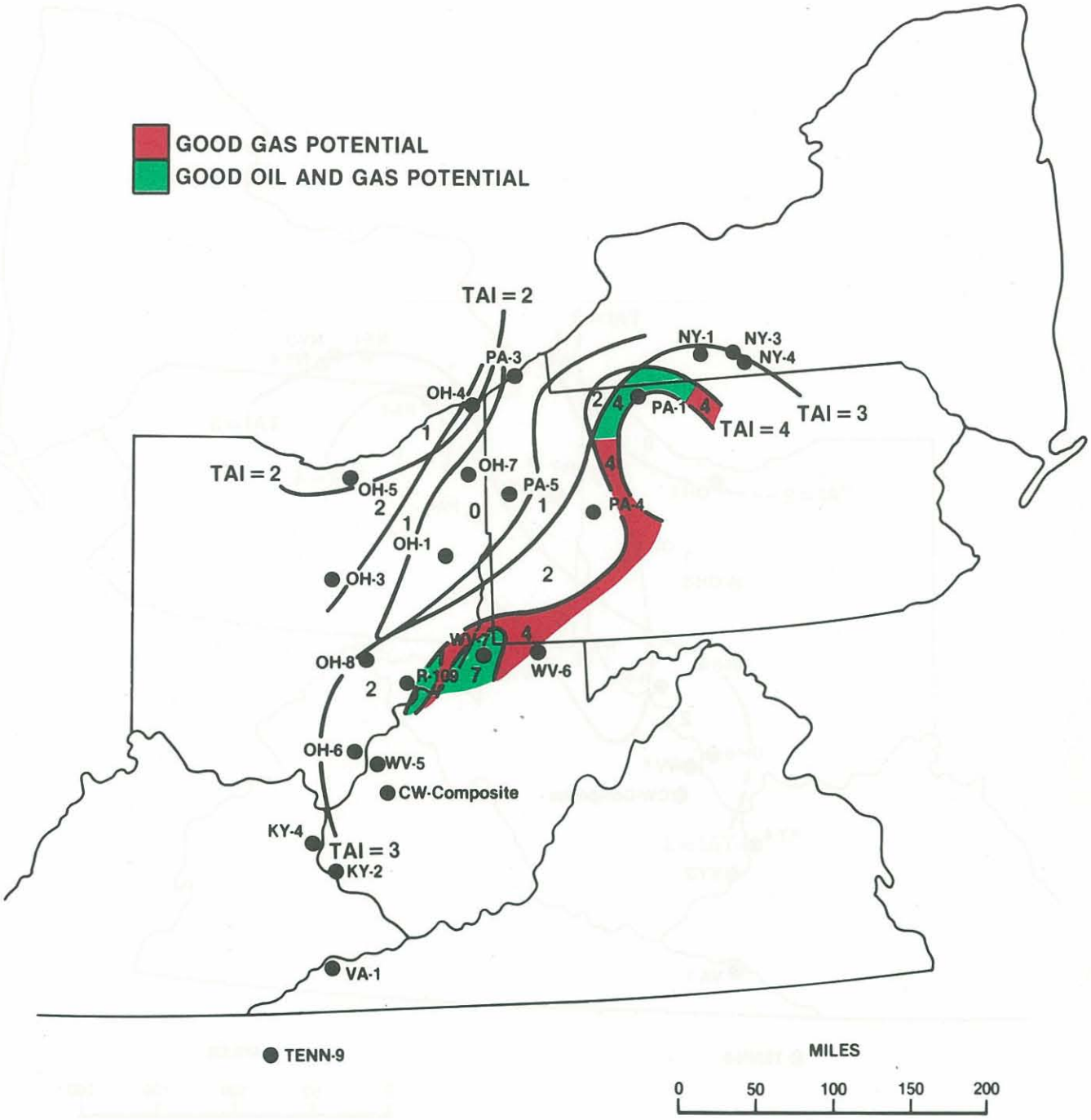


FIGURE 59

GENESEE / GENESEO TIME

MAP UNIT 4

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

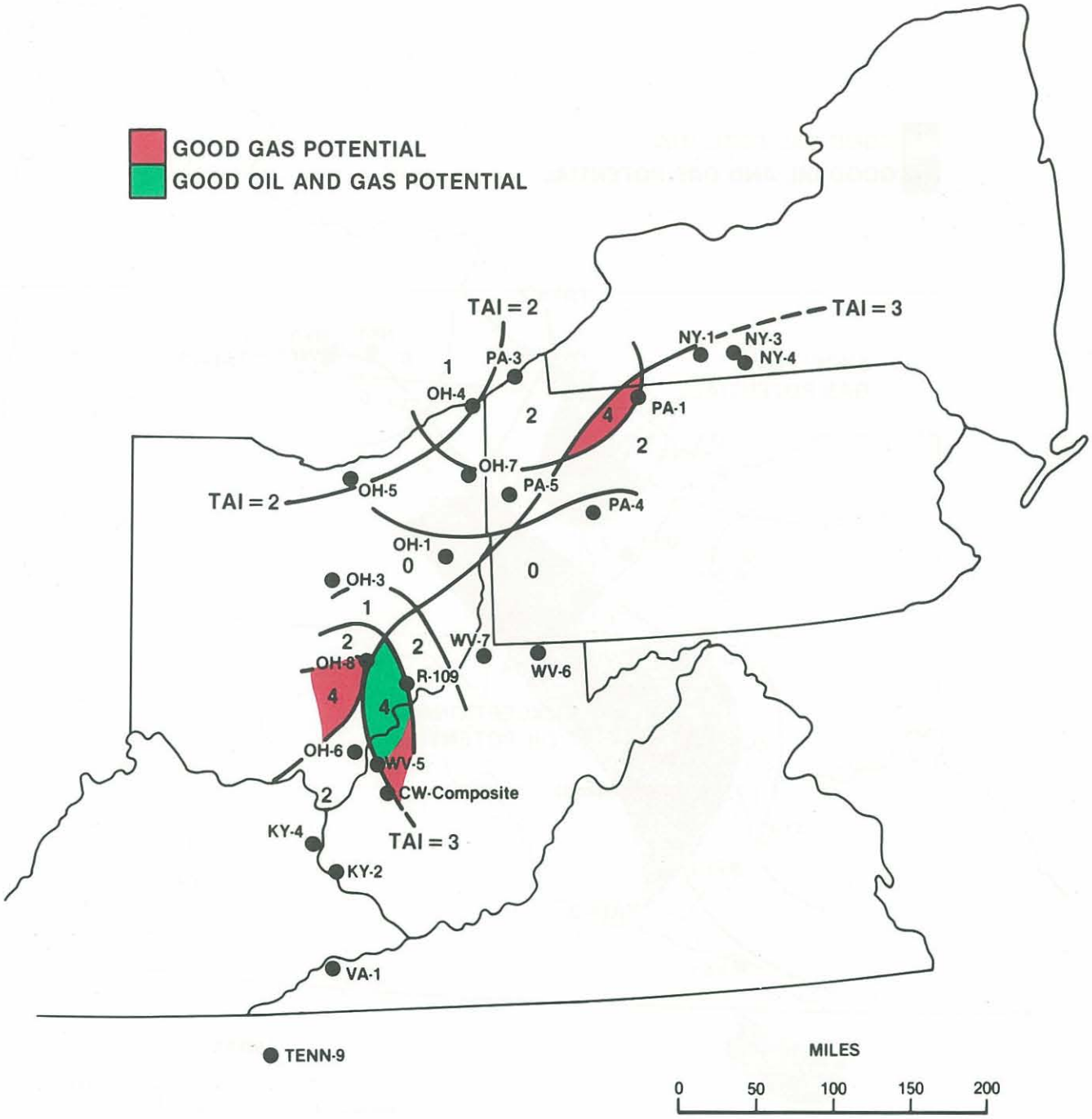


FIGURE 60

SONYEA / MIDDLESEX TIME

MAP UNIT 5

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

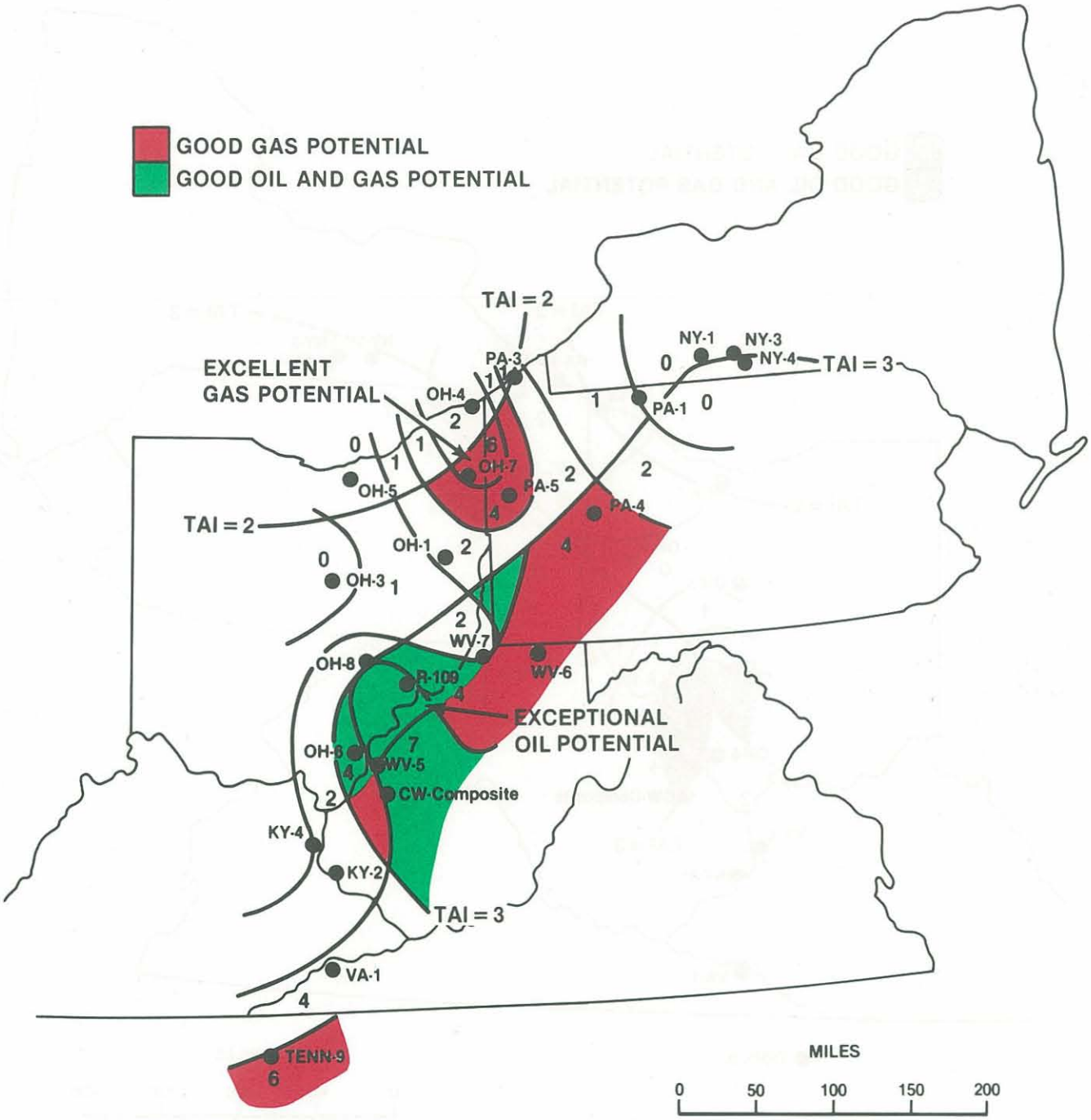


FIGURE 61

EARLY LOWER OLENTANGY / EARLY RHINESTREET TIME

MAP UNIT 6

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

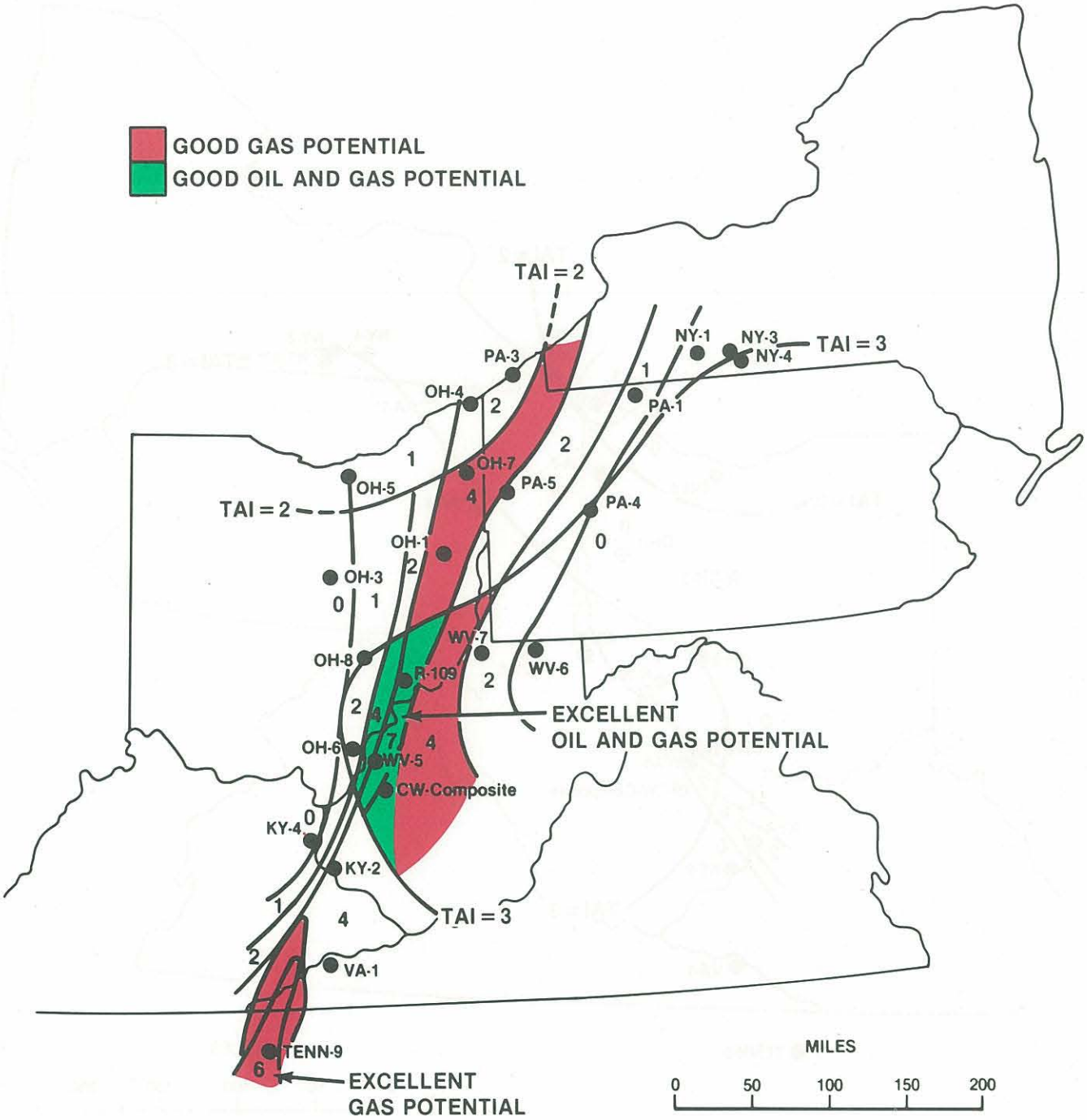


FIGURE 62

LATE LOWER OLENTANGY / LATE RHINESTREET TIME

MAP UNIT 7

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

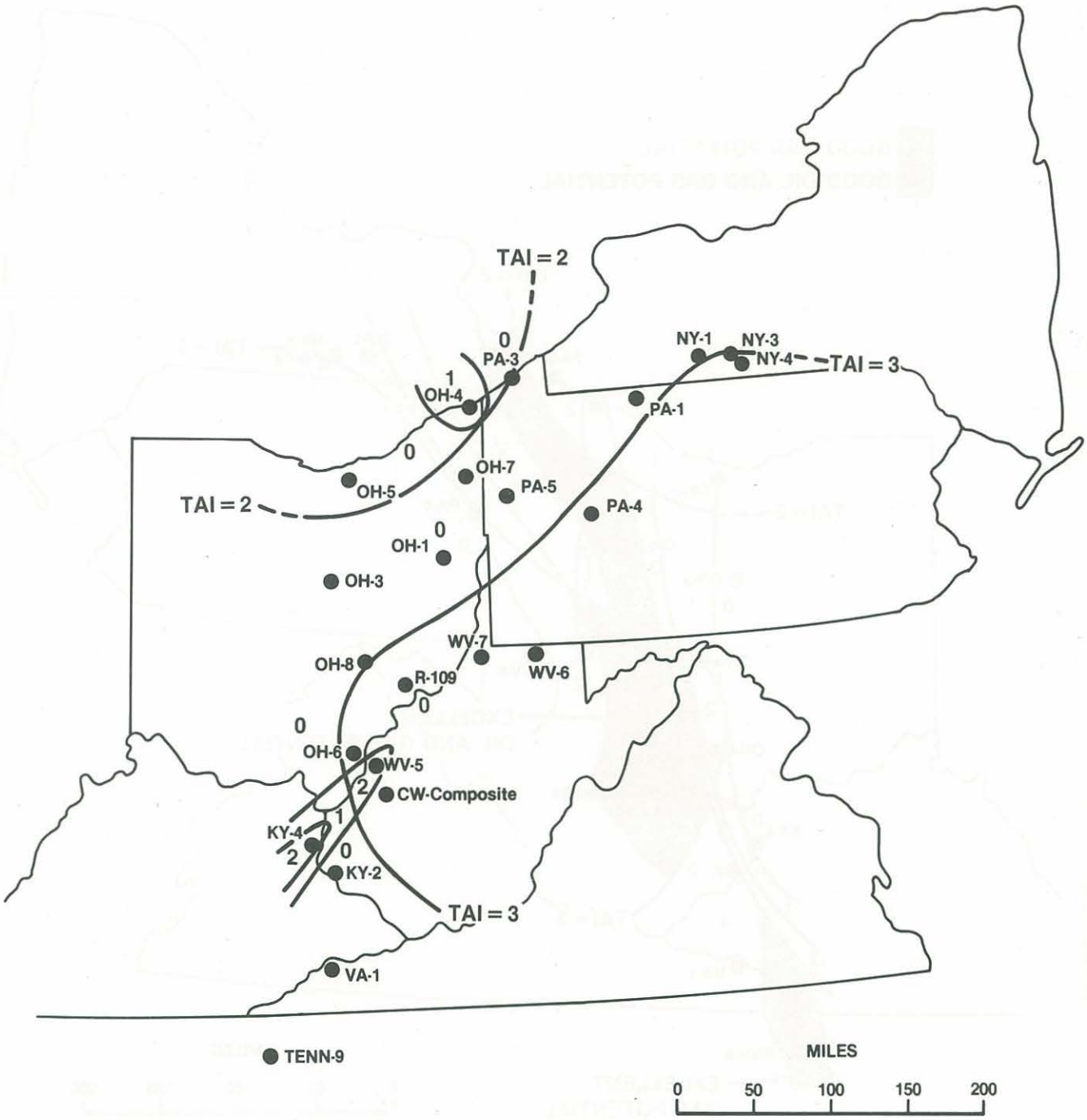


FIGURE 63

MIDDLE OLENTANGY / ANGOLA SHALE TIME

MAP UNIT 8

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

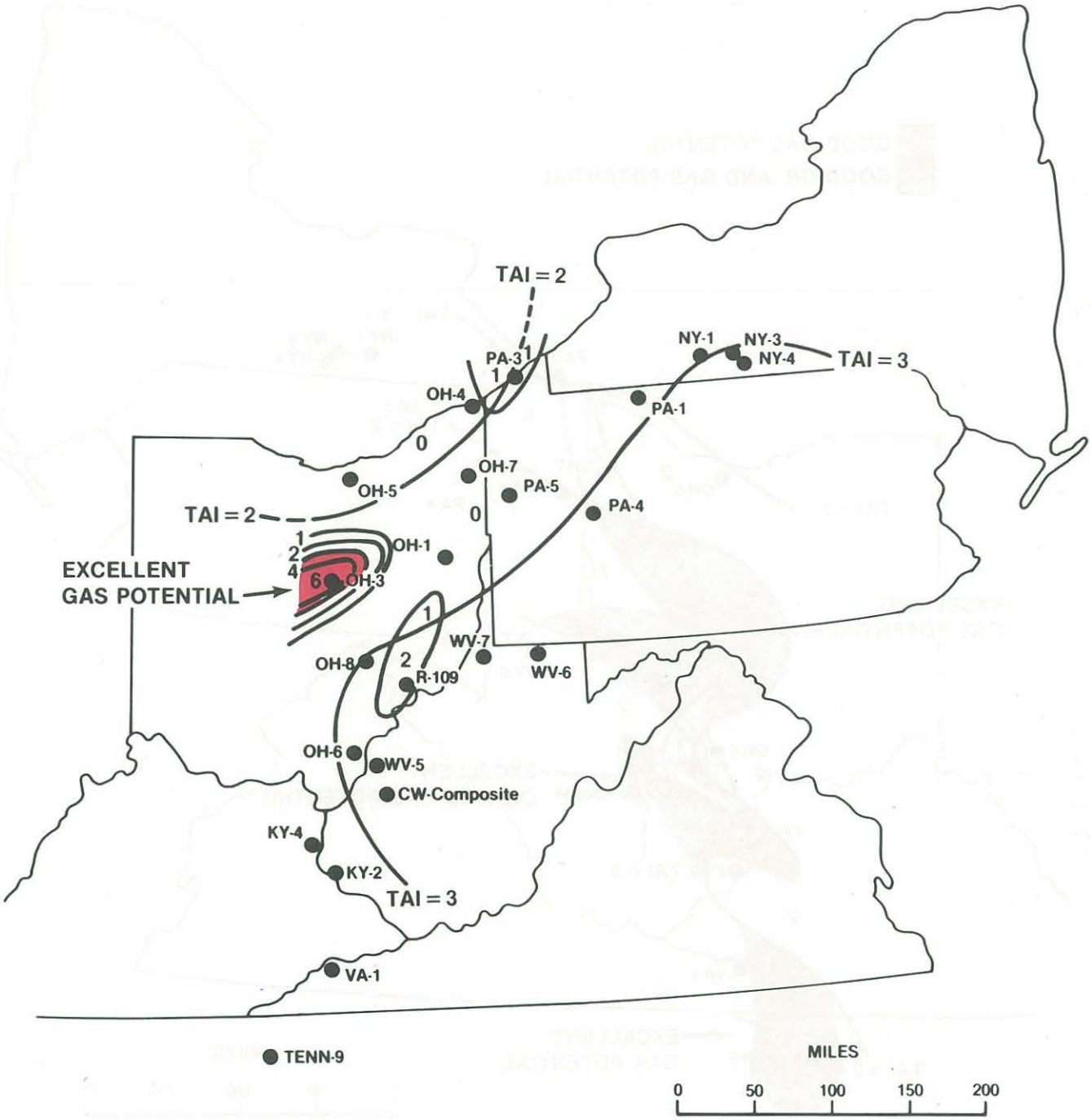


FIGURE 64

UPPER OLENTANGY / JAVA FM. HANOVER SHALE TIME

MAP UNIT 9

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

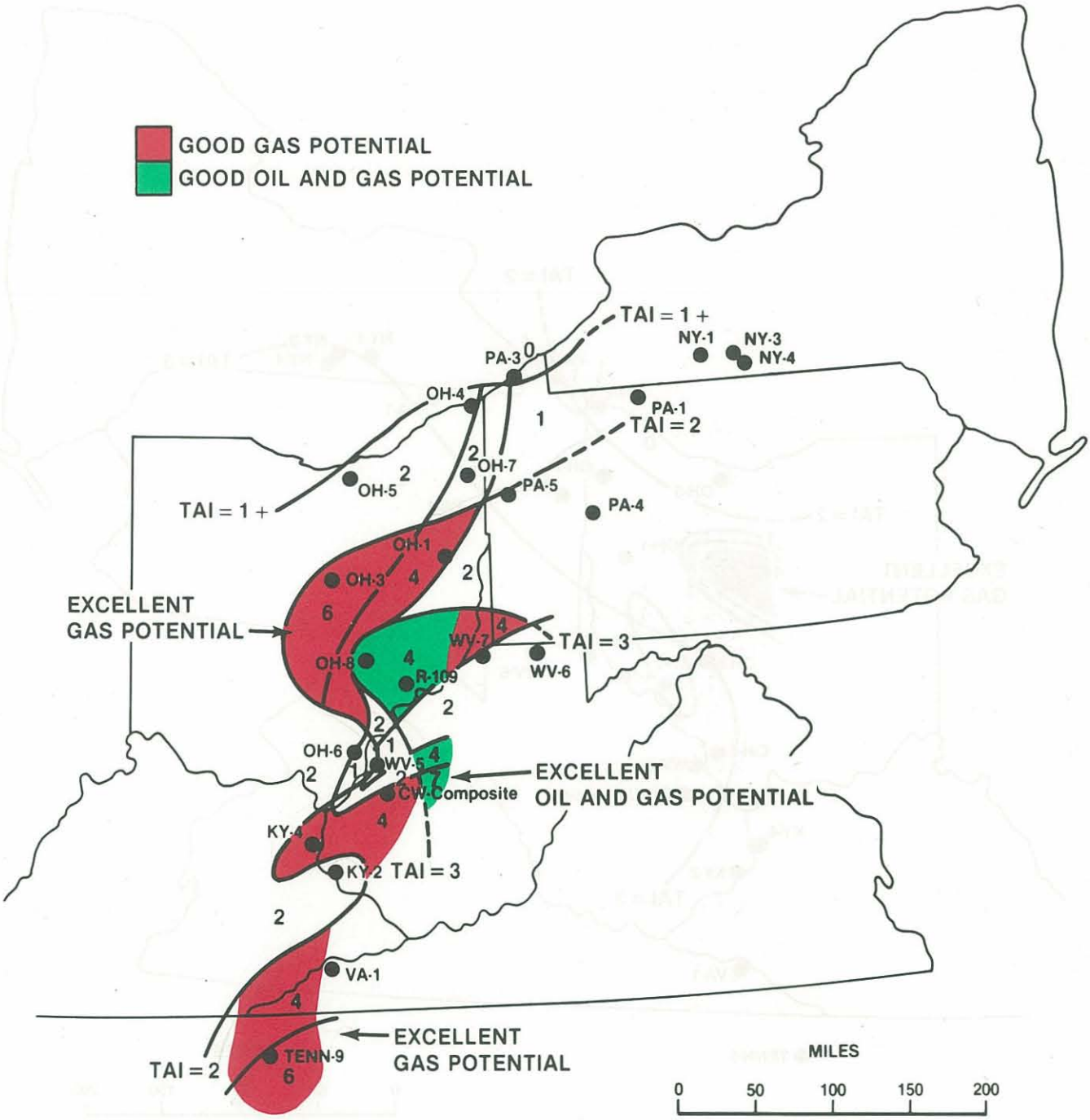


FIGURE 65

EARLY LOWER HURON / EARLY DUNKIRK TIME

MAP UNIT 10

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

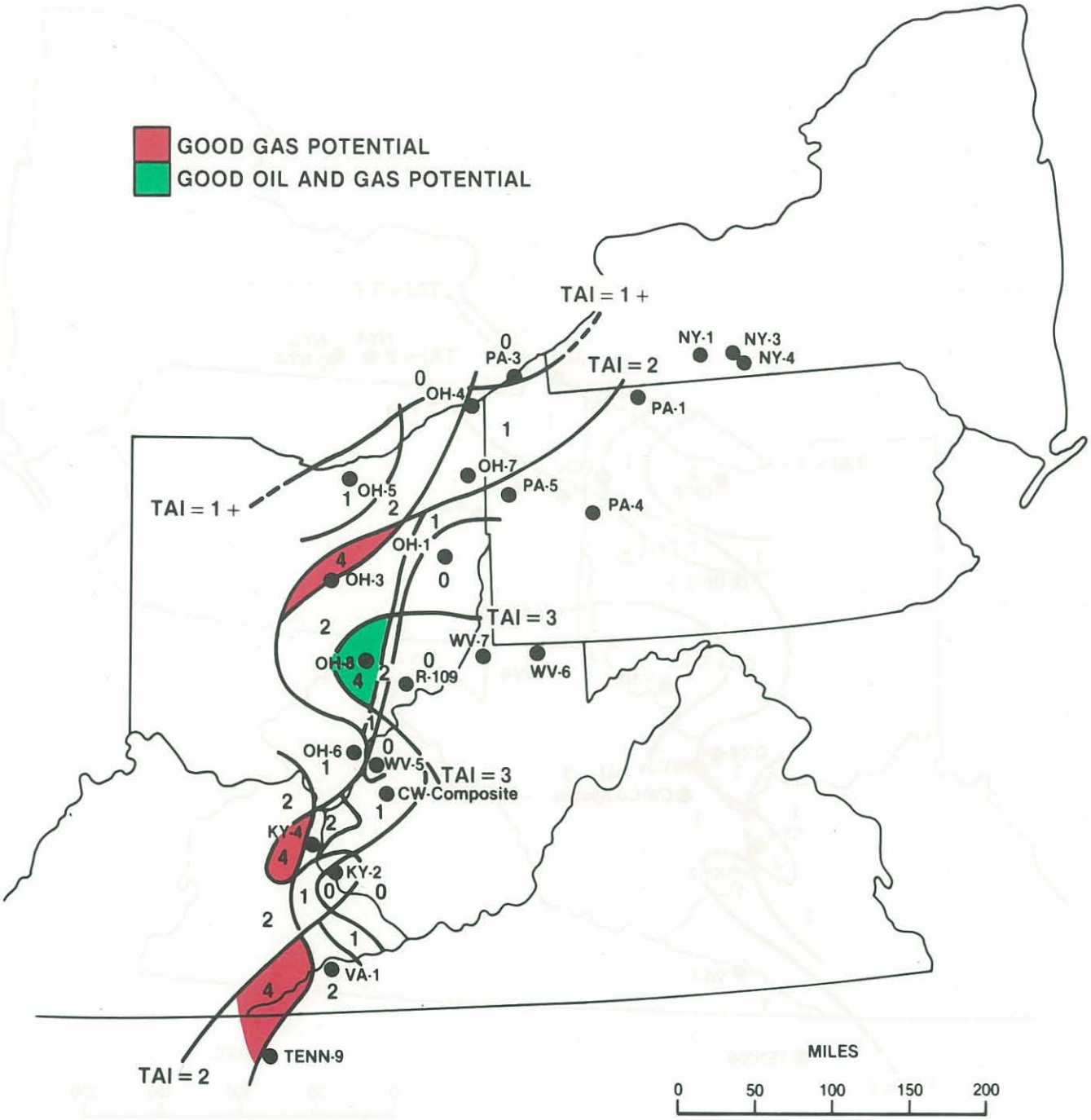


FIGURE 66

LATE LOWER HURON / LATE DUNKIRK TIME

MAP UNIT 11

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

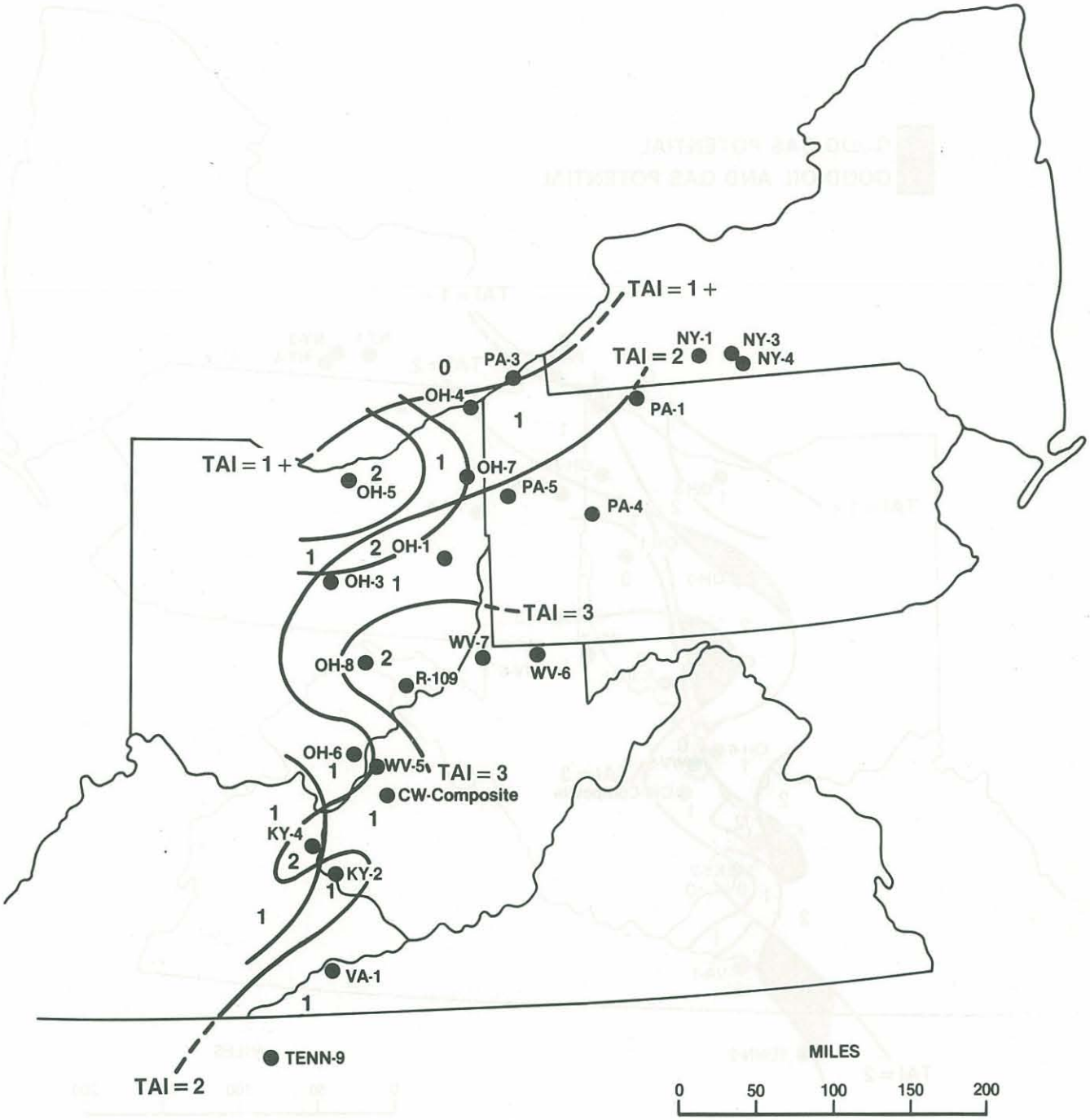


FIGURE 67

EARLY MIDDLE HURON TIME

MAP UNIT 12

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

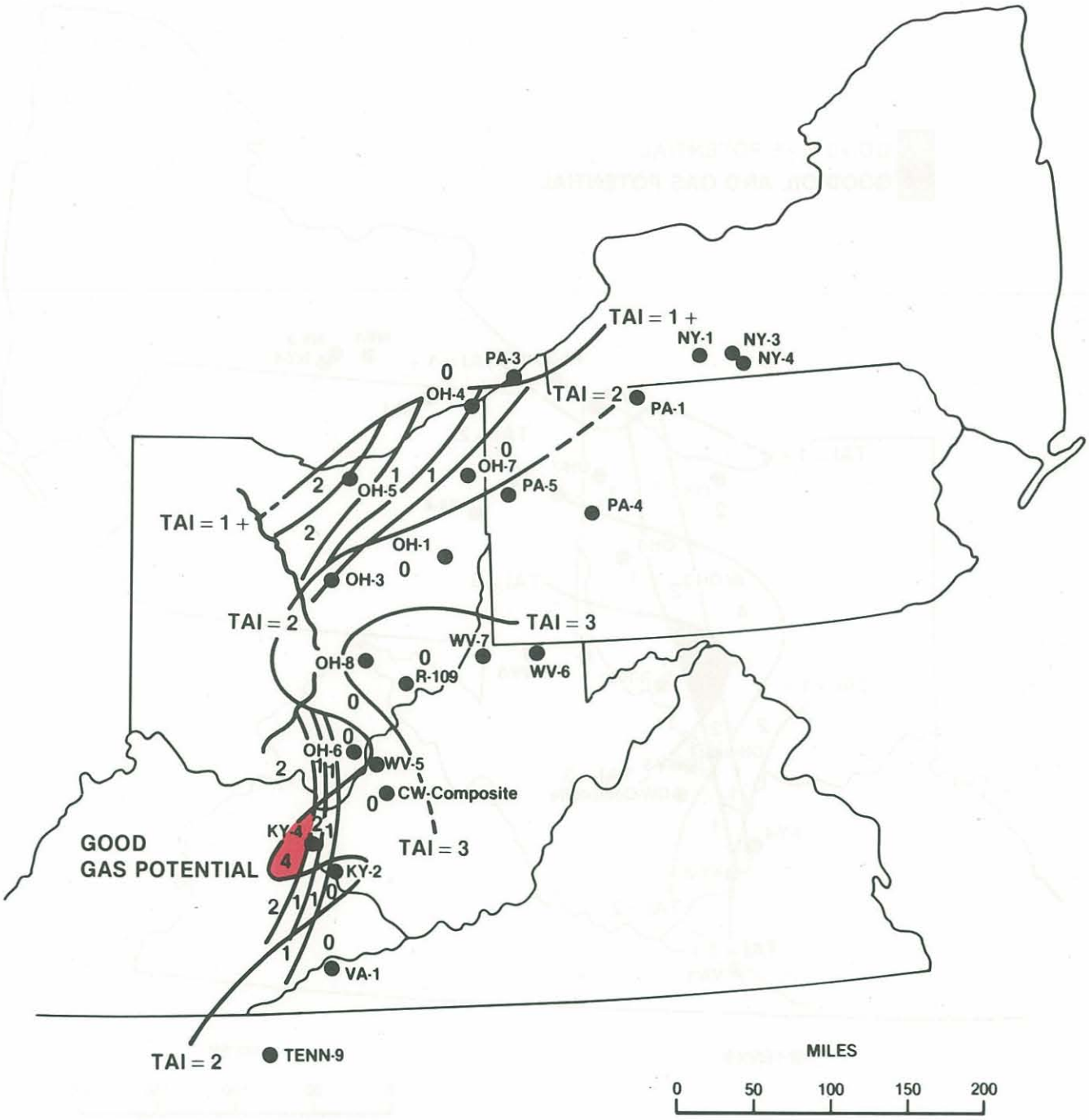


FIGURE 68

LATE MIDDLE HURON TIME

MAP UNIT 13

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

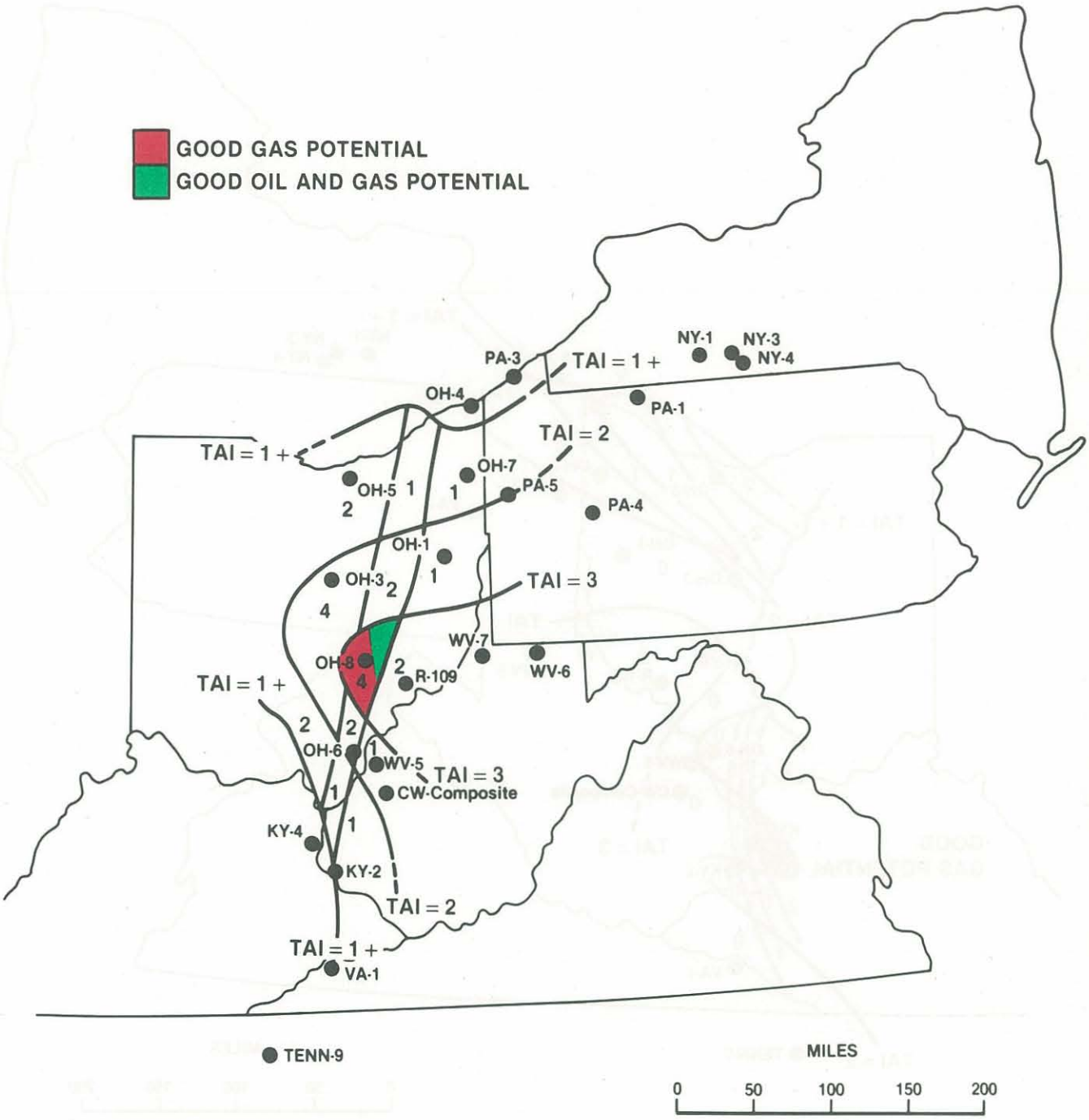


FIGURE 69

EARLY UPPER HURON TIME

MAP UNIT 14

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

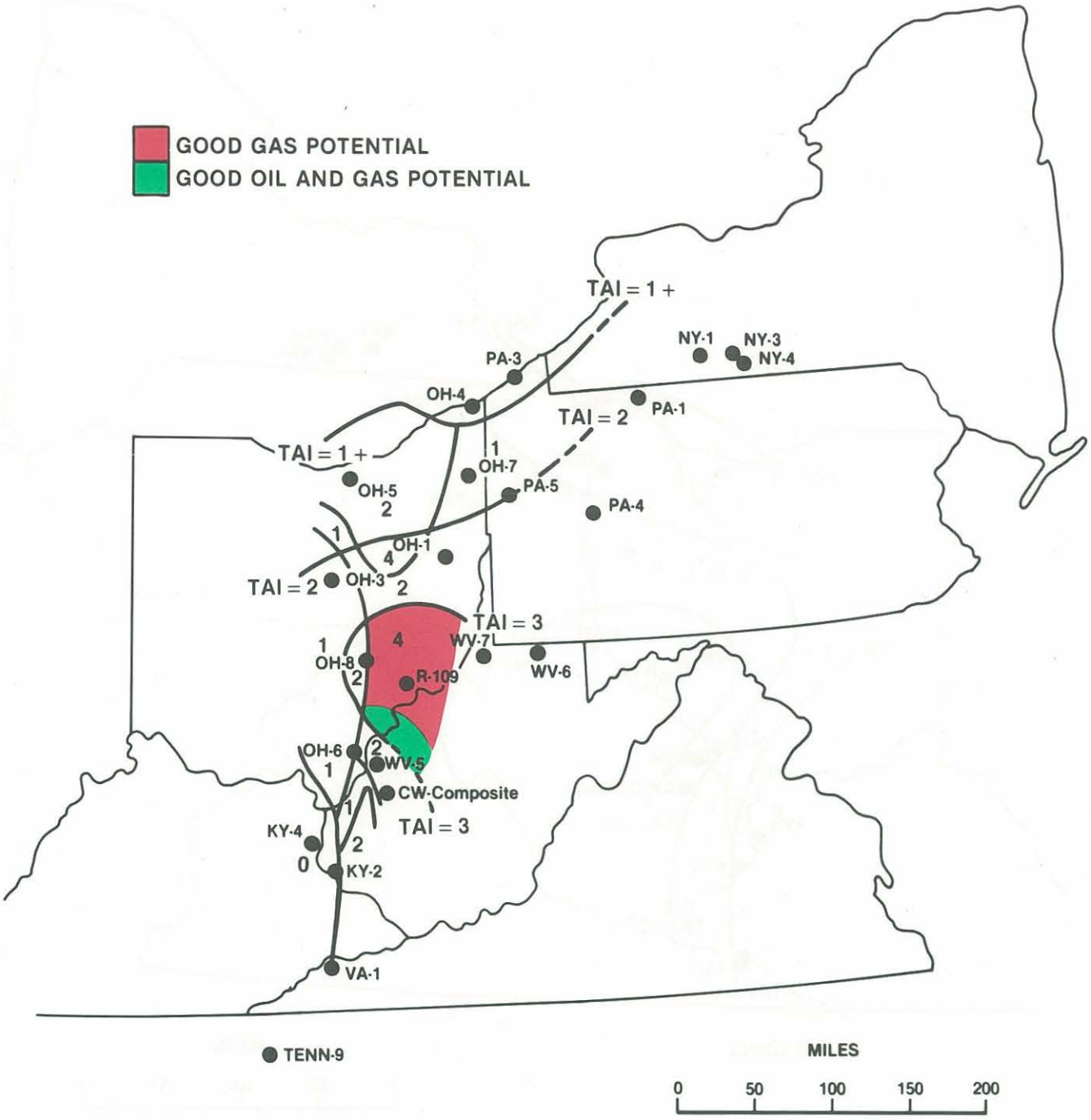


FIGURE 70

LATE UPPER HURON TIME

MAP UNIT 15

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

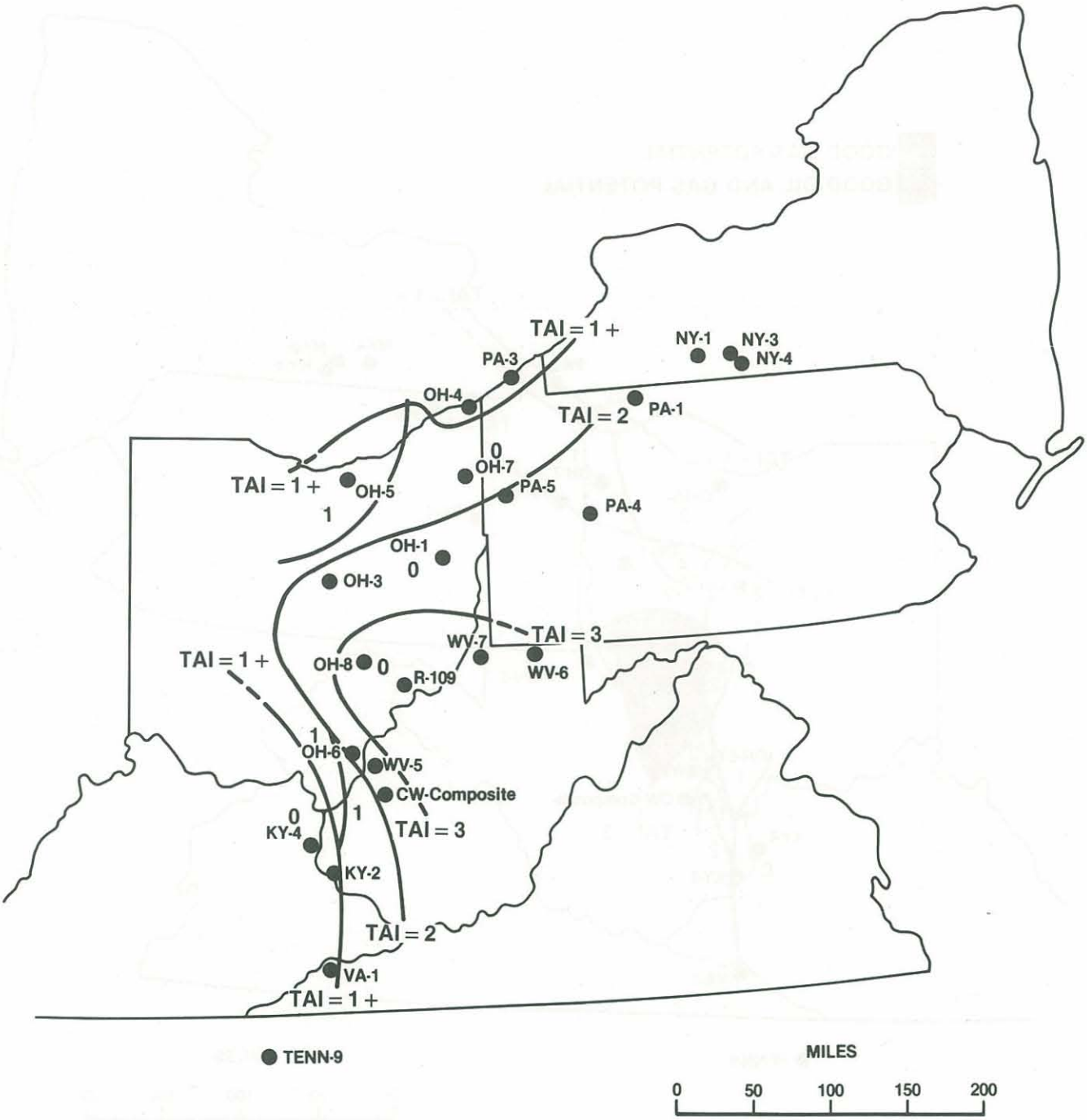


FIGURE 71

CHAGRIN TIME

MAP UNIT 16

MOUND

Prepared by Mound Facility

OIL AND GAS SOURCE ROCK POTENTIAL

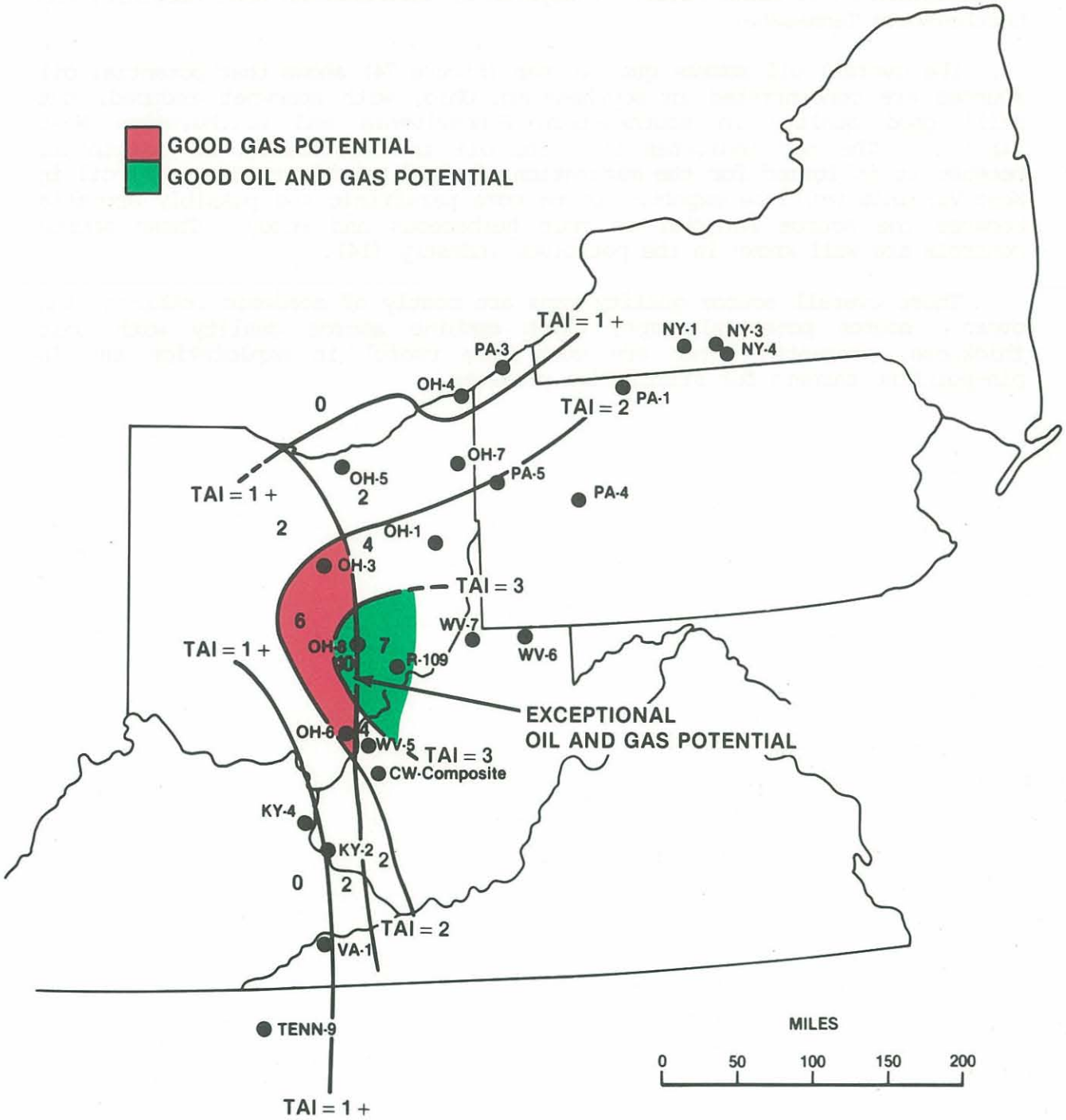


FIGURE 72

CLEVELAND TIME

MAP UNIT 17

MOUND

Prepared by Mound Facility

The overall gas source rock quality map (Figure 73) shows that, as far as source rocks of gas are concerned, the better ones are concentrated in southeastern Ohio, southwestern Pennsylvania, northeastern West Virginia, and northeastern Tennessee.

The overall oil source quality map (Figure 74) shows that potential oil sources are concentrated in southeastern Ohio, with somewhat reduced, but still good quality in southwestern Pennsylvania and northwestern West Virginia. The map indicates that the oil in Ohio should be naphthenic because it is formed for the maturation of algal organic matter. The oil in West Virginia would be expected to be more paraffinic and possibly aromatic because the source material is more herbaceous and woody. These source controls are well known in the petroleum industry (14).

These overall source quality maps are mostly of academic interest, the overall source potential maps, which combine source quality with unit thickness, presented later are much more useful in exploration and in pin-pointing targets for stimulation projects.

OVERALL GAS SOURCE ROCK POTENTIAL

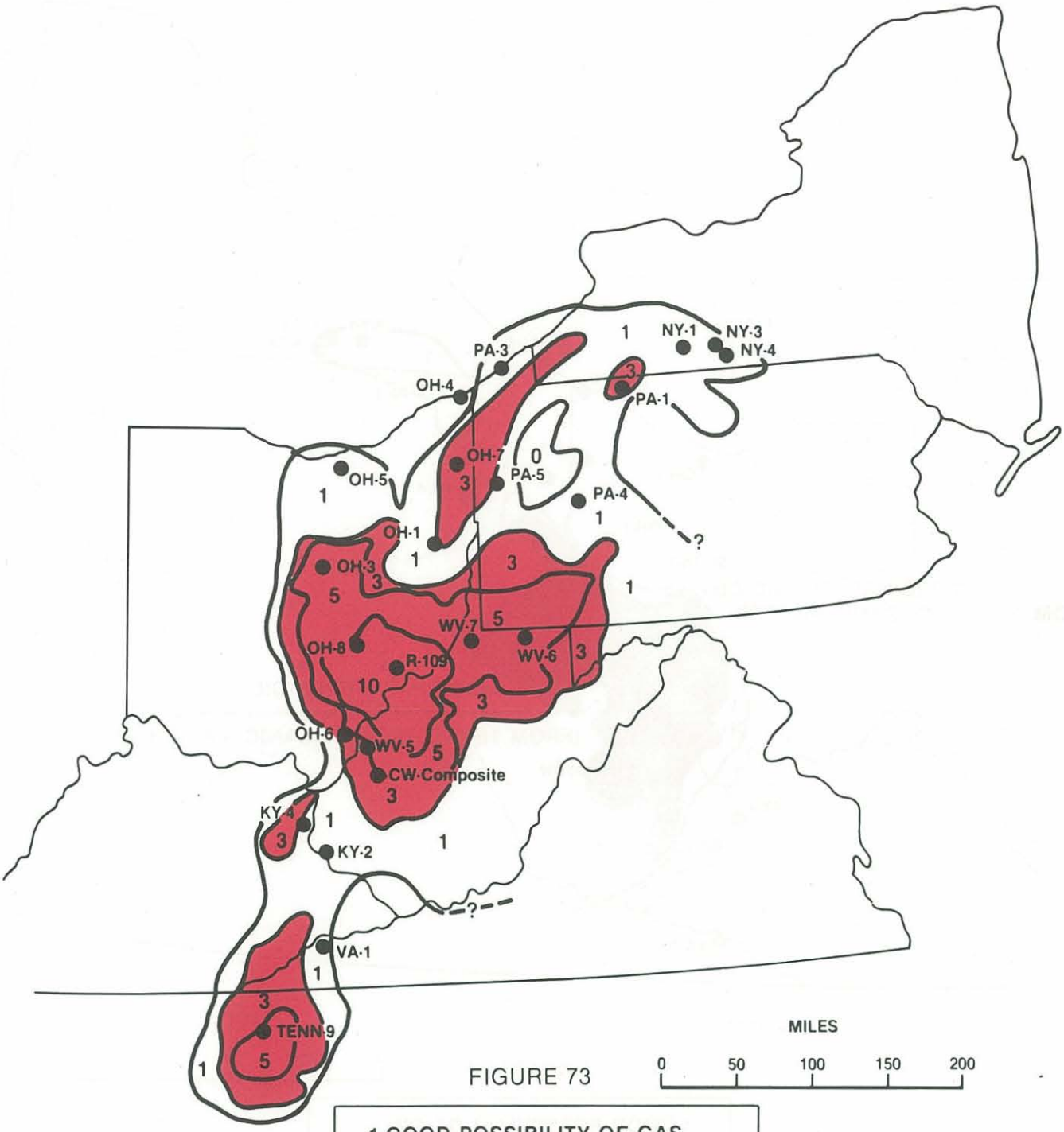


FIGURE 73

1-GOOD POSSIBILITY OF GAS FROM ONE INTERVAL

10-EXCELLENT POSSIBILITY OF GAS FROM SEVERAL INTERVALS

APPALACHIAN BASIN STUDY AREA

MOUND

Prepared by Mound Facility

OVERALL OIL SOURCE ROCK POTENTIAL

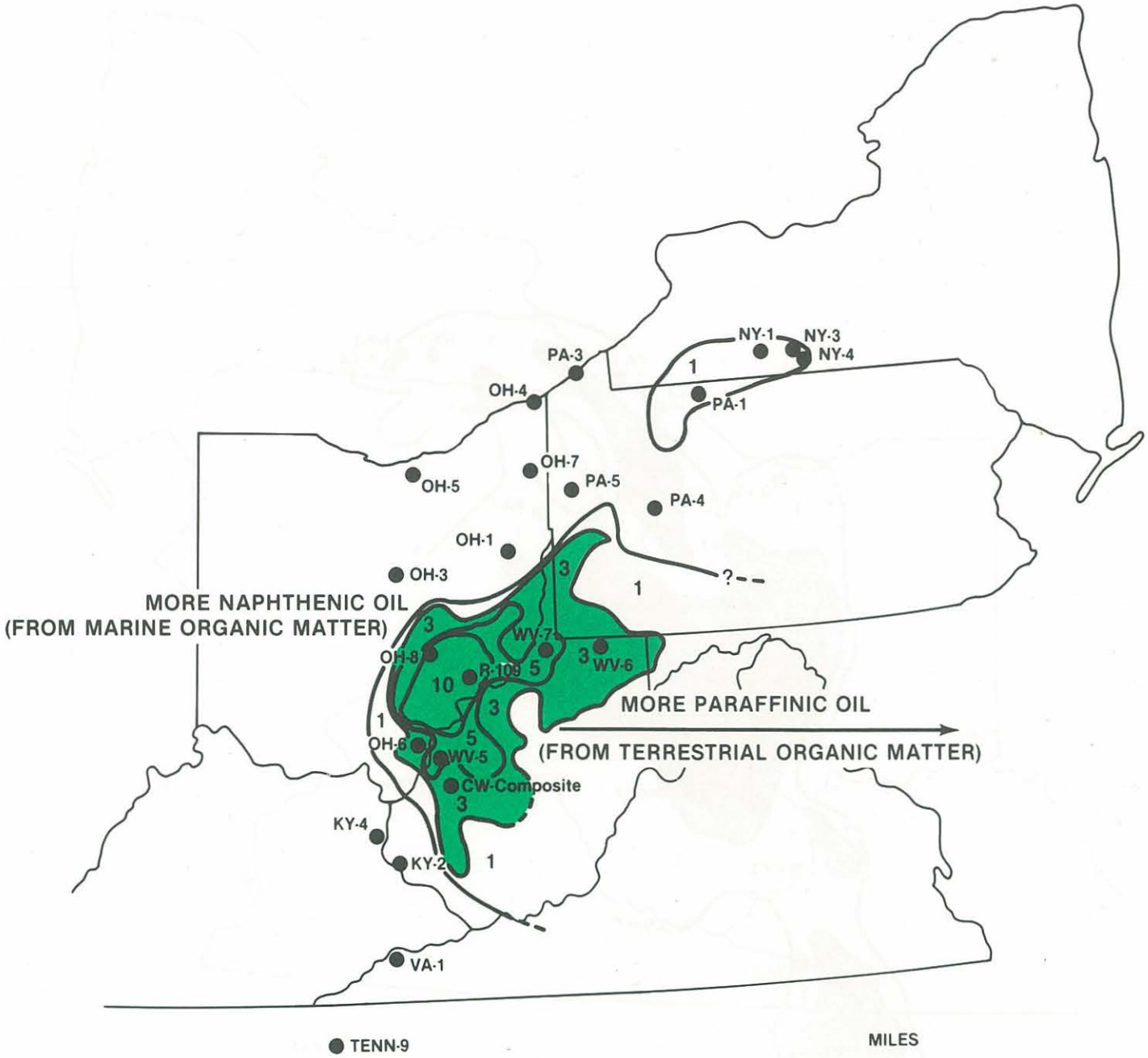


FIGURE 74

1-GOOD POSSIBILITY OF OIL FROM ONE INTERVAL

10-EXCELLENT POSSIBILITY OF OIL FROM SEVERAL INTERVALS

APPALACHIAN BASIN STUDY AREA

Geochemical Source Potential

The next step in determining the relative source potential of each unit and of the basin involved the cross plotting of the relative source quality values, shown in Figures 56 through 72, with the thickness of each unit. The numerical value of the relative source potential is the product of the source quality value for each individual unit times its thickness in feet. Thus, a very thin rock unit with exceptional source quality would not have very much potential. But a thick rock unit with only moderate source character would have an excellent potential. These maps were prepared next.

First it was necessary to construct isopach maps for the limited stratigraphic units into which the Upper Devonian was divided for this study. The stratigraphic data interpreted from well logs from each of the study wells was used, and the contours were smoothed by referring to the published isopach maps of the basin (18, 19, 20). The seventeen resulting isopach maps, the data from which were used to prepare the potential maps, are included as Figures 75 through 91.

The relative gas and oil source rock potential maps, Figures 92 through 119, show the range of the gas and oil potential ratings. Their unusual shapes and angularity are due to the fact that they are the product of cross plotting of four other maps: organic carbon distribution, biofacies distribution, thermal alteration index distribution, and unit thickness. Therefore, the precise areas and boundaries of the hydrocarbon potential fields are not important, the general locations and magnitude of the potential are.

The potential values are relative, of course, and range from less than 100 to over 1200. Therefore, there is over an order of magnitude range in the overall potential of different units to generate hydrocarbons. However, because of the anamolously high organic richness of the rocks in the Upper Devonian in the Appalachian Basin, the lower values would still be considered excellent sources in other basins of the world.

On this basis, the early Marcellus shale unit has only relatively fair (for the Upper Devonian of the Appalachian Basin, not when compared against other gas sources of the world) overall gas source potential (Figure 92) and fair oil source potential in a very limited area (Figure 93). This is the case in spite of its exceptional source quality, because it is a relatively thin unit over the entire basin. Nevertheless, there are fair possibilities for some accumulations of gas and light liquid hydrocarbons derived from this unit if reservoirs can be found within or contiguous to this source unit in the area around PA - 1 and in southwestern Pennsylvania.

The later Marcellus unit (Figure 93) has fair potential of sourcing some gas accumulations (Figure 94) and oil accumulations (Figure 95) in southwestern Pennsylvania, particularly directly south of PA - 4.

The Hamilton group (Figure 96) has relatively low potential to source commercial quantities of hydrocarbon.

The Genesee/Geneseo unit has exceptional source potential because it combines good hydrocarbon potential with thickness. Porosity accessible to

ISOPACH MAP
(Thickness in Feet)

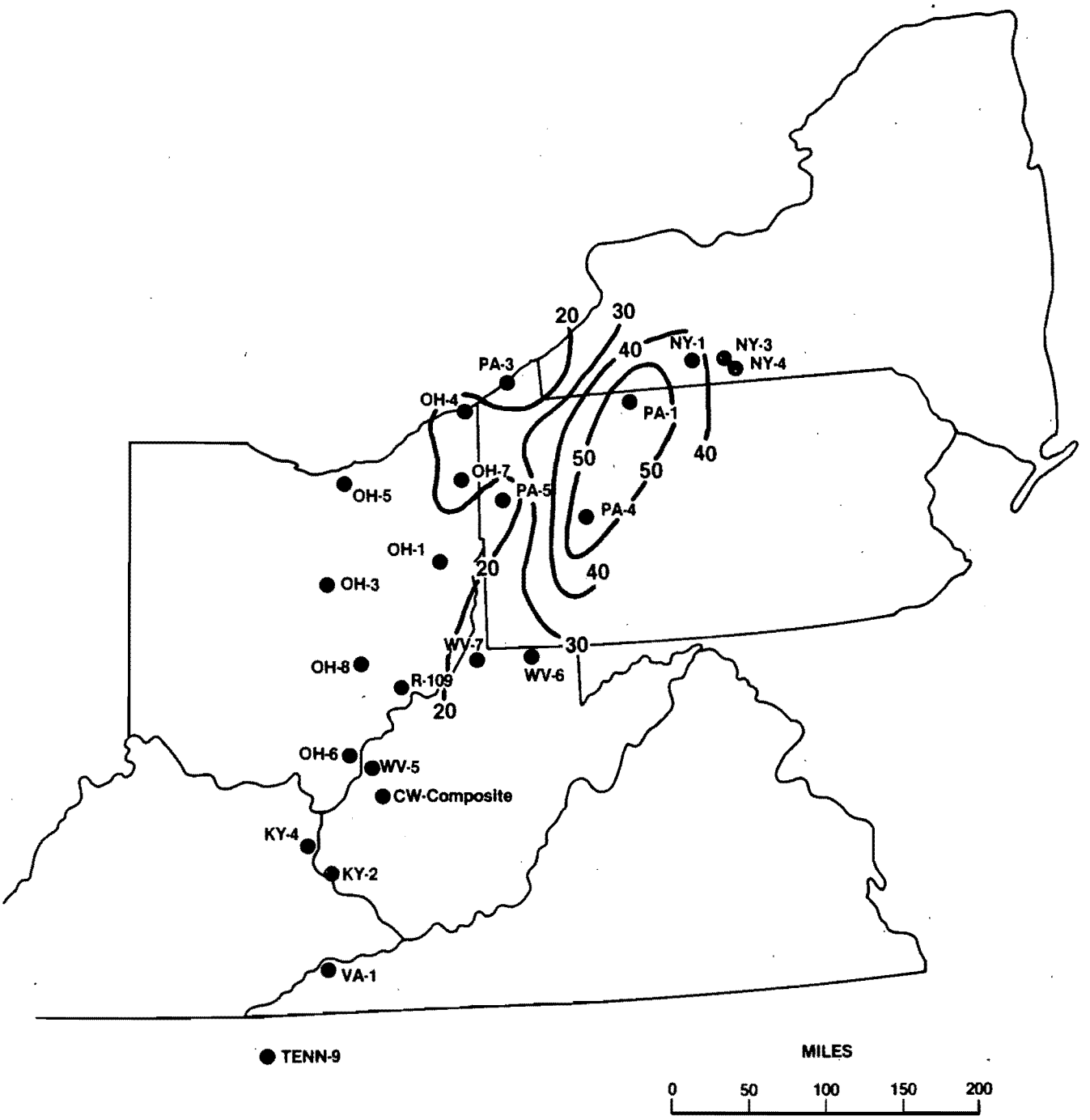


FIGURE 75

EARLY MARCELLUS TIME

Map Unit 1

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

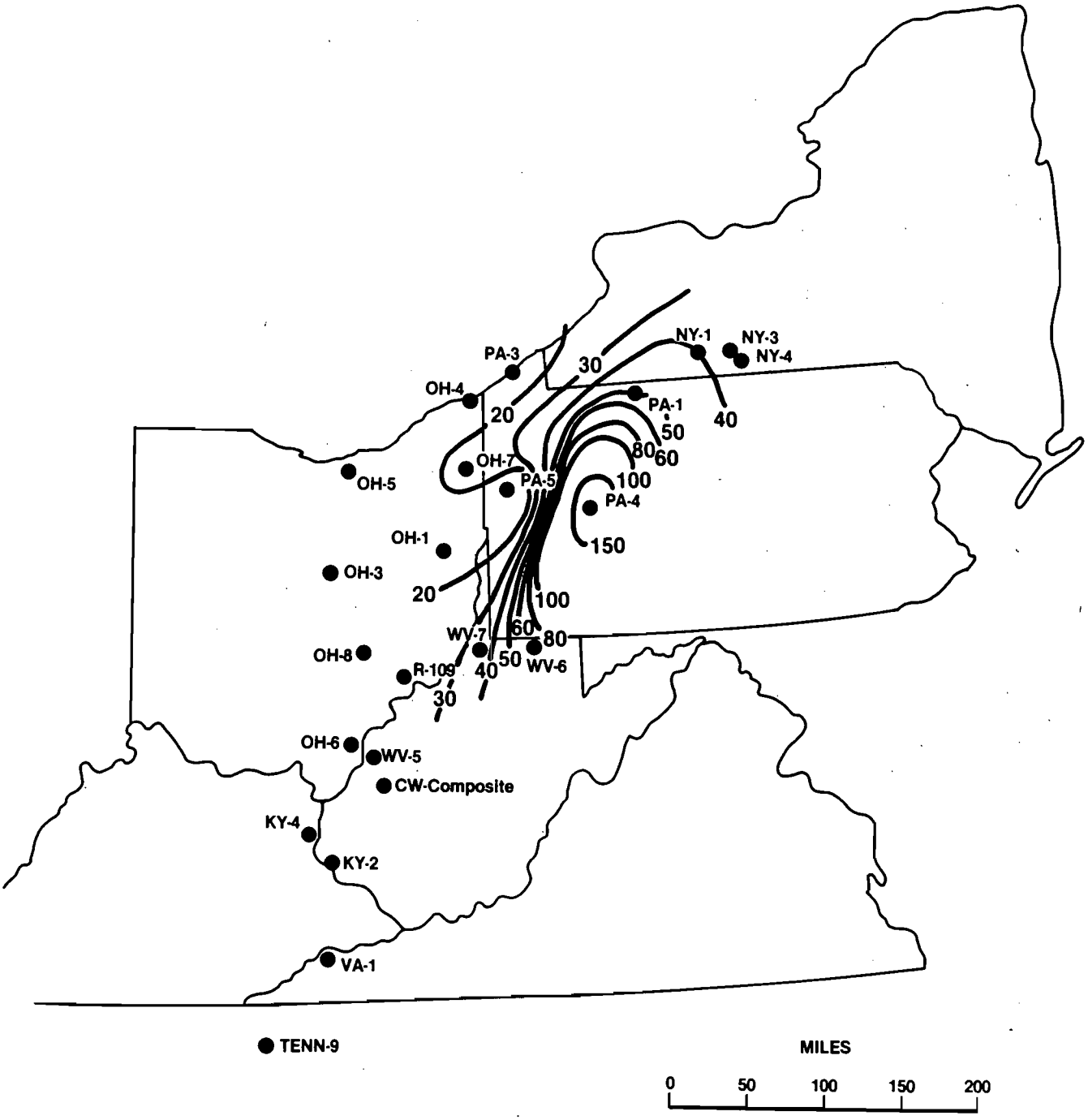


FIGURE 76

LATE MARCELLUS TIME

Map Unit 2

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

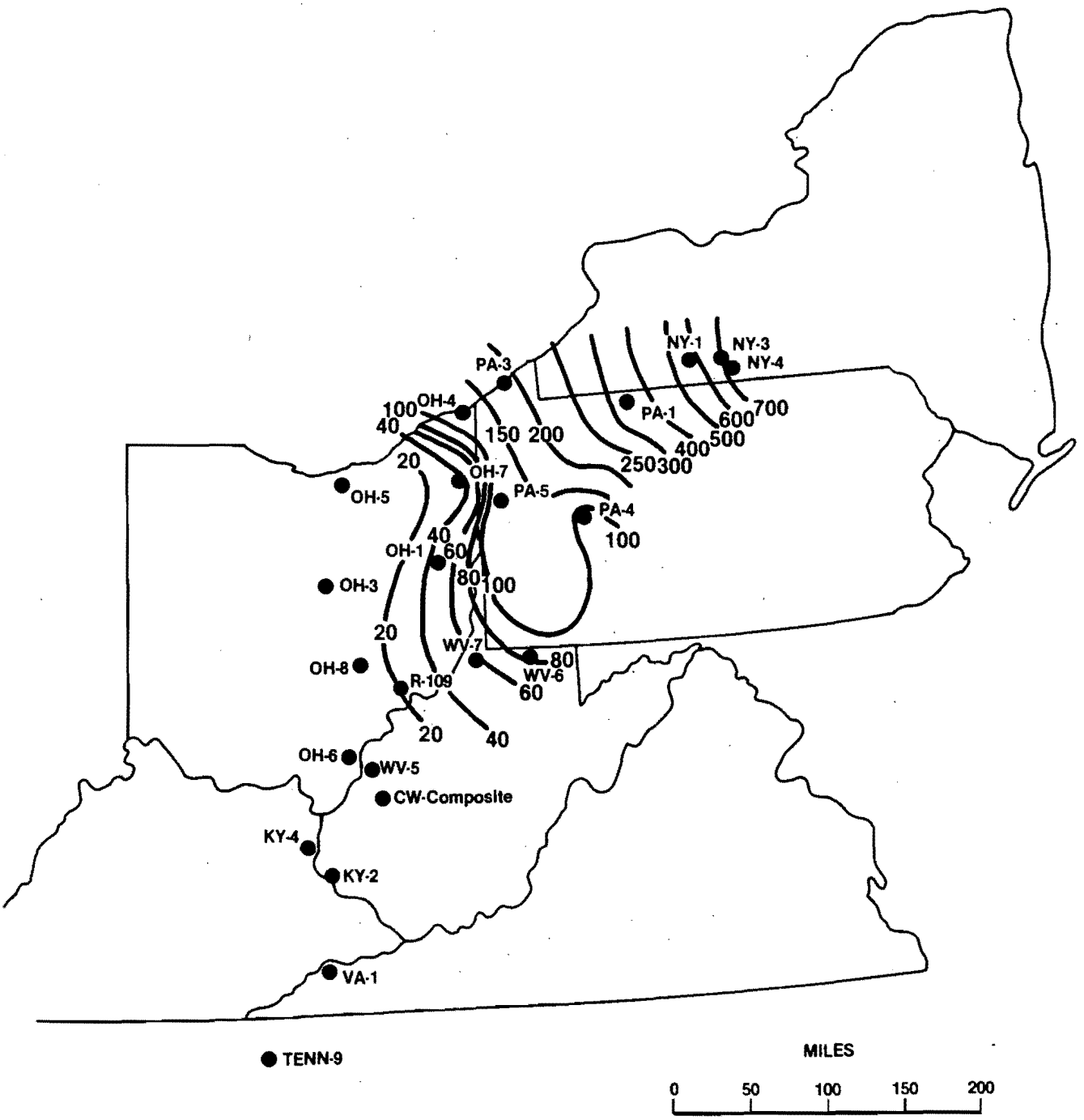


FIGURE 77

HAMILTON GROUP/POST-MARCELLUS TIME
Map Unit 3

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

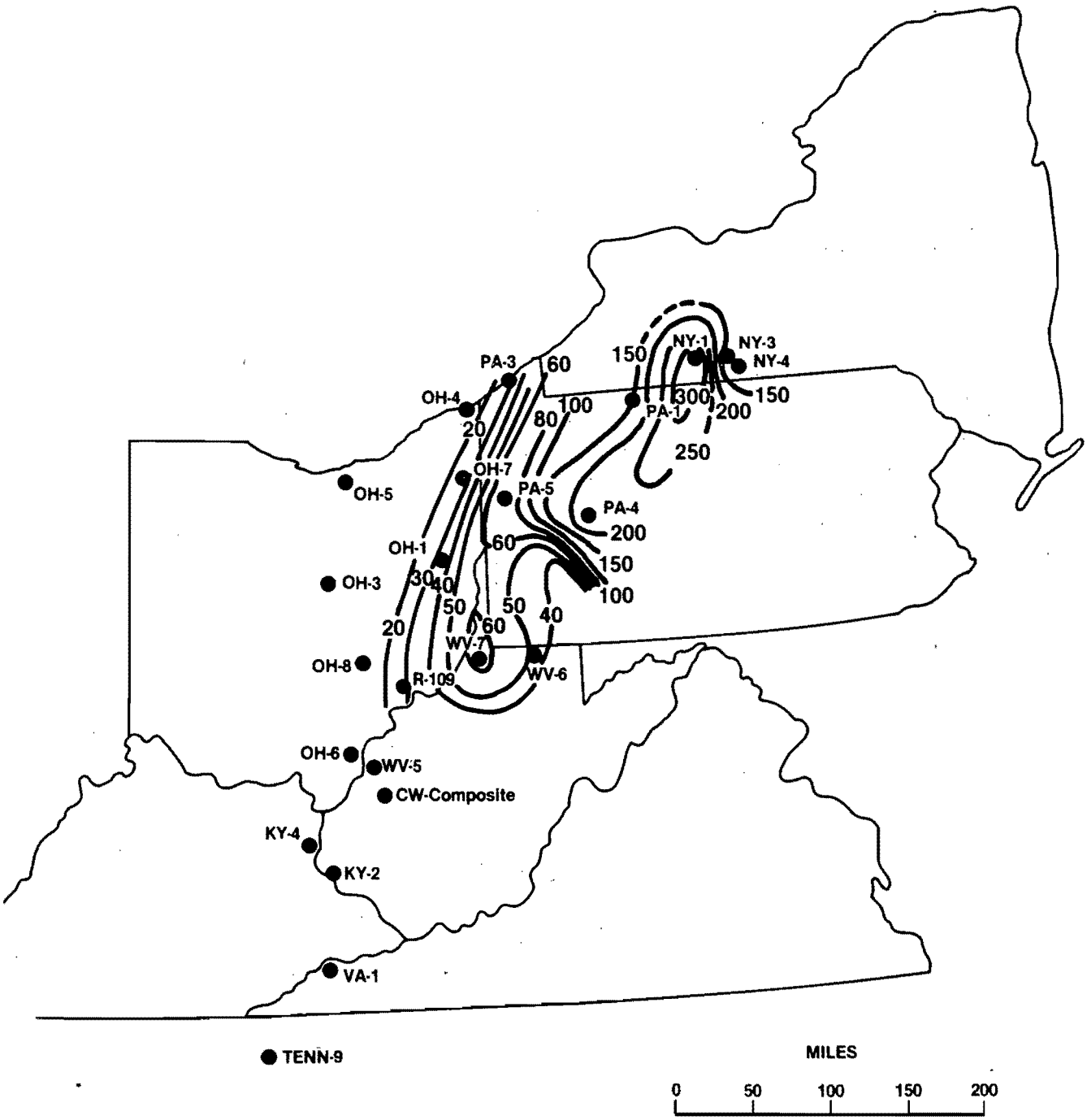


FIGURE 78

GENESEE/GENESEO TIME

Map Unit 4

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

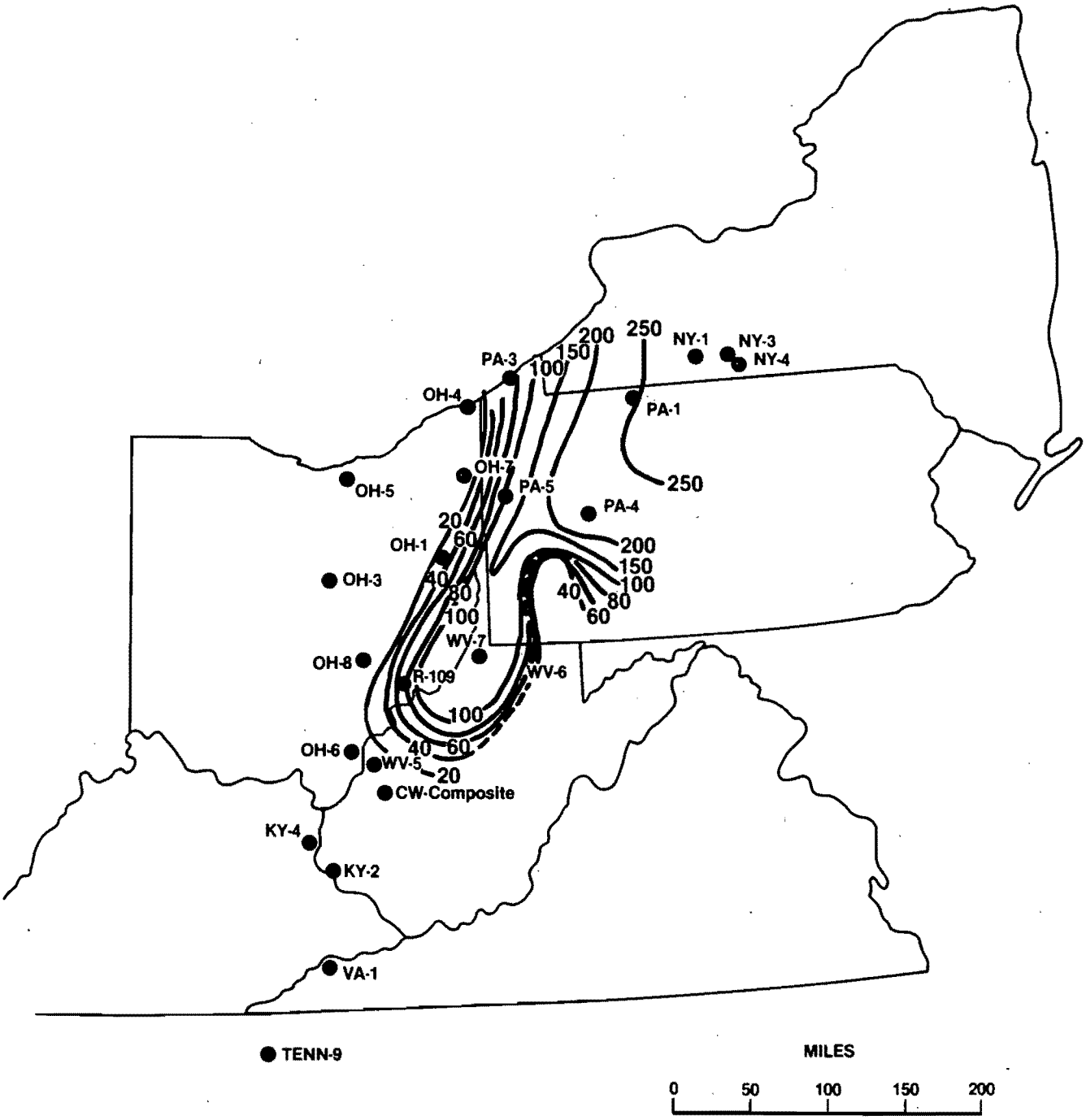


FIGURE 79

SONYEA/MIDDLESEX TIME

Map Unit 5

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

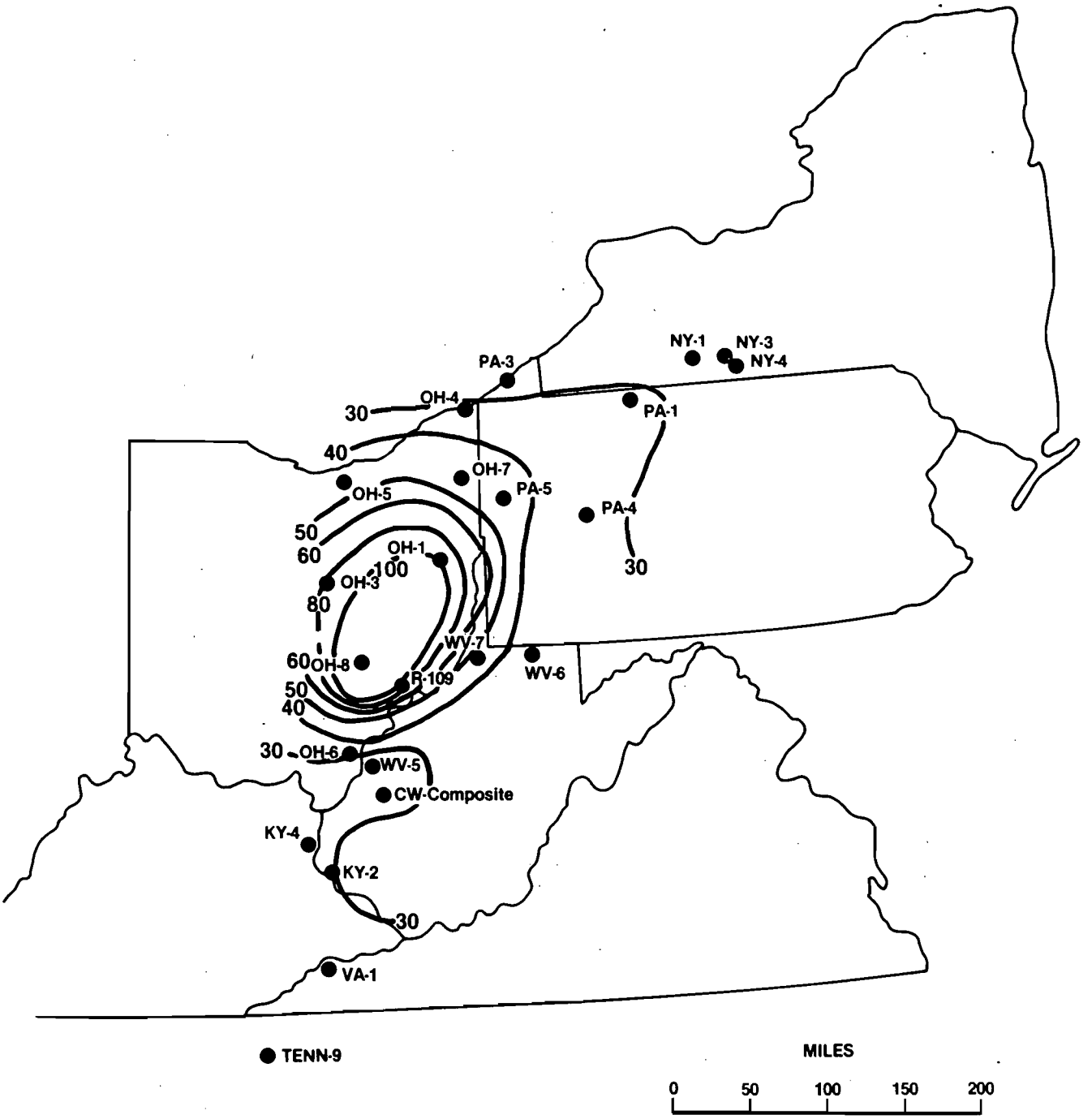


FIGURE 80

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

Map Unit 6

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

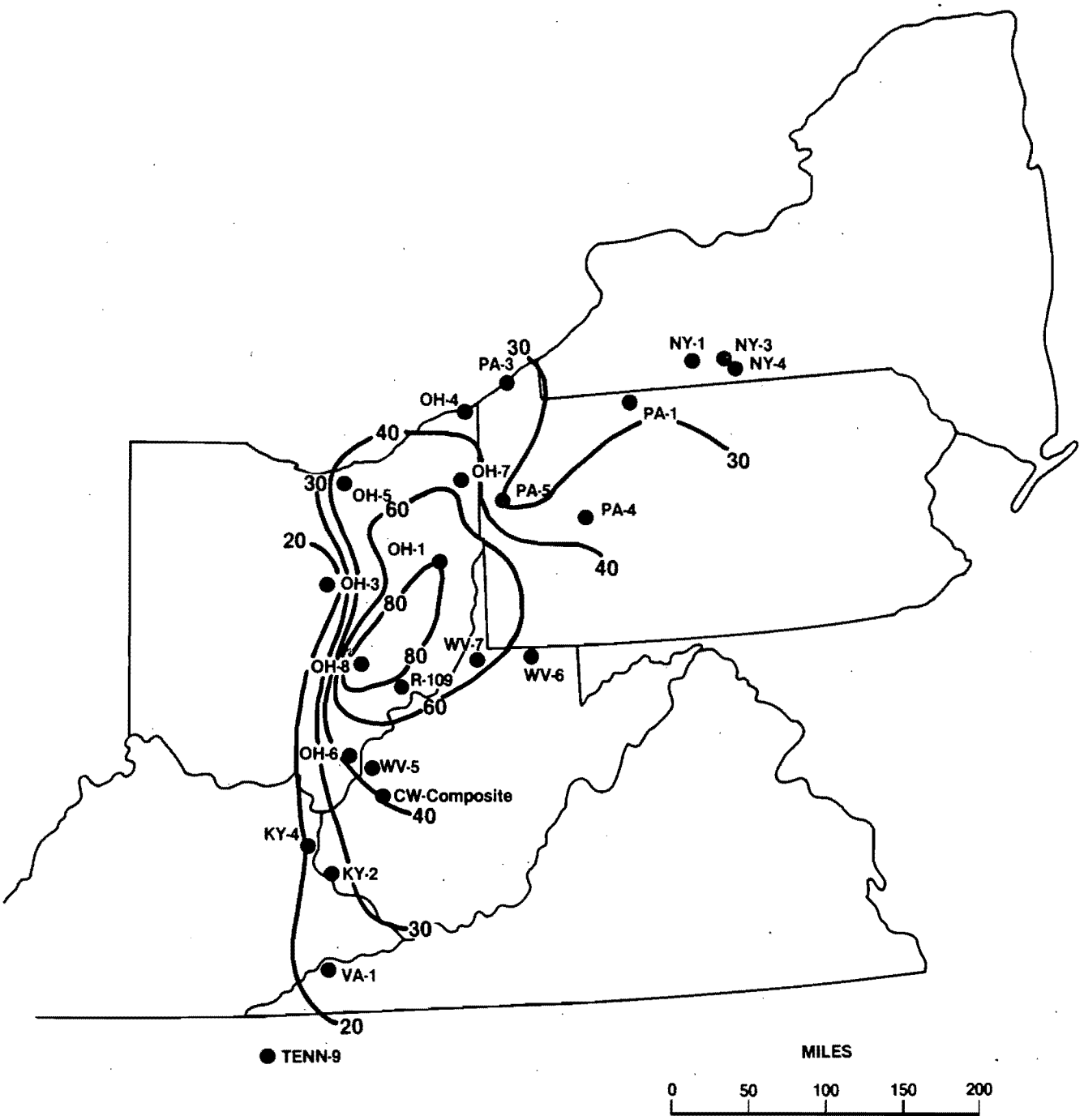


FIGURE 81

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

Map Unit 7

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

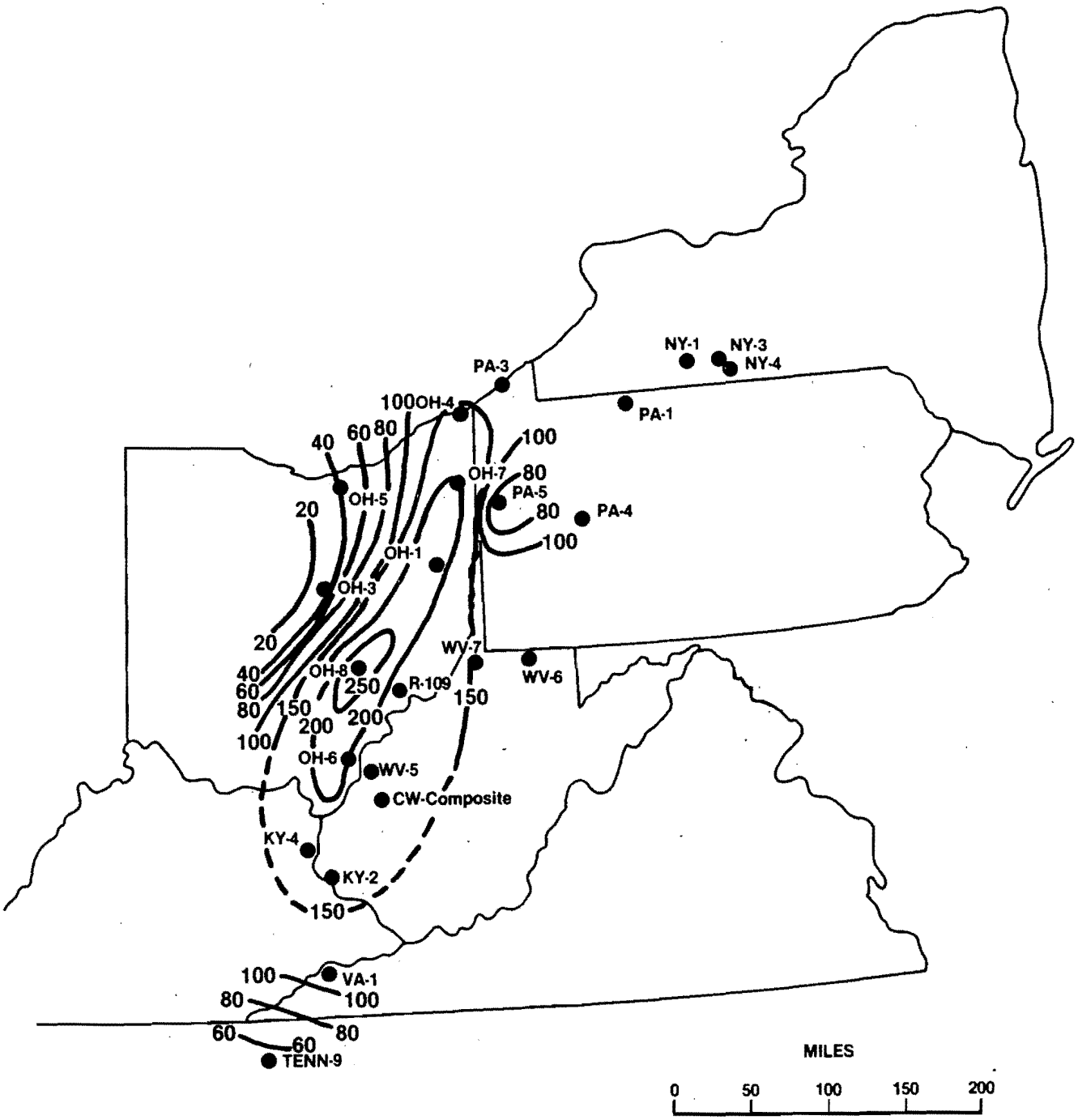


FIGURE 82

MIDDLE OLENTANGY/ANGOLA SHALE TIME

Map Unit 8

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

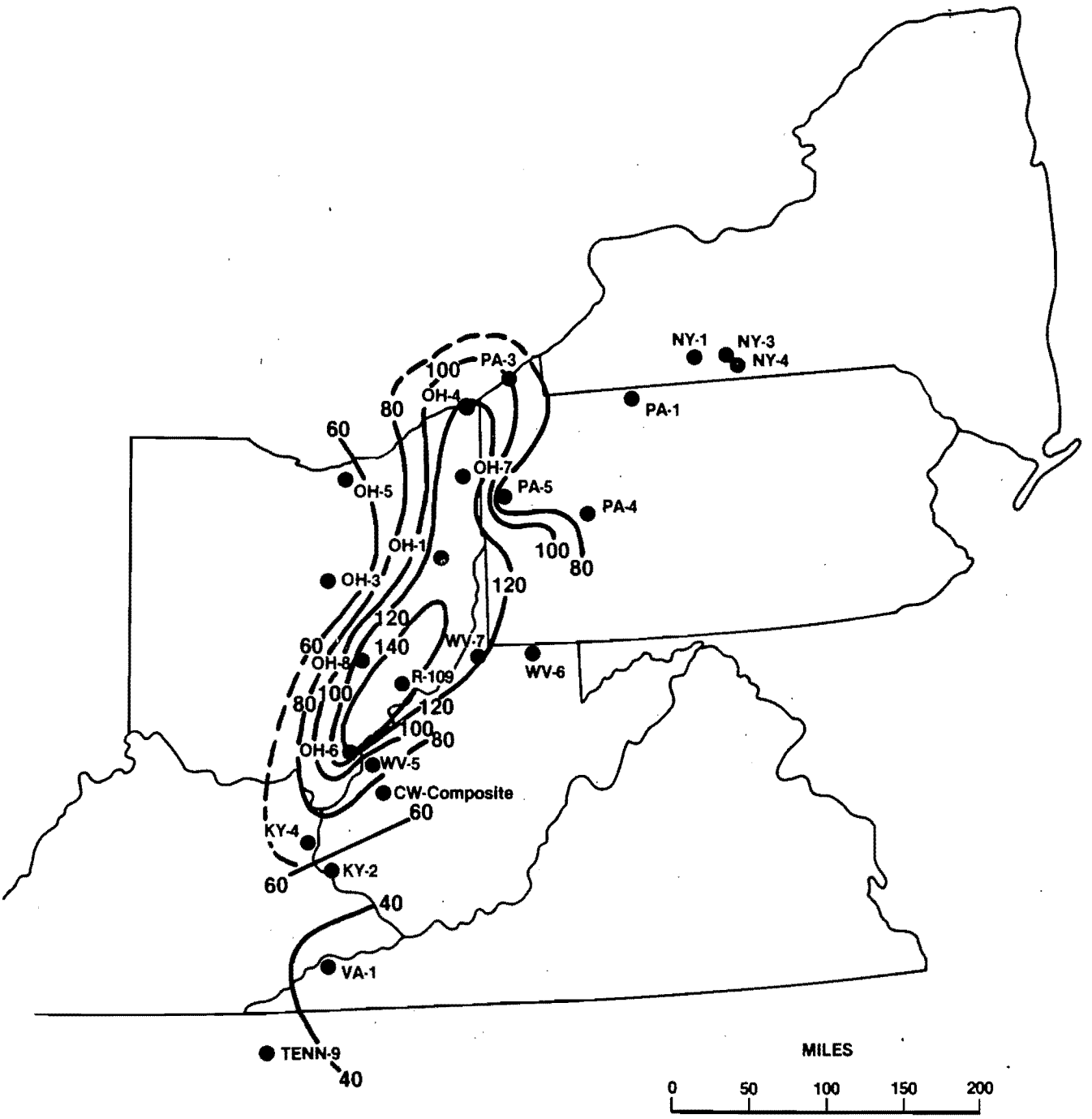


FIGURE 83

UPPER OLENTANGY/JAVA FM.
HANOVER SHALE TIME

Map Unit 9

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

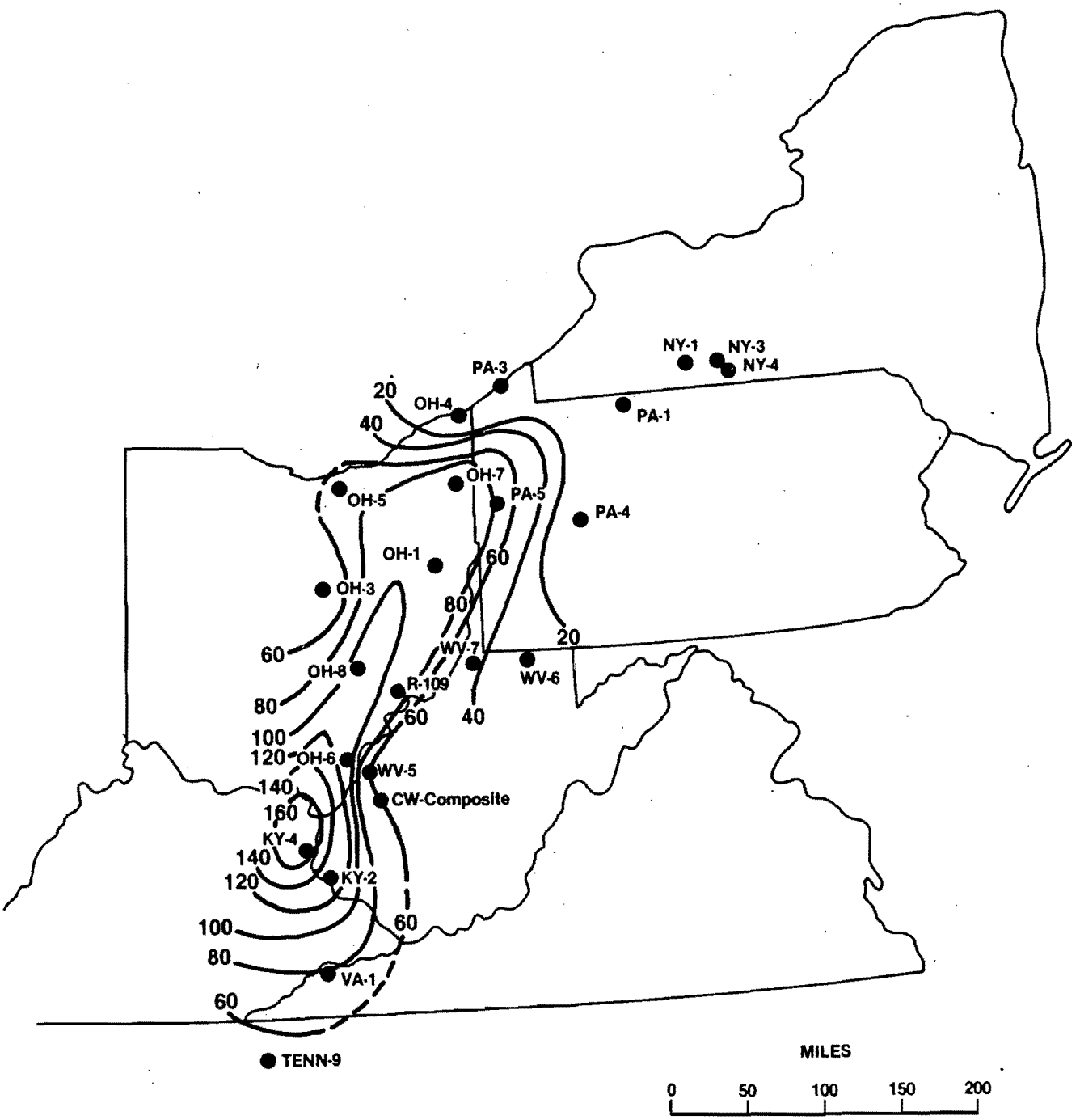


FIGURE 84

EARLY LOWER HURON/EARLY DUNKIRK TIME

Map Unit 10

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

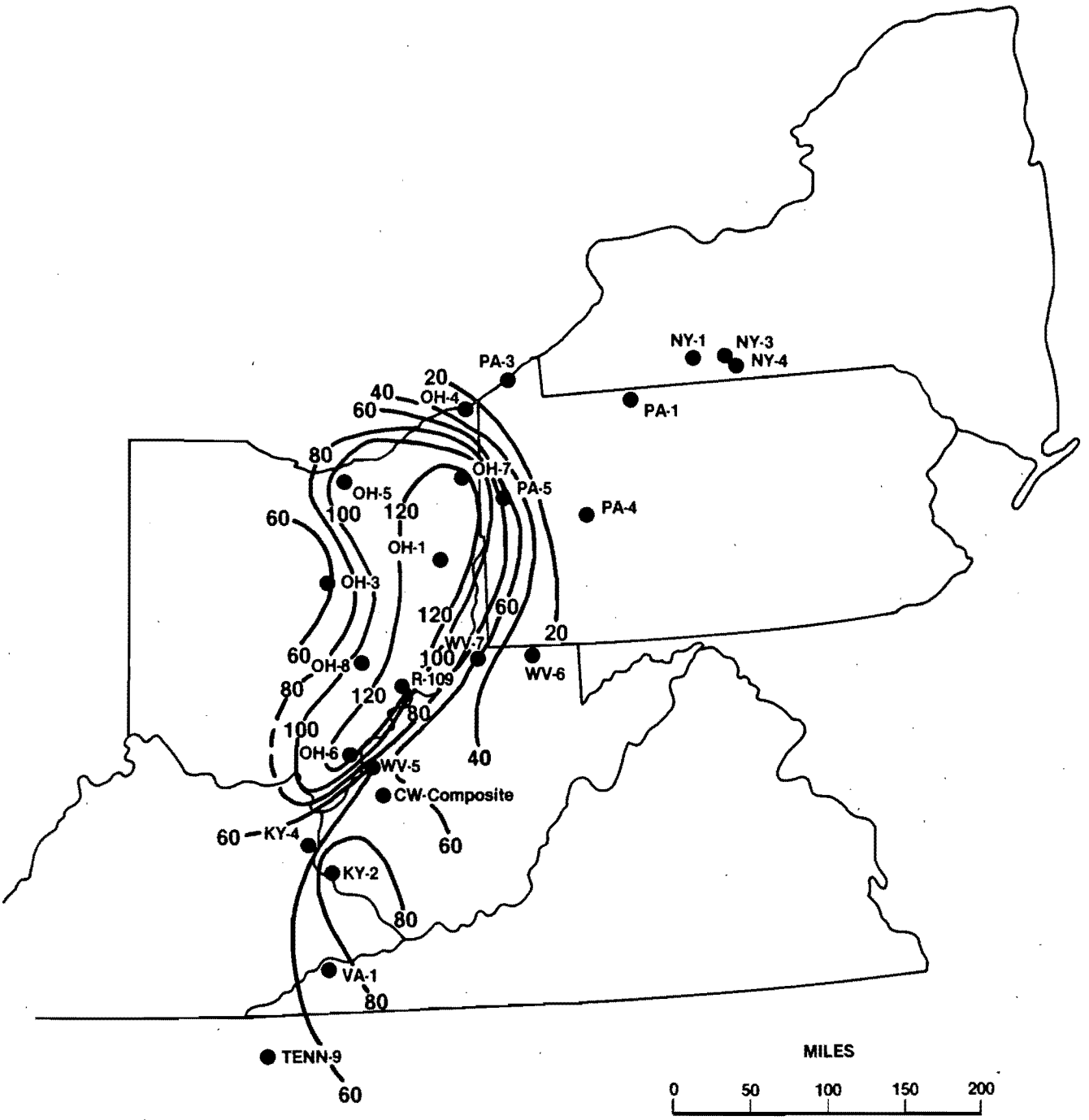


FIGURE 85

LATE LOWER HURON/LATE DUNKIRK TIME

Map Unit 11

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

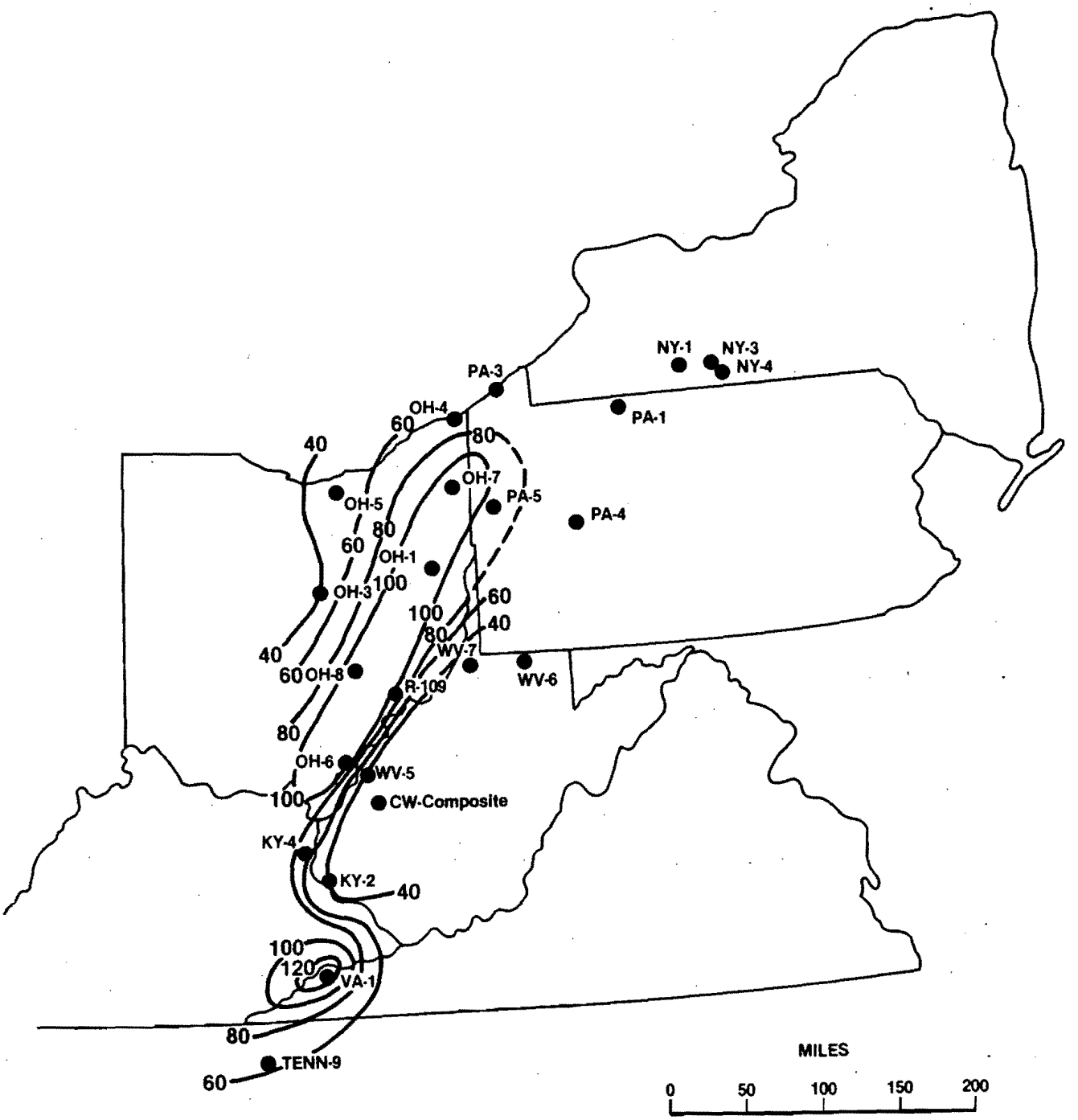


FIGURE 86

EARLY MIDDLE HURON TIME

Map Unit 12

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

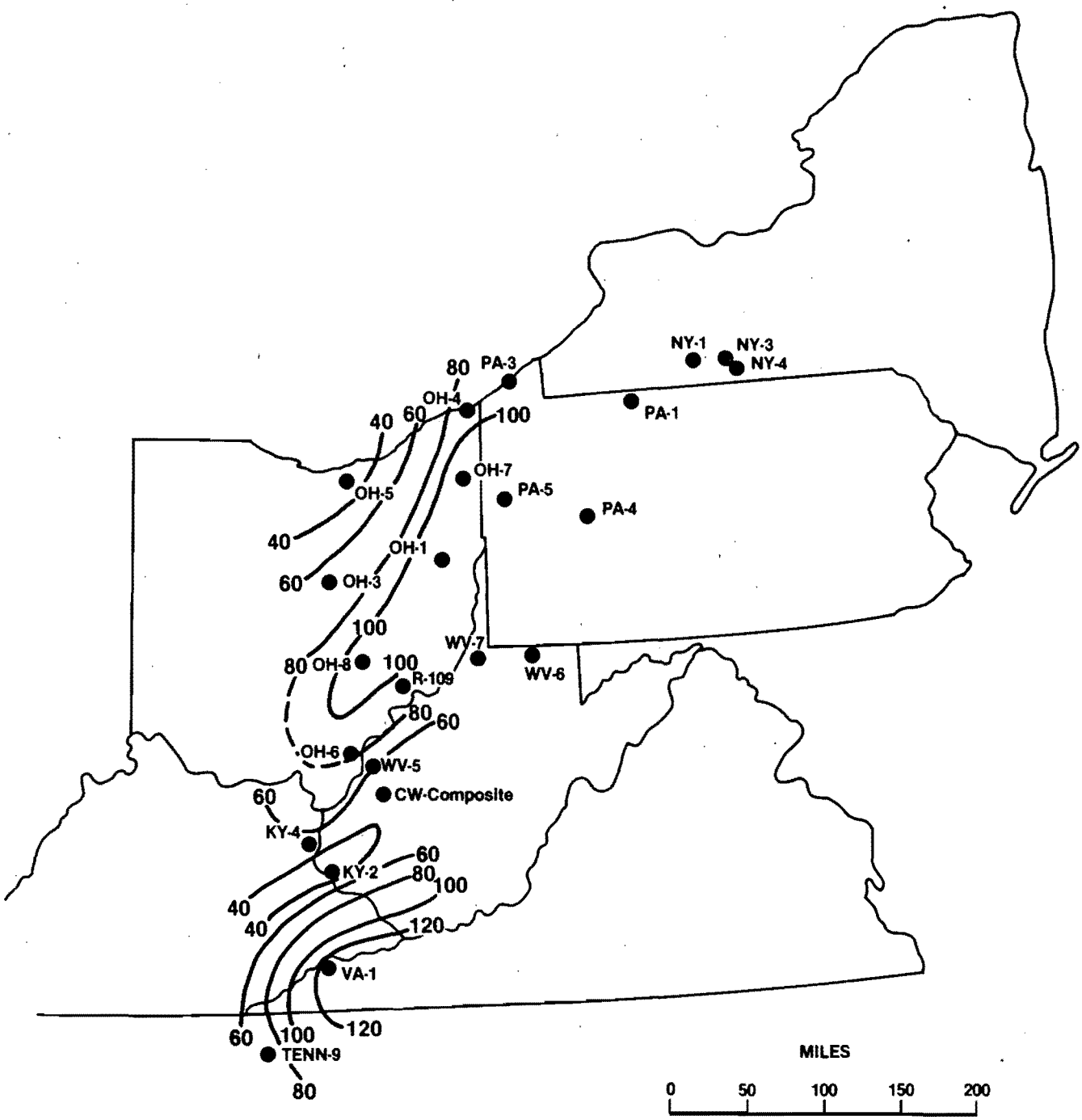


FIGURE 87

LATE MIDDLE HURON TIME

Map Unit 13

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

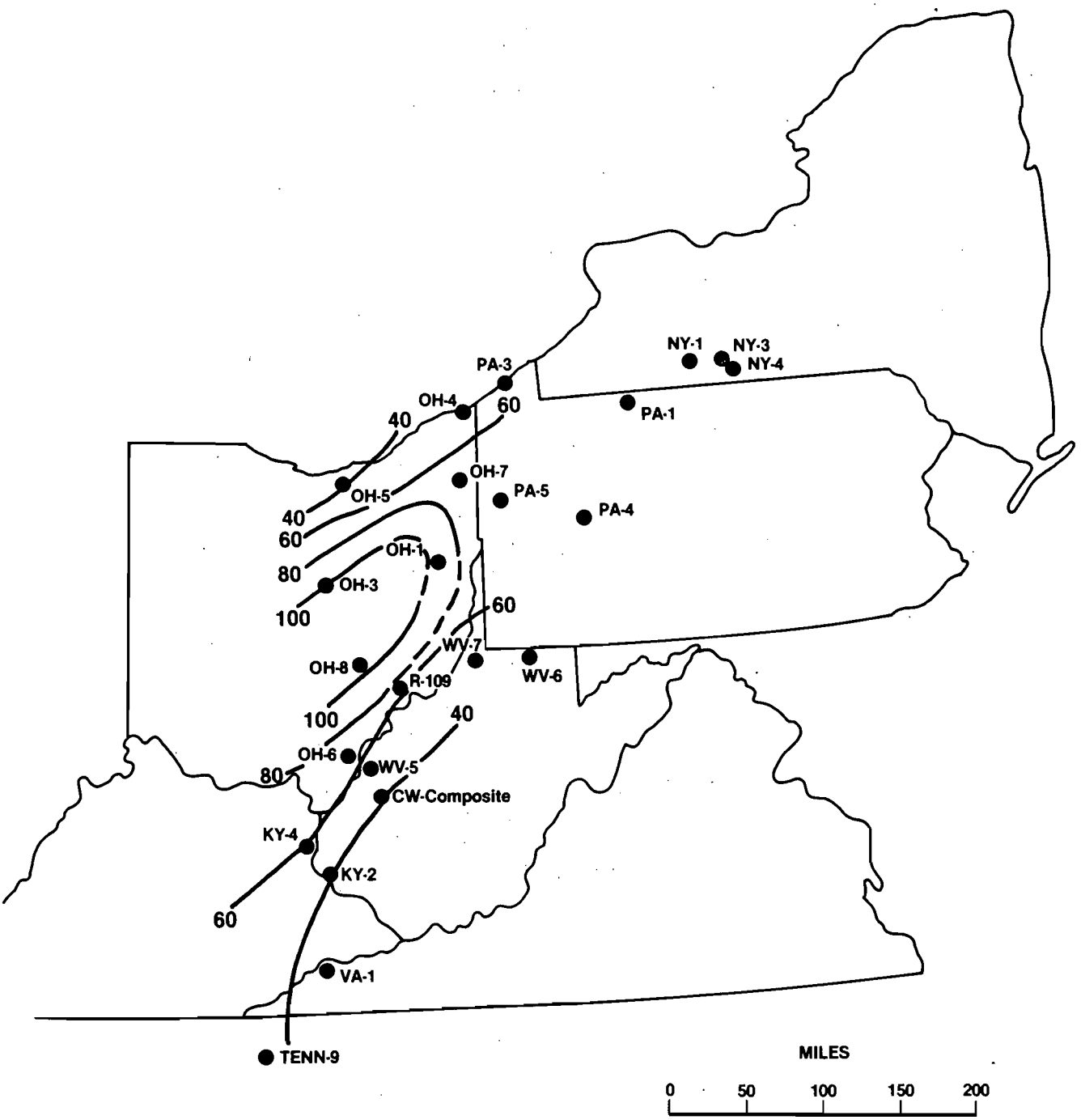


FIGURE 88

EARLY UPPER HURON TIME

Map Unit 14

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

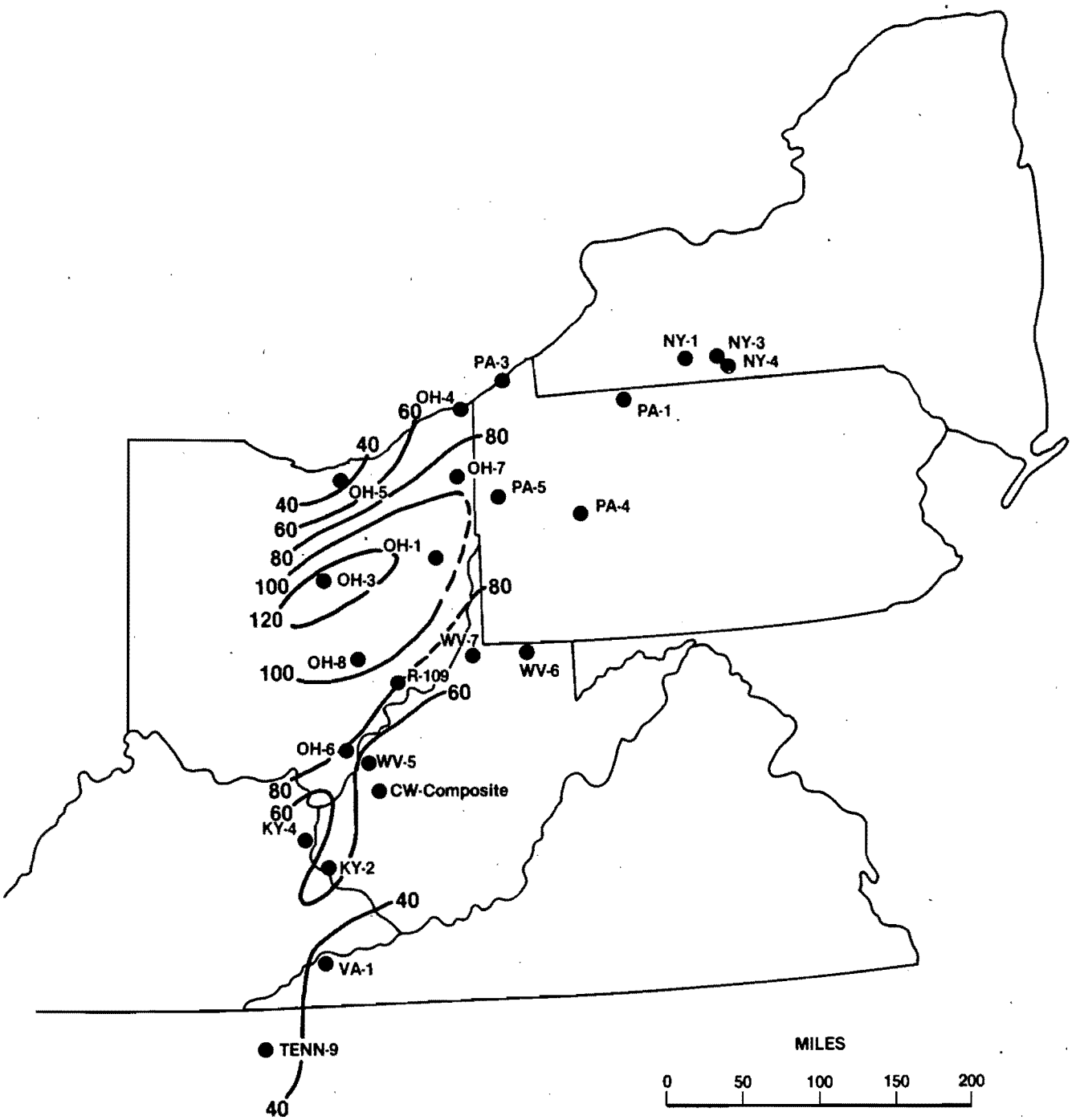


FIGURE 89

LATE UPPER HURON TIME

Map Unit 15

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

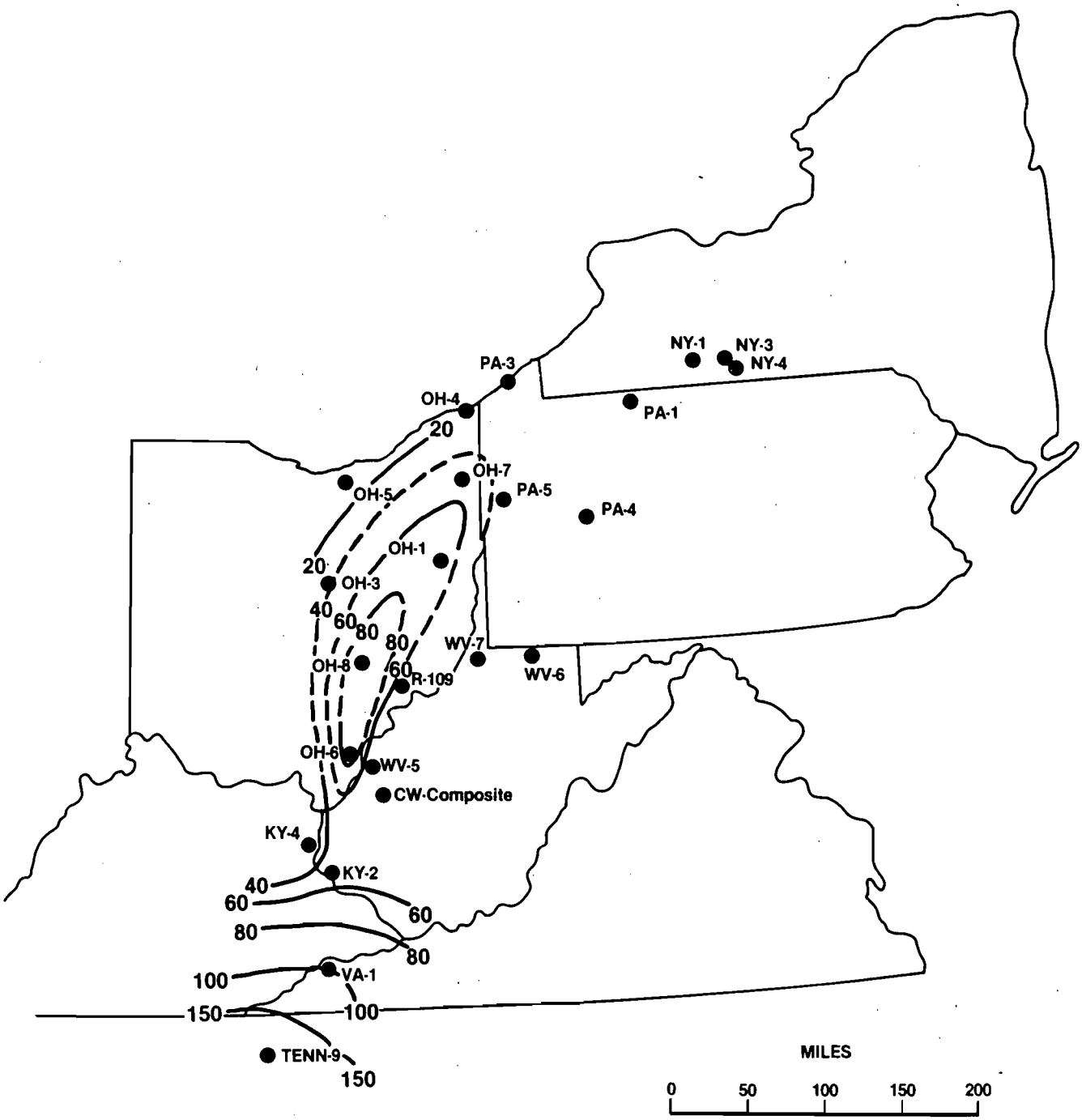


FIGURE 90

CHAGRIN TIME

Map Unit 16

MOUND

Prepared by Mound Facility

ISOPACH MAP
(Thickness in Feet)

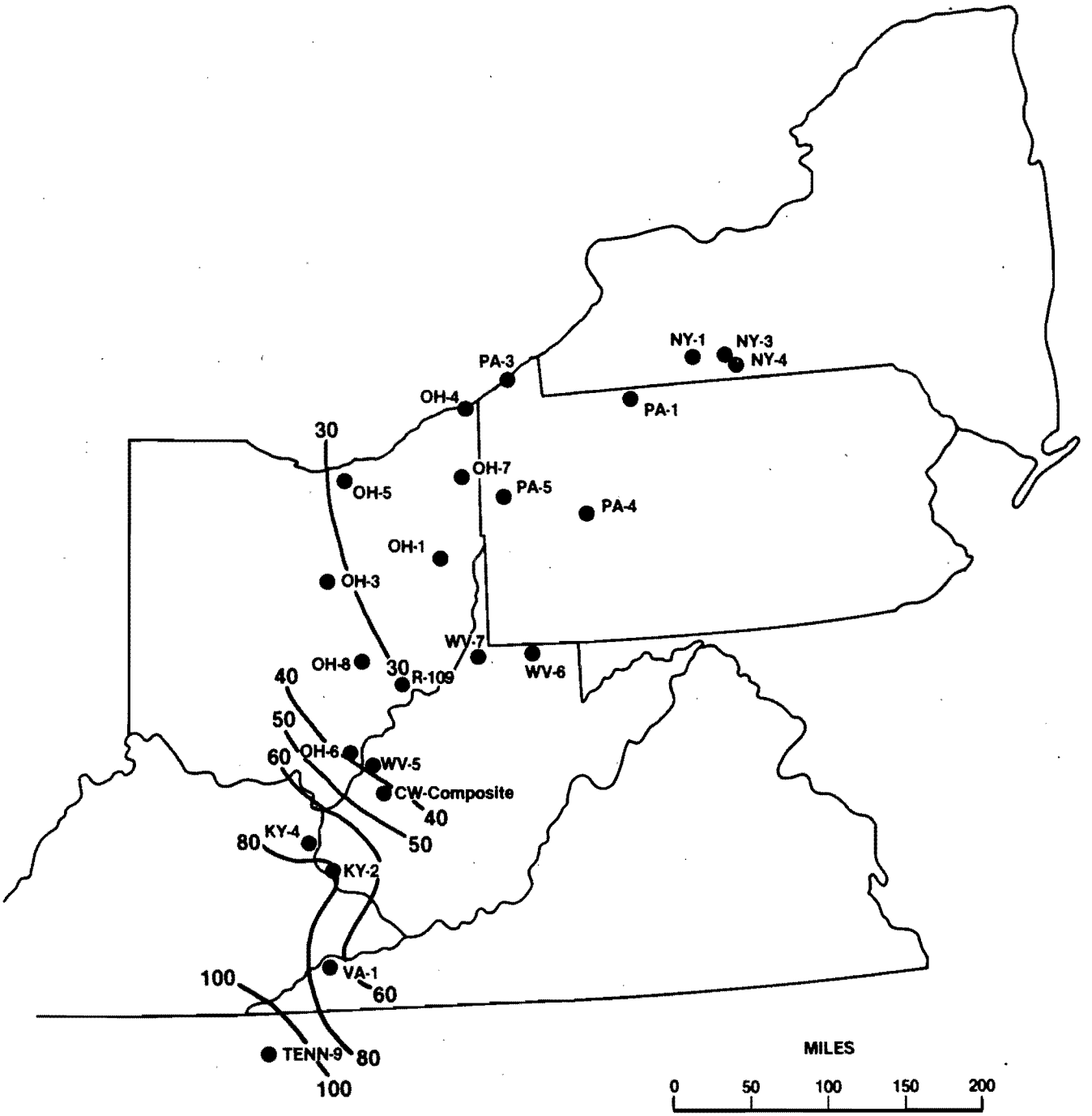


FIGURE 91

CLEVELAND TIME

Map Unit 17

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

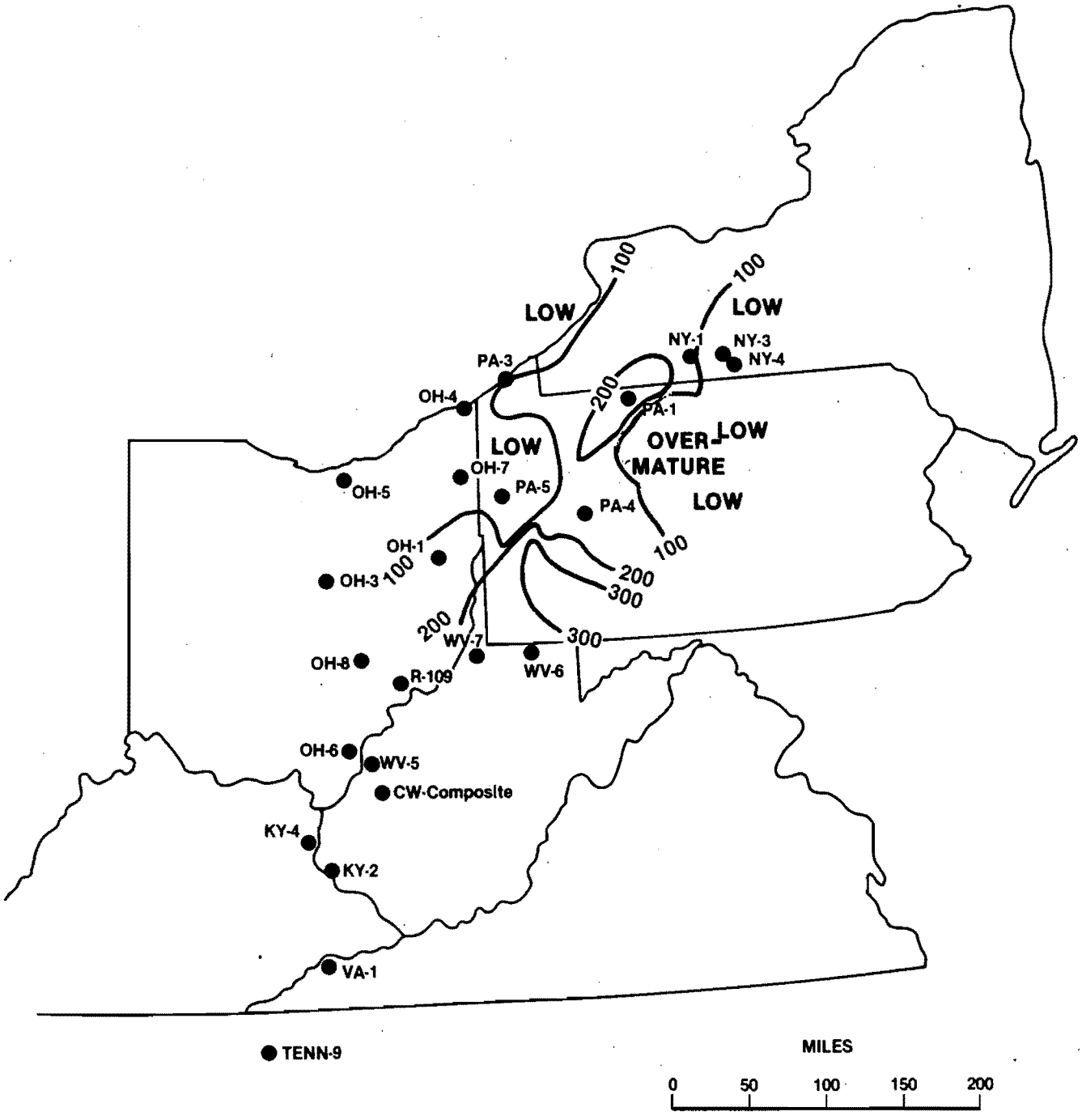


FIGURE 92

EARLY MARCELLUS TIME

Map Unit 1

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

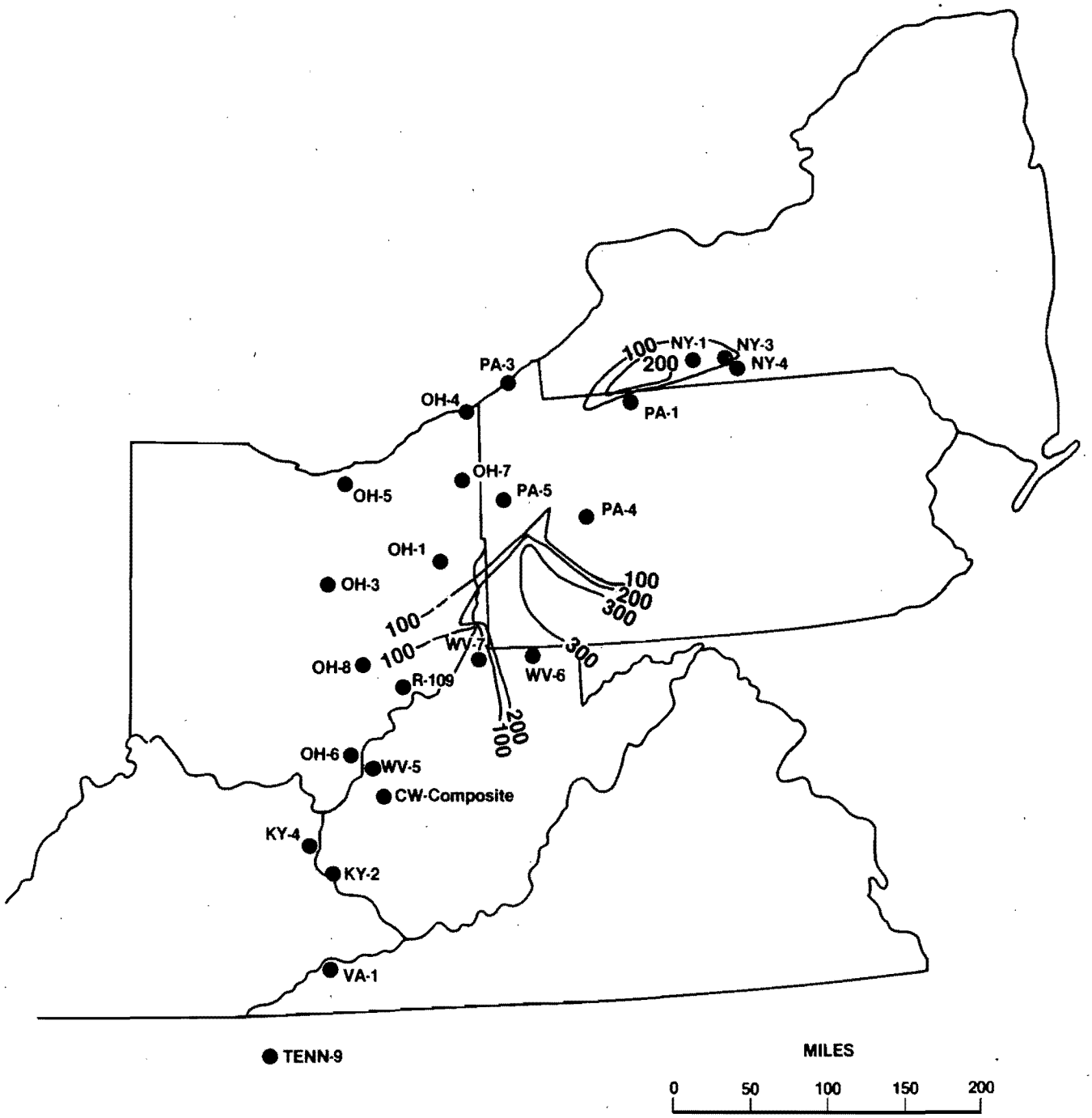


FIGURE 93

EARLY MARCELLUS TIME

MAP UNIT 1

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

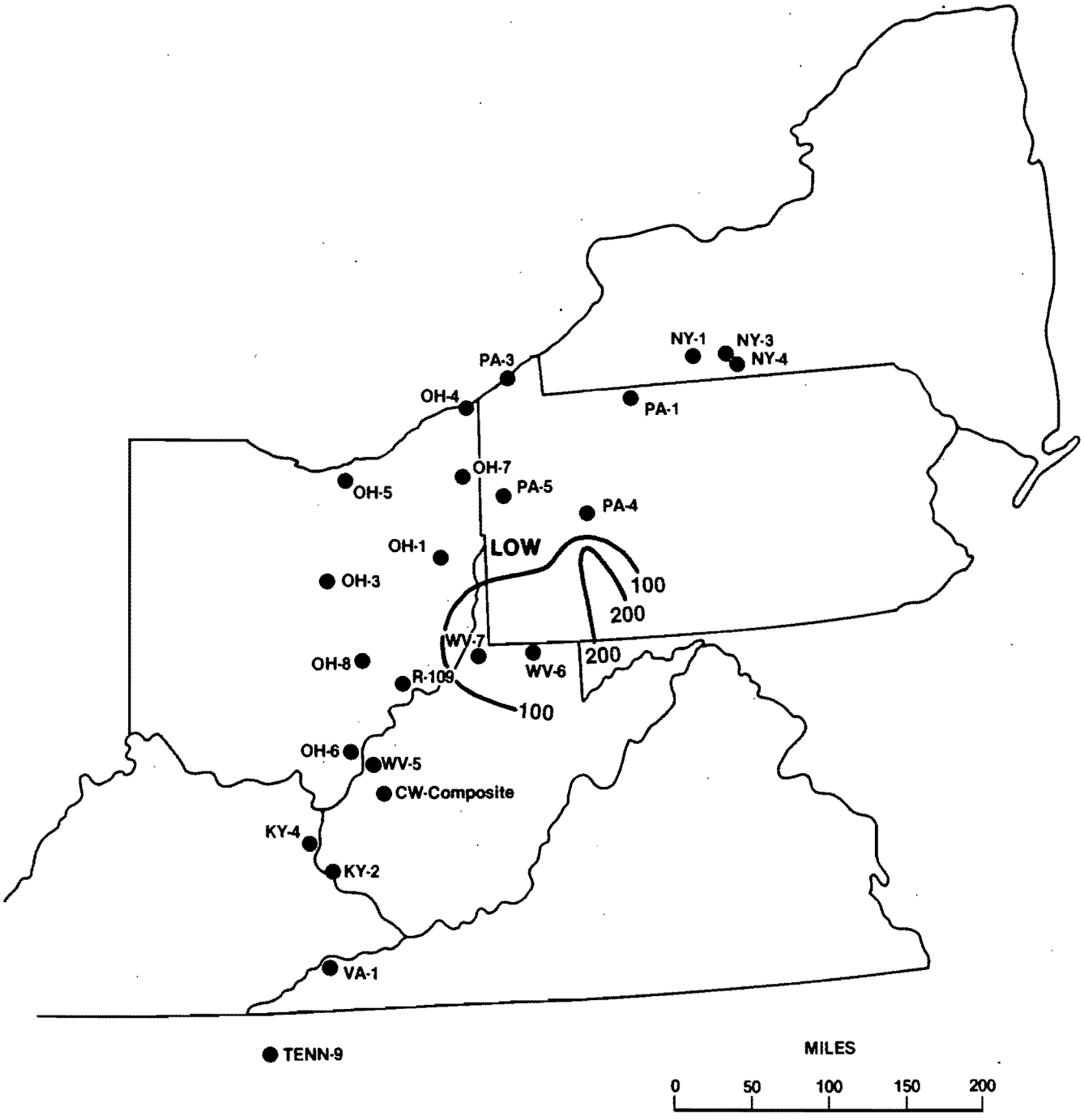


FIGURE 94

LATE MARCELLUS TIME

Map Unit 2

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

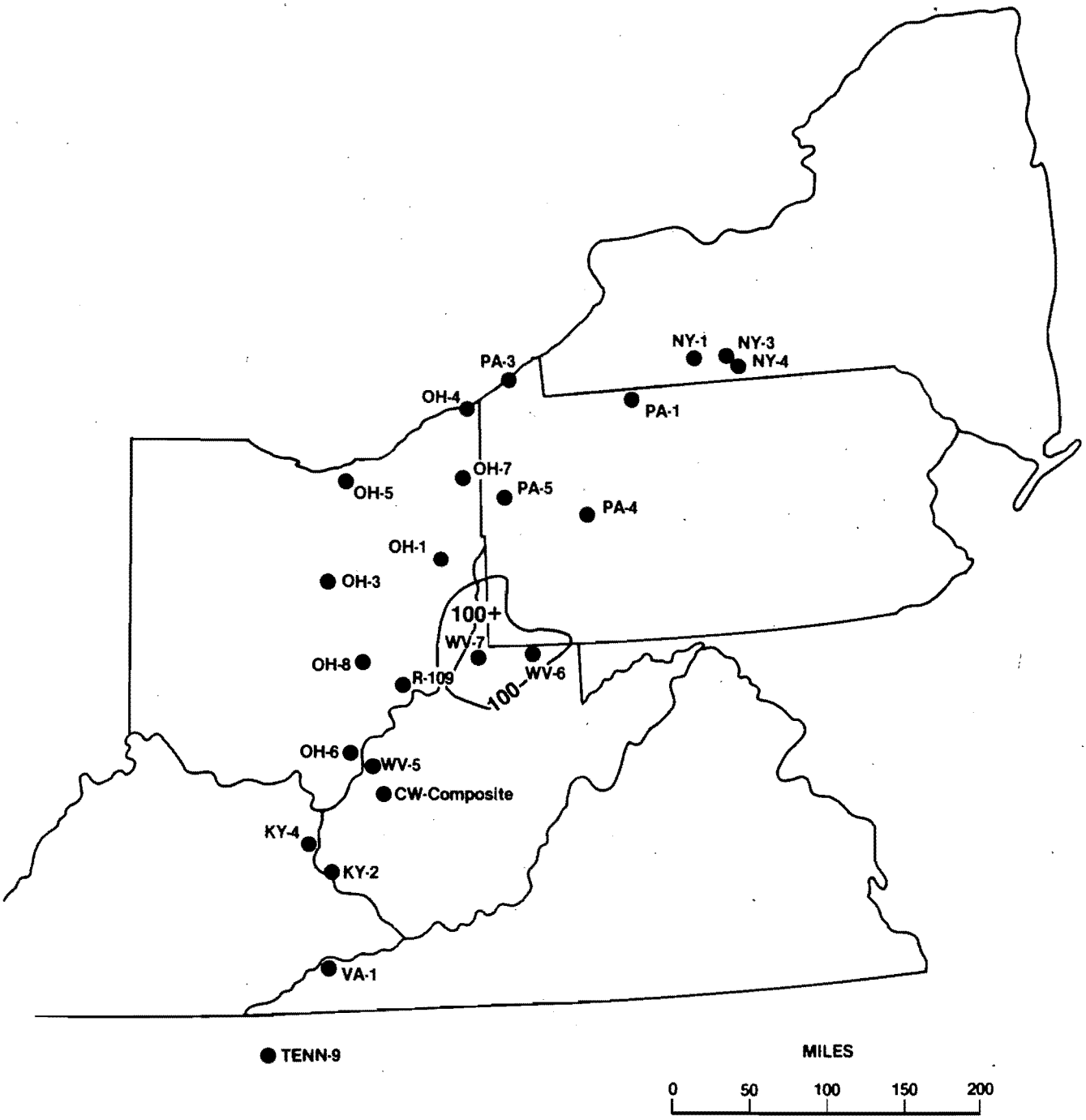


FIGURE 95

LATE MARCELLUS TIME

MAP UNIT 2

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

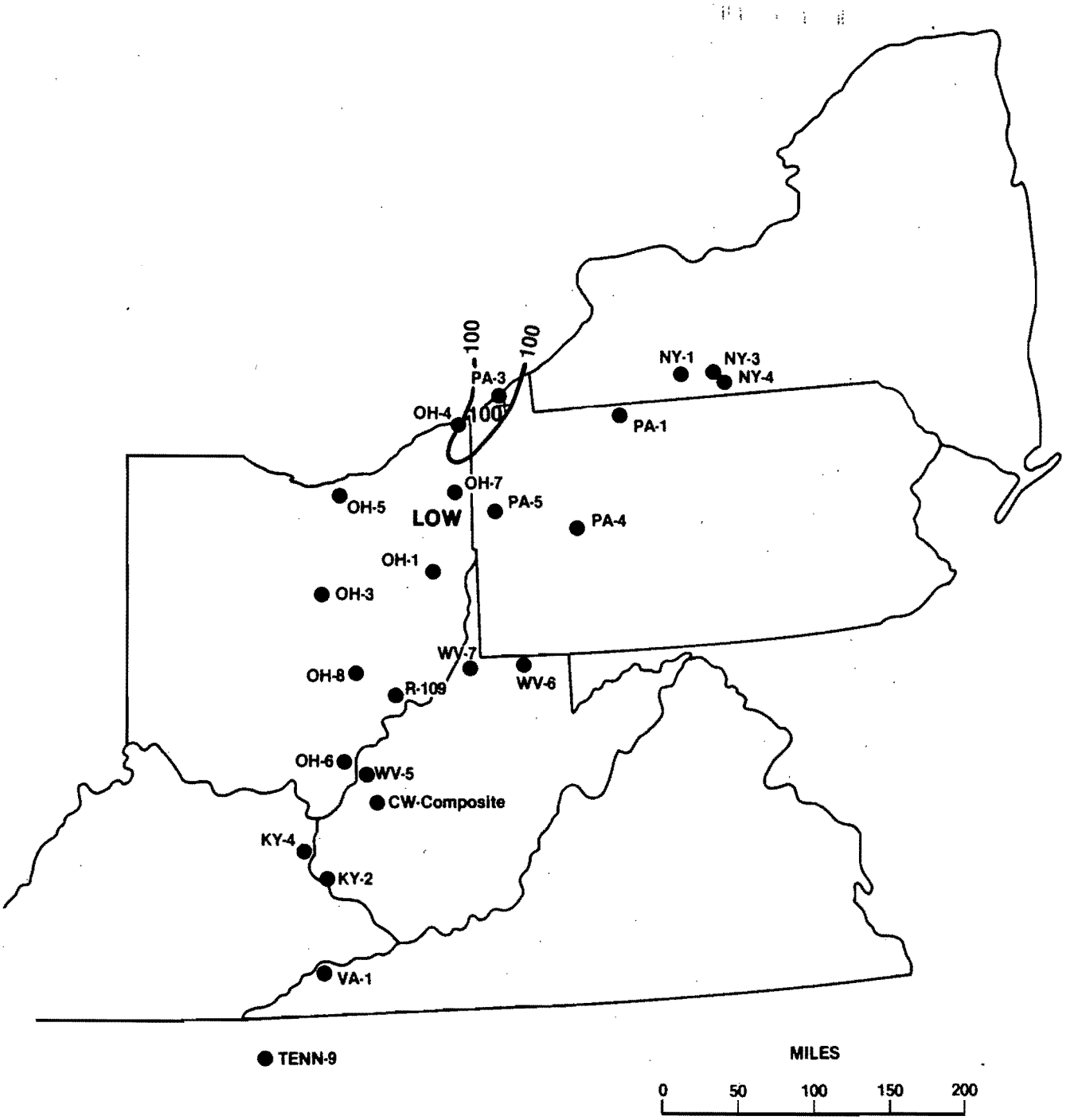


FIGURE 96

HAMILTON GROUP/POST-MARCELLUS TIME

Map Unit 3

MOUND

Prepared by Mound Facility

hydrocarbons in southwestern New York, northwestern Ohio, and the panhandle of West Virginia and the adjoining portions of Ohio would have an excellent chance of being filled with gas (Figure 97). In smaller zones within the areas of high gas potential near PA - 1 and NY - 1, there is excellent potential for accumulations of light oil (Figure 98). There is also another small area in northern West Virginia that has fair source potential for oil.

The Sonyea/Middlesex unit also has an area of excellent potential source rocks for gas (Figure 99), again because of a combination of modest potential and excellent thickness. The wedge of sediment with the highest potential is in extreme western New York and extends into Pennsylvania to the south to the PA - 4 well. This potential is for gas without associated liquids. There is another area of sediments with fair potential on either side of the Ohio-West Virginia boundary in the vicinity of R - 109. This unit could provide gas and oil (Figure 100) to nearby reservoirs.

While the early Lower Olentangy (early Rhinestreet) unit is not as thick as the units immediately below, it has an area of good gas (Figure 101) and good oil (Figure 102) source potential because of its exceptional source quality. This high-potential area for large volumes of gas and oil in associated reservoirs is found in southeastern Ohio. Additional fair potential for primarily gaseous hydrocarbons extends over much of eastern Ohio and northwestern West Virginia.

The later Lower Olentangy has fair-to-good potential for sourcing gas (Figure 103) in southeastern Ohio, and to a lesser extent, in northwestern West Virginia. Lower Olentangy rocks with somewhat lower gas potential blanket much of the basin. There is also an area with good source potential for oil in southeastern Ohio, and fair potential sources extend south from there into western West Virginia (Figure 104).

In spite of the occurrence of a thick section of the Middle Olentangy unit (Figure 105), it exhibits relatively less source potential than many of the other units basin wide, except for a small area of fair-to-good gas-prone source sediments at OH - 6 and extending southwest into Kentucky.

The Upper Olentangy (Figure 106) has three small areas where fair source potential might contribute gas to contiguous reservoirs. One of these areas is in southeastern Ohio, another in Central Ohio, and the third along Lake Erie in Pennsylvania.

Early Lower Huron rocks have good gas source potential over a large area as shown in Figure 107, and fair potential over a large part of the rest of the basin. The best source area is just west of the junction of Kentucky, West Virginia and Ohio boundaries, but a broader area of rocks with only slightly less potential extends both southward and northward from the richest area. Virtually all of this potential is for gas, except for an area that has fair-to-good potential for oil in southeastern Ohio, and an area with fair oil potential in west central West Virginia (Figure 108).

The upper Lower Huron unit has a limited area of good potential sources in east central Ohio mostly for gas (Figure 109), but also for some oil at the extreme southern end of the richest gas patch (Figure 110). The unit

RELATIVE GAS SOURCE POTENTIAL

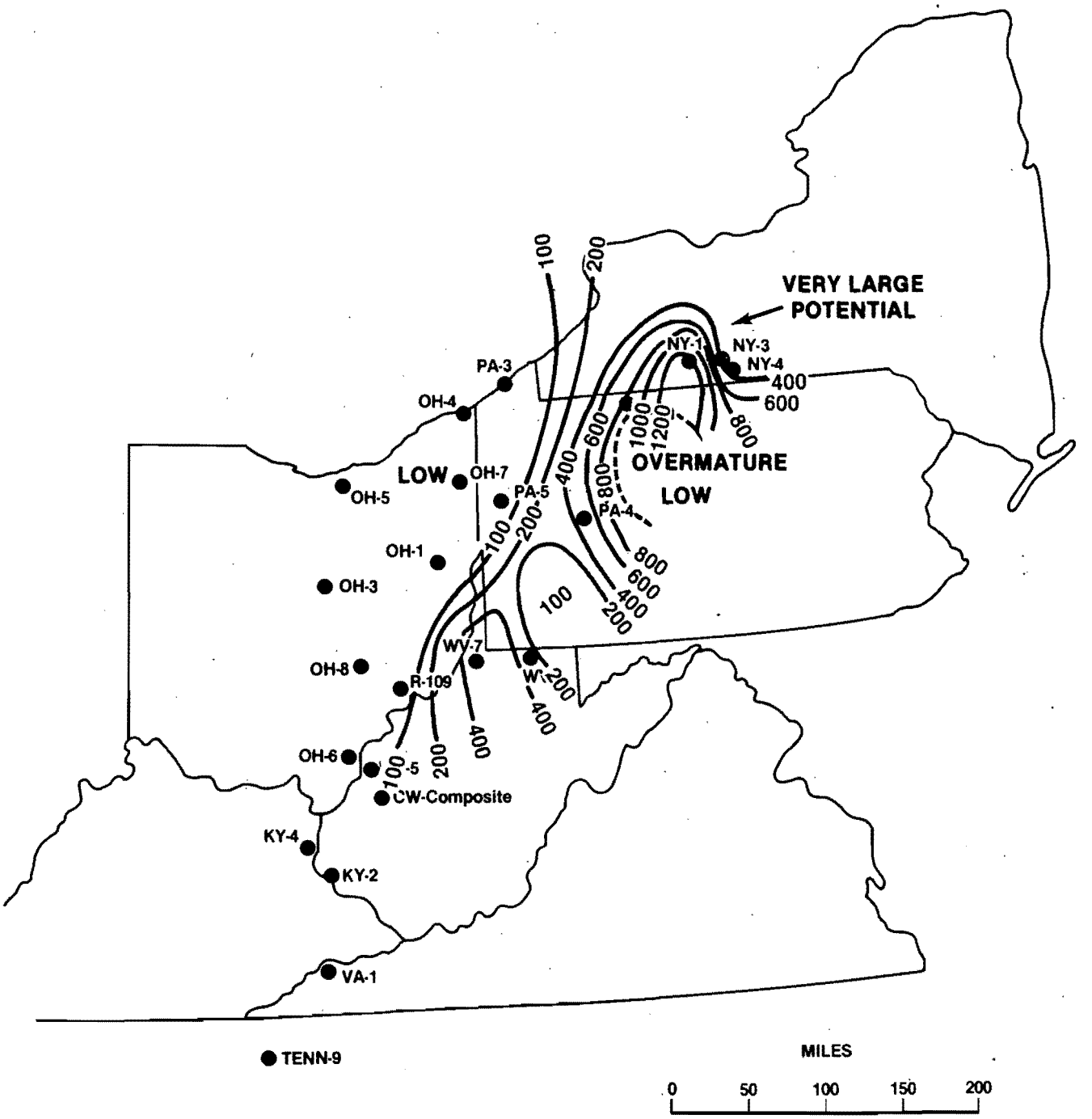


FIGURE 97

GENESEE/GENESEO TIME

Map Unit 4

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

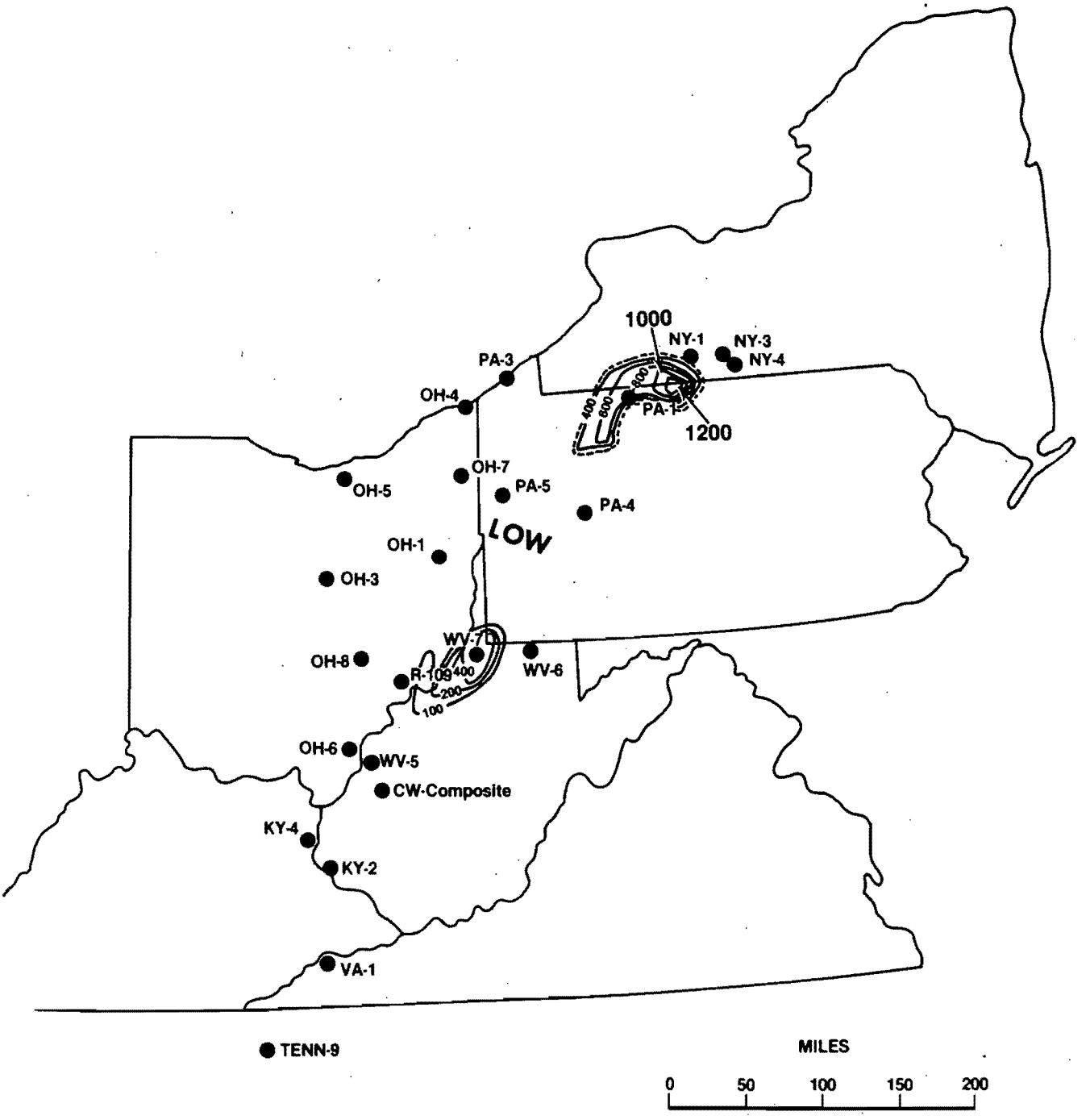


FIGURE 98

GENESEE/GENESEO TIME

MAP UNIT 4

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

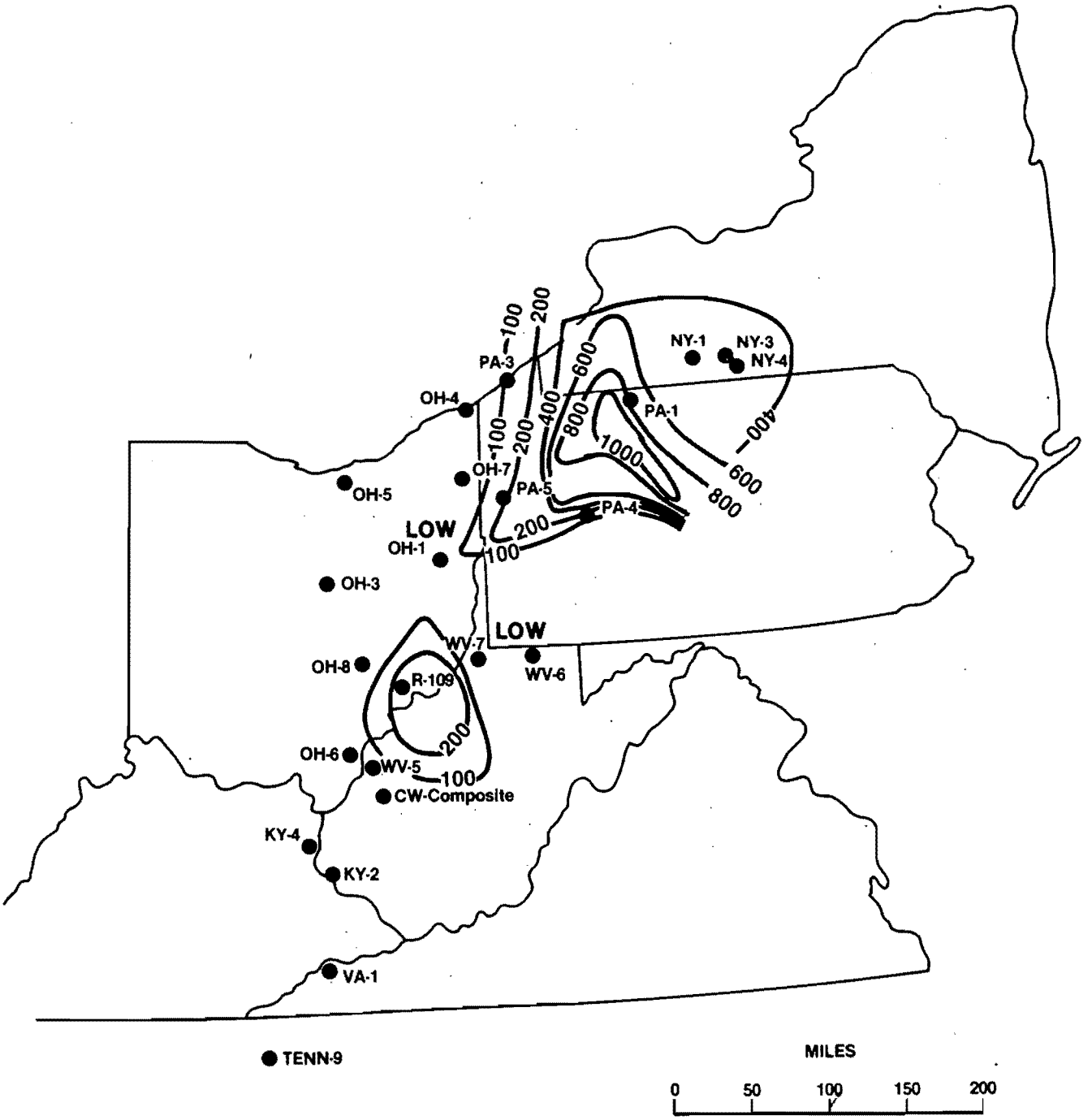


FIGURE 99

SONYEA/MIDDLESEX TIME

Map Unit 5

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

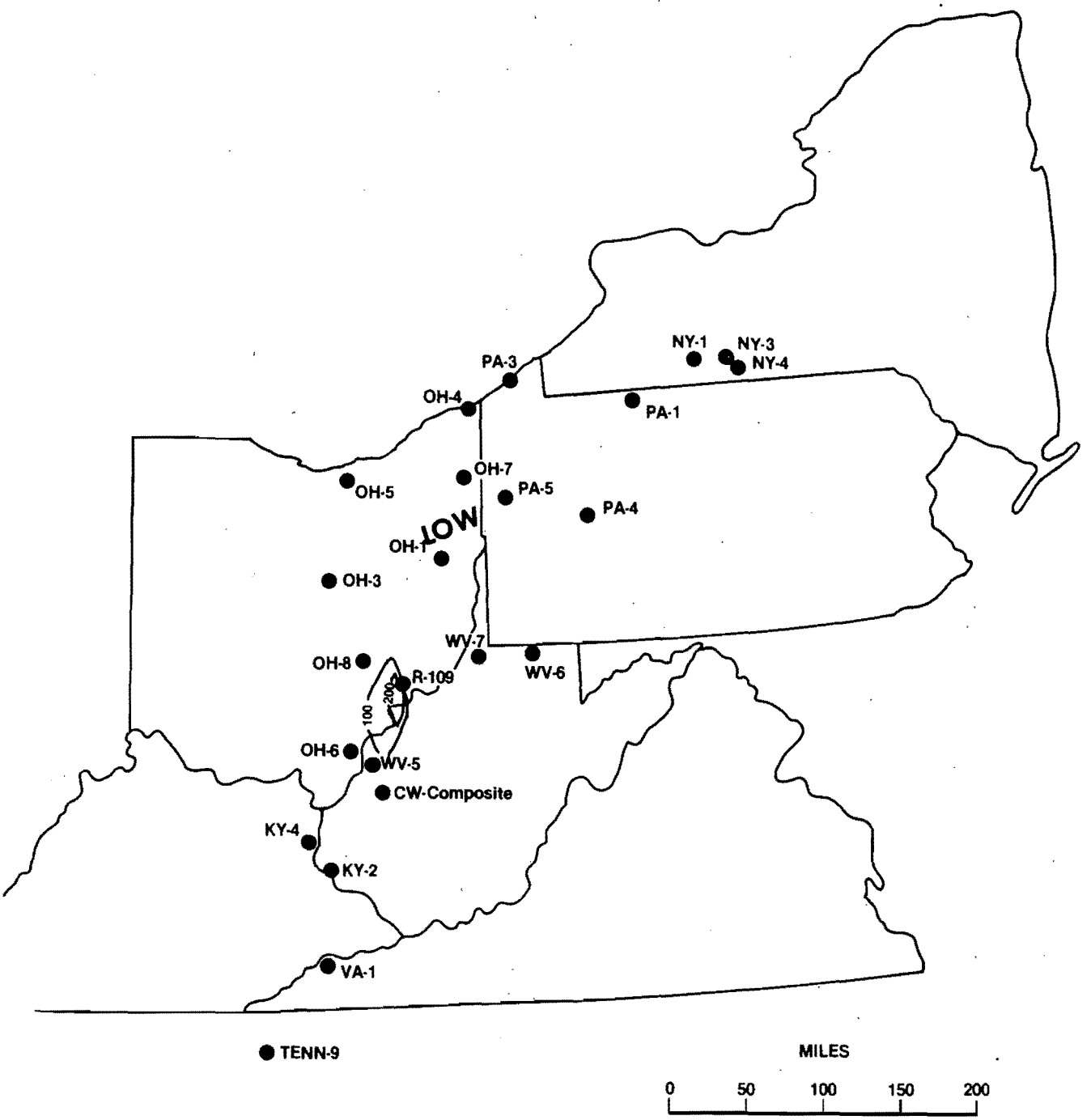


FIGURE 100

SONYEA/MIDDLESEX TIME

MAP UNIT 5

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

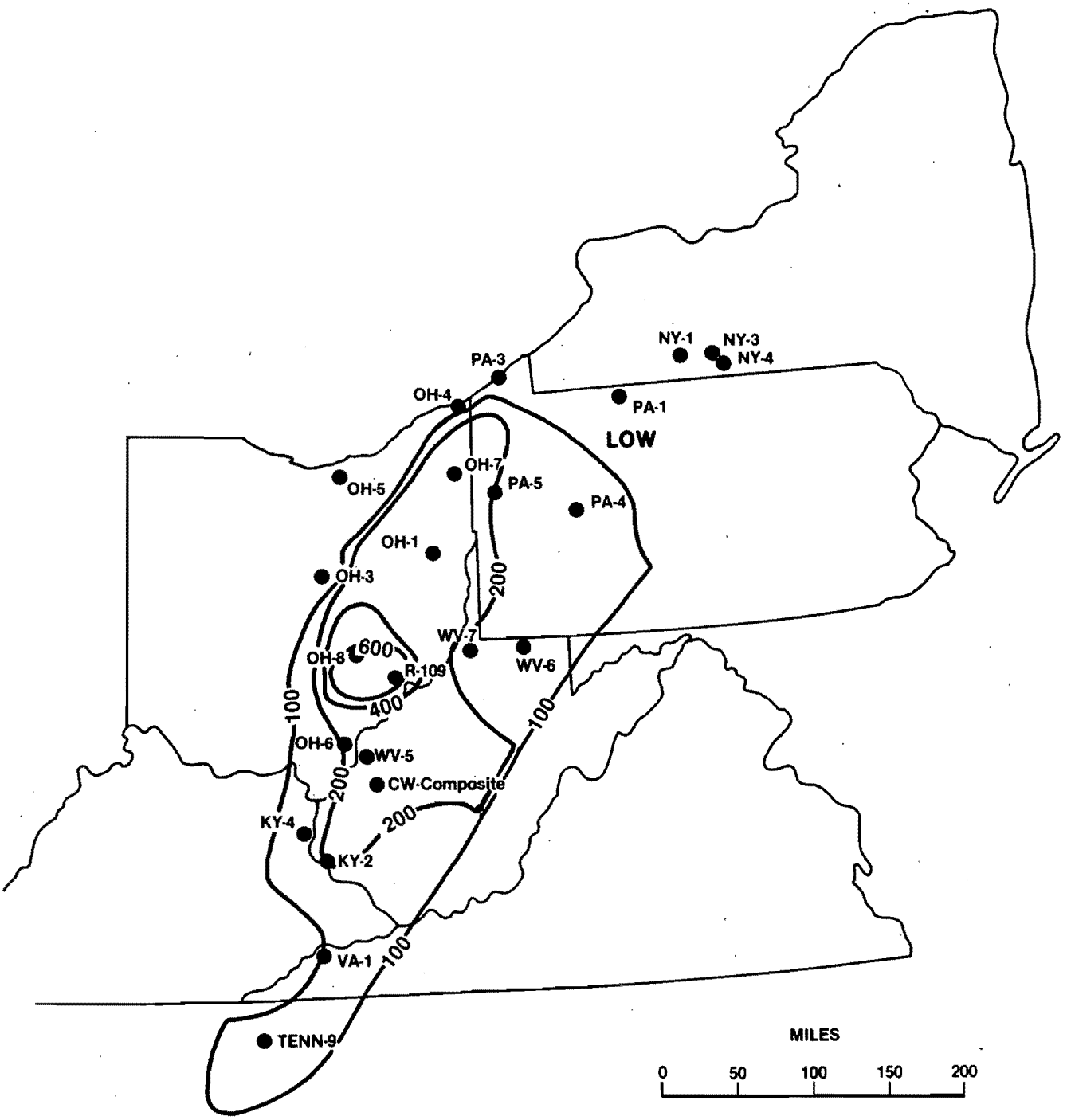


FIGURE 101

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

Map Unit 6

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

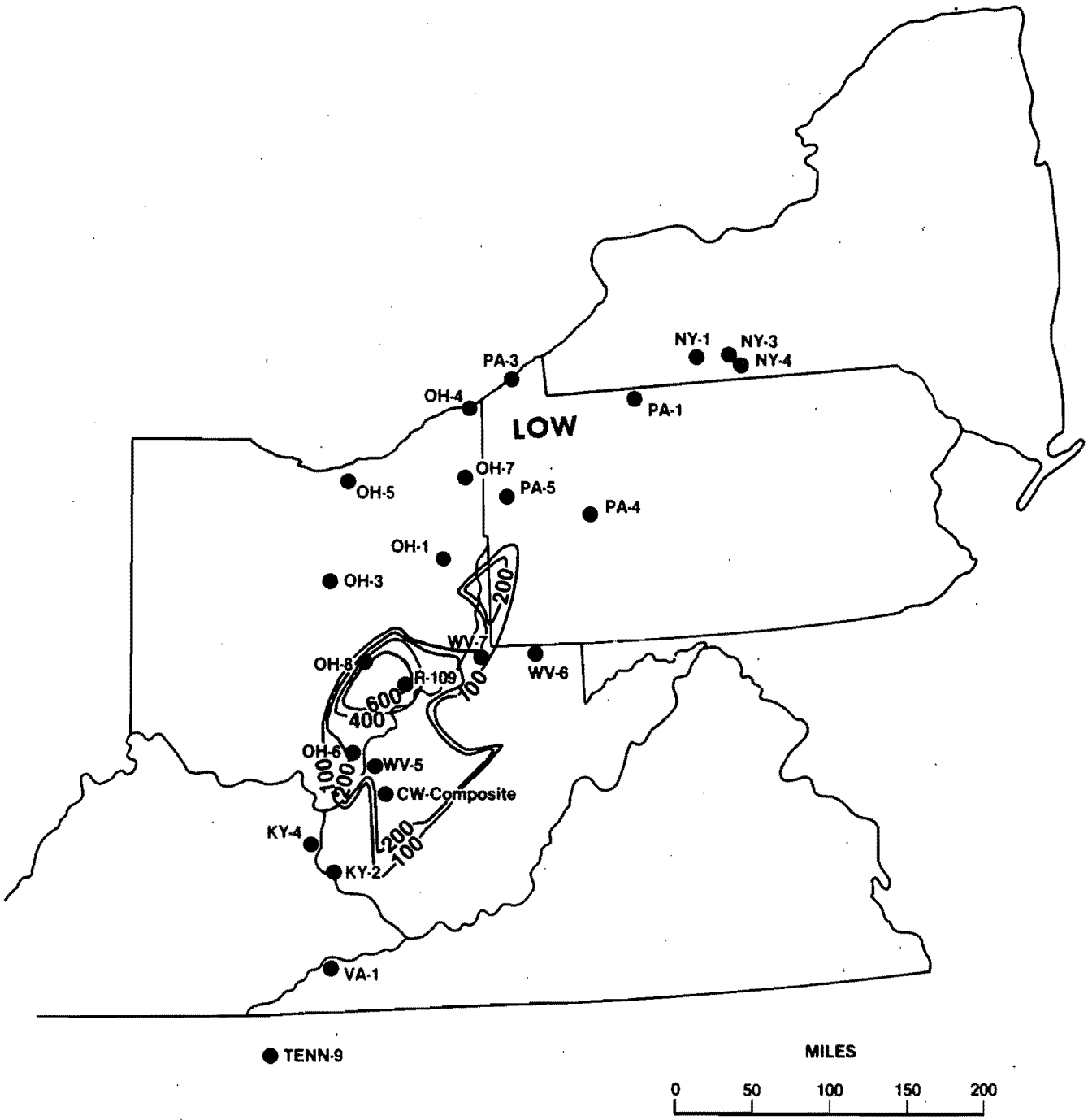


FIGURE 102

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

MAP UNIT 6

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

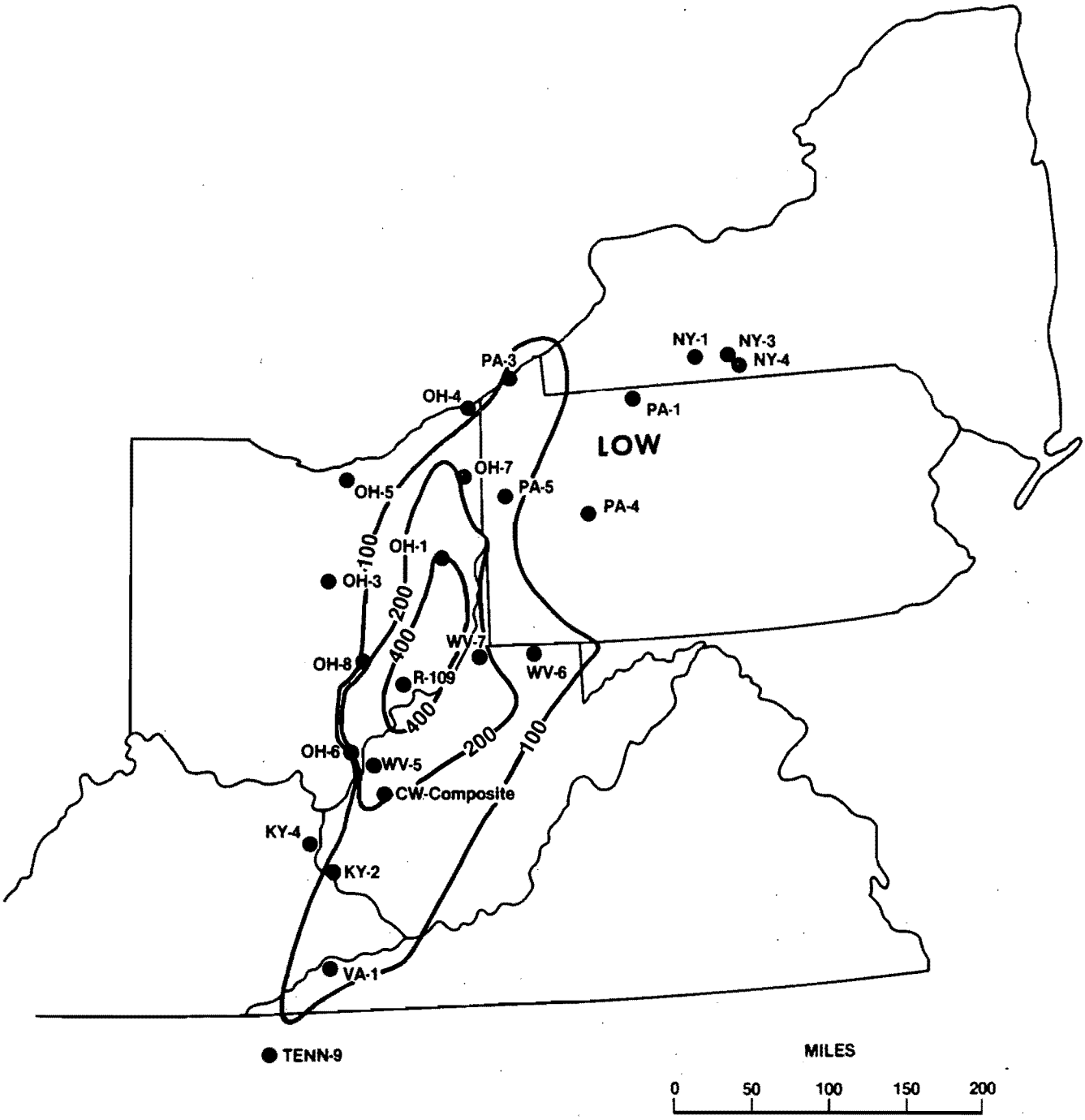


FIGURE 103

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

Map Unit 7

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

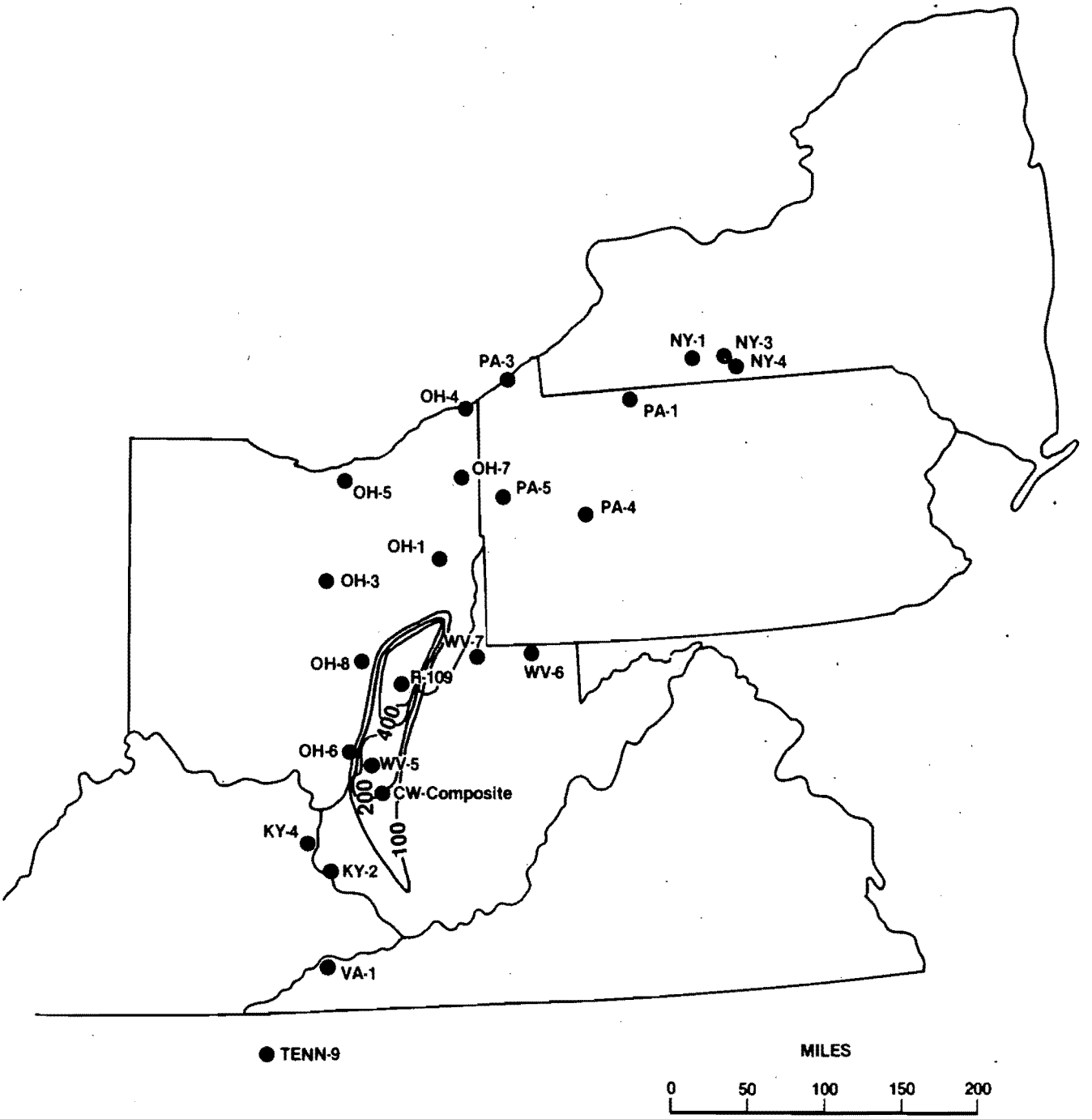


FIGURE 104

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

MAP UNIT 7

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

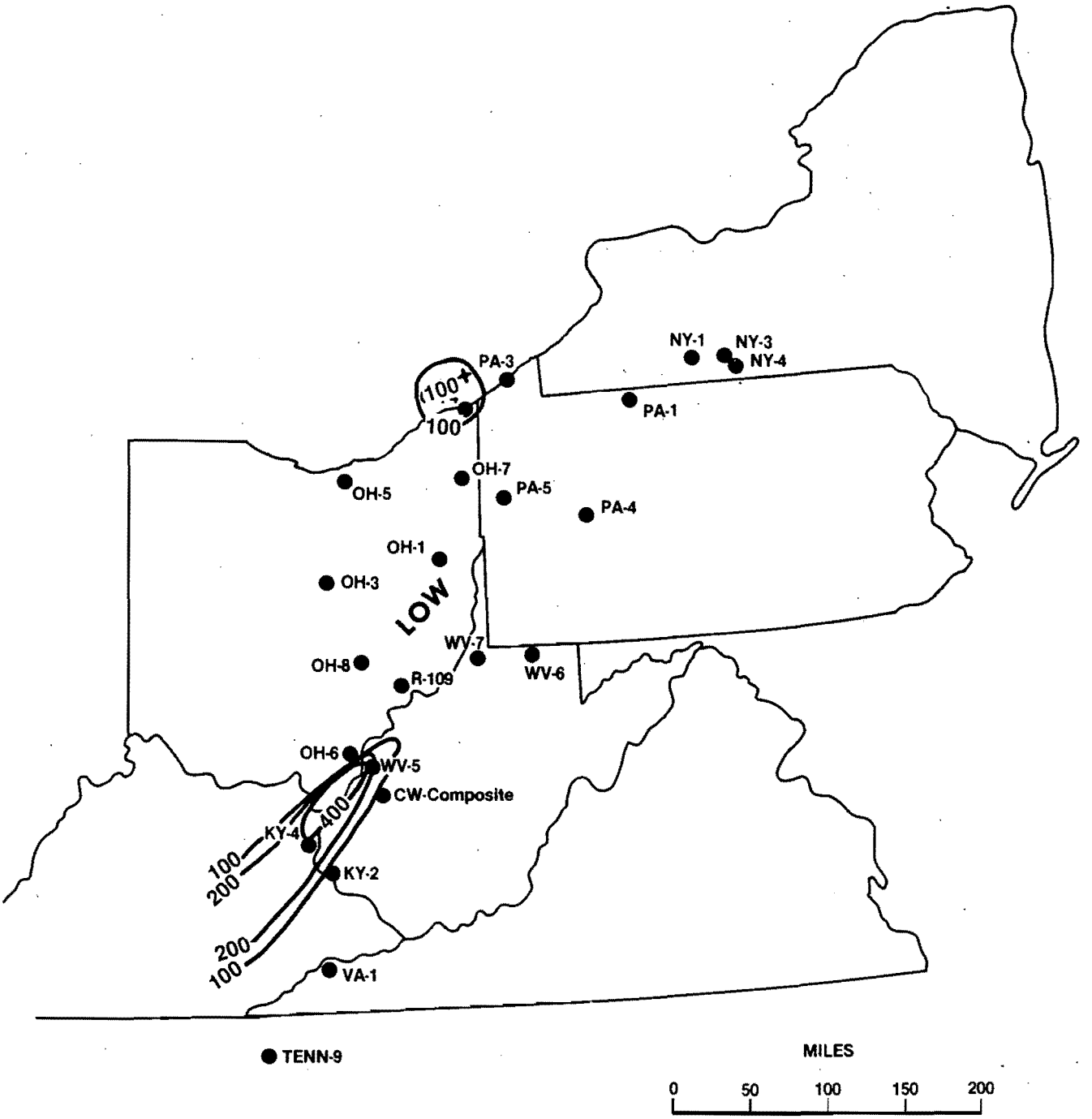


FIGURE 105

MIDDLE OLENTANGY/ANGOLA SHALE TIME

Map Unit 8

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

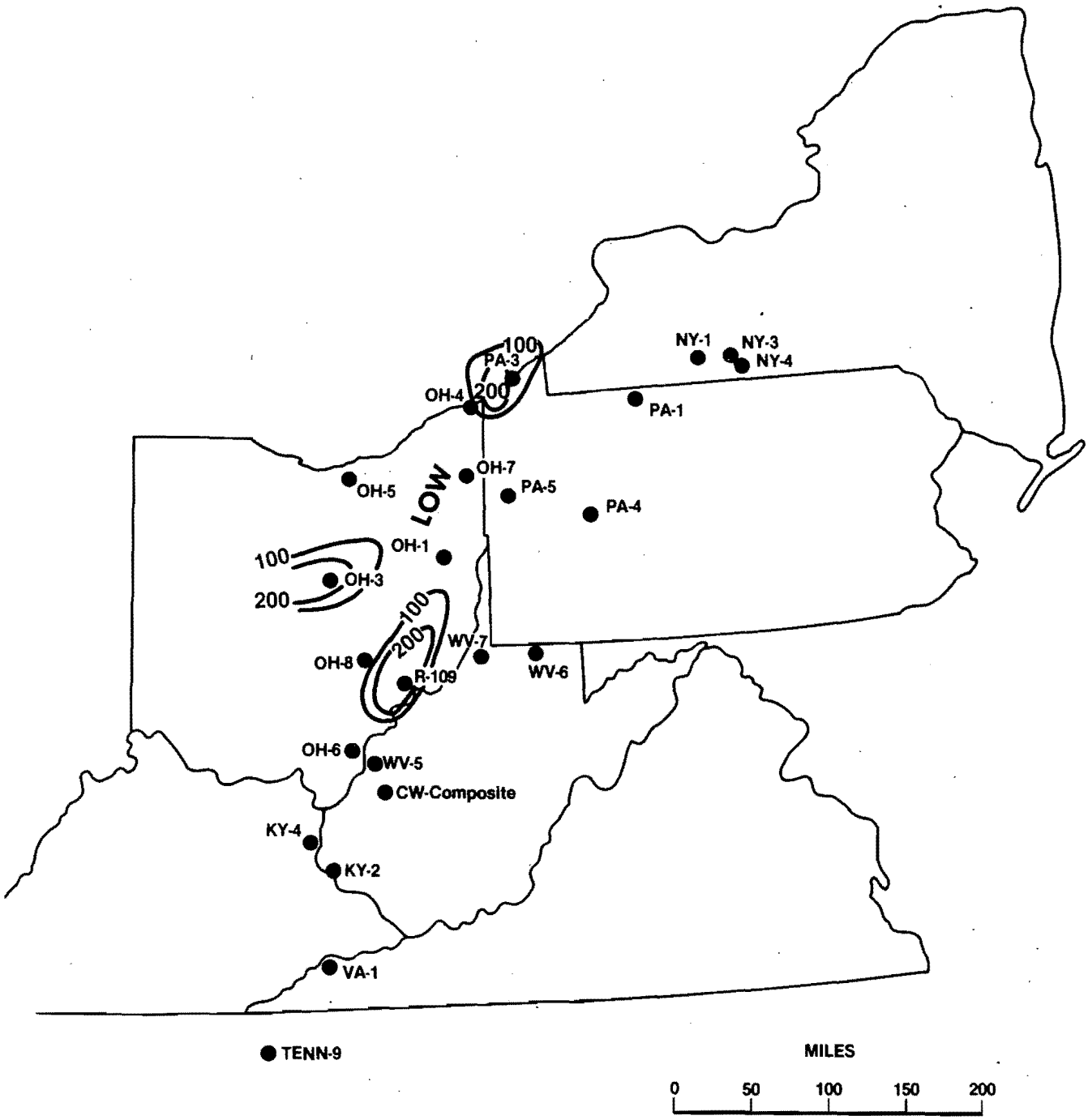


FIGURE 106

UPPER OLENTANGY/JAVA FM. HANOVER SHALE TIME

Map Unit 9

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

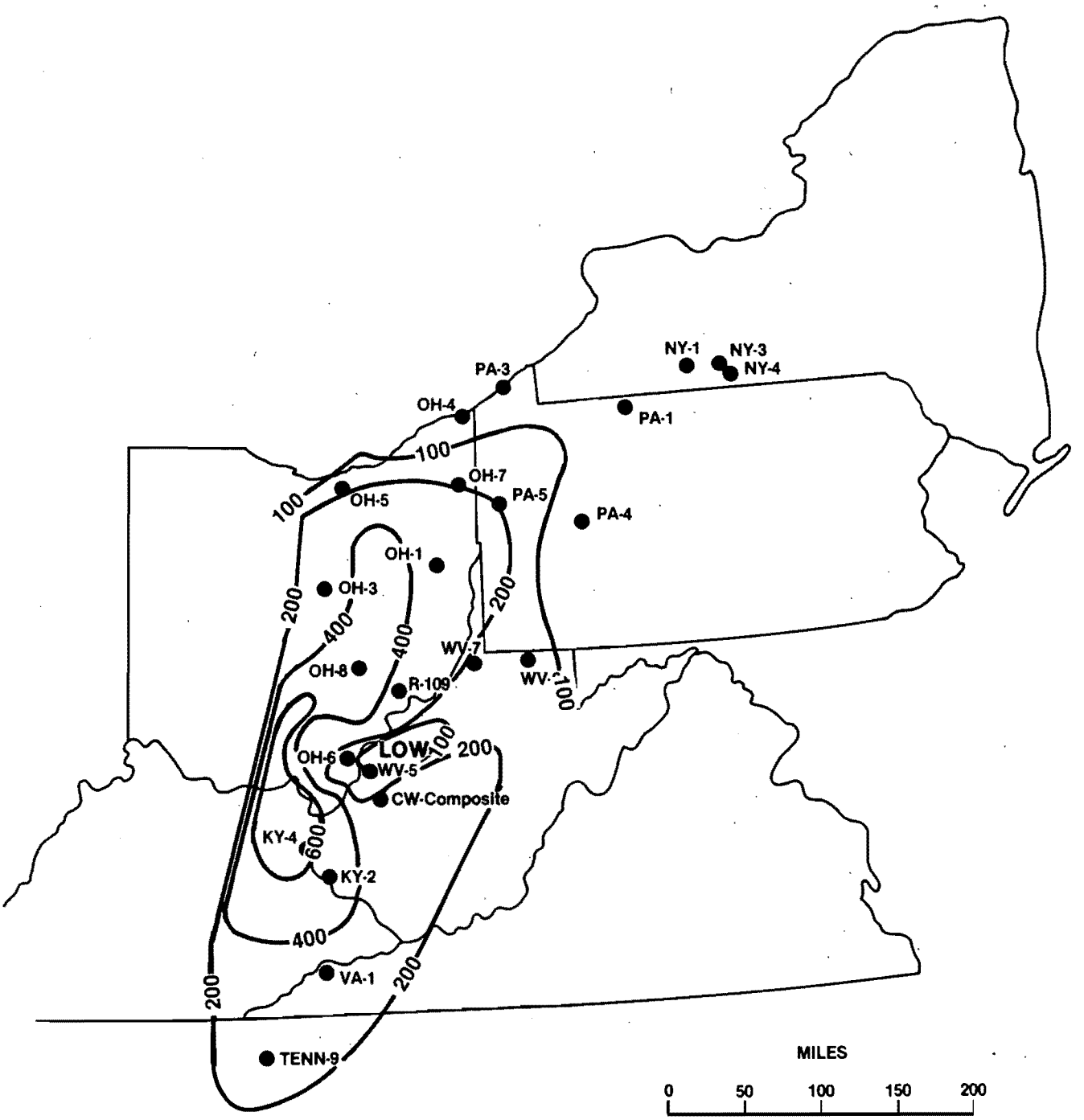


FIGURE 107

EARLY LOWER HURON/EARLY DUNKIRK TIME

Map Unit 10

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

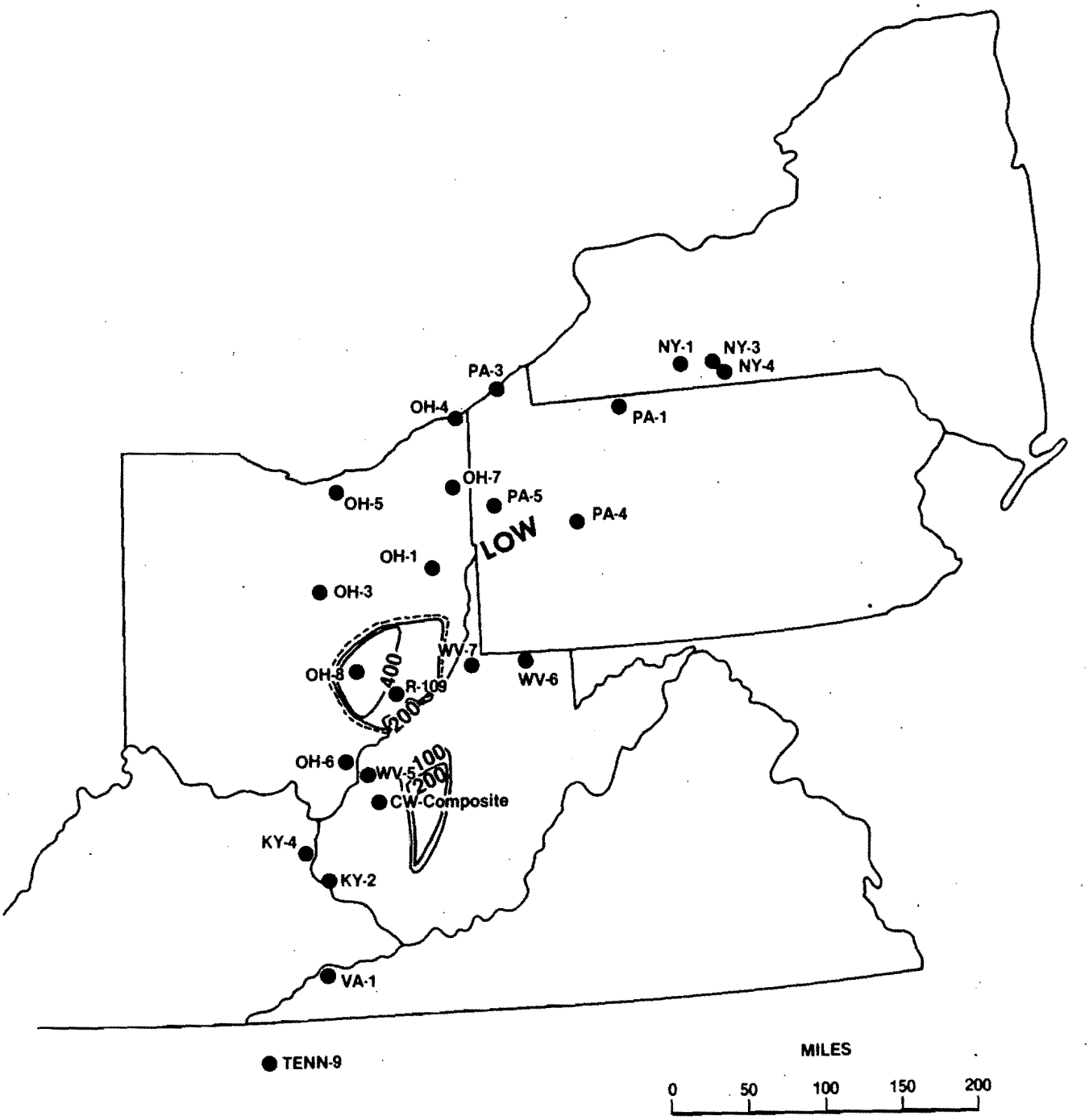


FIGURE 108

EARLY LOWER HURON/EARLY DUNKIRK TIME

MAP UNIT 10

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

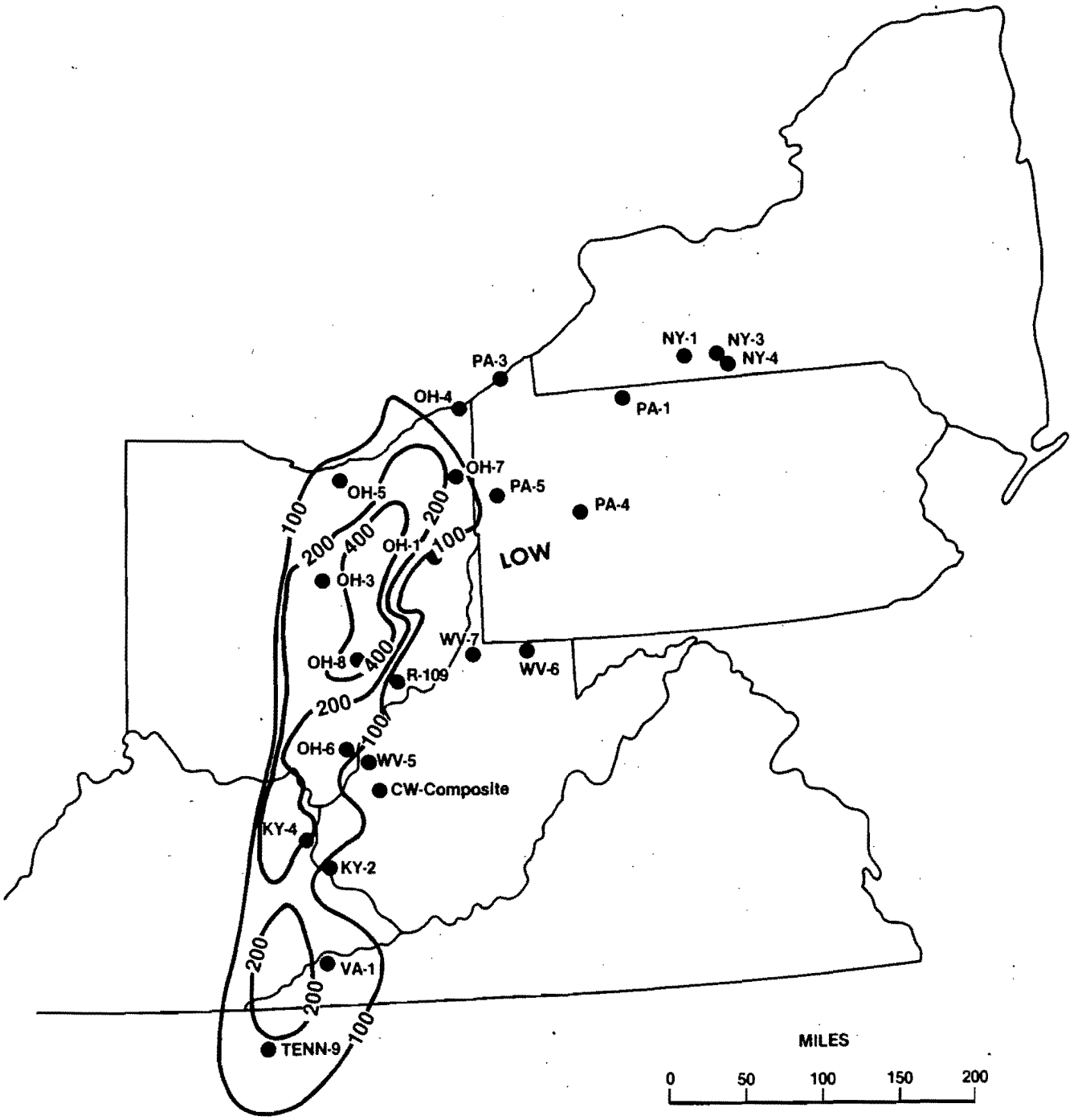


FIGURE 109

LATE LOWER HURON/LATE DUNKIRK TIME

Map Unit 11

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

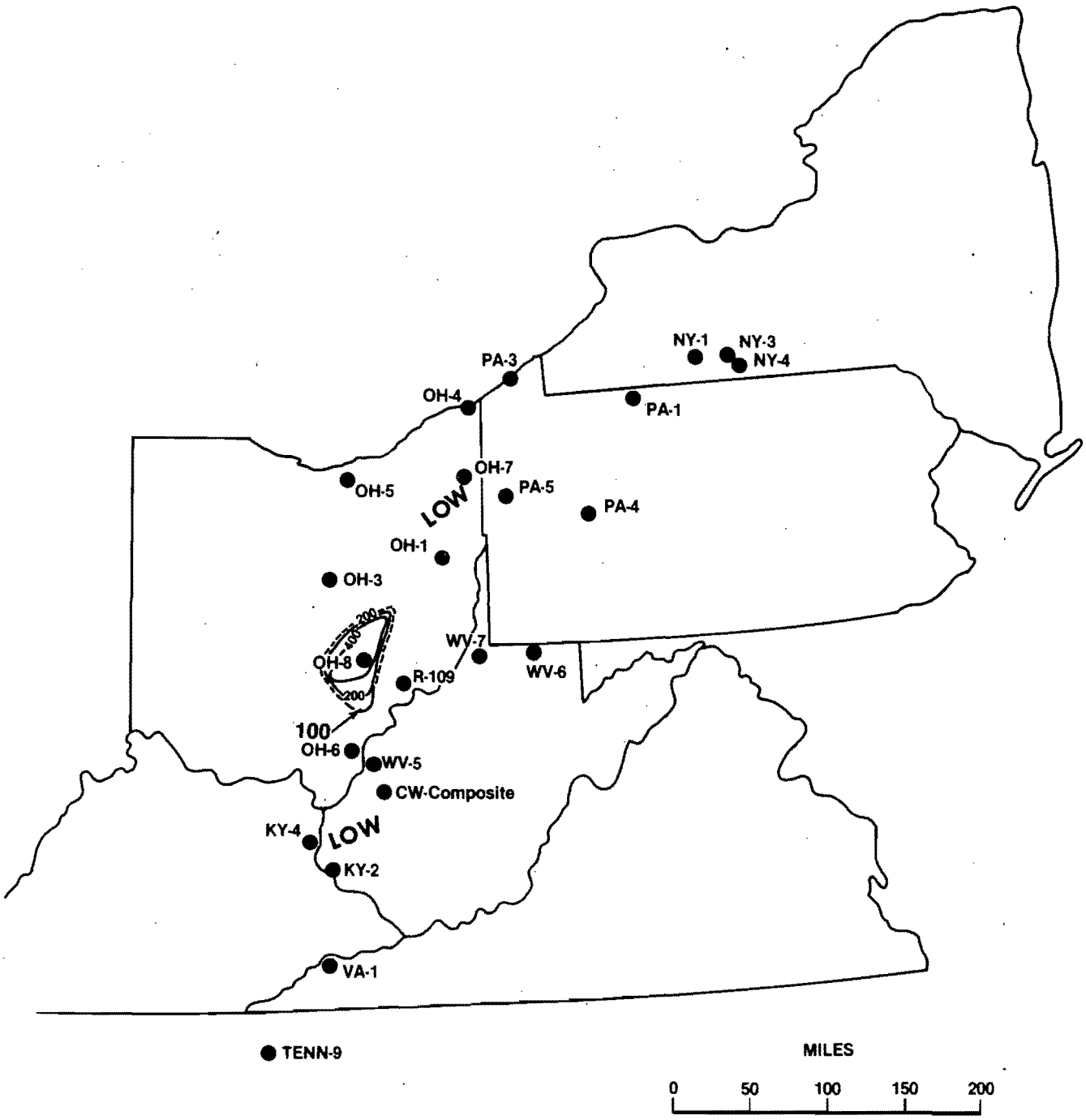


FIGURE 110

LATE LOWER HURON/LATE DUNKIRK TIME

MAP UNIT 11

MOUND

Prepared by Mound Facility

also has an elongate band of fair gas source potential stretching from north of TENN - 9 almost to OH - 4.

Figure 111, shows a patch of fair potential for gas in the early Middle Huron unit in eastern Ohio. Therefore, this unit could contribute gas to contiguous porosity if it could be found.

The later Middle Huron shale has only one small area where it has fair gas source potential in extreme southern Ohio and the adjacent part of Kentucky as shown in Figure 112. There are also two small areas with fair source potential in extreme northeastern Ohio and in eastern Kentucky that could contribute gas to porosity.

Figure 113 shows that the early Upper Huron unit has some good potential for gas in east-central Ohio, and a small area of good oil potential in the area near OH - 8 (Figure 114).

Figure 115 shows that the later Upper Huron has a similar distribution of rocks with good gas potential but they are more extensive. There is also a small area just northeast of OH - 6, WV - 5, and the Cottageville wells that has fair oil source potential (Figure 116).

The Chagrin has relatively less potential to source commercial quantities of hydrocarbons. This is shown on Figure 117. The Cleveland Shale unit, has a large area with fair potential for gas (Figure 118) and oil (Figure 119) accumulations in central Ohio.

The data from the above sets of gas and oil source potential maps were combined to produce composite maps of the gas-source and oil-source potential of the entire Upper Devonian section. The values on each of the gas and oil-source potential maps were summed on a matrix of uniform grid points on a 9 mile spacing. For convenience in mapping, the last two zeroes of the total were dropped, nevertheless the numbers are still relative indicators of the overall potential, i.e., where the best units are "stacked" in the basin.

The overall gas source potential of the Upper Devonian is shown in Figure 120. Practically the entire basin area studied has source rocks which are capable of giving up commercial quantities of gas to nearby reservoirs if they are present. However, some areas have relatively more, i.e., enormous, capacity to source gas. The richest of these is centered in southeastern Ohio, with rocks of somewhat less, but still excellent potential covering practically the eastern half of Ohio and into northwestern West Virginia. Another rich area is centered in southwestern New York and west north-central Pennsylvania. A third high-potential area is centered in Kentucky just west of the confluence of the Ohio, West Virginia and Kentucky borders.

Good overall oil source quality is more limited because oil requires the right kind of organic matter and more thermal alteration to generate commercial quantities than does gas. The areas where the richest oil sources are located are shown in Figure 121. The richest area is centered in Southeastern Ohio and spreads amoeba-like to the east and south. Another slightly less rich area is located in southwestern New York and west north-central Pennsylvania.

RELATIVE GAS SOURCE POTENTIAL

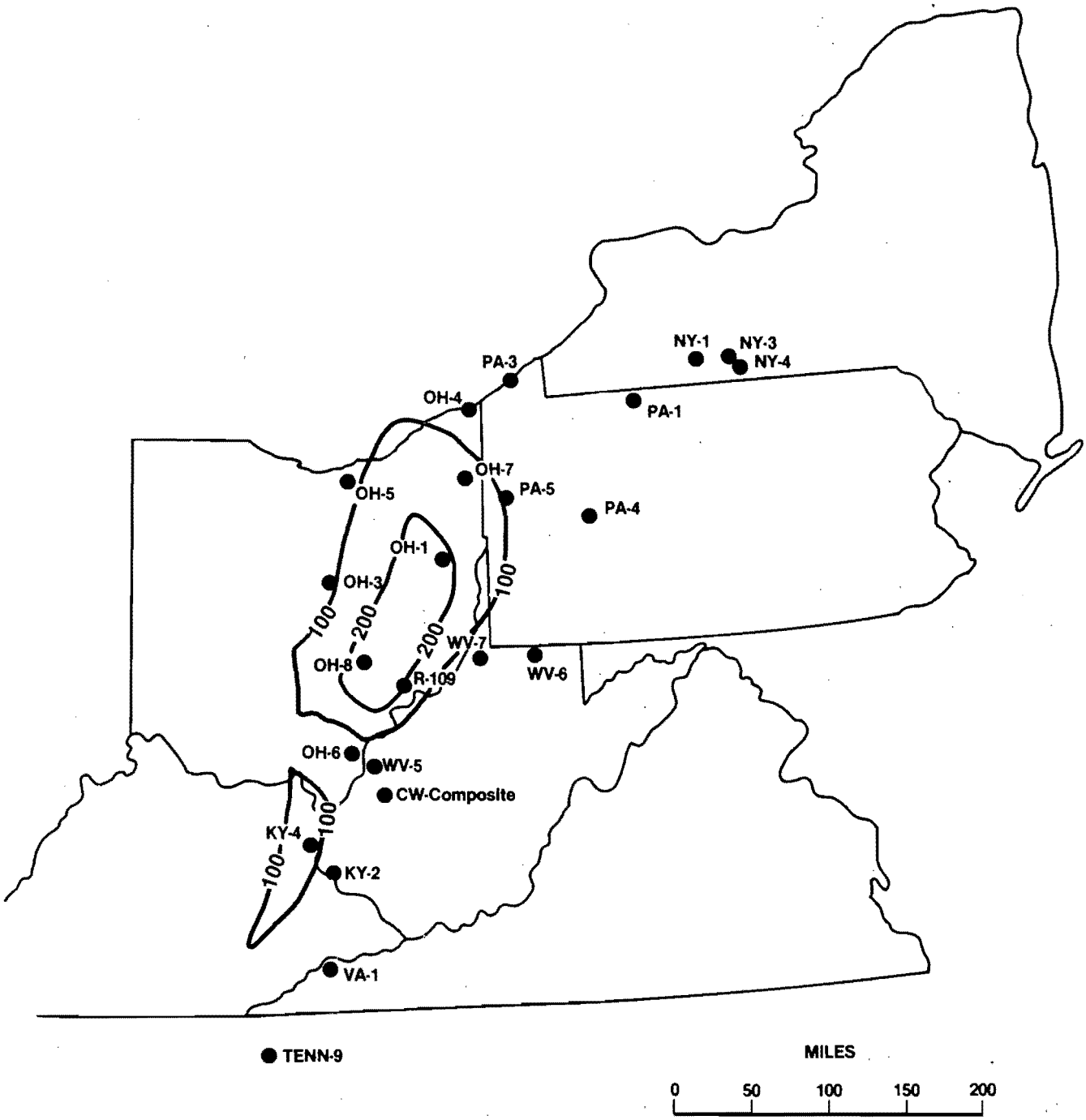


FIGURE 111

EARLY MIDDLE HURON TIME

Map Unit 12

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

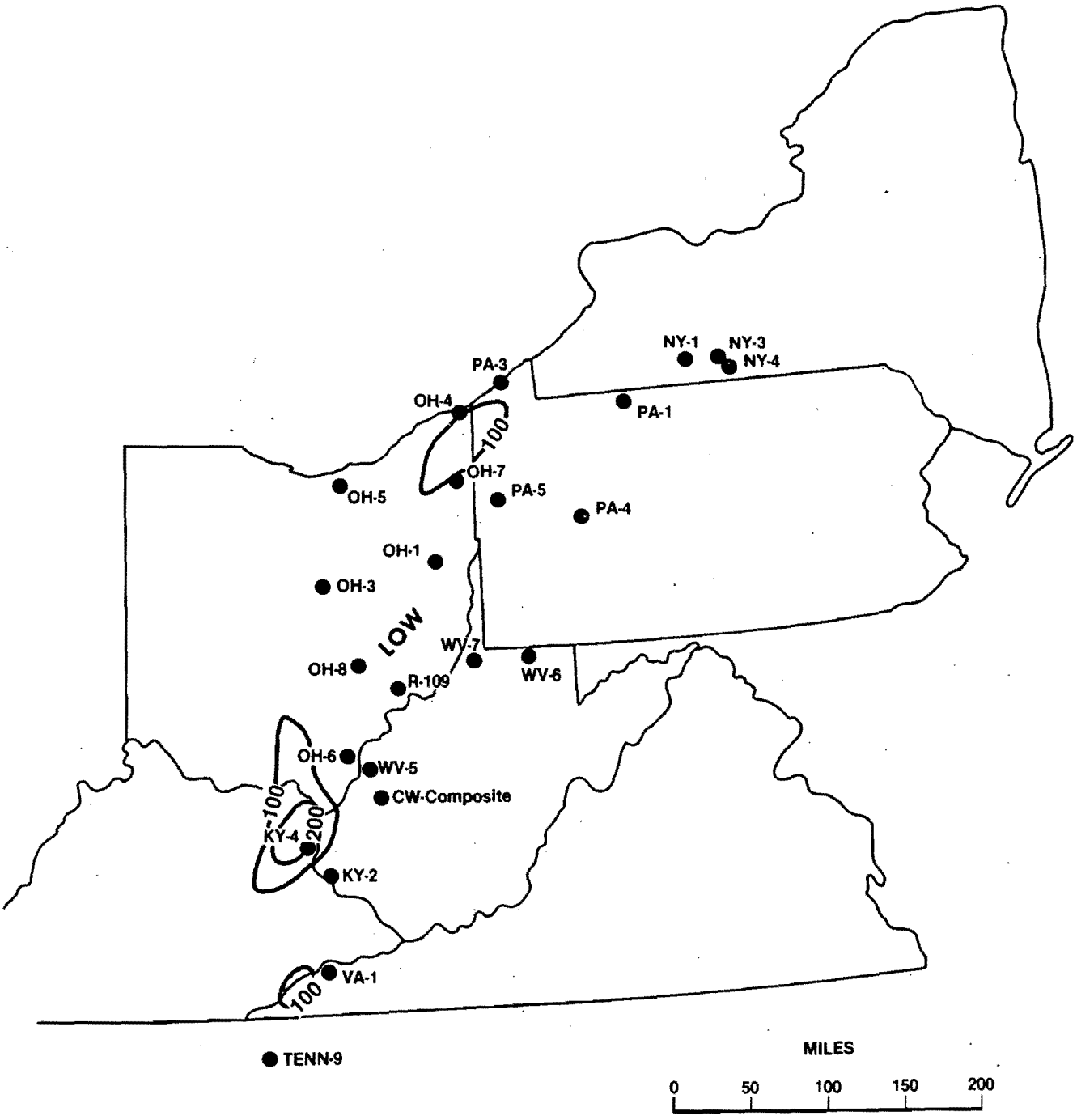


FIGURE 112

LATE MIDDLE HURON TIME

Map Unit 13

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

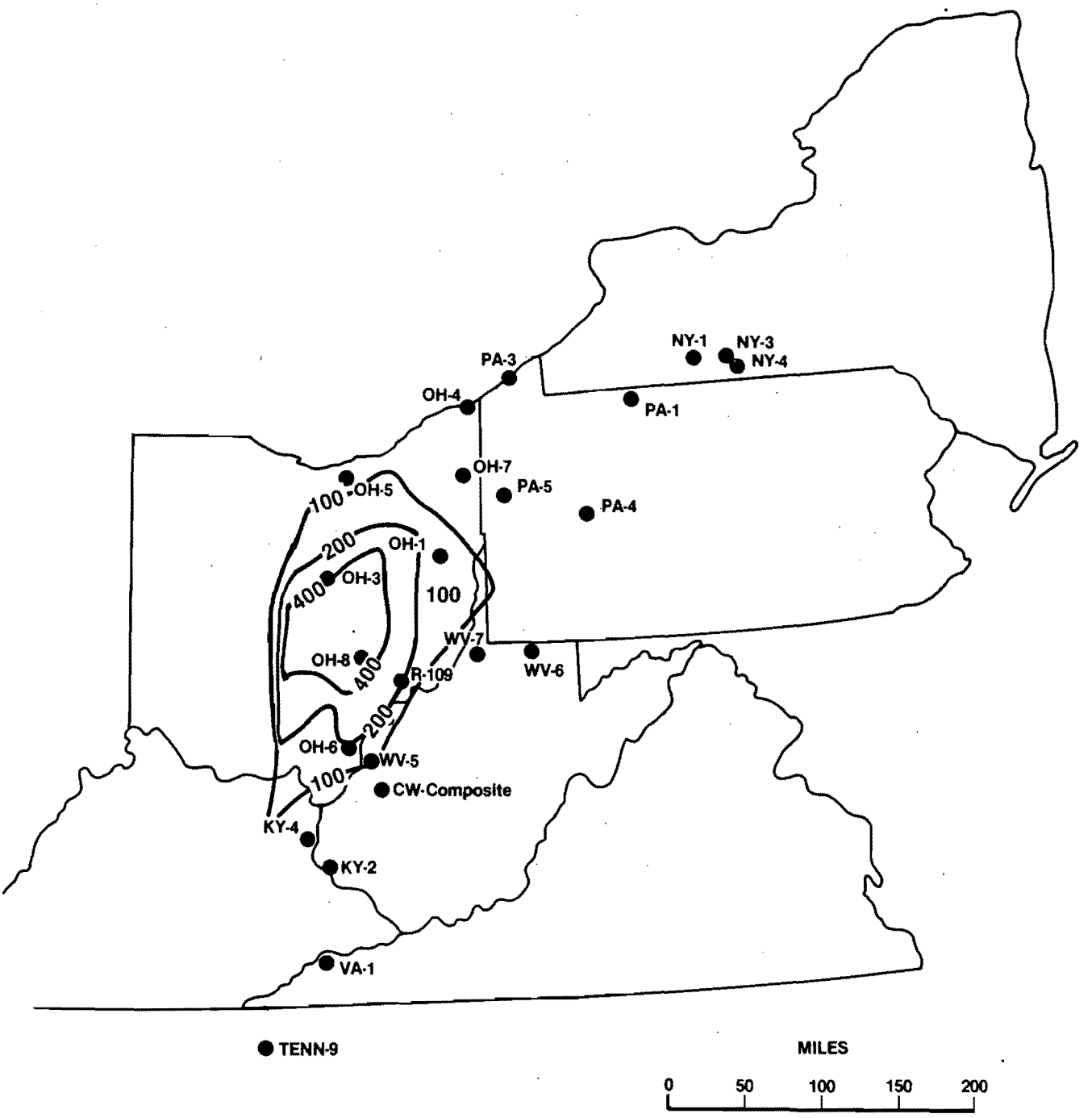


FIGURE 113

EARLY UPPER HURON TIME

Map Unit 14

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

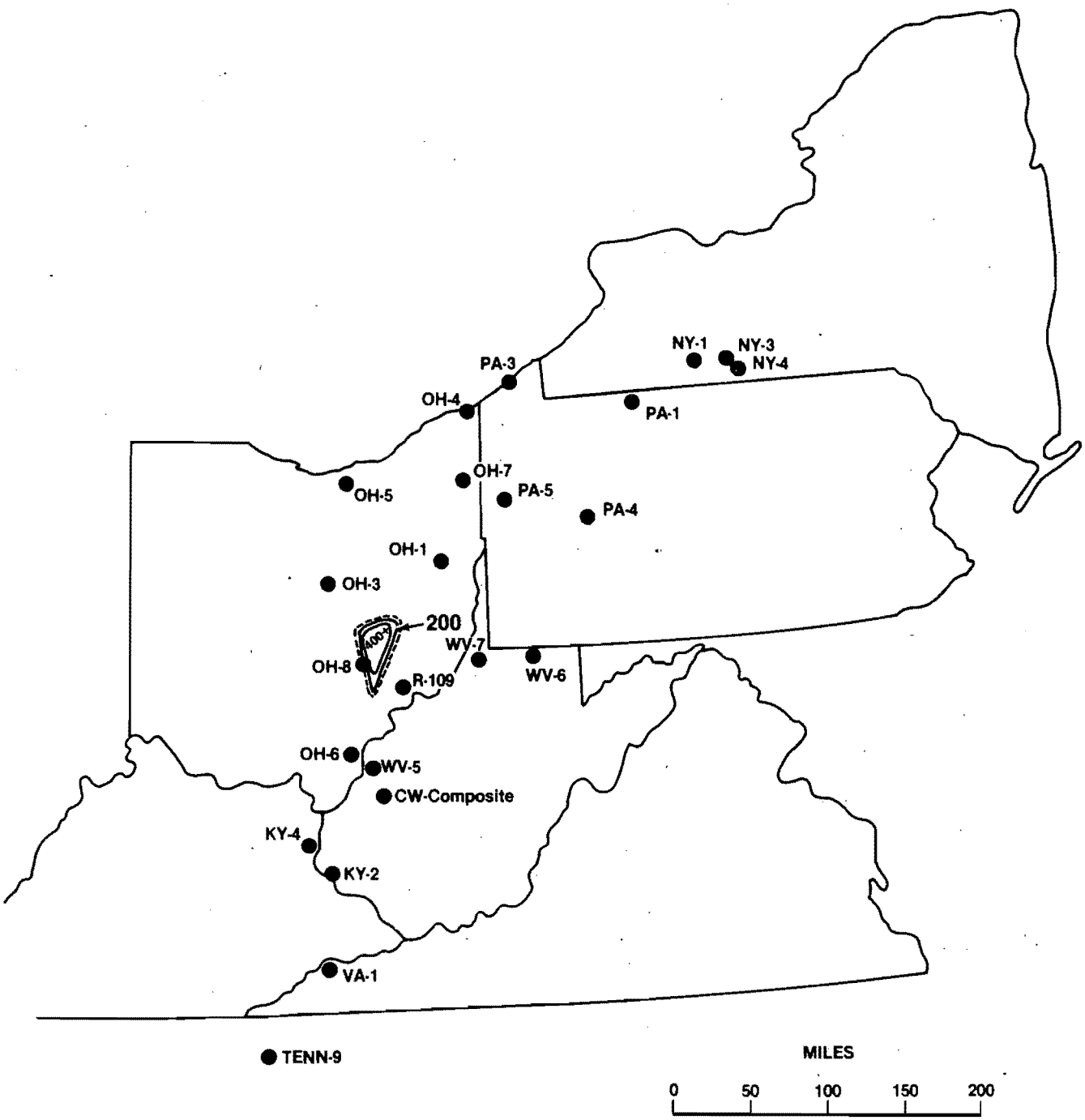


FIGURE 114

EARLY UPPER HURON TIME

MAP UNIT 14

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

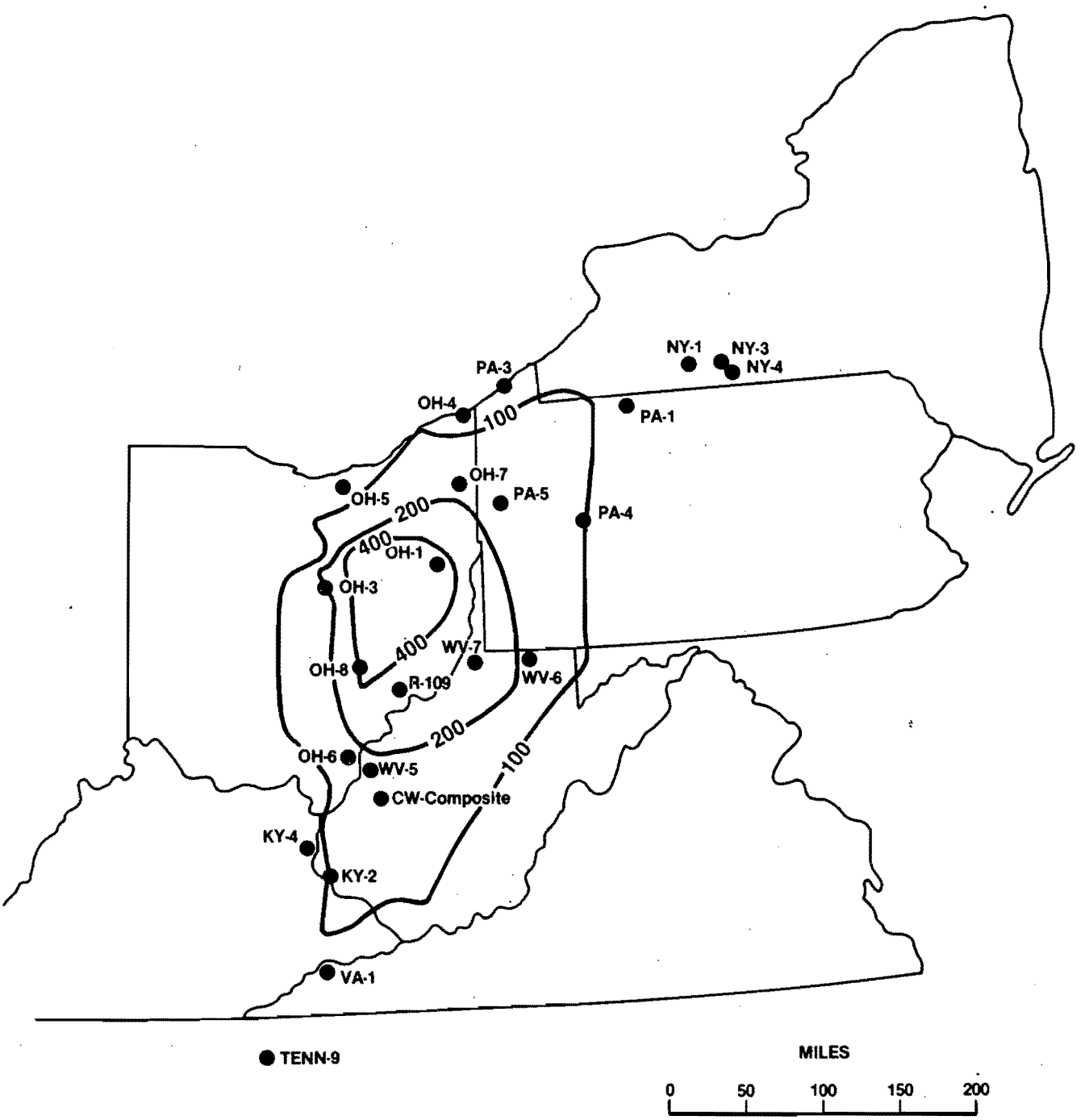


FIGURE 115

LATE UPPER HURON TIME

Map Unit 15

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

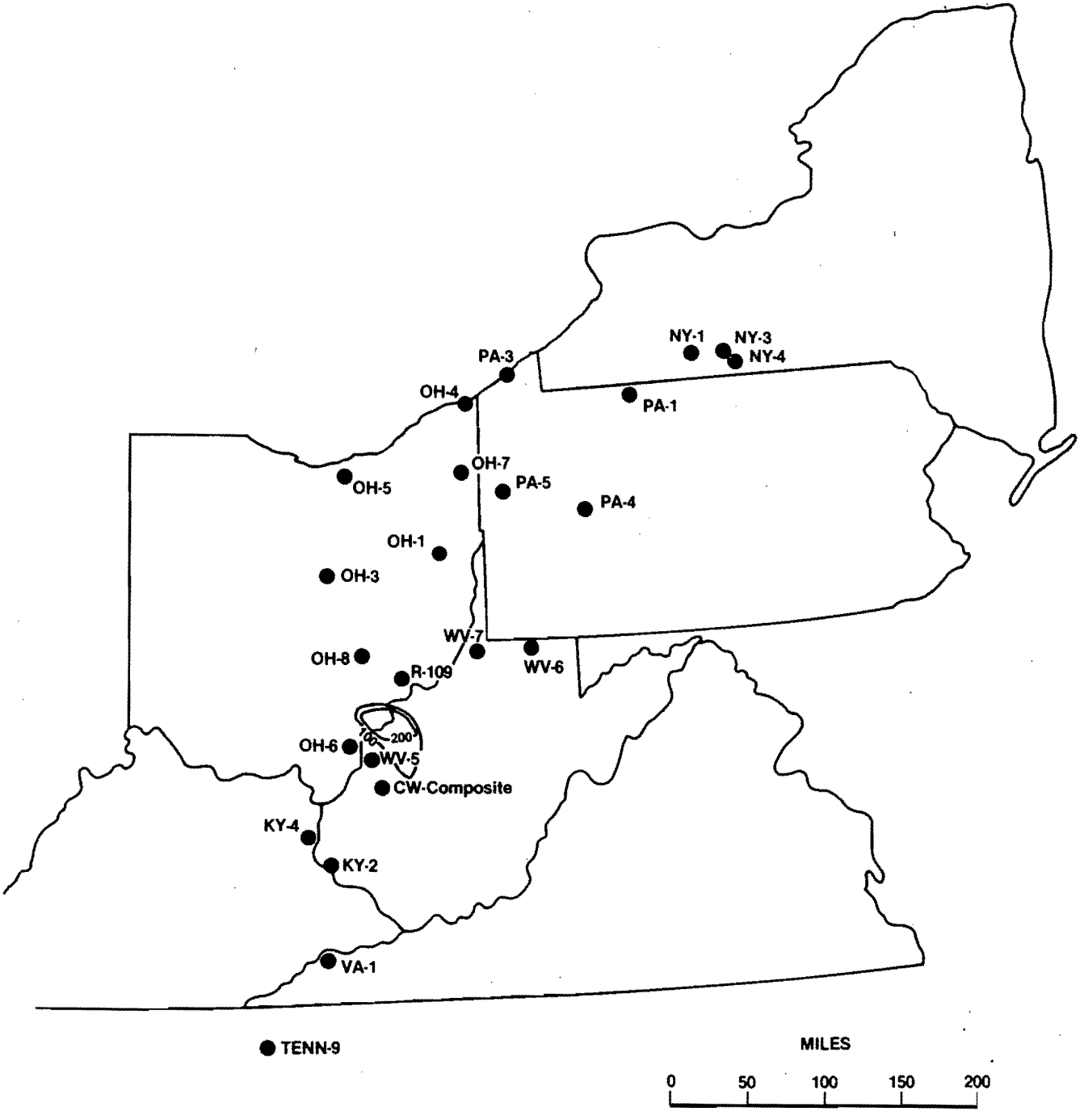


FIGURE 116

LATE UPPER HURON TIME

MAP UNIT 15

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

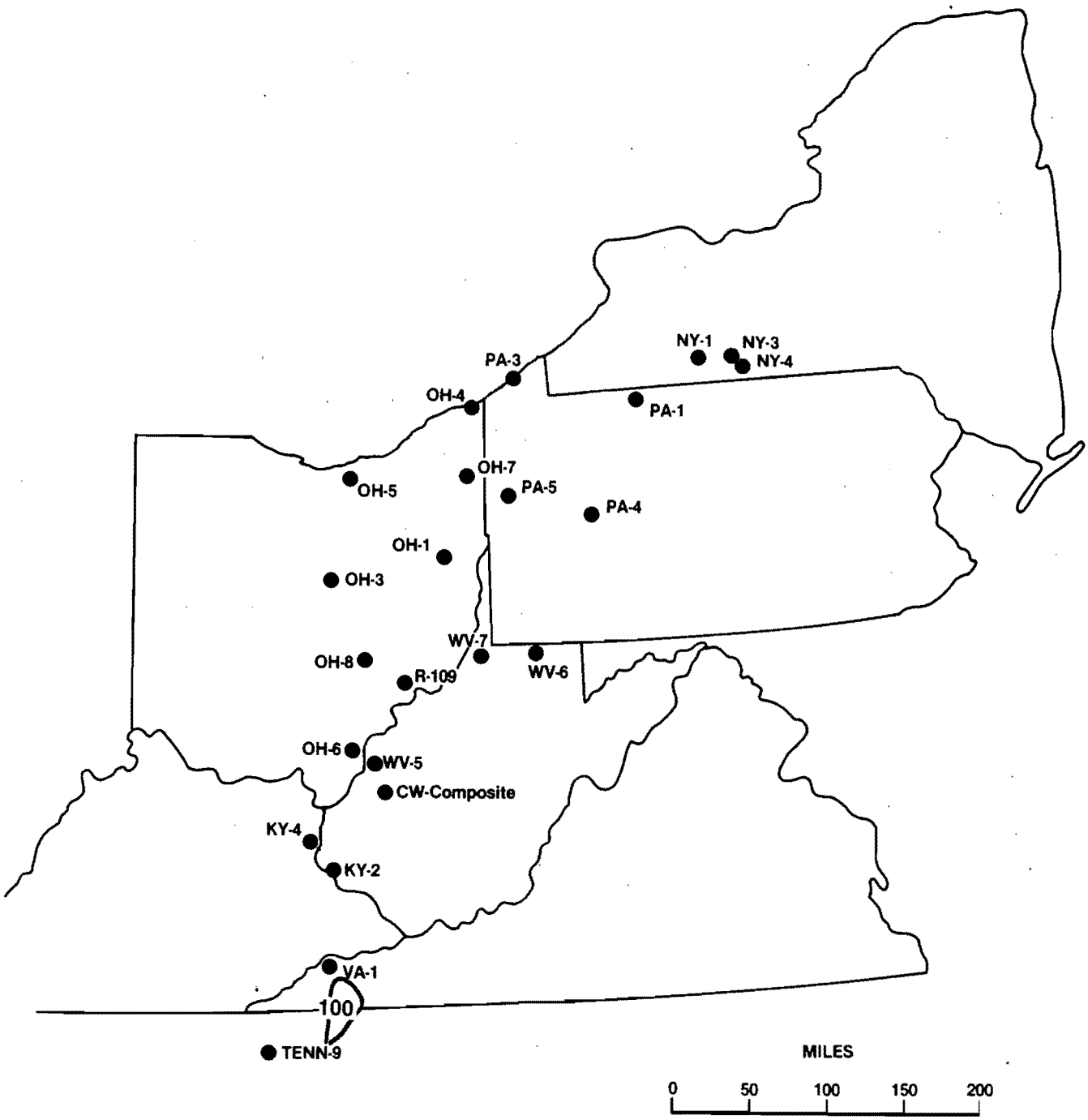


FIGURE 117

CHAGRIN TIME

Map Unit 16

MOUND

Prepared by Mound Facility

RELATIVE GAS SOURCE POTENTIAL

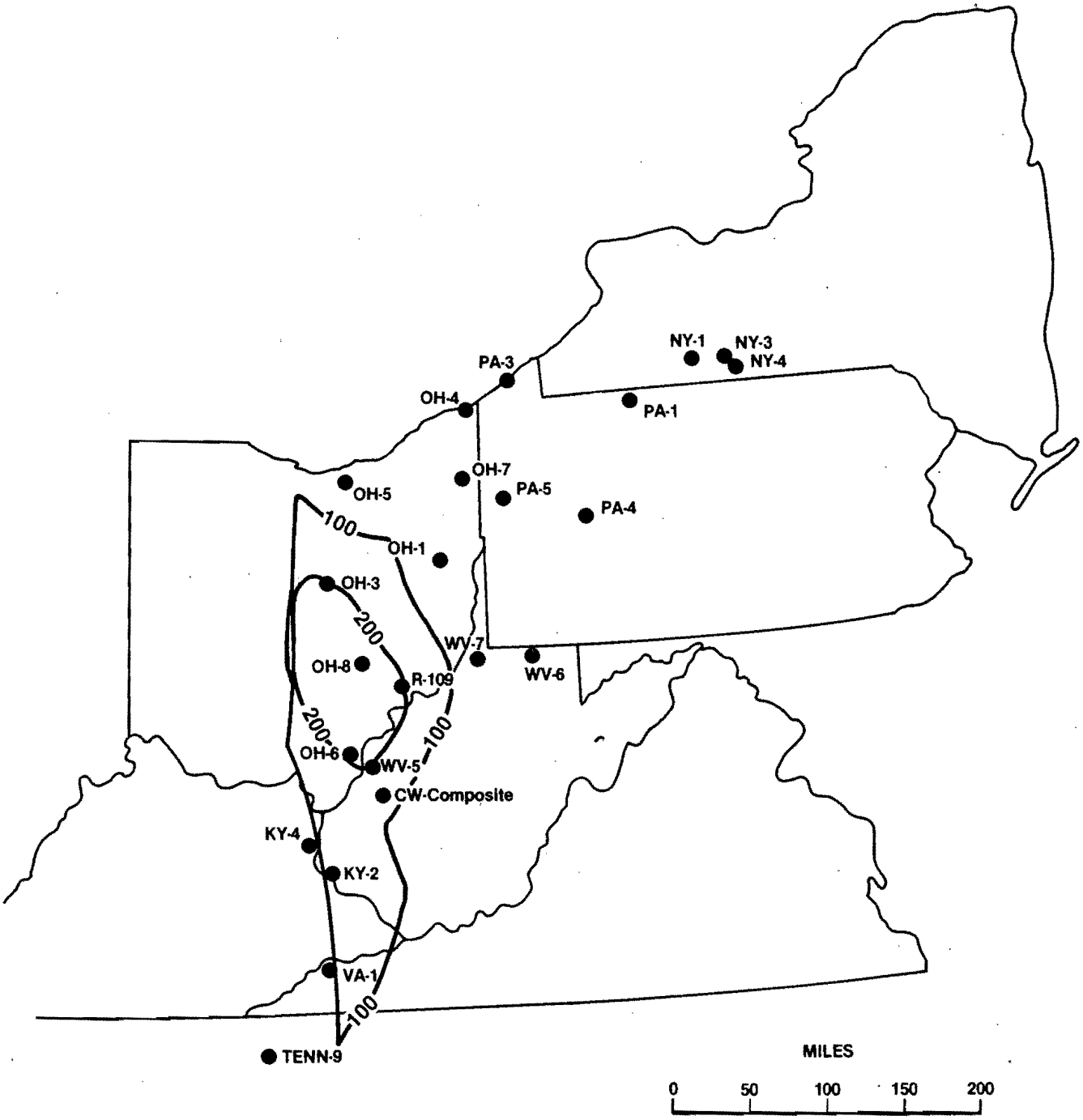


FIGURE 118

CLEVELAND TIME

Map Unit 17

MOUND

Prepared by Mound Facility

RELATIVE OIL SOURCE POTENTIAL

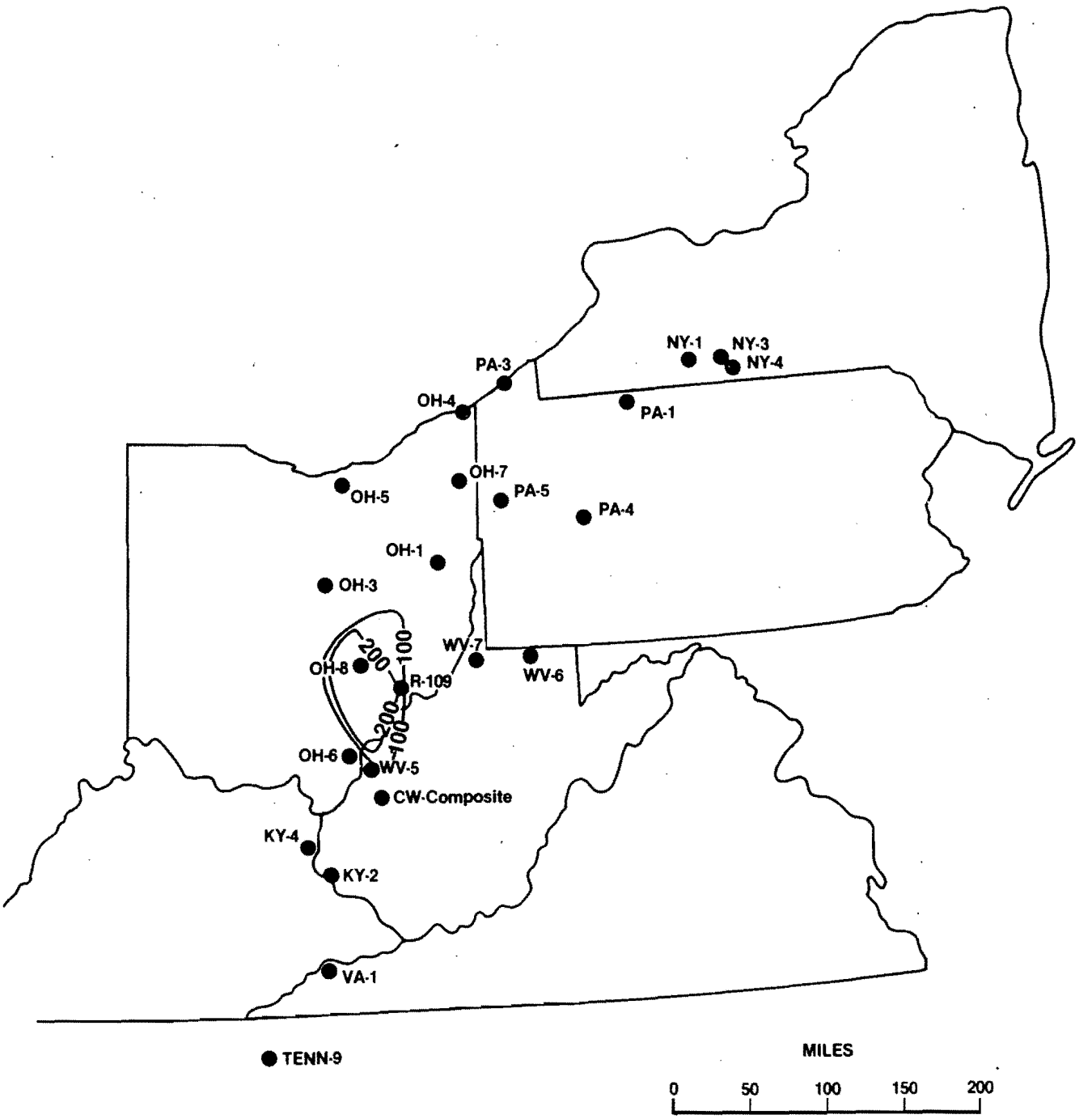


FIGURE 119

CLEVELAND TIME

MAP UNIT 17

MOUND

Prepared by Mound Facility

OVERALL GAS SOURCE POTENTIAL

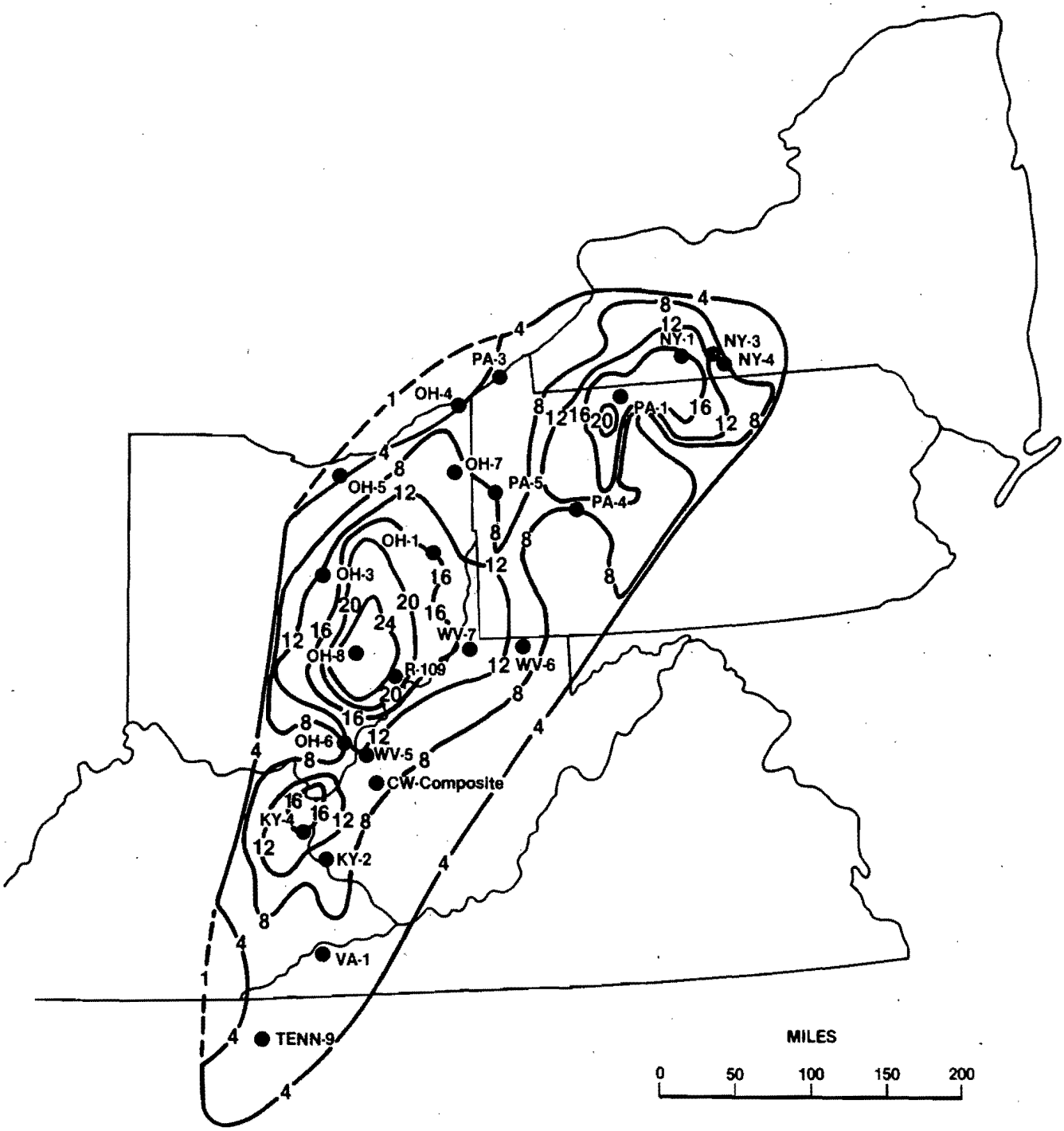


FIGURE 120

CONTOUR VALUES X 100 = RELATIVE POTENTIAL

UPPER DEVONIAN SHALES

MOUND

Prepared by Mound Facility

OVERALL OIL SOURCE POTENTIAL

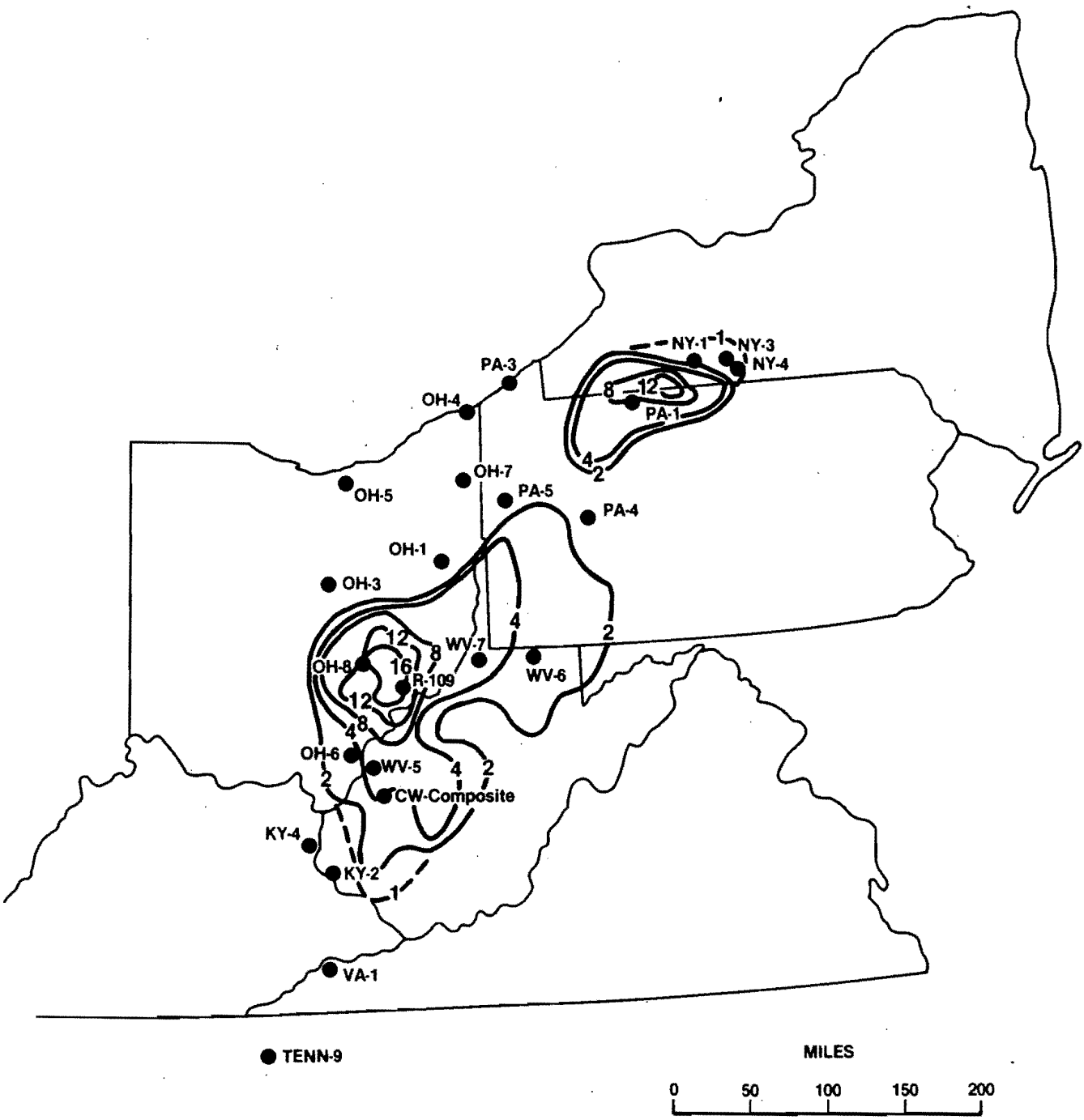


FIGURE 121

CONTOUR VALUES X 100 = RELATIVE POTENTIAL

UPPER DEVONIAN SHALES

MOUND

Prepared by Mound Facility

It is important to keep in mind that all of the areas within the 1 or 2 contour lines contain what would be considered good to exceptional oil sources in other basins of the world. If the shales themselves were fractured and/or interbedded with thin siltstone stringers, or if there were more typical sand or carbonate reservoir rocks in formations immediately above or below the rich source units, commercial production would be expected.

This exercise in geochemistry testifies to the fact that the primary control on oil and gas occurrence in the Upper Devonian (in the portion of the basin studied) is something other than the distribution of source rocks. Obviously, the paucity of porosity and permeability in the Upper Devonian rocks has kept the dark shale units from sourcing one of the greatest oil and gas-producing provinces of the world.

Other Geochemical Parameters

In addition to the critical exploration parameters, organic carbon, organic matter type, thermal alteration index and gas contents (particularly those from controlled off-gassing), other detailed geochemical analyses were run on samples from thirty Appalachian Basin wells. The analyses included a full suite designed to characterize the organic matter as completely as possible, as discussed in the introduction to this report, and shown diagrammatically in Figures 1 and 2.

As the analytical phases of the project wound down, it became apparent that the four aforementioned parameters were the ones that were going to be the most useful for a regional assessment of hydrocarbon potential (21). The others were useful for confirming the potential interpreted from the more diagnostic ones, and also revealed some unique and unusual characteristics of the hydrocarbon source rocks in the Appalachian Basin.

The data on heavy hydrocarbon contents and carbon isotope ratios will be discussed in detail. Other geochemical results will for the most part be relegated to well summary plots which are included as Appendix B.

Three of the four criteria deemed critical for delineating the potential of the Appalachian Basin (total organic carbon, biofacies type, thermal alteration index) give an excellent overall appraisal of the potential of the rocks if there is porosity available to receive the hydrocarbons indigenous to the sources. (The fourth parameter, gas content, will be discussed in the next major section of this report.) The lack of permeability in the shales and the lack of major porous units in fluid (migration) continuity with the source shales are the limiting factors that keep the Upper Devonian rocks from being the source of a truly major petroleum-producing province.

Cross-contouring these three parameters, and combining them with current knowledge of geochemical controls of oil and gas occurrence, shows where the oil and gas should be, other things being equal. Gas should be found in any porosity in virtually any part of the basin, but particularly large quantities would be expected where the greatest gas-generating capacity is localized. As shown earlier in Figure 120, the most favorable of these are located in southeastern Ohio and in the west north-central Pennsylvania. However, slightly less but still excellent potential extends from these areas over most of the northeastern and western reaches of the basin.

Oil potential is more localized, but blankets most of the west central part of the basin as well as part of the northeastern end (Figure 121).

The striking result of the heavy hydrocarbon extractions was that the great majority of the samples of the Upper Devonian shales had sufficient quantities of heavy hydrocarbons that they would be classed as good to exceptional potential sources of liquid hydrocarbons, i.e., OIL. On the average, they contain an order of magnitude more hydrocarbon than do a suite of representative shales collected from all over the world, as shown in Figure 122.

The relative ability of the Eastern Gas Shales to source oil would be expected to be exceptional if the generally used classification criteria,

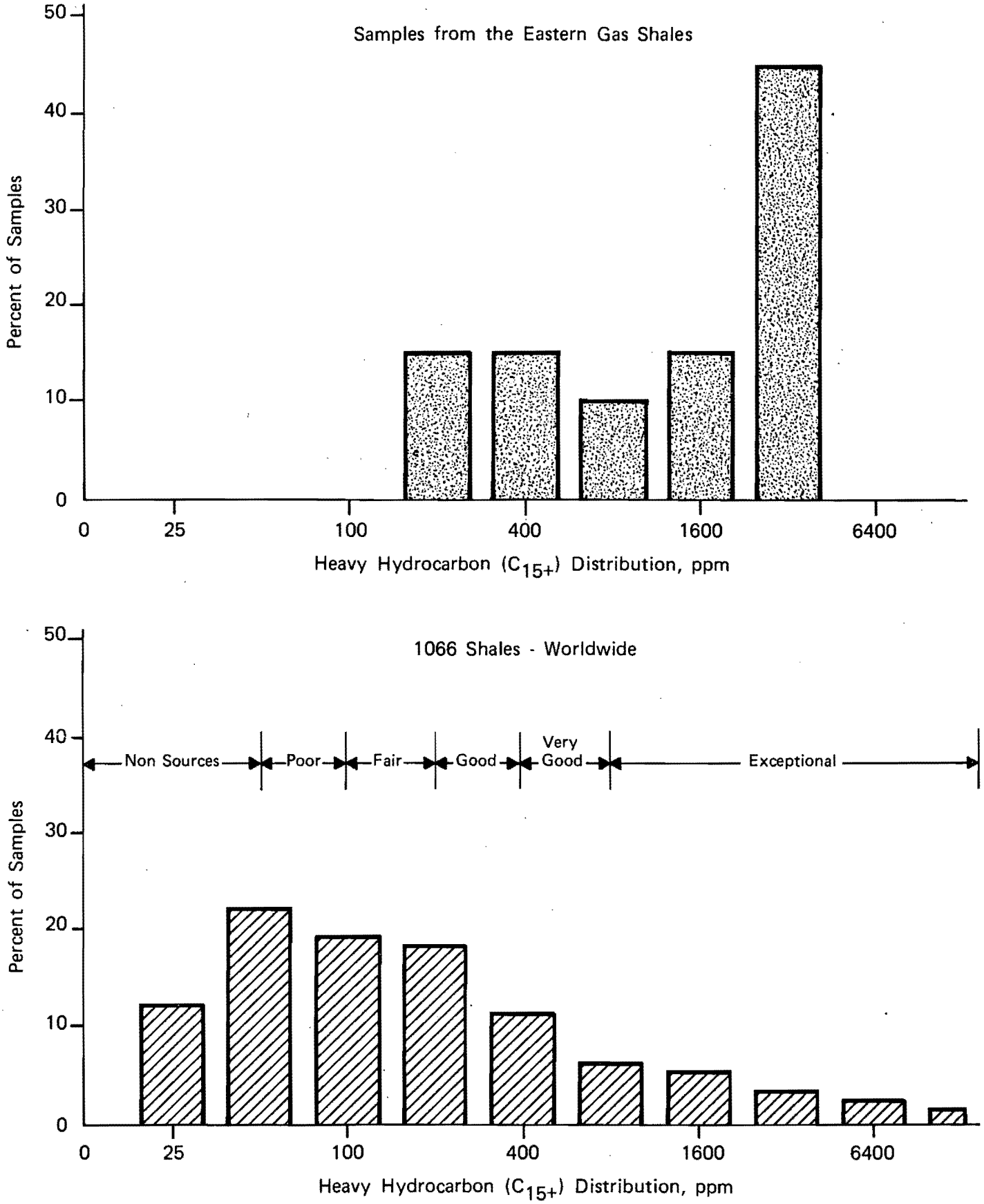


FIGURE 122 . Heavy Hydrocarbon Distribution of the Eastern Devonian Shales from the Appalachian Basin Compared with Other Shales.

shown diagrammatically in Figure 123, are applied. The few samples that would be classed exclusively as good gas sources are primarily from the VA - 1 well, and reflect the more woody-coaly nature of its organic matter and its relatively high degree of thermal maturity.

Also, as was pointed out in an earlier report (21), the quantities of hydrocarbon, particularly the ratios of heavy hydrocarbon to organic carbon, are anomalously high for rocks with as low thermal alteration indices as indicated by the kerogens in these Gas Shales. This same discrepancy was noted for both the absolute quantity of gas and its richness relative to the percent organic carbon. Moreover, the ethane-plus contents were anomalously high for the thermal alteration indices. Thus, the hydrocarbon contents and composition indicate (as well as the paraffin contents and the paraffin-napthene ratios of the extractable hydrocarbons) that virtually all of the shale samples in the study (except at well VA - 1) are in the oil-generating stage of thermal maturity, while the TAI's indicate that the oil generation stage has just begun.

This apparent discrepancy led to one of important research findings of the project. It shows that in relatively older rocks, Paleozoic in particular, the trade off of time for temperature in the kinetics of source rock maturation and hydrocarbon generation make it necessary to modify the standard interpretations of source criteria: wet gas and oil generation have taken place in rocks with lower TAI's and reflectances than standard charts and tables show. The observation supports the contention (21) that the breakdown of kerogen into a less hydrogen-rich kerogen and more hydrogen-rich gaseous or liquid hydrocarbon is an equilibrium process, when the products of the reaction are retained, their activity increases, and the reaction is retarded until some of the product is removed or escapes.

The trade-off of time for temperature has been recognized for some time (22, 23) but the published divisions between sources vs non-sources and oil vs gas sources are lumped for potential source rocks of all ages from the Precambrian to the Holocene.

Another important characteristic of the Upper Devonian Shales of this basin was also recognized earlier (21). That is that for any given well, and probably within different environments within each well, the ratio of heavy hydrocarbon to organic carbon is quite constant, i.e., can be characterized by a straight line with a slope of 1, on a diagram such as Figure 123. This indicates that very little migration of the heavy hydrocarbons from richer to leaner shales or to contiguous porosity has taken place. These large hydrocarbons, with greater than fifteen carbon atoms per molecule, are apparently locked in place in the very impermeable Upper Devonian shales.

The linear relations of gaseous hydrocarbons to organic carbon also testify to the retention of virtually all of the hydrocarbons, even the smallest ones, produced during diagenesis and catagenesis in the impermeable shales. The narrow pore throats throughout these very impermeable shales must have prevented virtually all of the hydrocarbons formed in them from escaping. They are retained in the pores in which they were formed.

The carbon isotope ratios of the gases provide additional confirmation that the Devonian Shales have retained all their produced hydrocarbons

HEAVY HYDROCARBON VS ORGANIC CARBON CONTENT SOURCE RATING PLOT FOR DEVONIAN SHALES OF THE APPALACHIAN BASIN

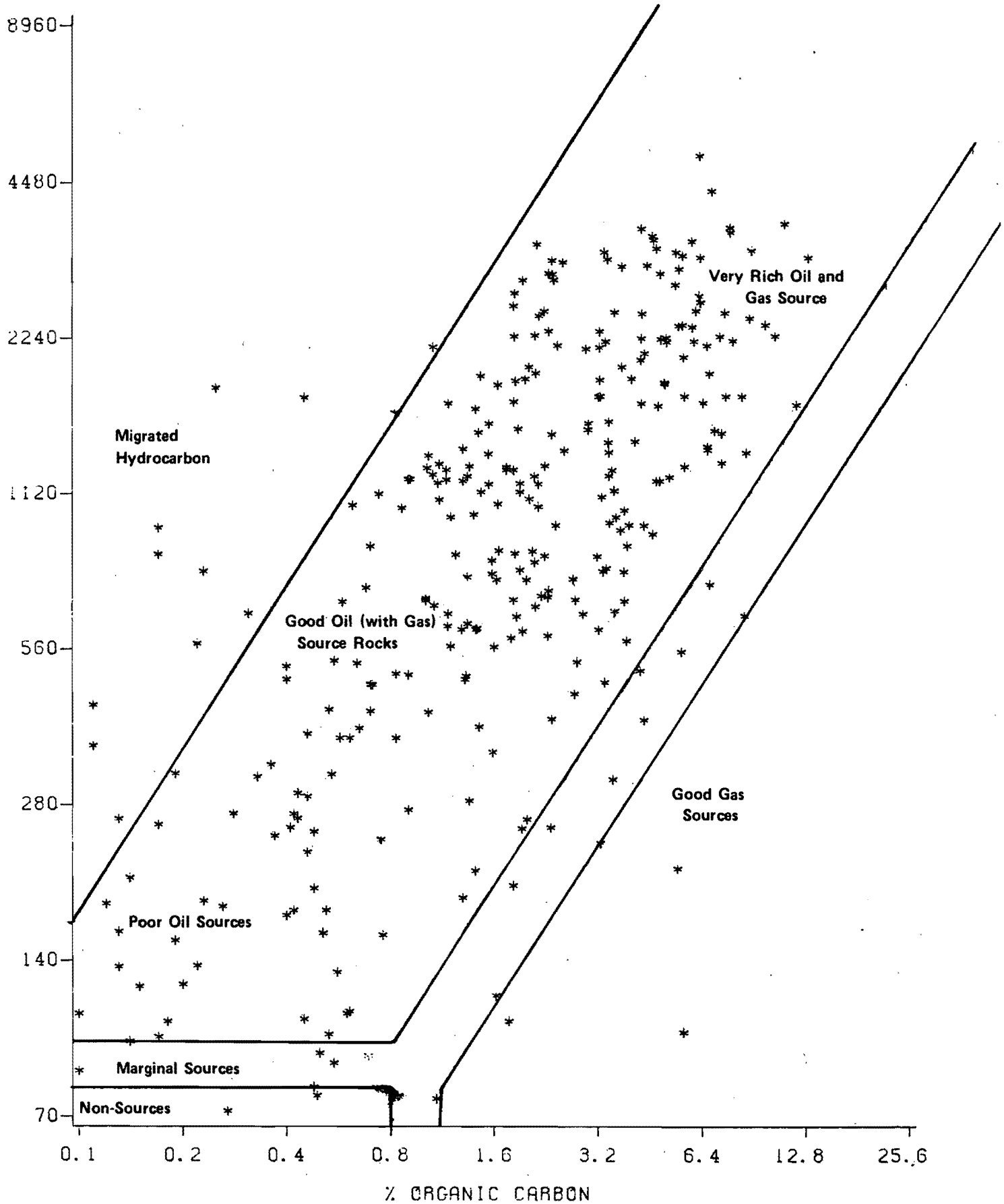


FIGURE 123

virtually from the time of deposition. While the carbon isotope composition of the kerogen itself (Table 2) is well within the range of other shale kerogens of the world (24), it is somewhat anomalous in that the kerogen in the marine (Tasmanites and algal) facies is heavier (less negative) than would normally be expected for marine organic matter. This suggests a greater contribution of the terrestrial organic matter from the emergent highlands than heretofore expected.

From the standpoint of hydrocarbon retention of the shales, the carbon-13 values of near-50% are too negative for gases derived from rocks that have undergone the degree of thermal alteration that the Devonian shales have experienced (24). The values would be consistent if the rocks only contained the very first, relatively small, volumes of gas that are given up at the very onset of thermal maturation, or catagenesis. At the same time, the values are too positive for microbially produced gases (25). This leads to the conclusion that the gases are a mixture of microbially produced (diagenetic) and catagenically produced hydrocarbons. This strongly suggests that these rocks have been very impermeable since very early in their history, i.e., since shortly after deposition, and that they have retained much of the gas produced by bacteria immediately beneath the sediment-water interface. This being the case, they must also have retained virtually all of the catagenic gas since the inception of the thermal cracking processes. Therefore the rocks themselves provide conclusive evidence that the shales have been a virtual closed system since deposition - thus explaining its departure from normal source rock characteristics.

Therefore, with the stimulation methods being investigated, it appears that the optimum location for stimulation projects is in the shales with the greatest amount of gas - the location of which is reported here, and which is a function of the amount of organic matter, its nature, an the degree of thermal alteration it has experienced. Fracture networks that coincide or are contiguous to these most favorable facies should also be sought so that the wells can maximize the extent of the drainage channels and the shale/porosity interface.

The search for oil in these rock units can also be narrowed down to a search for potential fractures and silt stringers in the favorable geochemical areas. Since the kerogen type changes from Tasmanites or algal in the western and southwestern parts of the basin to more terrestrial in the east, any crude oils would be more naphthenic in the west and more paraffinic in the east. However, with the shortage of domestic crude, the composition of the crude is only incidental.

TABLE 2

Carbon Isotope Data Determined from the Devonian Shale Samples

Zone	Map Unit	Well	Ranges of Values For ^{13}C (TOC)	Ranges of Values For $^{13}CH_4$
Early Marcellus Time	1	PA-2	-30.4 to -30.0	-28.1 to -22.4
		WV-6	N.D.	-24.0
		WV-7	-29.8 to -28.3	N.D.
Late Marcellus Time	2	PA-2	-29.6	-20.5
		WV-6	N.D.	-25.5
		WV-7	-29.6	N.D.
		OH-4	-28.9	-54.9 to -52.3
		PA-3	-27.5	N.D.
Hamilton Group/Post Marcellus Time	3	PA-2	-29.5 to -29.1	-30.5 to -27.0
		WV-6	N.D.	-32.5 to -27.9
		OH-4	-28.8	N.D.
		PA-3	-27.8 to -27.1	-50.2
Genesee/Geneseo Time	4	PA-2	-29.4 to -29.1	-35.5 to -19.8
		WV-7	-30.5 to -30.1	N.D.
		NY-1	-31.4 to -26.8	-45.5 to -39.5
Sonyea/Middlesex Time	5	WV-7	N.D.	-40.8 to -40.6
		NY-1	-28.9 to -28.5	-48.8 to -38.8
Early Lower Olentangy/ Early Rhinestreet Time	6	WV-7	-33.5 to -31.3	-38.9 to -38.8
		OH-3	-29.1	N.D.
		NY-1	-28.6 to -27.1	-50.6 to -48.0
		OH-4	N.D.	-53.6
		PA-3	-30.0 to -28.1	-53.2

TABLE 2 (CONTINUED)

Zone	Map Unit	Well	Ranges of Values For ^{13}C (TOC)	Ranges of Values For $^{13}CH_4$
Late Lower Olentangy/ Late Rhinestreet Time	7	WV-7	-29.1 to -28.3	-45.9 to -42.7
		KY-2	N.D.	-53.9
		NY-1	-30.8 to -25.2	-54.6 to -50.2
		PA-3	-30.2 to -29.0	-52.7 to -51.9
Middle Olentangy/ Angalo Shale Time	8	WV-5	N.D.	-48.7 to -46.9
		KY-2	-26.7	-54.6 to -48.7
		OH-4	N.D.	-53.0 to -50.4
		PA-3	-27.8	-50.9
Upper Olentangy/Java FM. Hanover Shale Time	9	KY-4	-30.9	-50.9 to -49.5
		WV-5	N.D.	-49.6
		KY-2	N.D.	-52.2 to -50.6
		OH-3	-29.4	-51.1
		OH-4	-30.3	-55.7 to -52.6
		PA-3	-30.0 to -27.3	-53.7 to -53.3
Early Lower Huron/ Early Dunkirk Time	10	KY-4	N.D.	-54.0
		VA-1	-28.7	-40.7 to -36.4
		KY-2	-28.9	-53.1 to -52.6
		OH-3	N.D.	-52.5
		PA-3	-28.8	N.D.
Late Lower Huron/ Late Dunkirk Time	11	KY-4	-30.5 to -29.5	-53.3 to -51.6
		WV-5	N.D.	-50.7 to -50.5
		VA-1	-29.3	-43.2 to -38.3
		KY-2	N.D.	-53.5
		OH-3	-30.2 to -30.1	-50.3 to -47.8
		OH-4	-30.0	-52.7 to -52.1
		PA-3	-28.7 to -25.7	N.D.

TABLE 2 (CONTINUED)

Zone	Map Unit	Well	Ranges of Values For ^{13}C (TOC)	Ranges of Values For $^{13}CH_4$
Early Middle Huron Time	12	KY-4	-29.4	-53.2 to -50.6
		VA-1	-28.1	-44.6 to -40.6
		KY-2	N.D.	-50.1
		OH-3	-31.0 to -30.1	-54.1 to -52.5
		PA-3	-29.5 to -29.0	N.D.
Late Middle Huron Time	13	KY-4	-30.2 to -30.0	-52.4 to -51.7
		WV-5	N.D.	-49.6
		KY-2	N.D.	-48.8
		OH-3	-30.5 to -27.3	-54.1 to -47.6
Early Upper Huron Time	14	KY-4	-30.3 to -29.0	-53.2 to -51.0
		WV-5	N.D.	-49.4
		KY-2	N.D.	-48.7
		OH-3	-30.4	-53.1 to -50.5
Late Upper Huron Time	15	KY-4	-30.4	-50.1
		WV-5	N.D.	-51.6
		KY-2	-30.0	-41.9 to -34.6
		OH-3	-30.2 to -28.9	-54.6 to -49.4
Chagrin Time	16	KY-4	-30.6	-52.2 to -48.8
		WV-5	N.D.	-49.4
		VA-1	-25.6	-44.4
		KY-2	-27.5	-51.5
		OH-3	-29.8	-54.6

TABLE 2 (CONTINUED)

Zone	Map Unit	Well	Ranges of Values For ^{13}C (TOC)	Ranges of Values For $^{13}CH_4$
Cleveland Time	17	KY-4	-30.3 to -28.3	-52.7 to -49.8
		VA-1	-27.9	-45.3 to -39.6
		KY-2	-30.2	-52.4

N.D. - Not Determined

Discussion

From the point of view of the petroleum geochemist, the Upper Devonian rocks of the Appalachian Basin have exceptional potential to generate (i.e., source) large volumes of oil and gas. There is an abundance of algal organic matter, either Tasmanites or other marine algae as well as large quantities of herbaceous organic derivatives. In other basins, the former type of kerogen is a promising sign in the search for oil and gas, and the oil is usually of the naphthenic type. The latter type, while not as encouraging as the algal kerogen, is still often associated with large commercial oil and gas fields, the oil usually being of a more paraffinic type.

Various amounts of more woody terrestrial organic matter also characterized parts of many of the units. And, while this type of organic matter is not as encouraging a sign, it can still generate significant quantities of gas, and small quantities of oil which tends to be of a more aromatic or paraffinic nature.

In light of the widespread occurrence of such excellent oil and gas source rocks, the production history of these rocks has been extremely disappointing. The major reason for this disappointment is the paucity of reservoirs associated with the organic-rich Upper Devonian shales. Most giant oil and gas fields of the world are produced from thick porous sands or limestones in juxtaposition with, or fluid continuity with, good petroleum source rocks, but source rocks with no better, and sometimes less, potential than that of the Upper Devonian of the Appalachian Basin.

These more typical geological relationships do not occur in the geological setting of interest. Therefore, the future likelihood of exploitation of this resource depends on two improvements in technology. The first of these will require the sharpening of our ability to locate naturally occurring porosity within the rich shales themselves. This porosity is made up of networks of natural fractures and/or thin silt stringers, the location of which may be facilitated by detailed lithofacies studies, improved well log analysis, structural geology, and aerial photo analysis.

The second technological improvement that will increase the realization from this vast resource will be in stimulation methodology. Industry needs a documented stimulation program for every situation encountered in the shale; i.e., what current methods should be employed and what modifications need to be made for shale depth, thickness, lithology, mineralogy, physical and mechanical properties, organic richness, gas content, etc. The very magnitude of the resource itself justifies a continuing effort toward these ends.

GAS CONTENTS

Background

One of the most recent estimates of the magnitude of the resource in the Eastern Gas Shale Basins has been based on the thickness of the dark and the gray shale, the relative proportions of which in turn were based on the gamma-ray log response, and the estimated average volumes of gas associated with each of these (26). It was an either-or situation and no intermediate values of gas contents for shales with intermediate organic contents was considered. Another estimate is based on pyrolysis yields of a handful of samples (27); others seem to be even more subjective (28).

The geochemical program has made it possible to make more accurate estimates of gas-in-place in the shales because one of the analyses is a direct measurement of gas contained in freshly taken cores from different parts of the basin. The measurement, as originally applied to well samples in the early part of the program, gave low estimates of the gas in place, because gas was lost as the core was brought out of the hole, and while the core was being measured and described, however quickly, before samples were sealed in gas-tight containers.

However, as part of the program, a controlled off-gassing procedure was developed, and the accuracy of the gas-in-place estimates derived from it were confirmed with the pressure-retaining core barrel (29). These accurate estimates, together with the kerogen, biofacies and thermal alteration index data were then used to develop algorithms from which indigenous gas contents have been calculated for each rock unit at each well location.

An example of the comparison of the gas contents determined by the geochemical source rock assessment method, the resource assessment method, and the gas-in-place algorithm is shown in Table 3. The algorithms for the other 16 stratigraphic units studied in this report are included in Appendix C.

The term "indigenous gas" means the gas produced by kerogen during the entire natural thermal evolutionary process before natural migration or loss during core retrieval and sample handling. These values are probably the most accurate estimates of gas-in-place available today.

As the Table shows, the geochemically determined and calculated indigenous gas contents are usually much larger than the amounts estimated from the resource measurements. This was confirmed in the controlled off-gassing experiments in which it was found that the gas release is primarily exponential. Therefore, much more gas was lost during the retrieval of the core and subsequent handling at the well-site than had been realized. This was further confirmed by observations in the field that the core, when freshly extruded from the core barrel, often was out-gassing rapidly enough to be heard and to be observed as rapidly forming and bursting bubbles in the water film on the cores. This manifestation of the gas disappeared within a few seconds, but the samples for resource assessment often had to be exposed to atmospheric pressure with the gas escaping to the

TABLE 3

Gas Content Determinations
Early Marcellus Time

Most accurate?

Why?

This is the old gasing method?

Well	Experimentally Determined Total Gas	Organic Carbon (%)	Thermal Alteration Index	Geochemically Determined Total Gas	Estimated Indigenous Gas Content
OH-8	33.70	6.65	3.40	290.38	292.38
PA-1	17.81	2.51	3.50	113.35	113.60
PA-4	14.59	1.37	3.60	67.30	63.78
PA-3	16.73	3.15	2.10	88.41	84.73
PA-5	95.18	1.50	3.40	65.53	65.95
WV-7	16.84	4.21	3.50	187.57	190.54
NY-4	21.77	1.77	3.48	80.29	76.65
OH-4	17.51	2.18	2.30	54.25	60.33
OH-7	68.69	3.64	2.30	117.99	108.26

what are the units of measure?

atmosphere for approximately one to two hours while the core was measured, described, photographed, etc.

In a few cases, the calculated indigenous gas contents are smaller then the measured ones. In these cases, some of the gas must have migrated into the samples from sites in the section with greater organic matter contents. So, in spite of the low permeabilities, there is some redistribution of the gas within the shales.

Experimentally Determined Gas

The distribution of the experimentally determined gas was mapped to show the relative richness of various regions and stratigraphic intervals within the basin. These maps are included as Figures 124 through 140. The data are expressed as MCF/AF (thousand cubic feet of gas per acre-foot of shale). The erratic appearance of the contours and distribution of absolute values reflects the fact that the data represent gas contents retained in the rock after the majority of the gas had already escaped prior to the samples being sealed in the pressure-tight containers at the well site. Therefore, the values which may be helpful in pinpointing gas-rich locations, are a function of the original gas contents of the rocks, but badly distorted because of variations in permeability, which allows the gas to escape at different rates in different cores, and the widely different times elapsing between core recovery and sealing the samples into the cans.

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

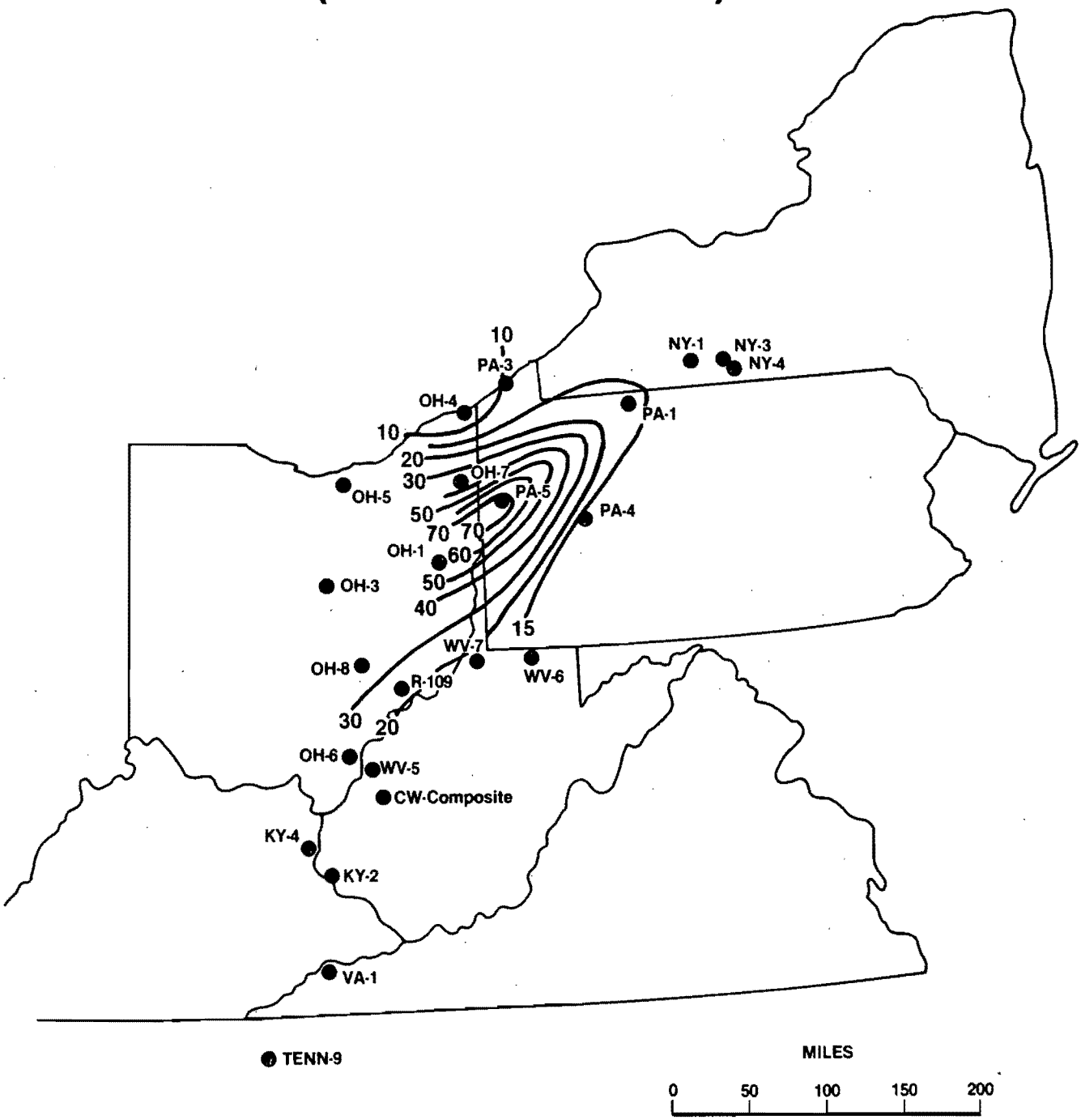


FIGURE 124

EARLY MARCELLUS TIME

Map Unit 1

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

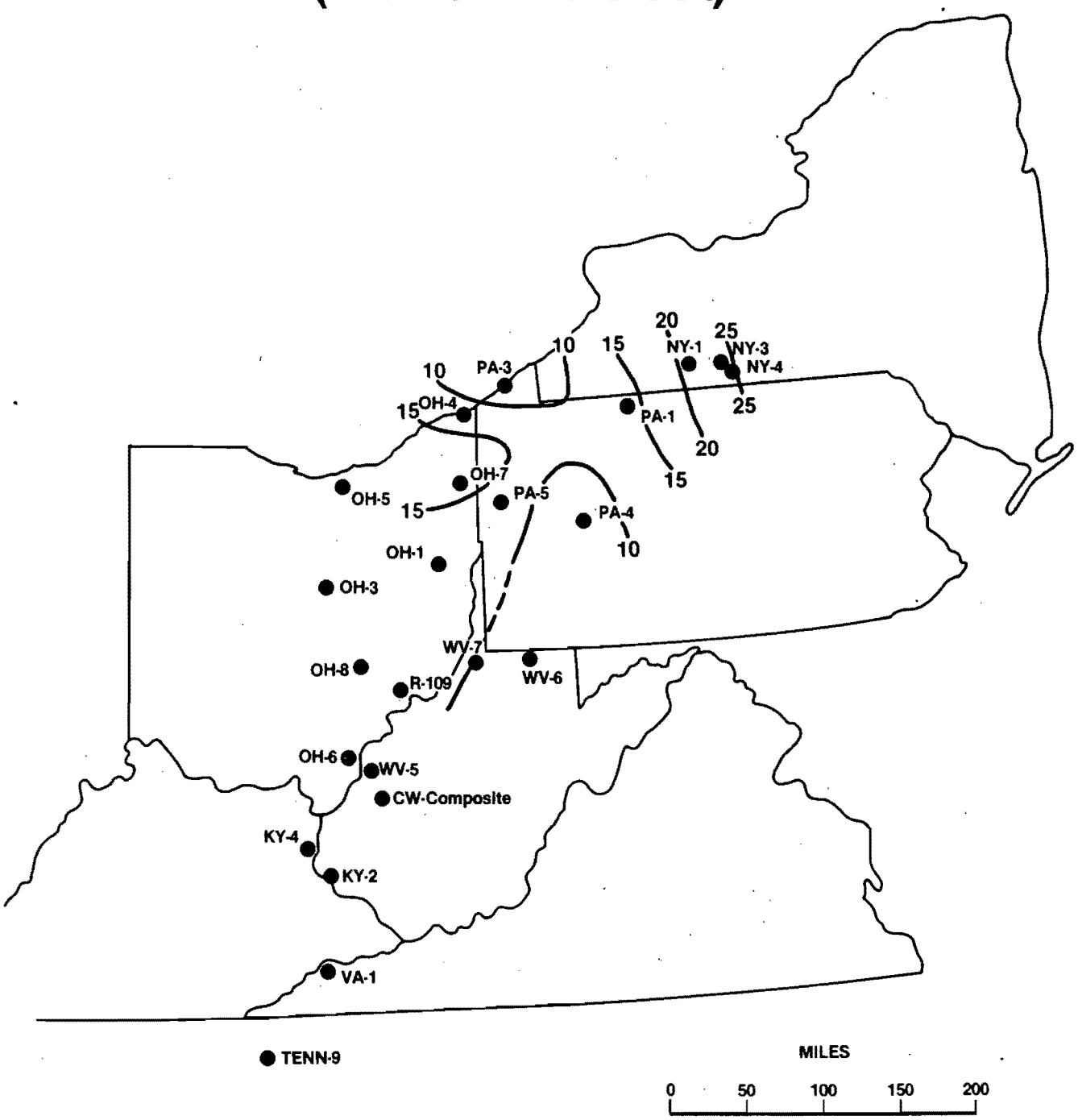


FIGURE 125

LATE MARCELLUS TIME

Map Unit 2

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

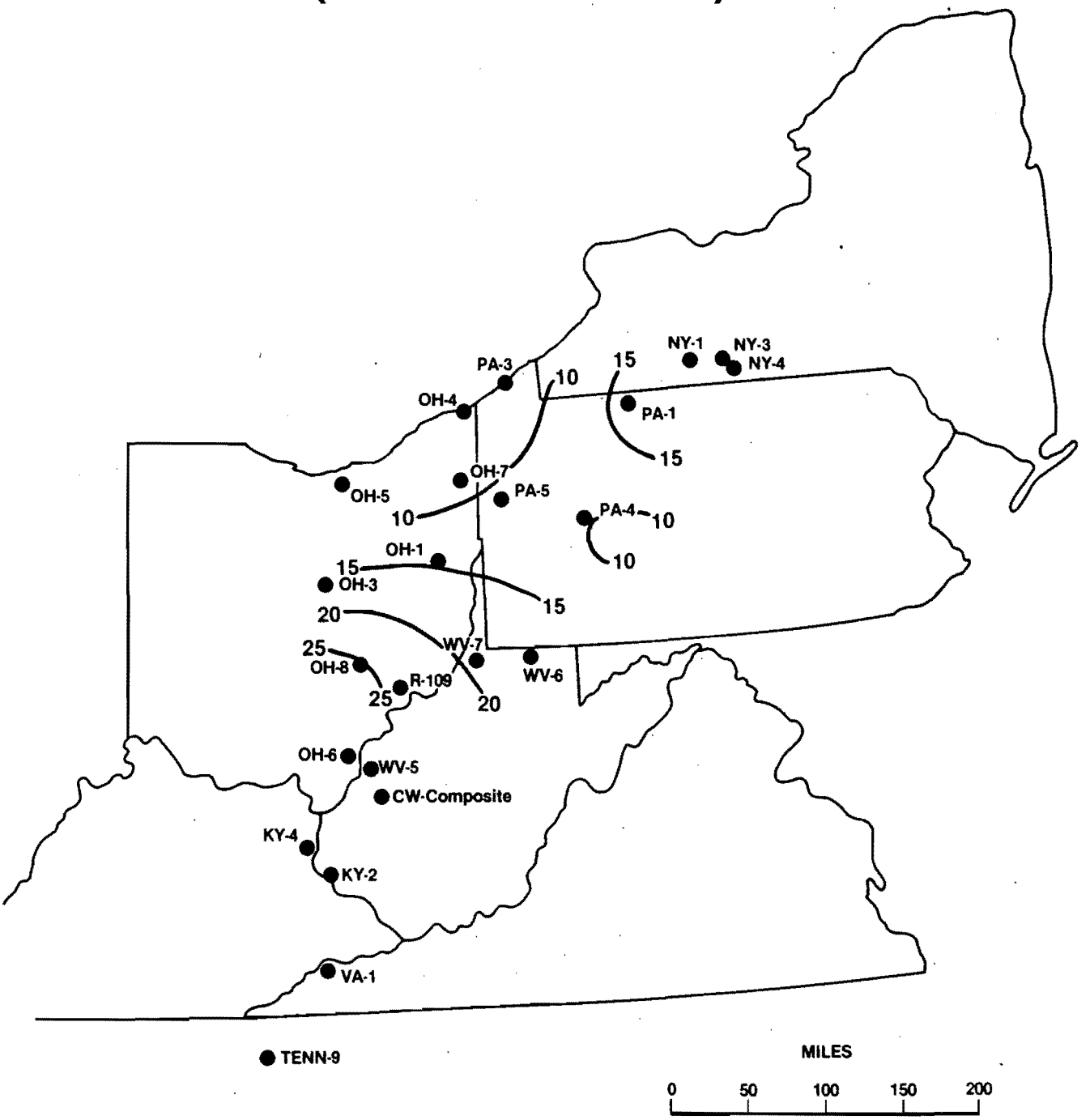


FIGURE 126

HAMILTON GROUP/POST-MARCELLUS TIME

Map Unit 3

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

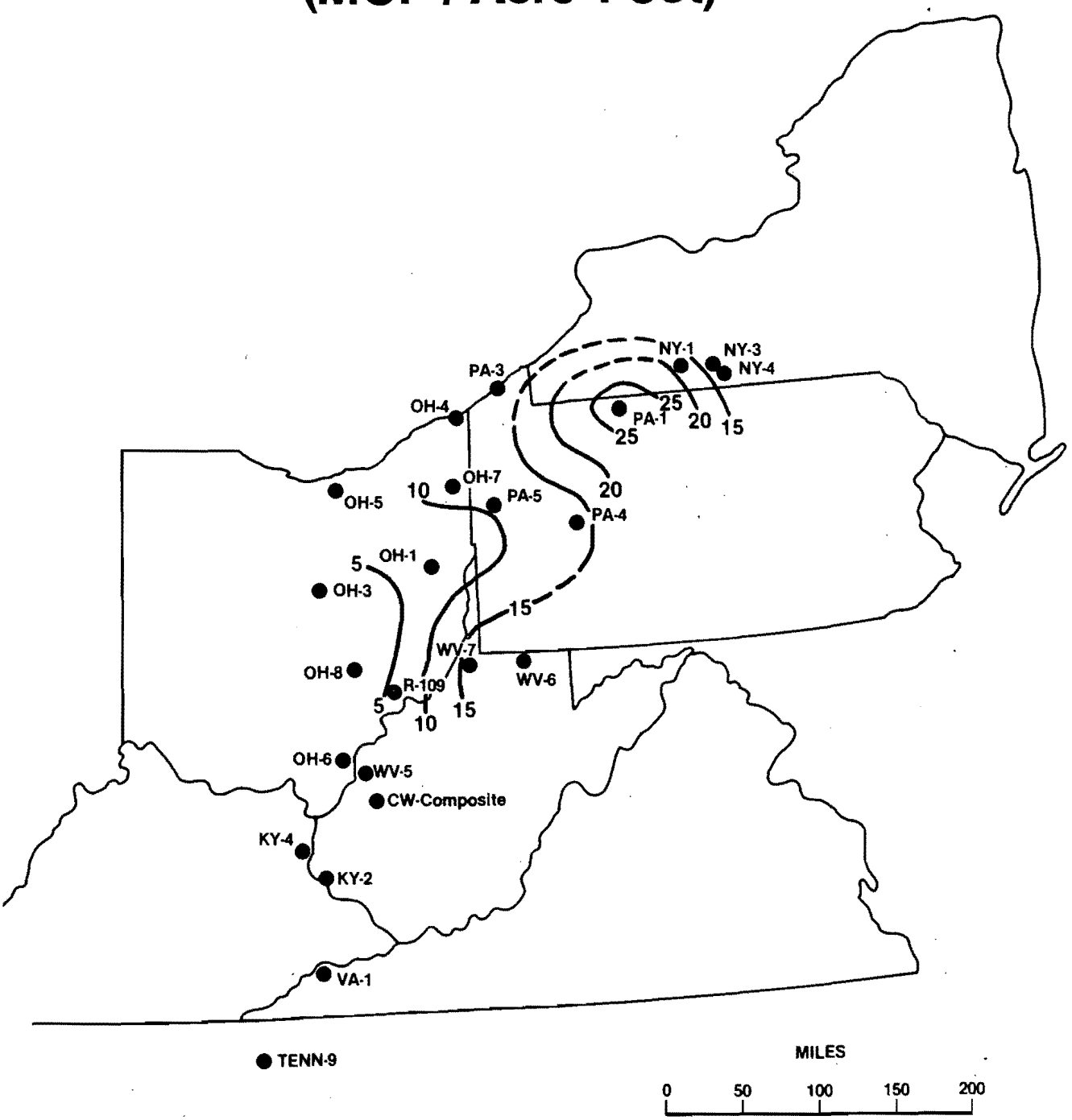


FIGURE 127

GENESEE/GENESEO TIME

Map Unit 4

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

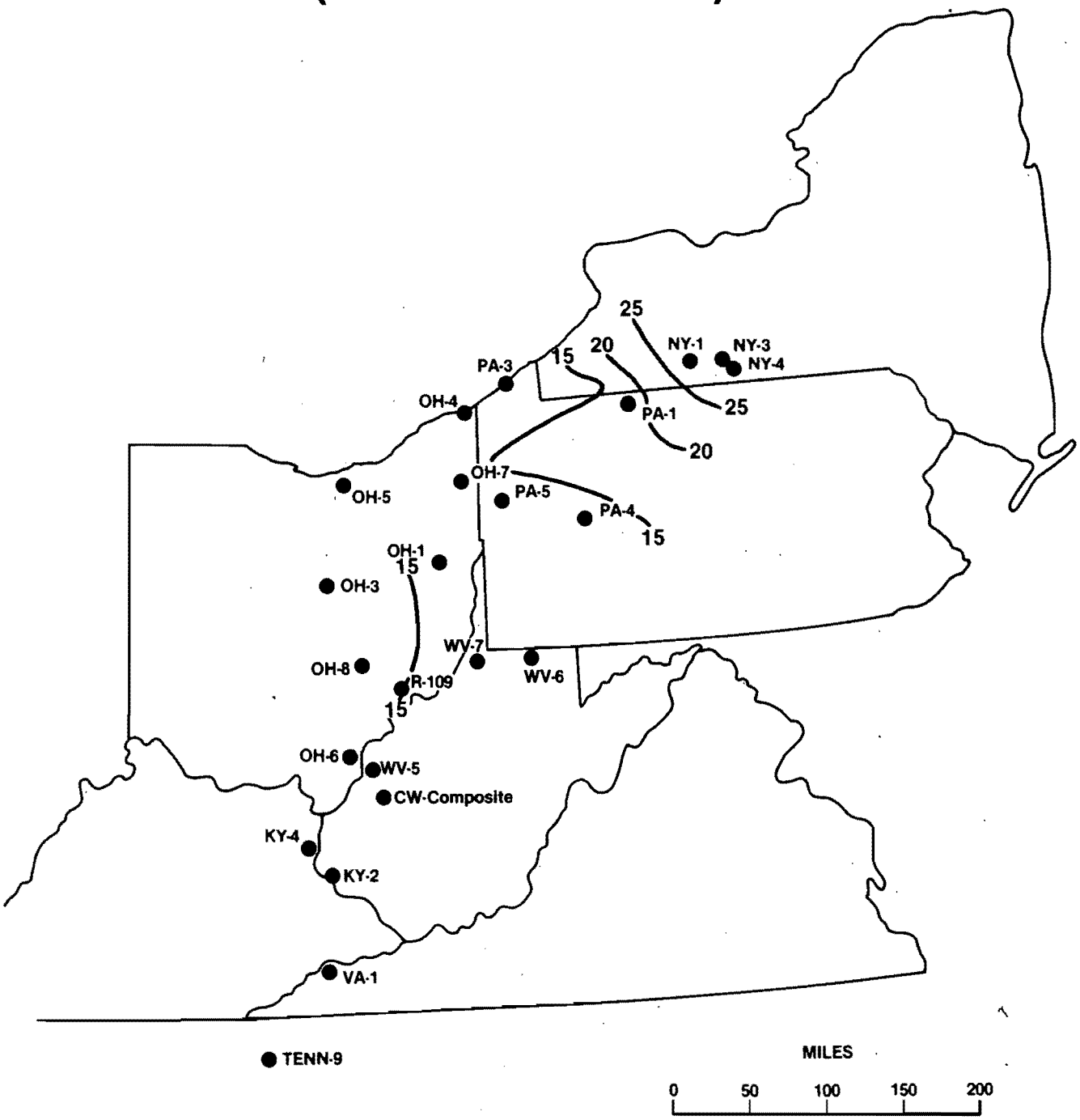


FIGURE 128

SONYEA/MIDDLESEX TIME

Map Unit 5

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

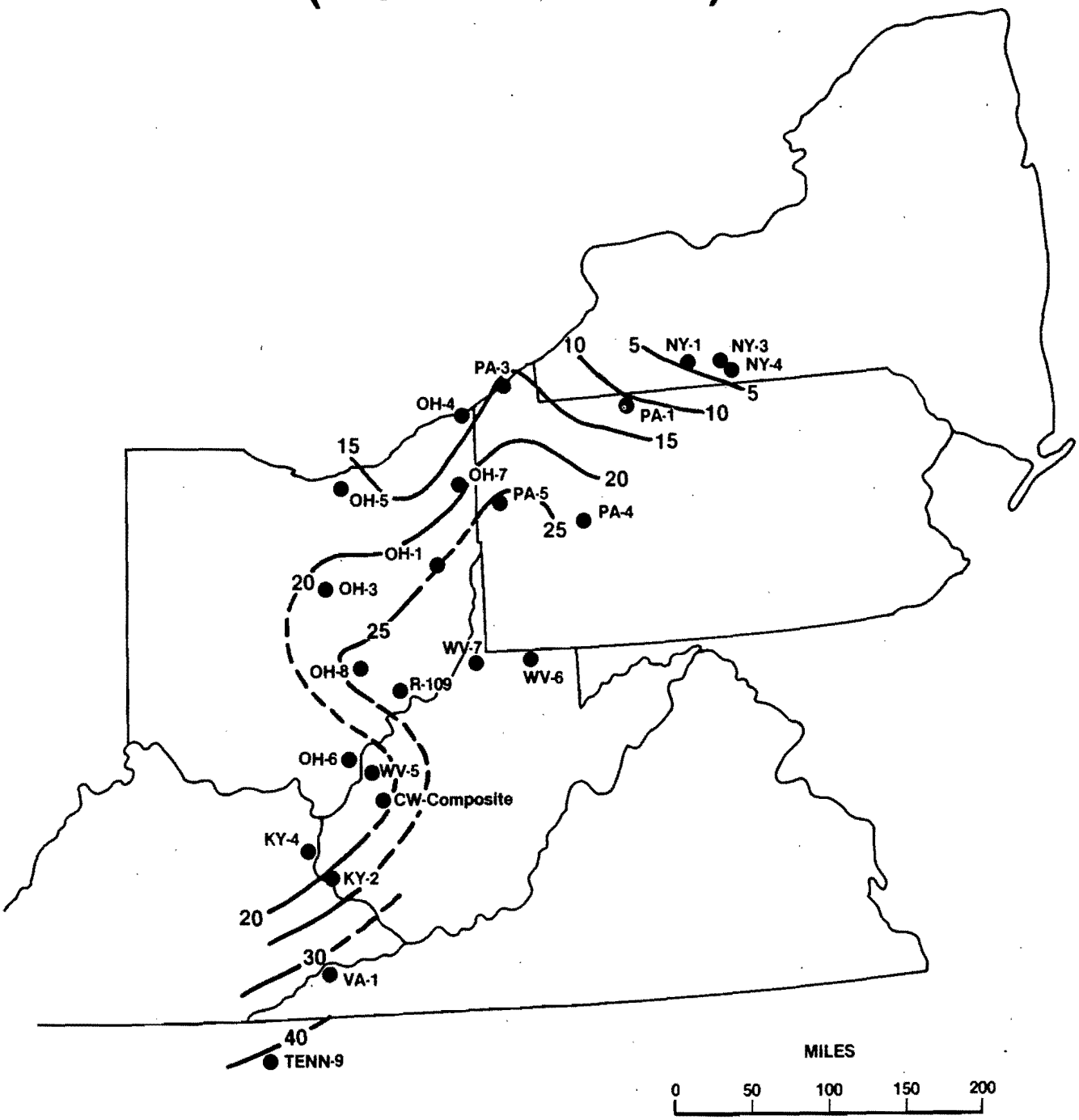


FIGURE 129

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

Map Unit 6

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

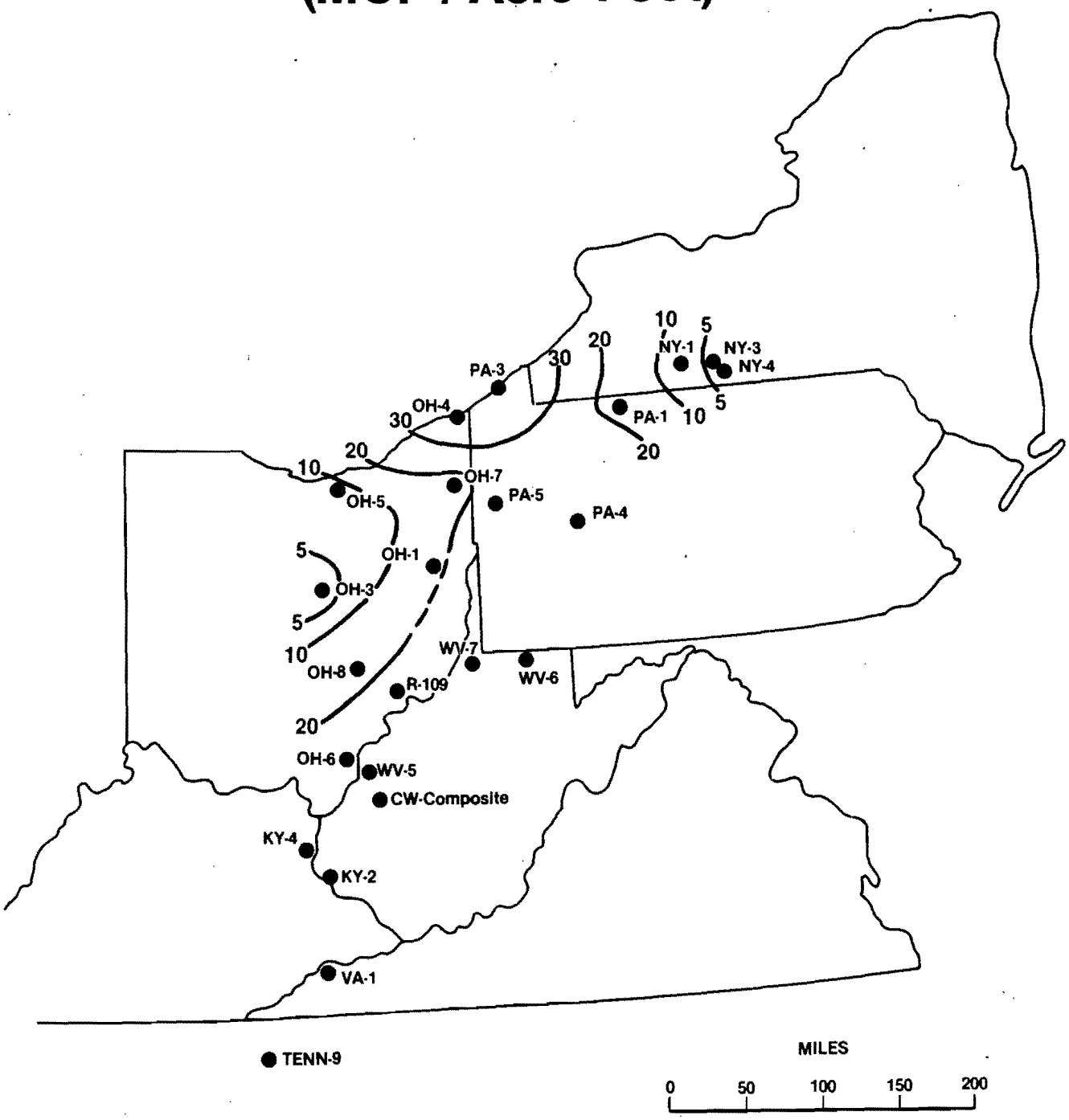


FIGURE 130

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

Map Unit 7

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

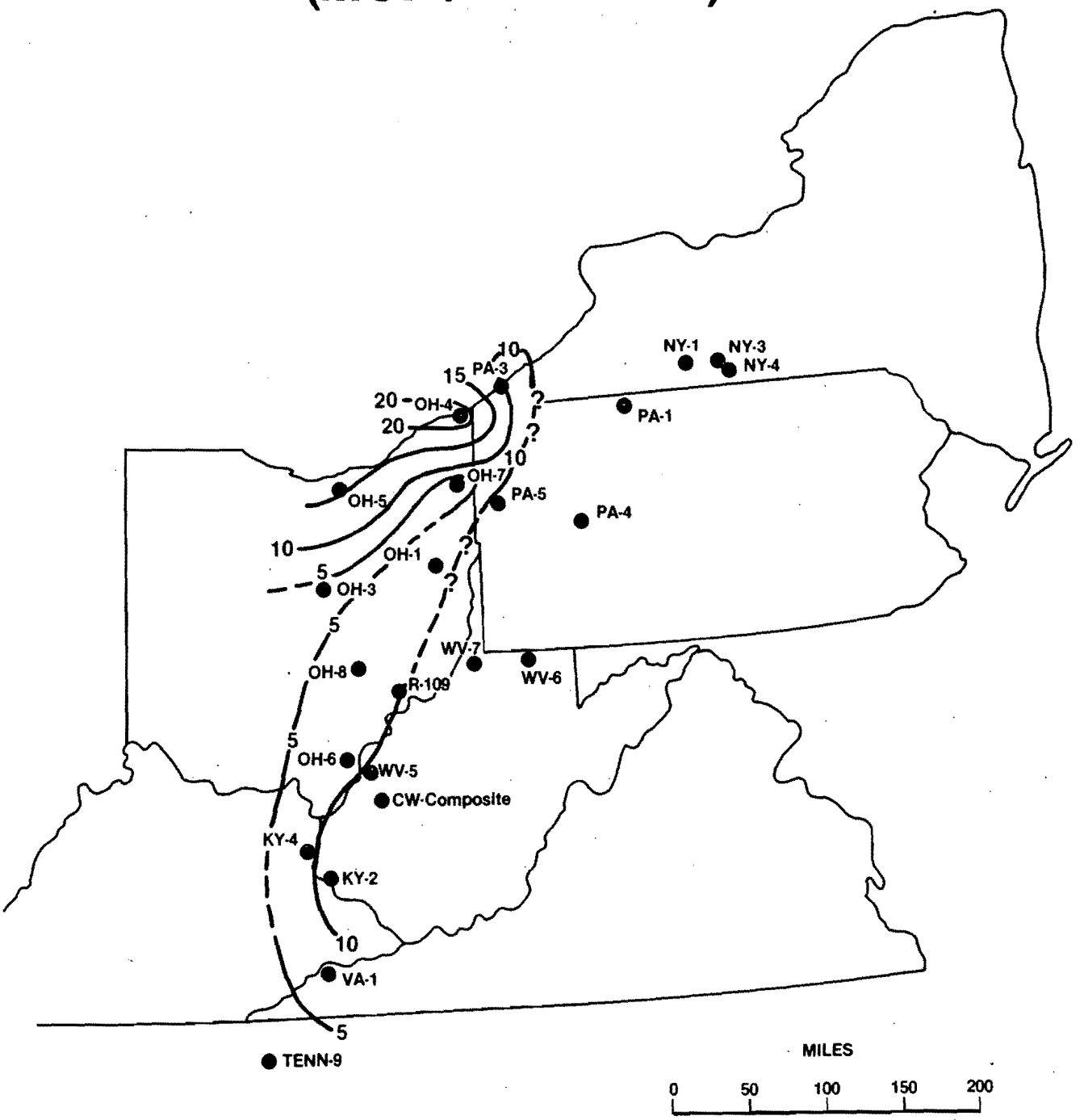


FIGURE 131

MIDDLE OLENTANGY/ANGOLA SHALE TIME

Map Unit 8

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

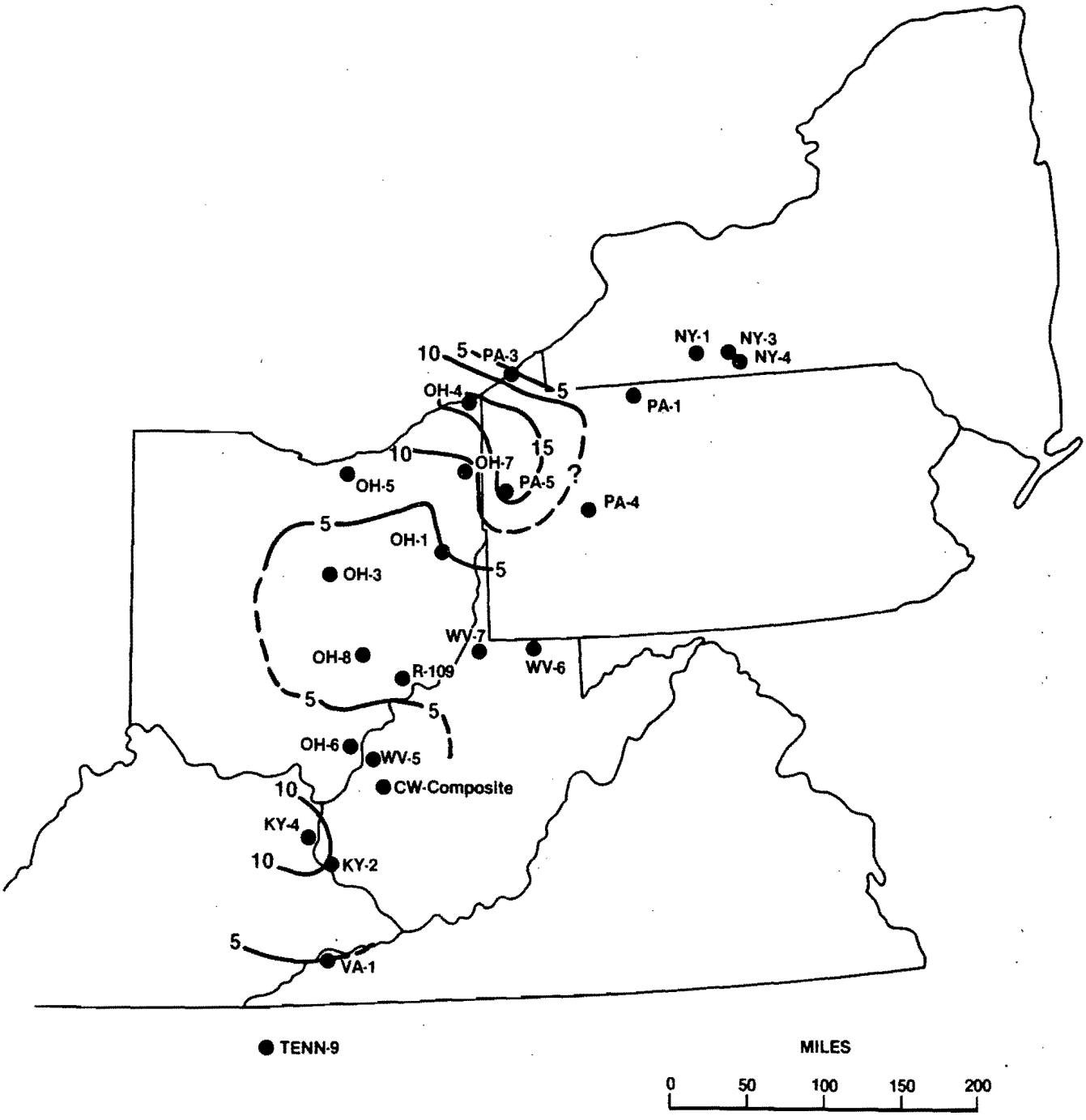


FIGURE 132

UPPER OLENTANGY/JAVA FM. HANOVER SHALE TIME

Map Unit 9

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

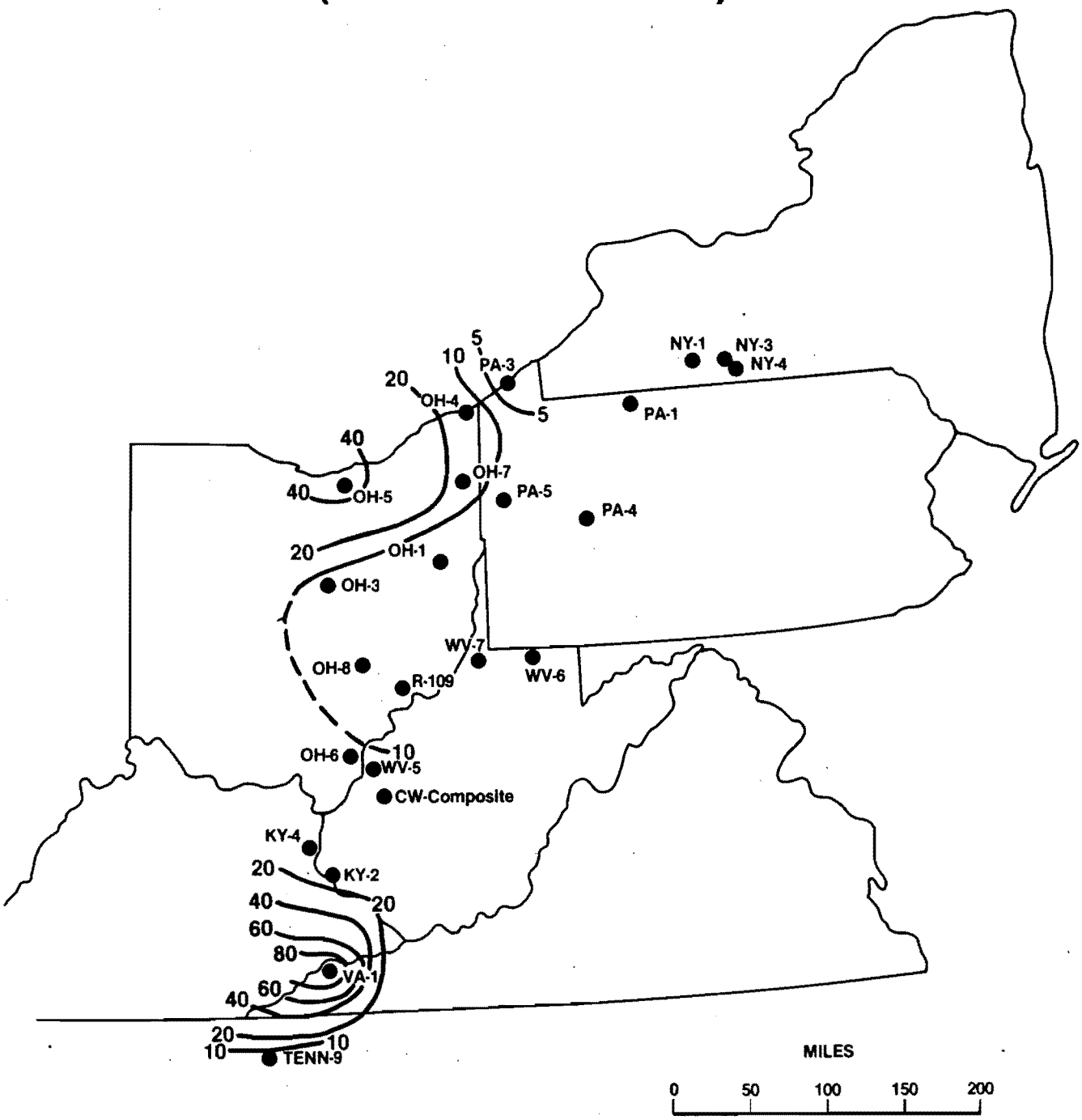


FIGURE 133

EARLY LOWER HURON/EARLY DUNKIRK TIME

Map Unit 10

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

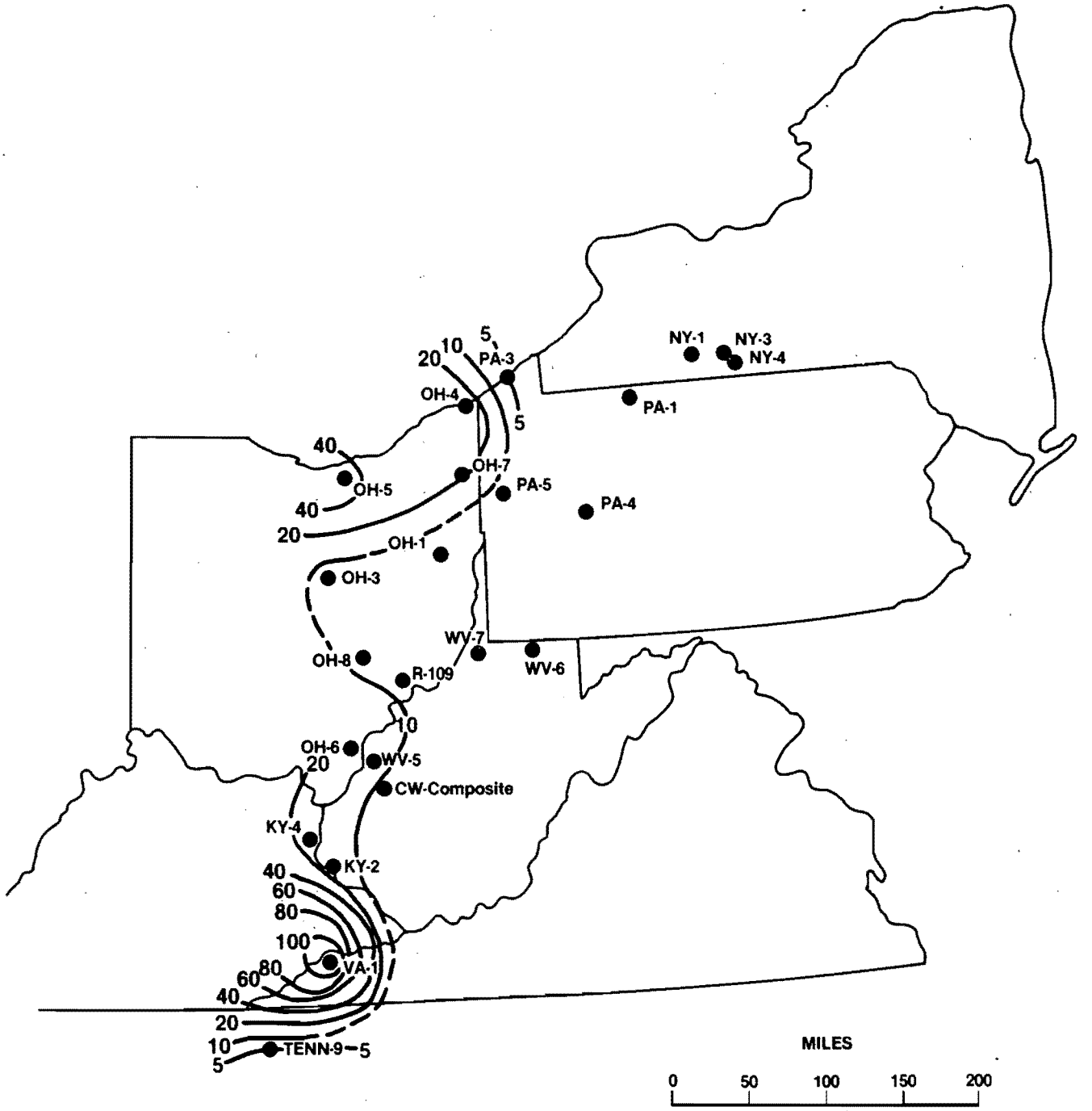


FIGURE 134

LATE LOWER HURON/LATE DUNKIRK TIME

Map Unit 11

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

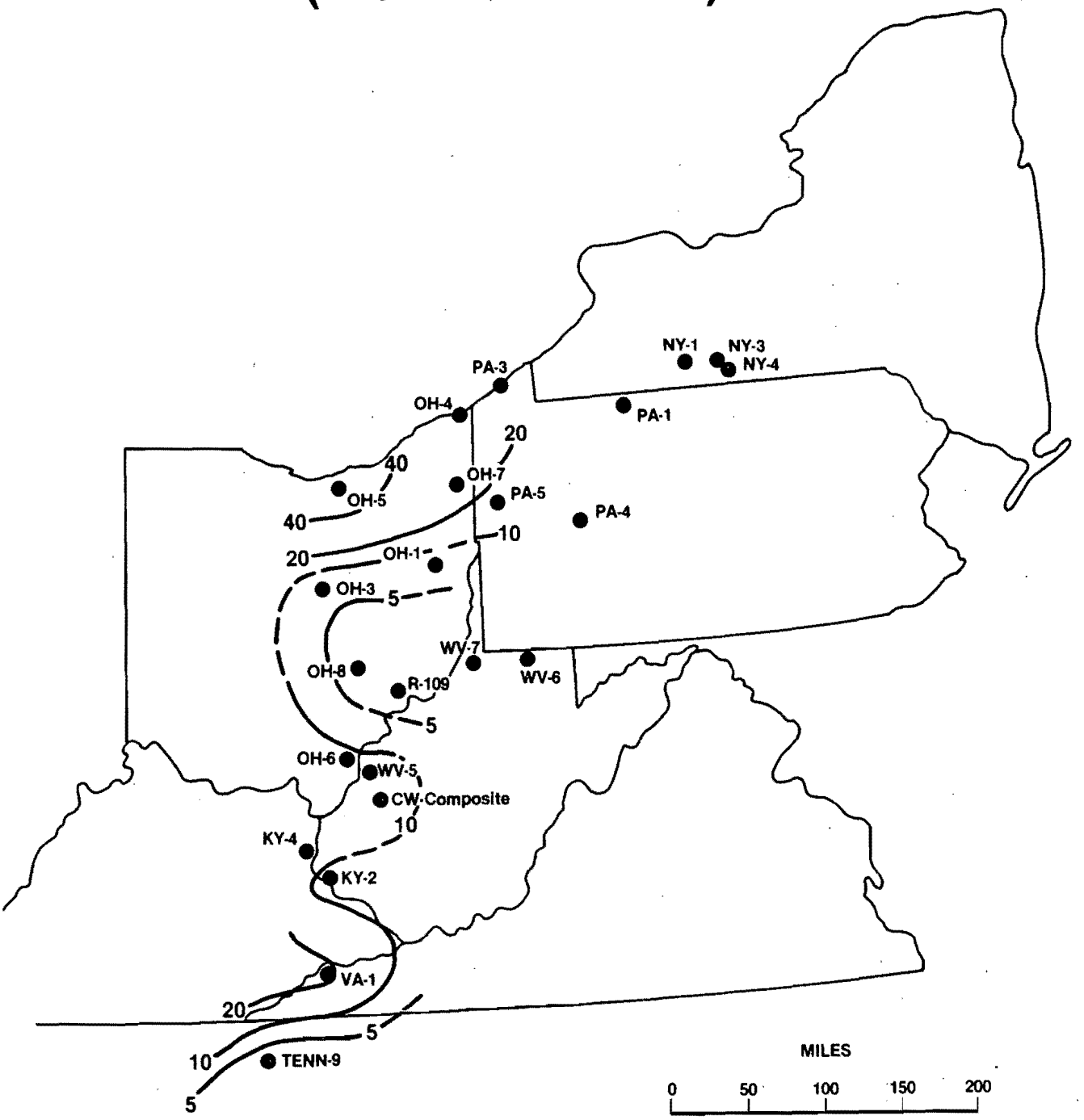


FIGURE 135

EARLY MIDDLE HURON TIME

Map Unit 12

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

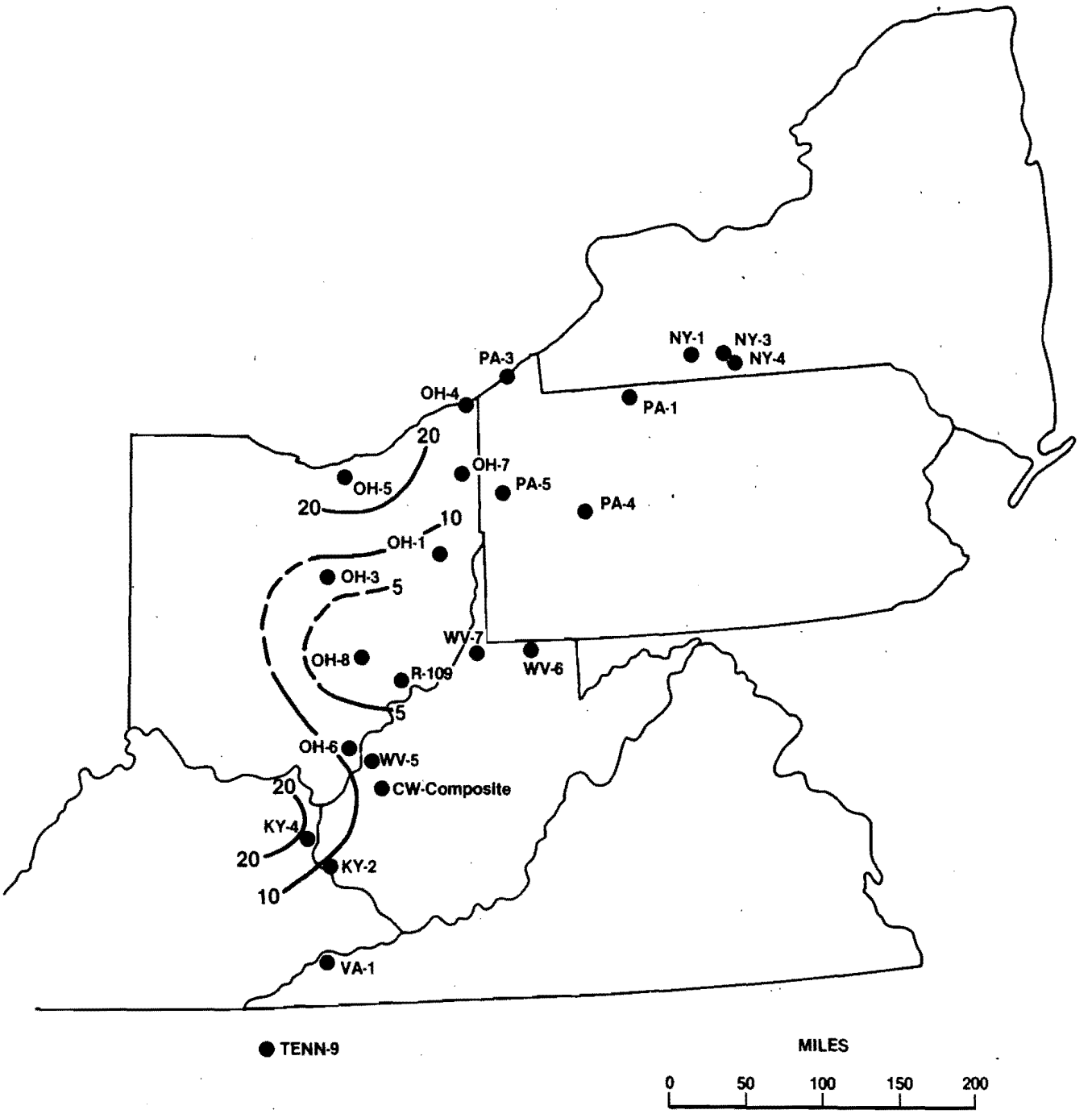


FIGURE 136

LATE MIDDLE HURON TIME

Map Unit 13

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

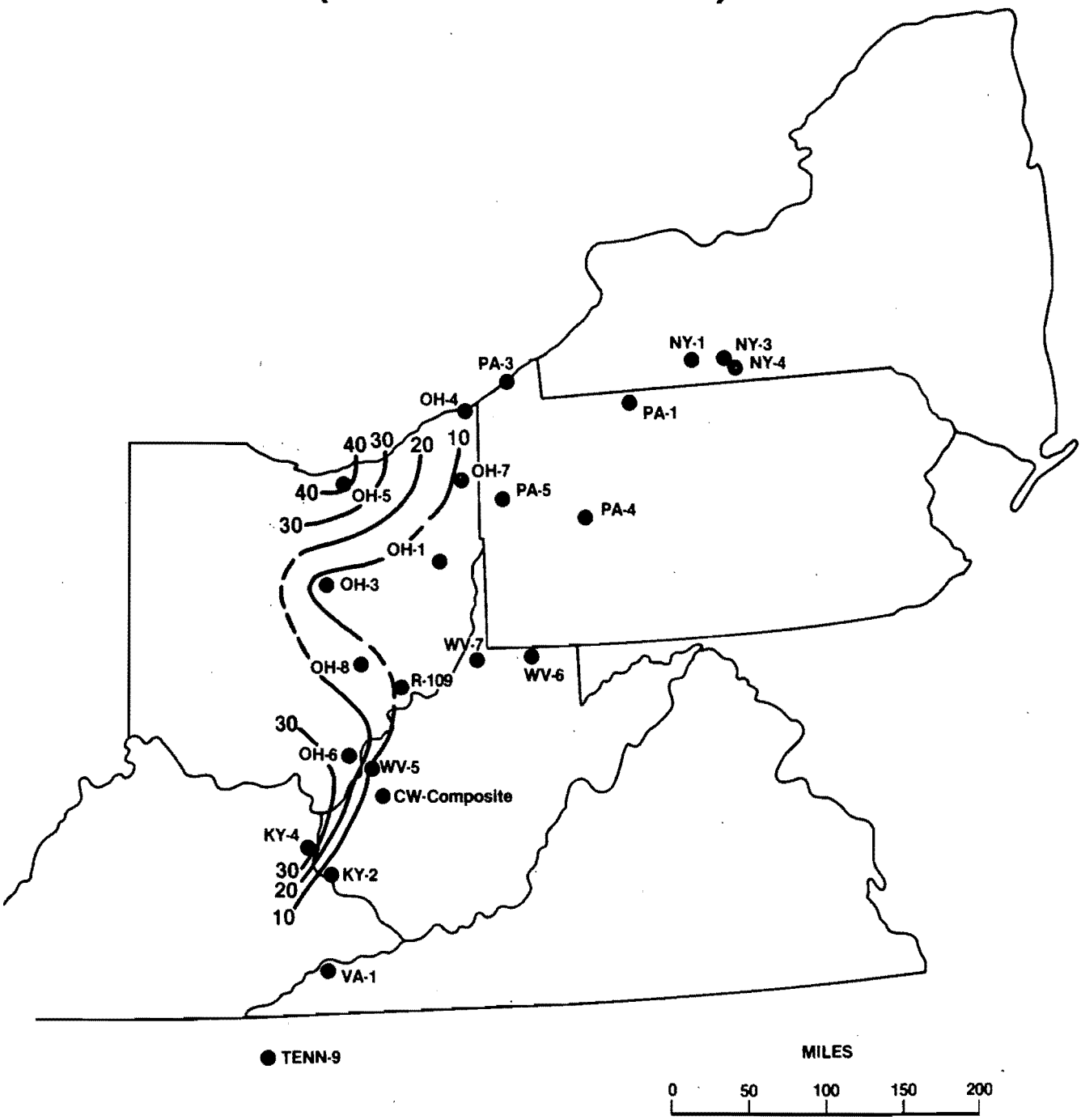


FIGURE 137

EARLY UPPER HURON TIME

Map Unit 14

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

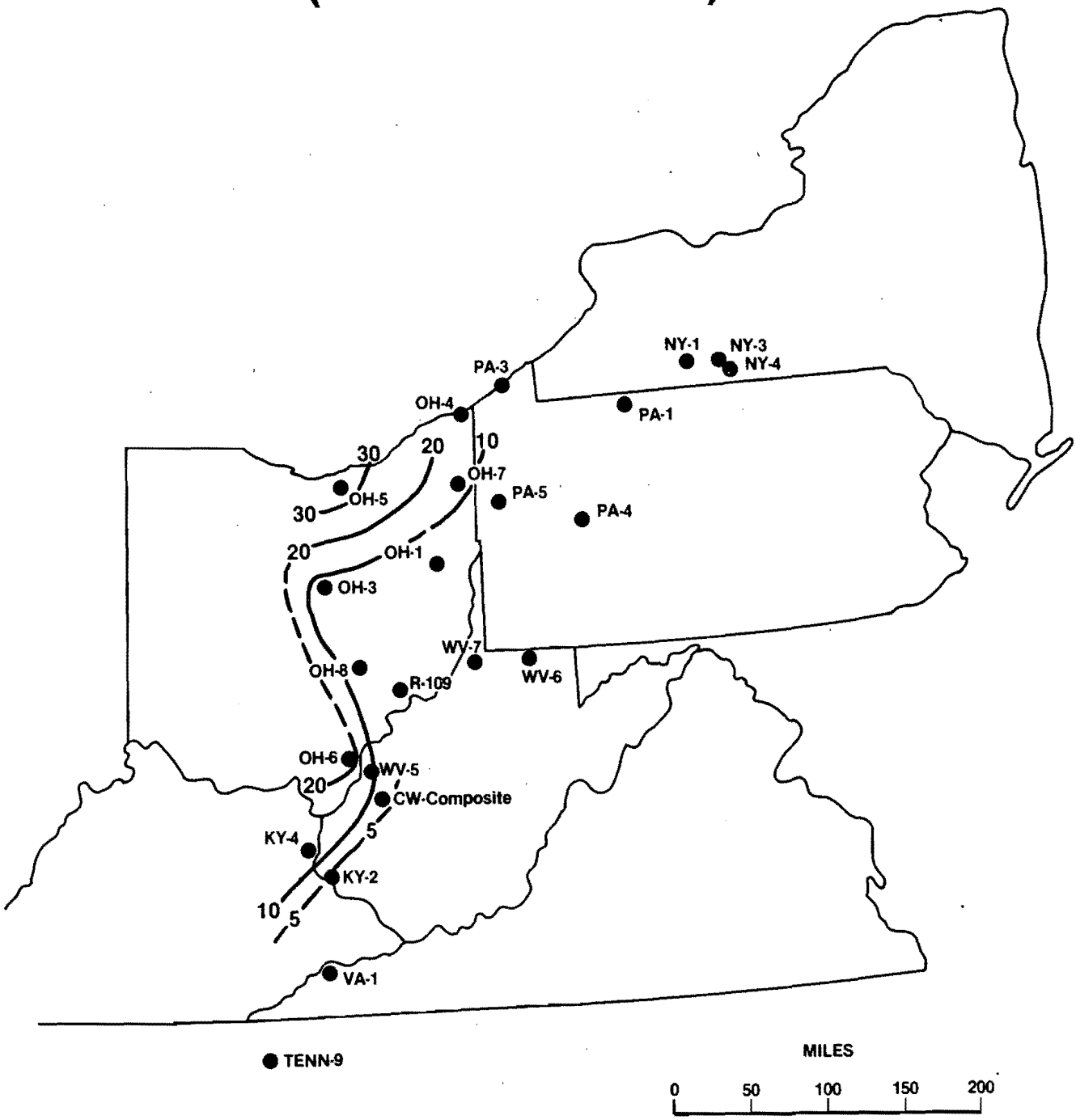


FIGURE 138

LATE UPPER HURON TIME

Map Unit 15

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

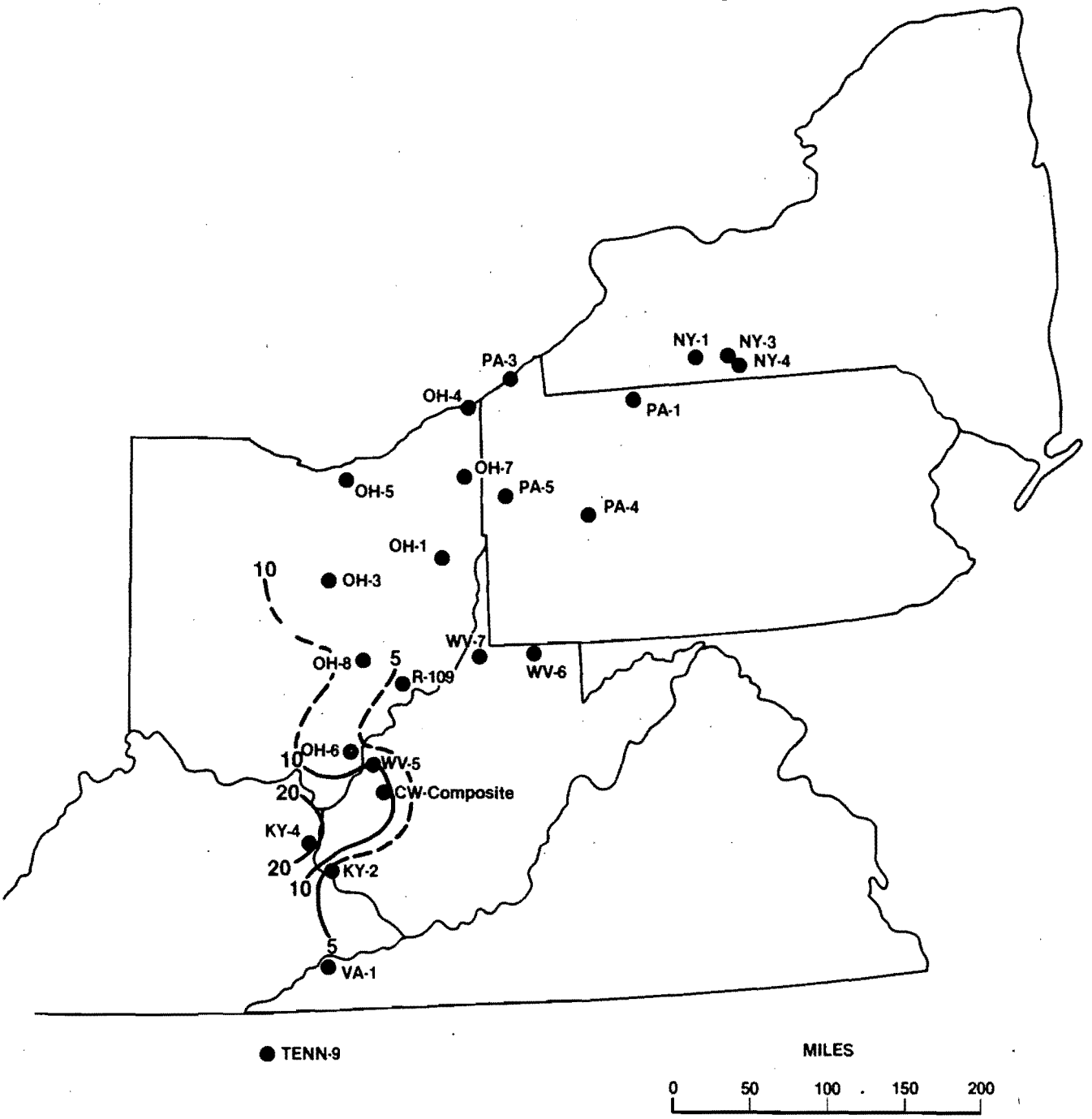


FIGURE 139

CHAGRIN TIME

Map Unit 16

MOUND

Prepared by Mound Facility

EXPERIMENTALLY DETERMINED GAS CONTENT (MCF / Acre Foot)

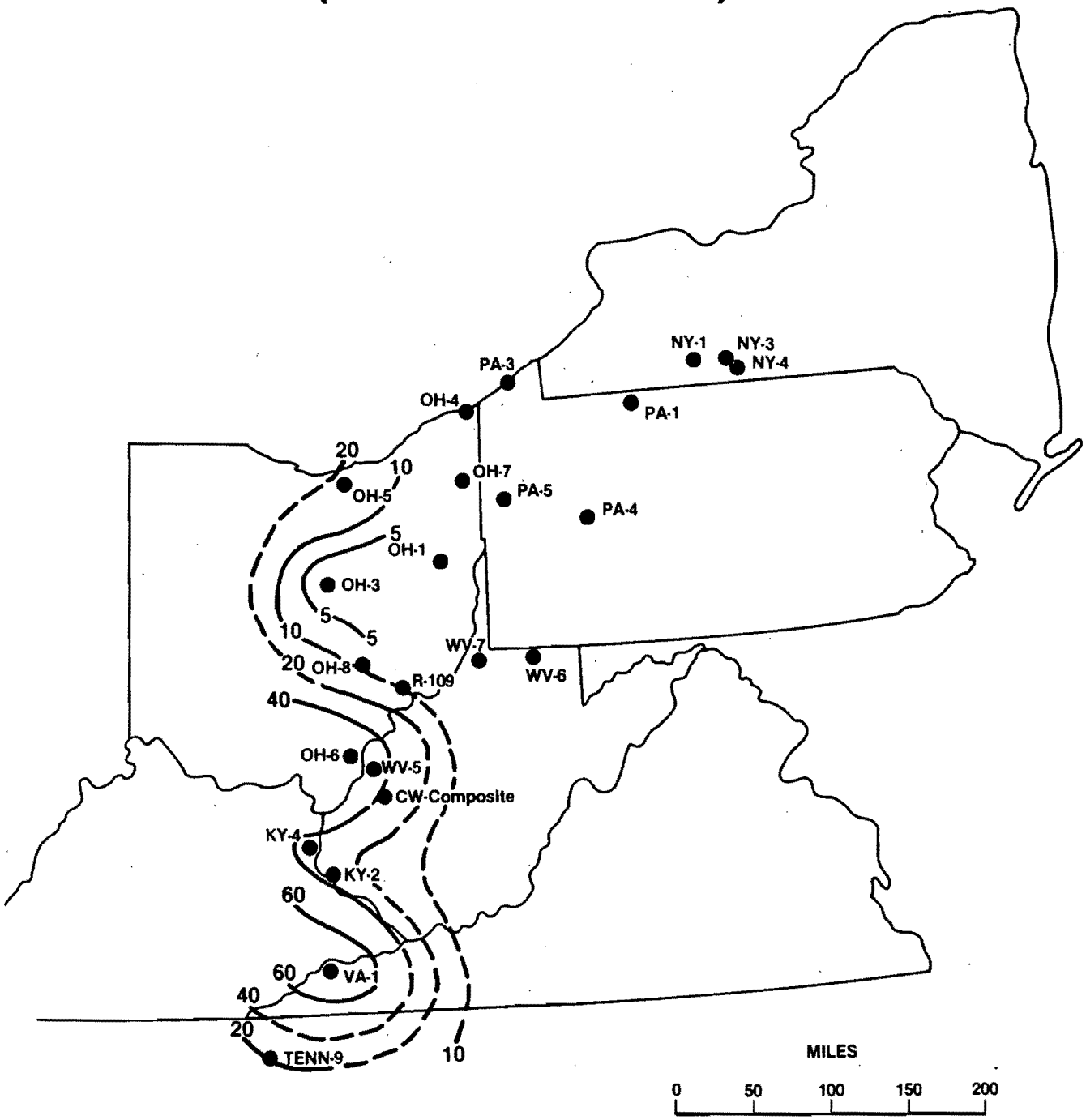


FIGURE 140

CLEVELAND TIME

Map Unit 17

MOUND

Prepared by Mound Facility

Indigenous Gas

The indigenous gas contents calculated with the algorithms discussed earlier are presented in map form in Figures 141 through 157. These give a more accurate picture of the richness of the undisturbed shale, and the distribution of that richness regionally. These values are also presented as MCF/AF.

The next step in the assessment was to combine the richness of the rock in each interval with the thickness of each interval to give the distribution of the total quantities of gas in each unit. These data are shown in map form in Figures 158 through 174, on which the data are expressed as (MCF/Acre)/100. In other words a figure 50 on a contour means 5000 thousand cubic feet, or 5 million cubic feet (5MMCF), in each acre of that particular rock unit.

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

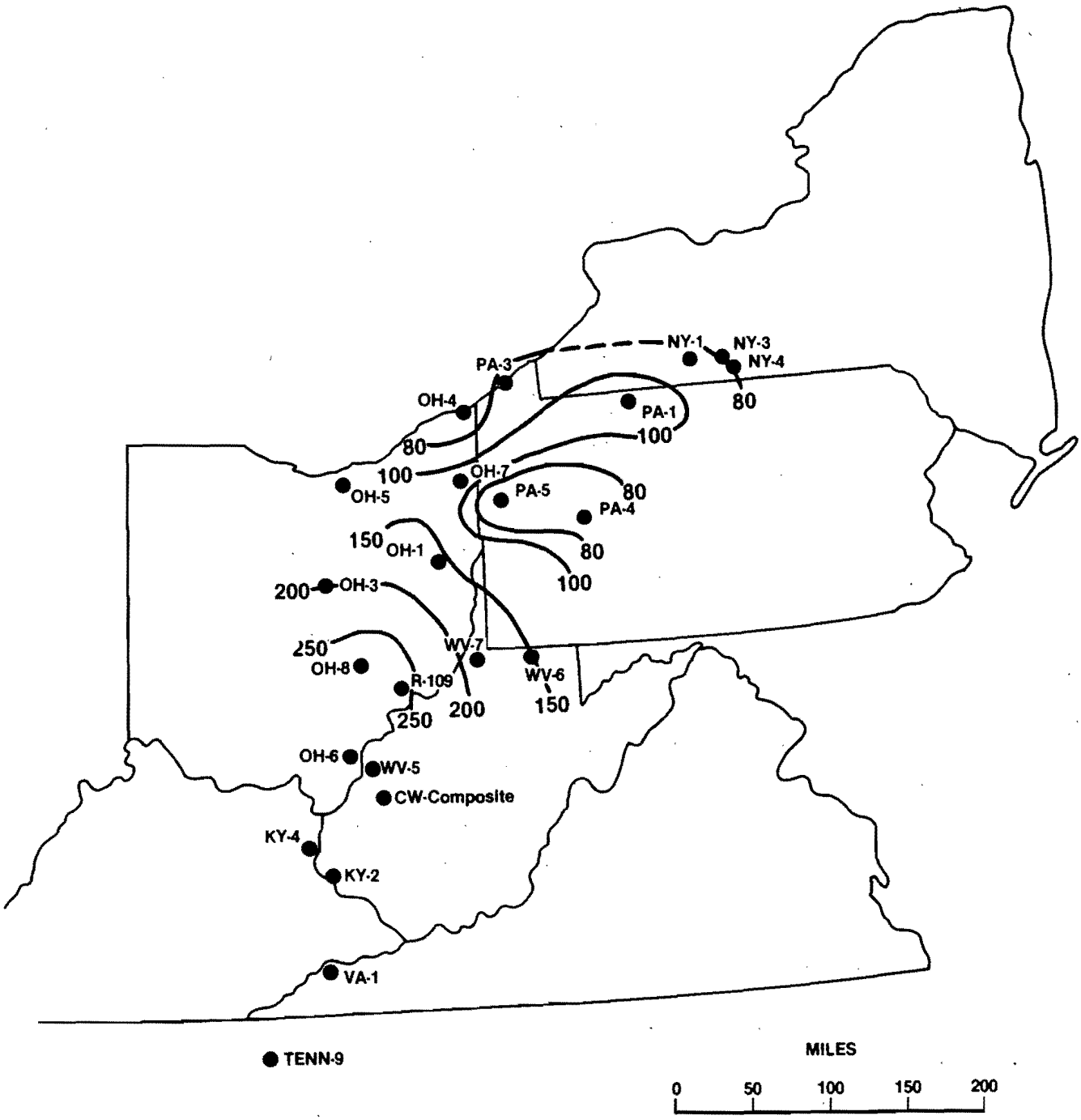


FIGURE 141

EARLY MARCELLUS TIME

Map Unit 1

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

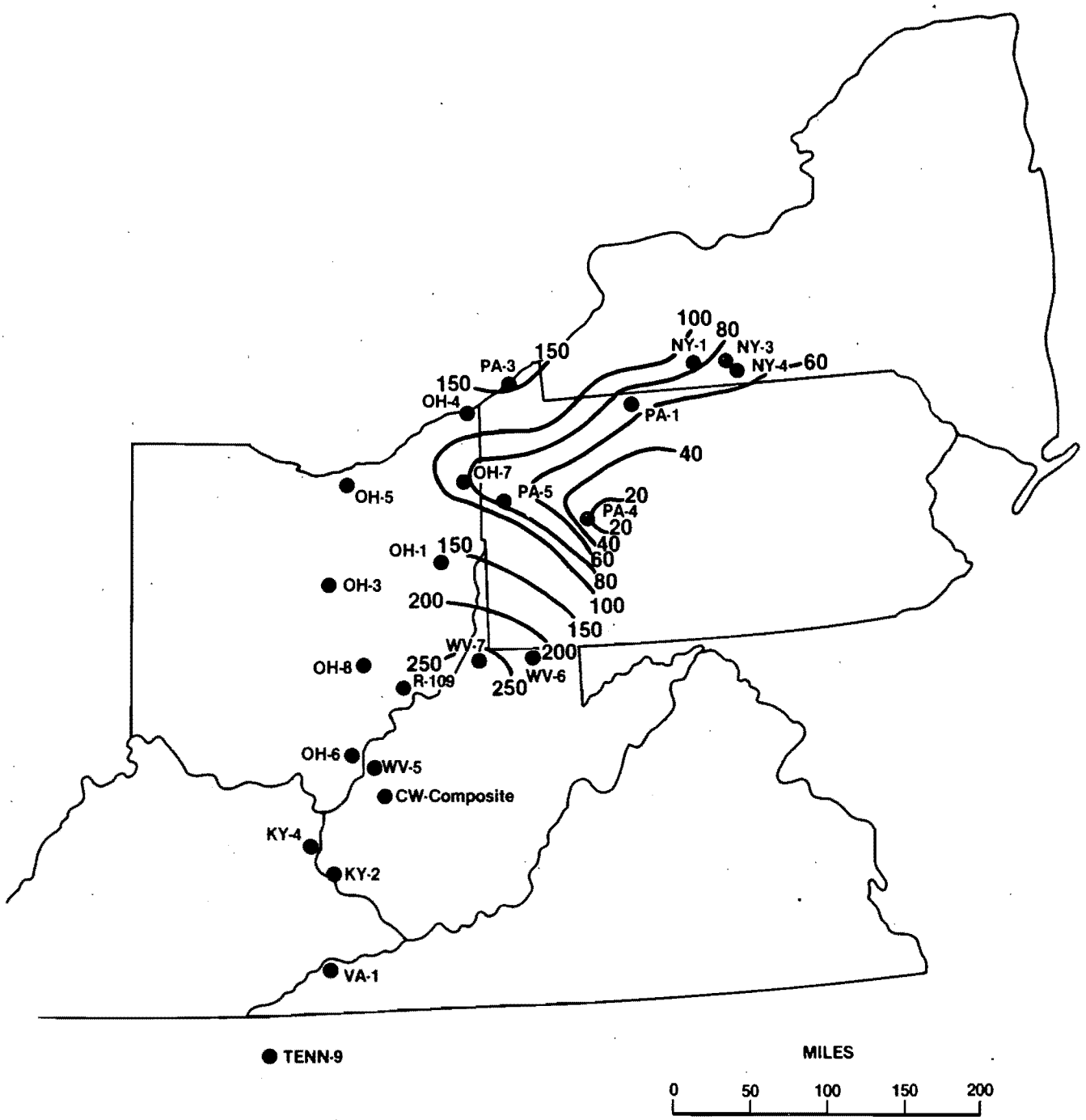


FIGURE 142

LATE MARCELLUS TIME

Map Unit 2

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

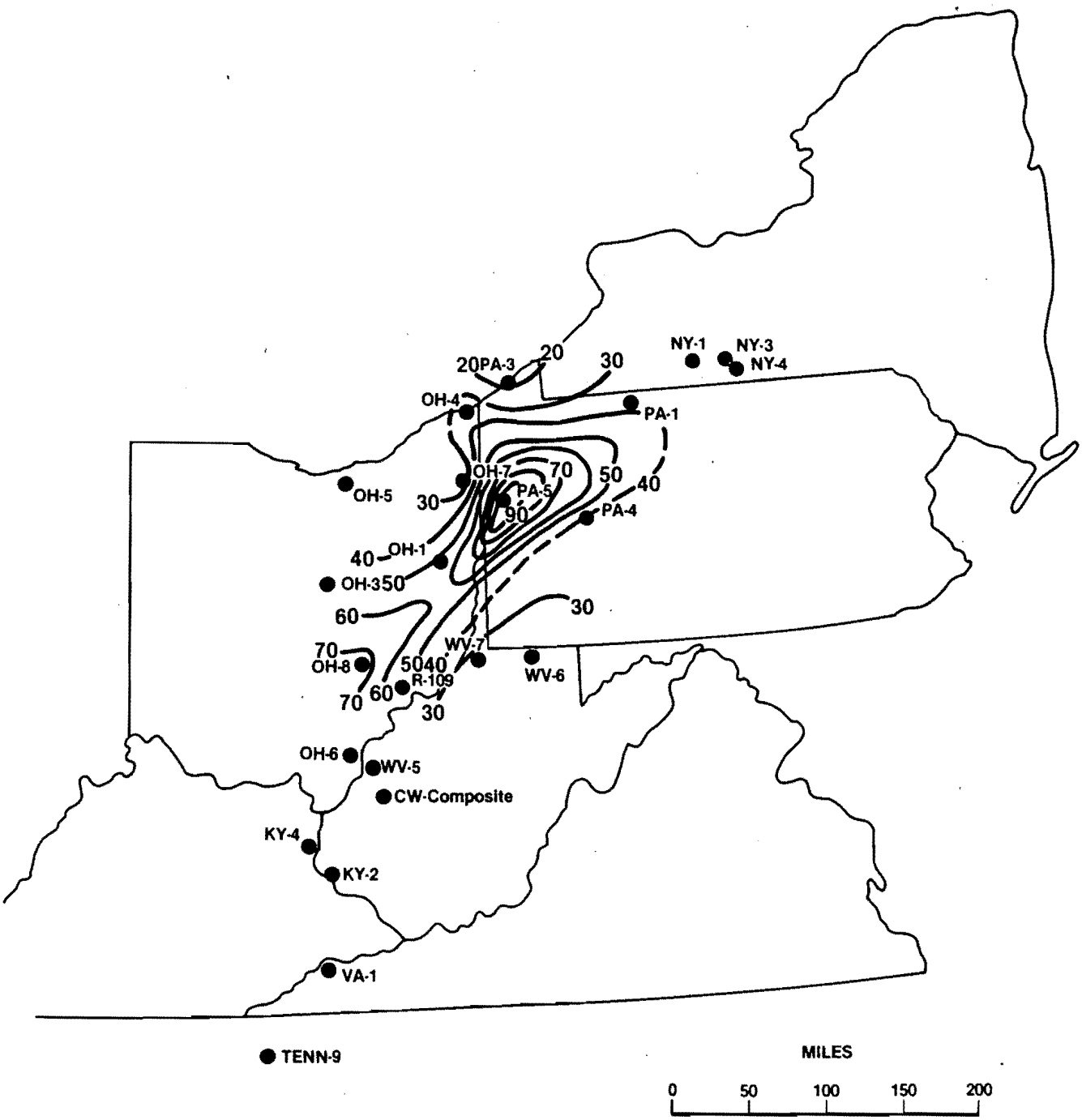


FIGURE 143

HAMILTON GROUP/POST-MARCELLUS TIME

Map Unit 3

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

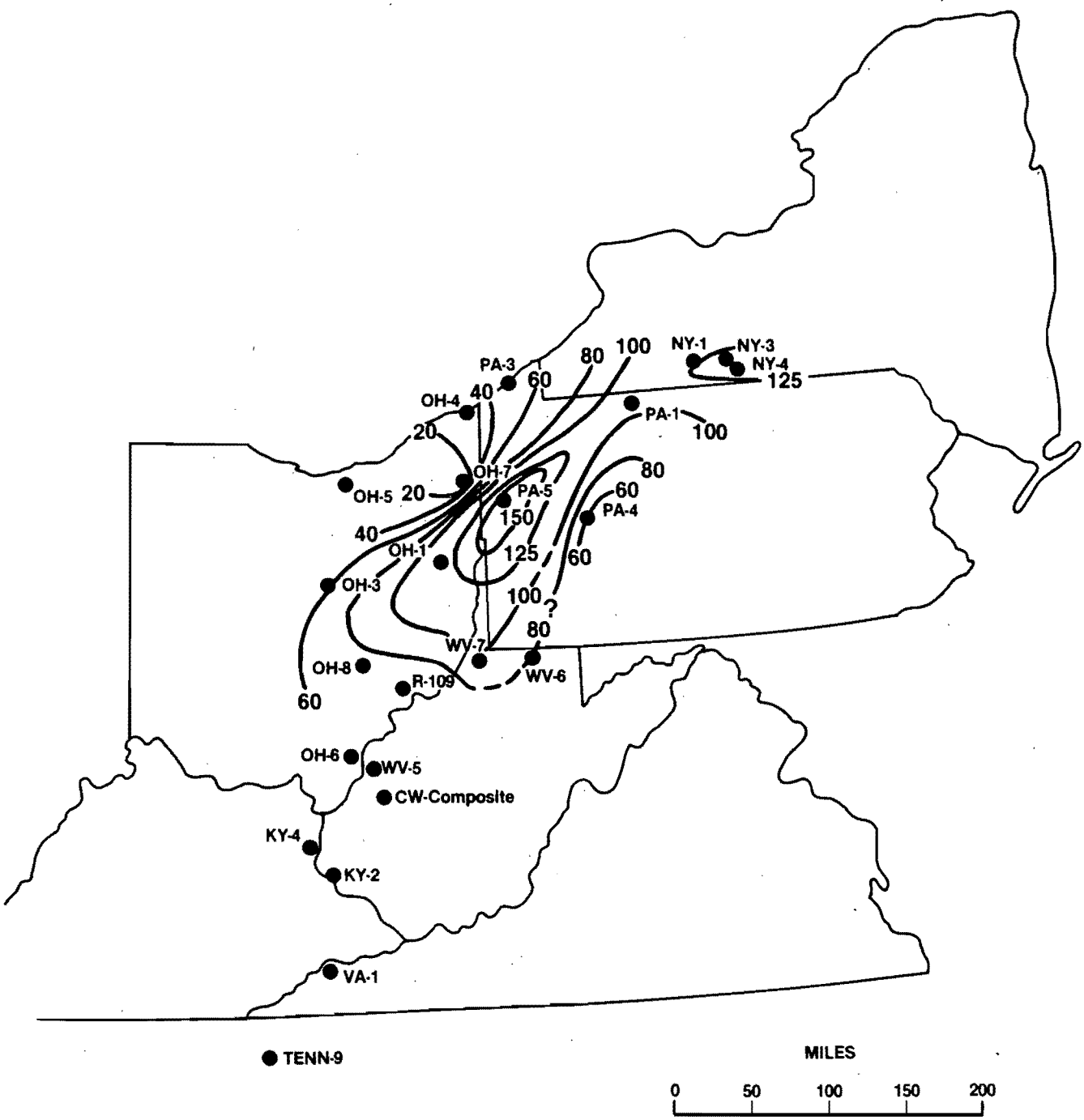


FIGURE 144

GENESEE/GENESEO TIME

Map Unit 4

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

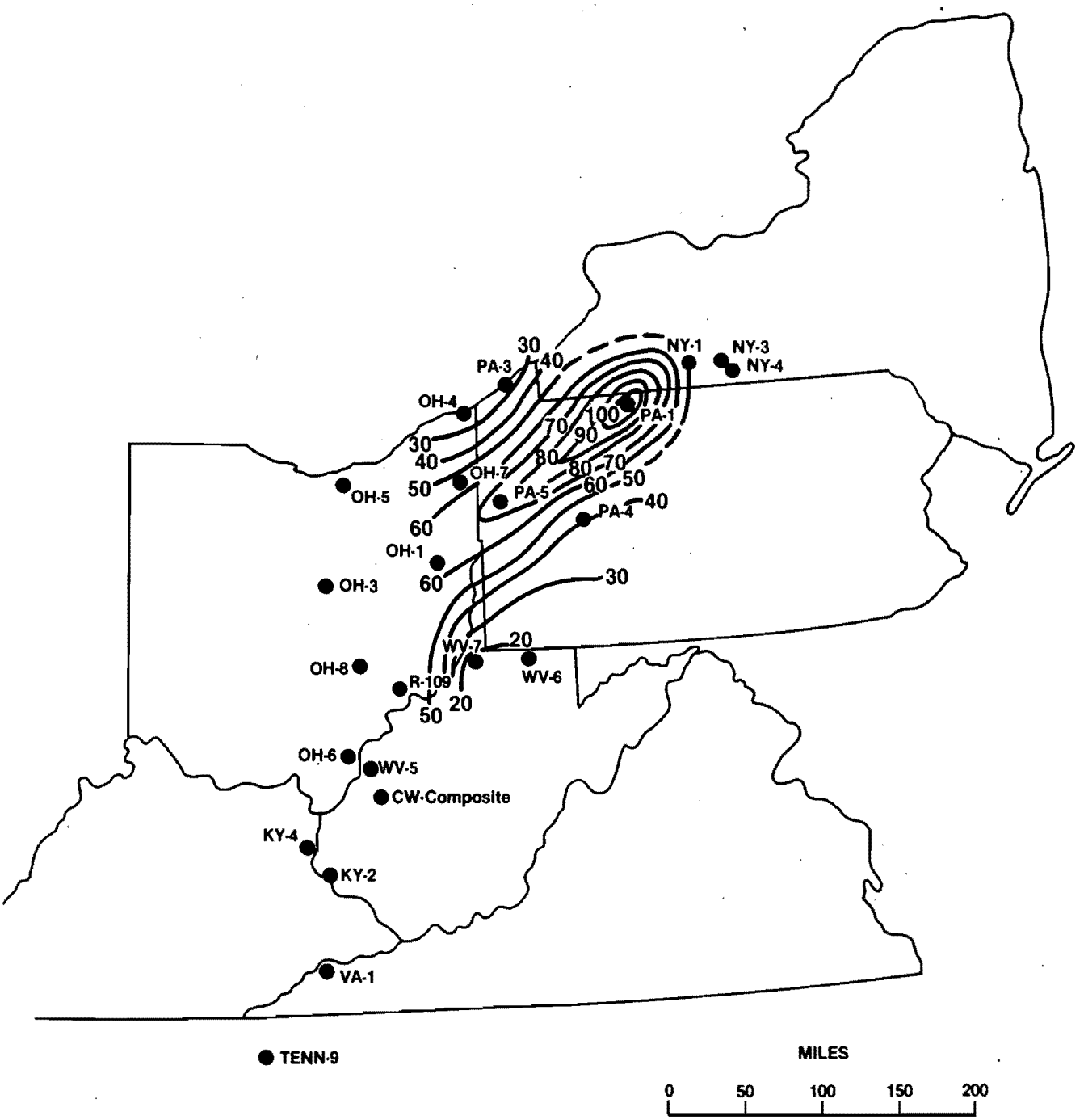


FIGURE 145

SONYEA/MIDDLESEX TIME

Map Unit 5

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

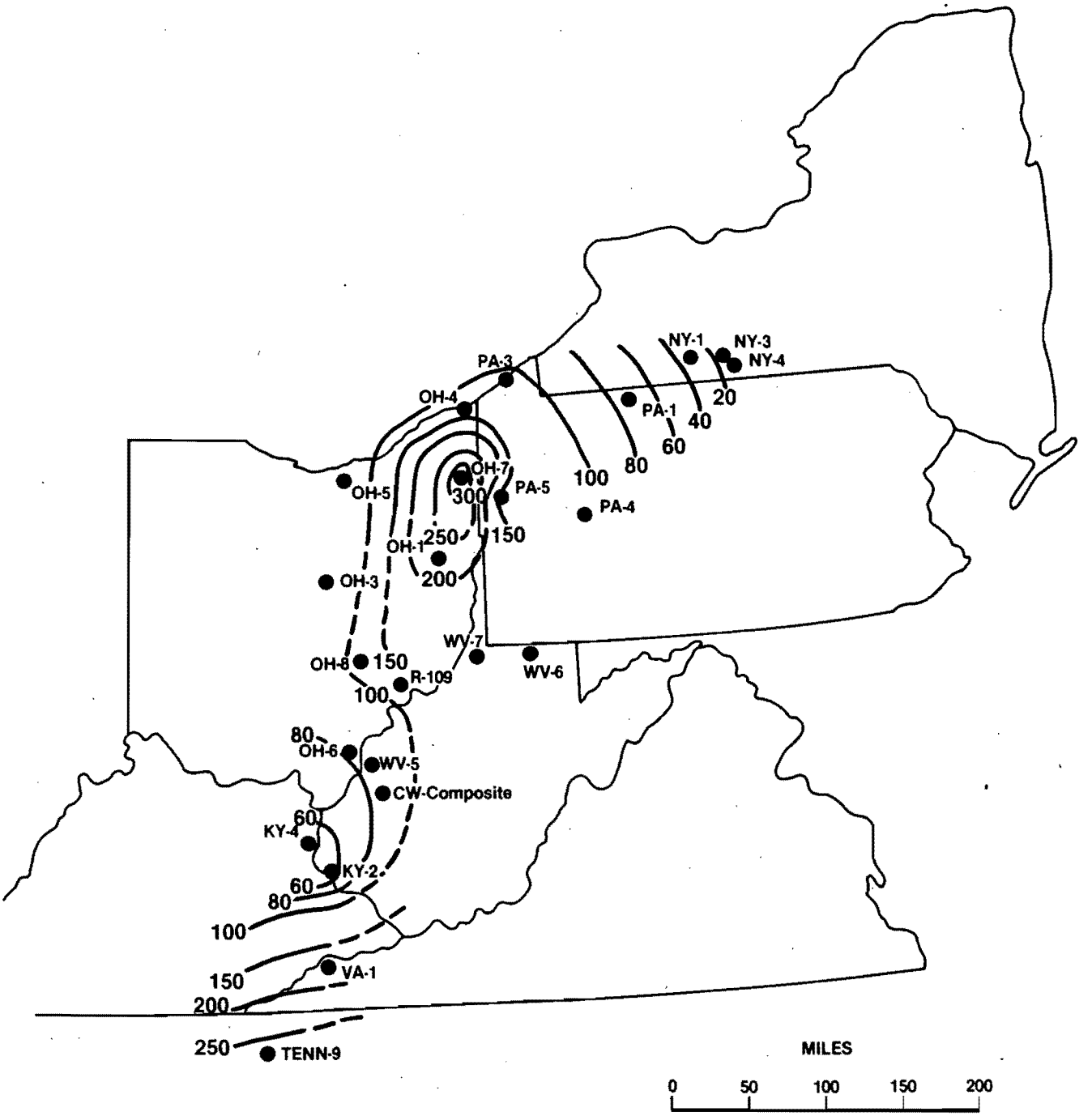


FIGURE 146

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

Map Unit 6

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

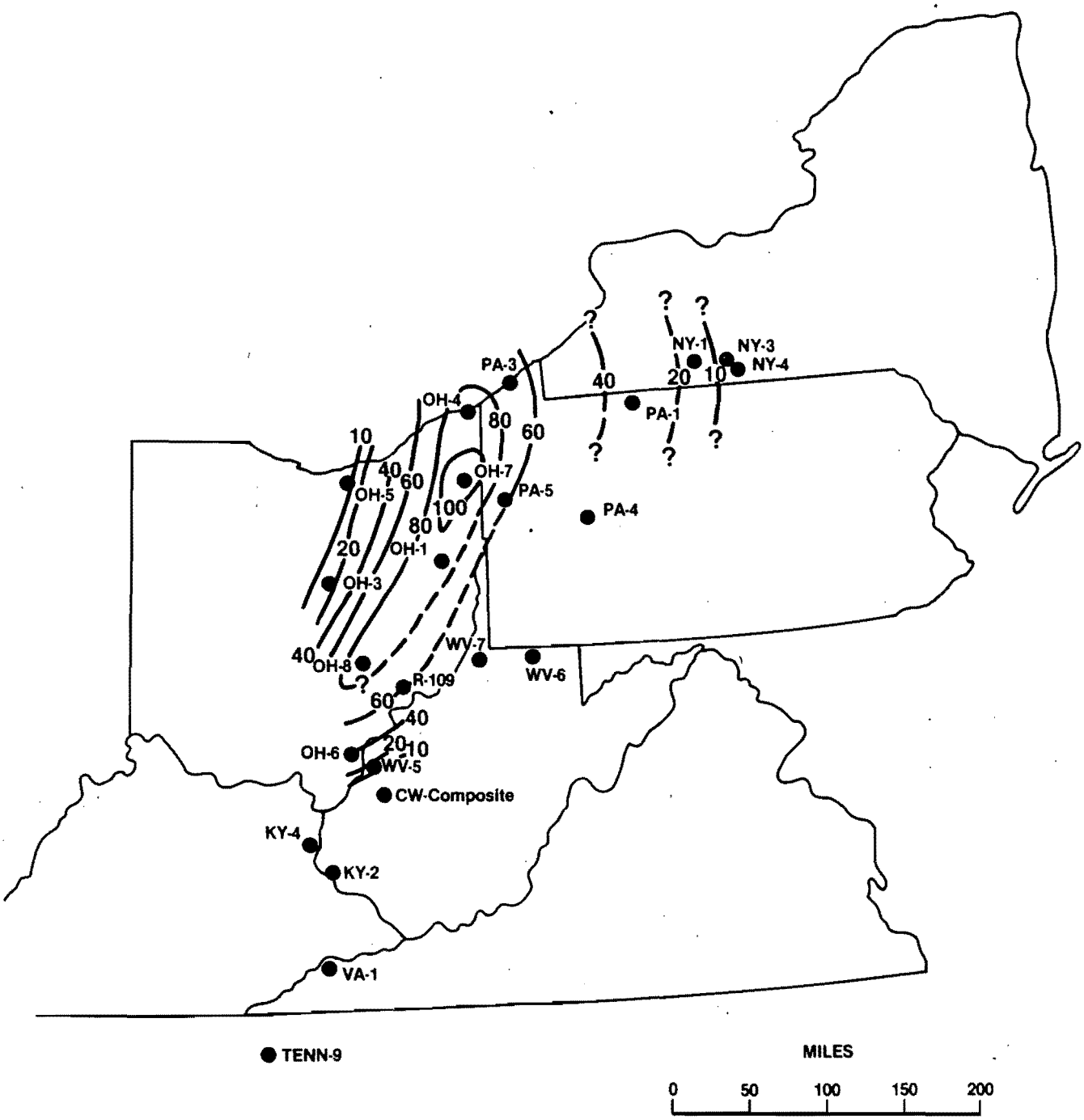


FIGURE 147

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

Map Unit 7

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

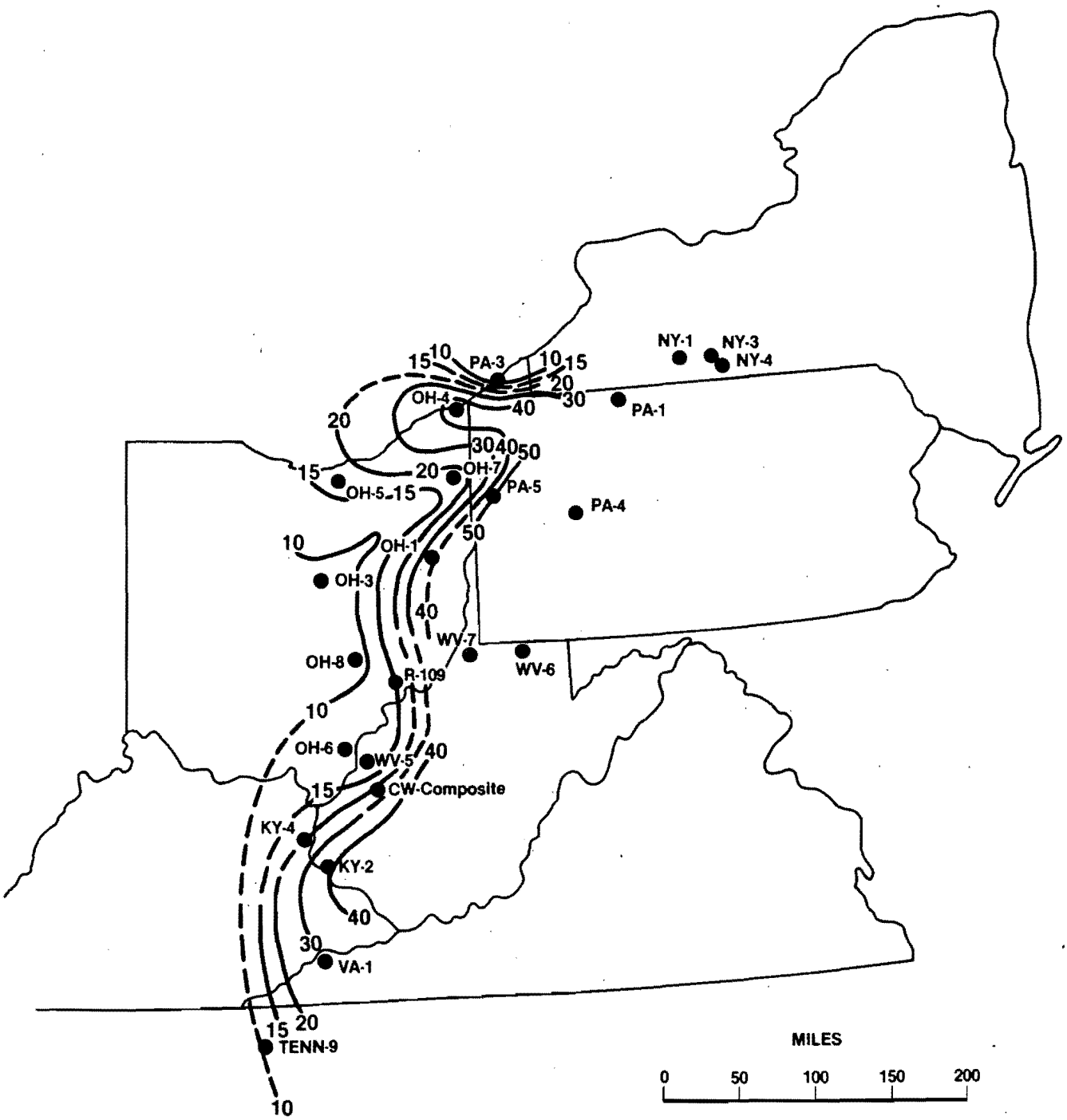


FIGURE 148

MIDDLE OLENTANGY/ANGOLA SHALE TIME

Map Unit 8

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

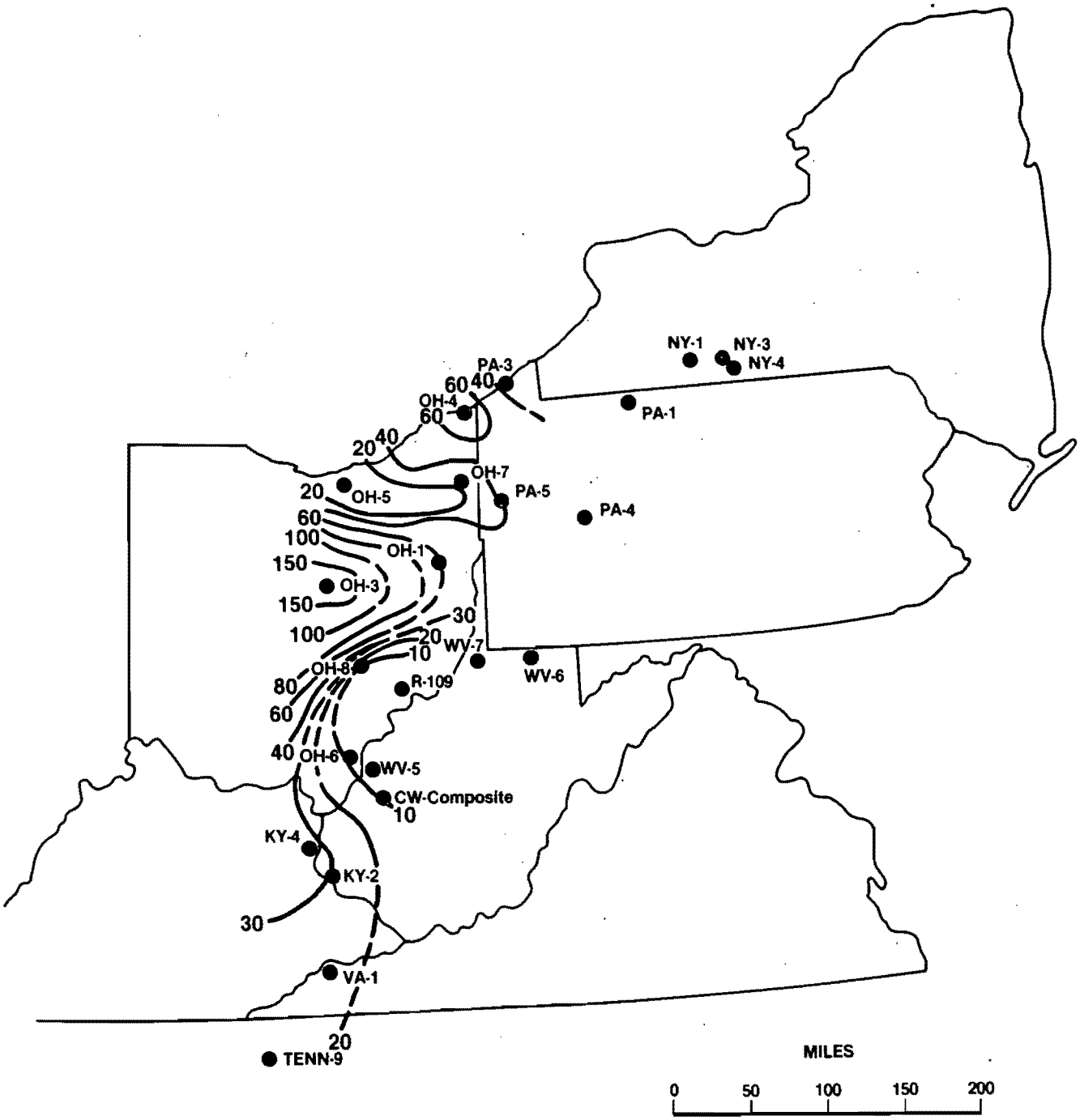


FIGURE 149

UPPER OLENTANGY/JAVA FM. HANOVER SHALE TIME

Map Unit 9

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

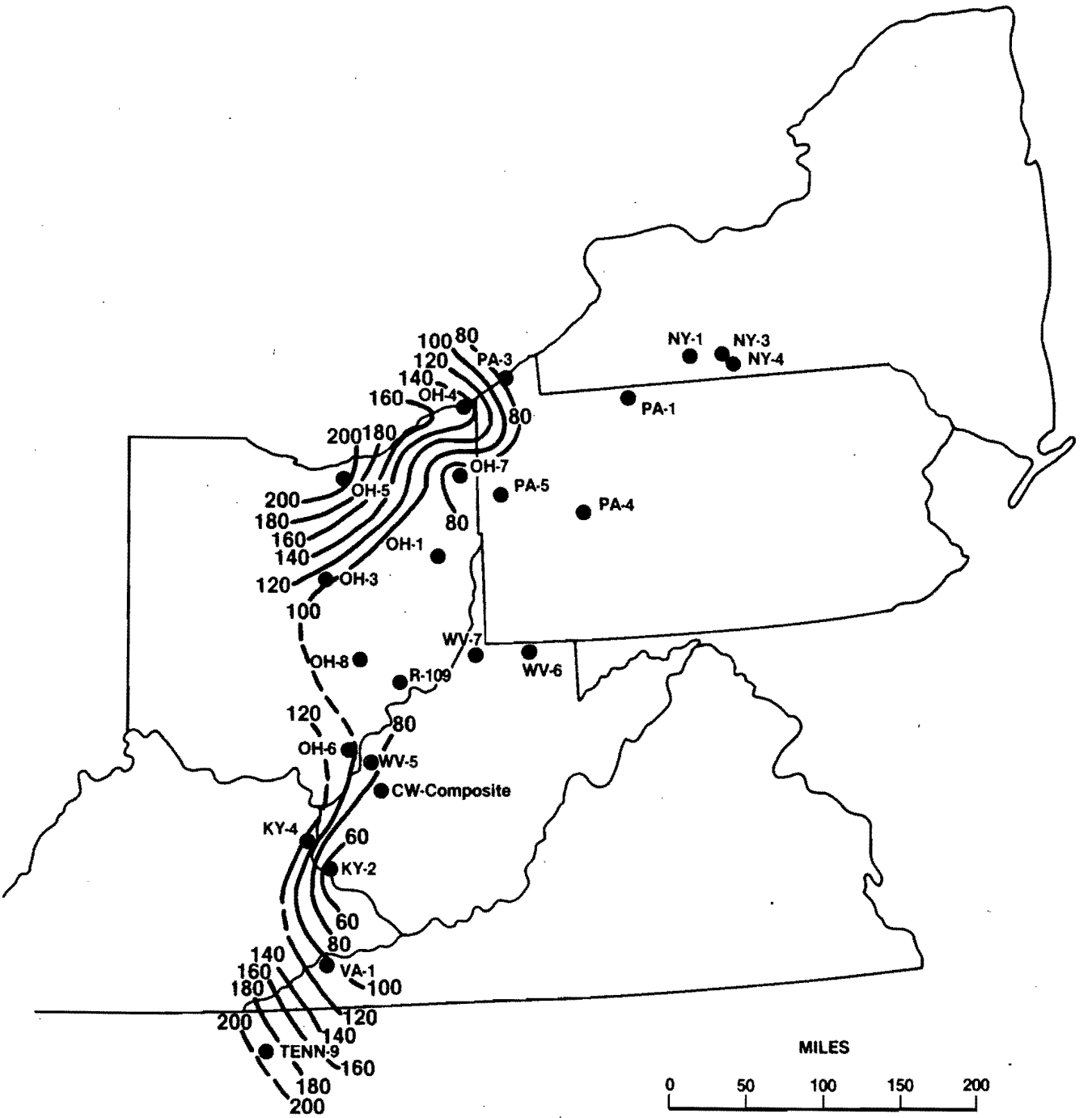


FIGURE 150

EARLY LOWER HURON/EARLY DUNKIRK TIME

Map Unit 10

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

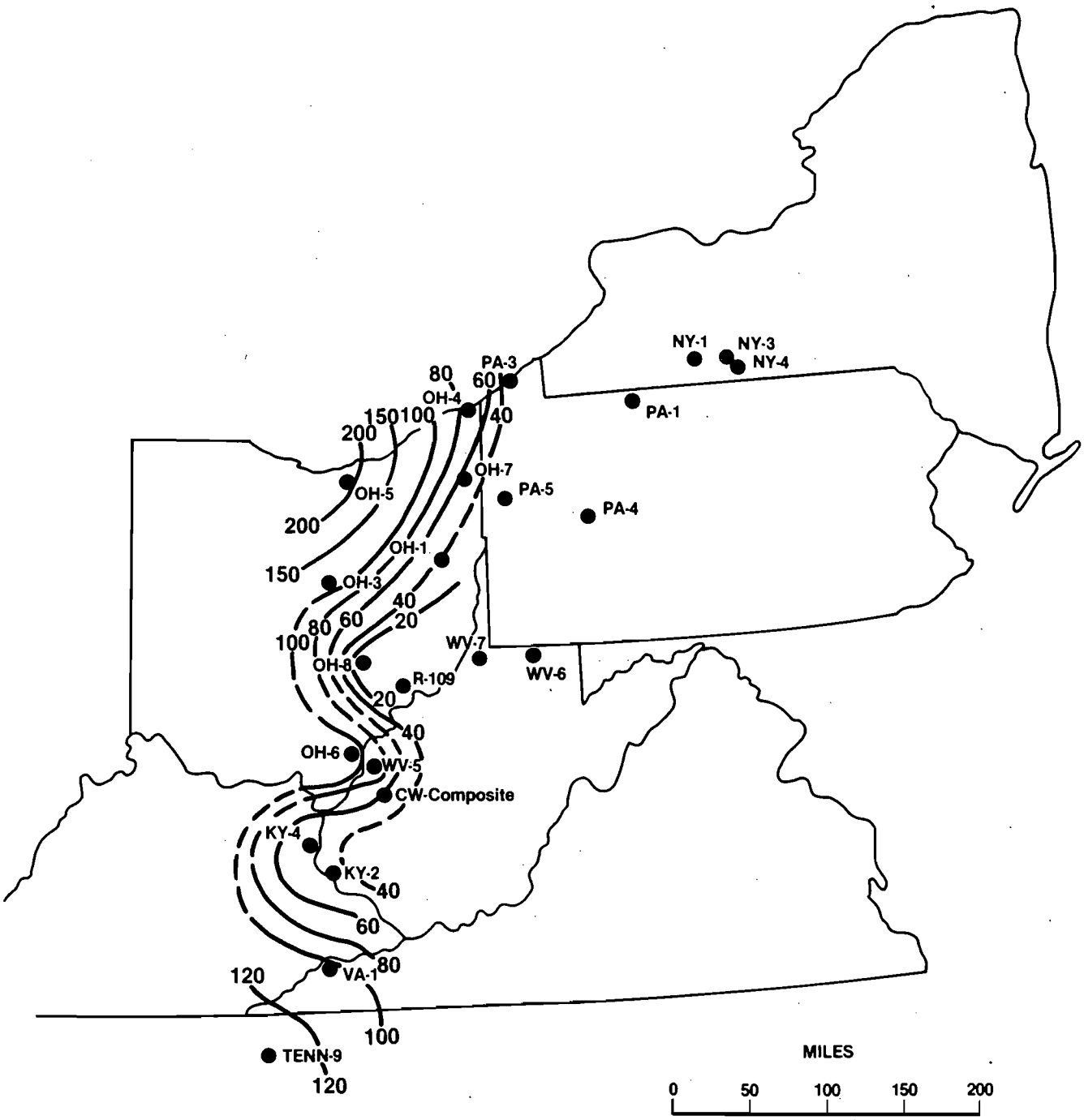


FIGURE 151

LATE LOWER HURON/LATE DUNKIRK TIME

Map Unit 11

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

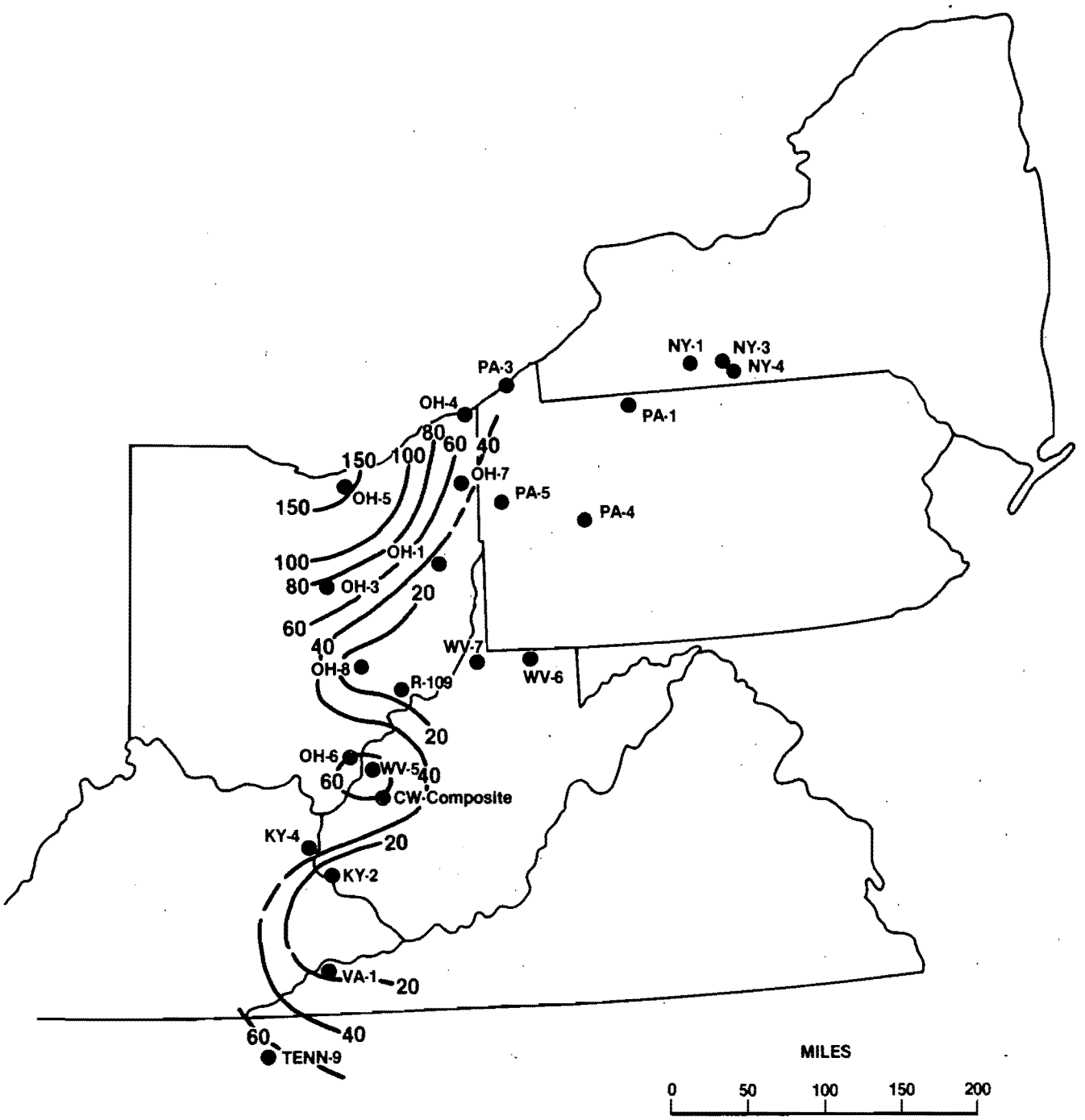


FIGURE 152

EARLY MIDDLE HURON TIME

Map Unit 12

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

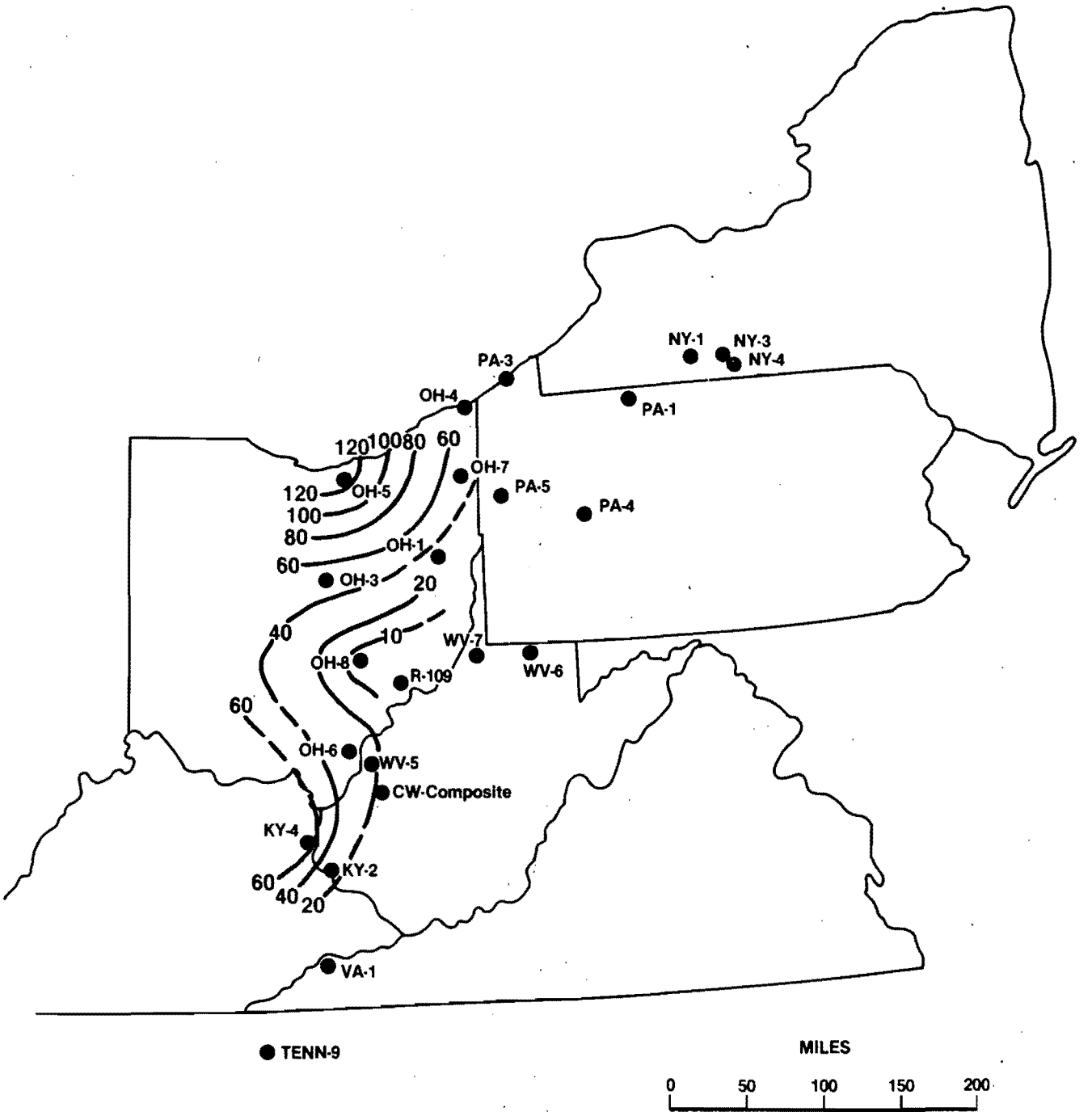


FIGURE 153

LATE MIDDLE HURON TIME

Map Unit 13

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

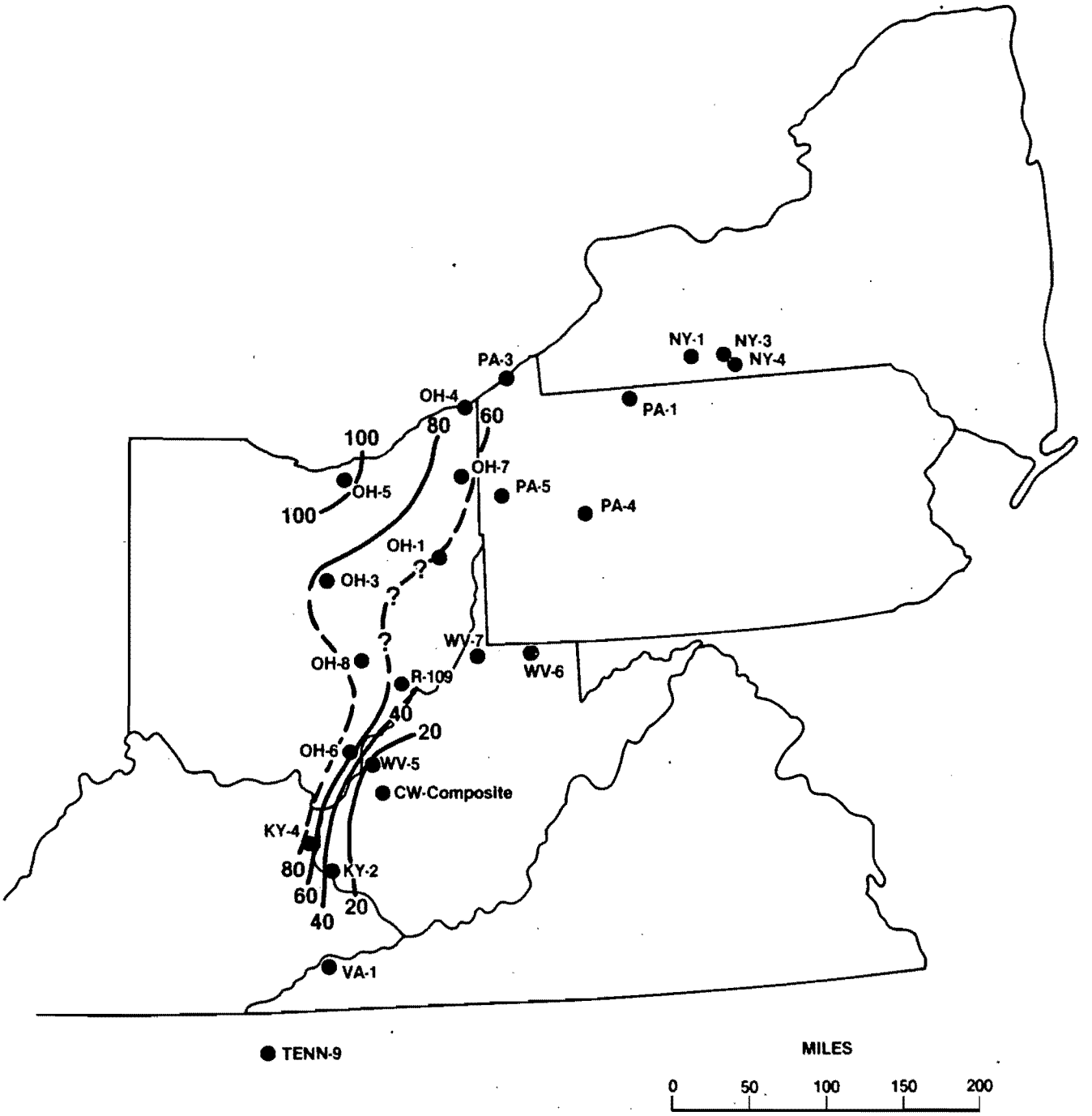


FIGURE 154

EARLY UPPER HURON TIME

Map Unit 14

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

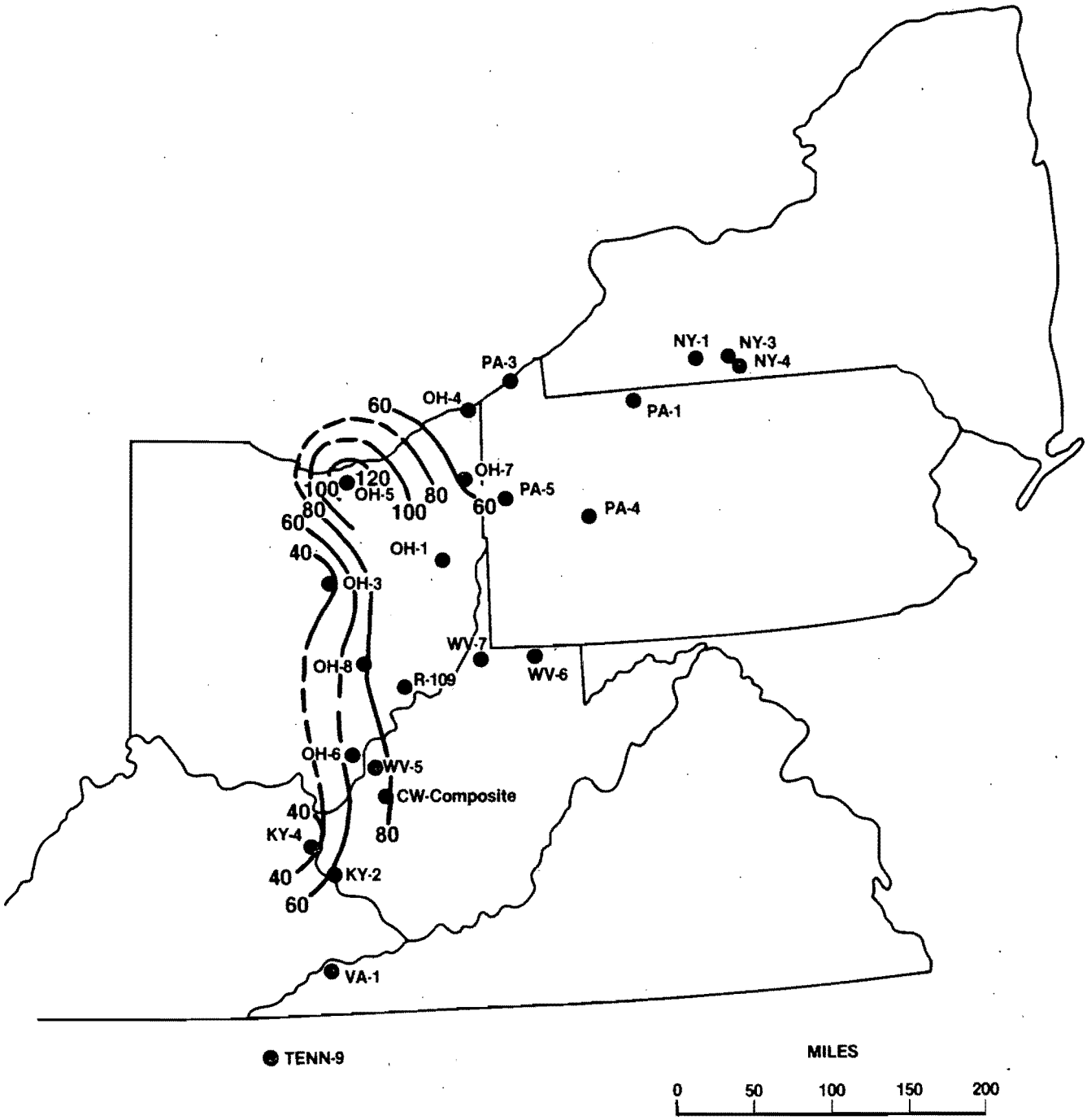


FIGURE 155

LATE UPPER HURON TIME

Map Unit 15

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

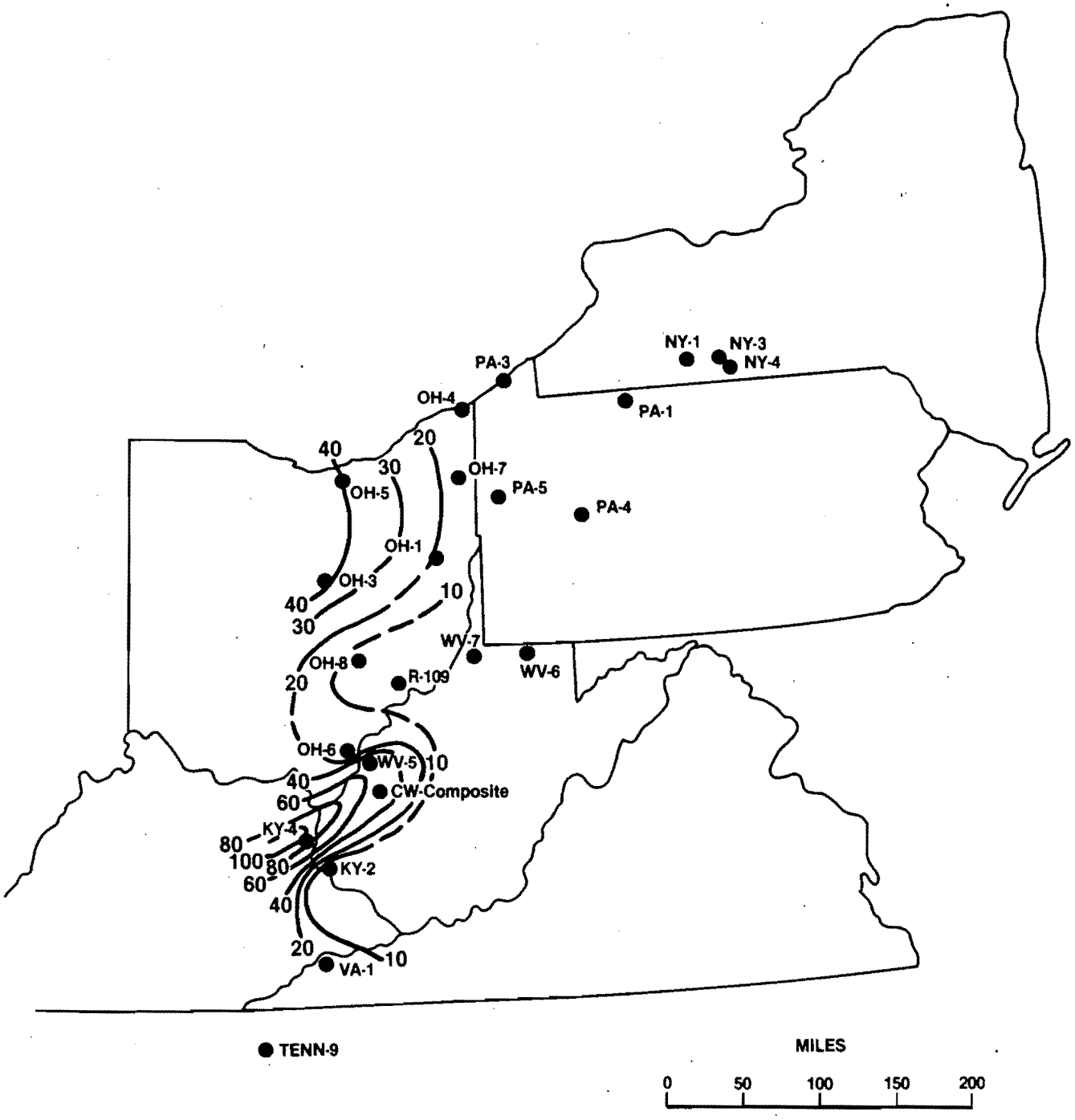


FIGURE 156

CHAGRIN TIME

Map Unit 16

MOUND

Prepared by Mound Facility

CALCULATED INDIGENOUS GAS CONTENT (MCF / Acre Foot)

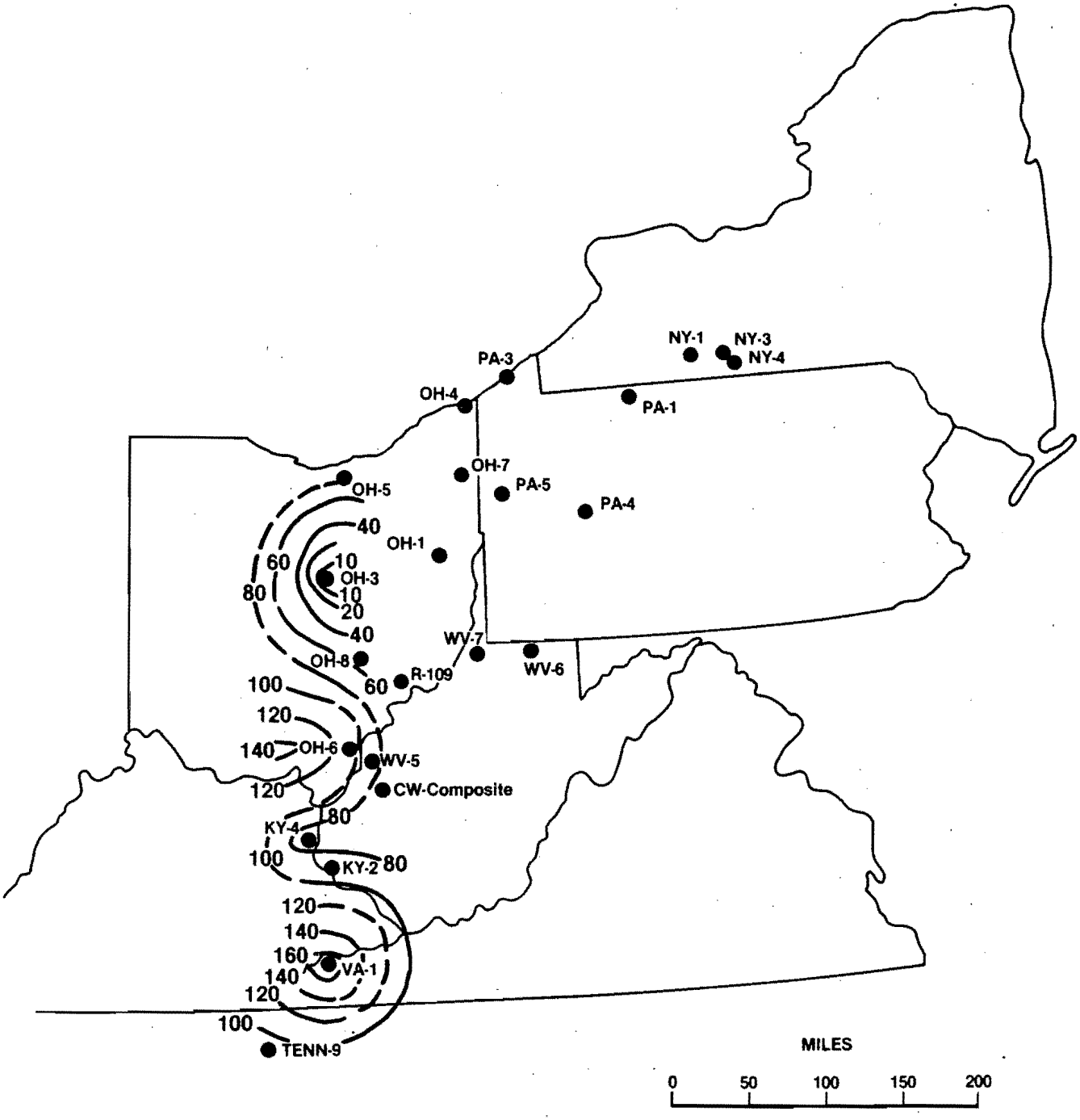


FIGURE 157

CLEVELAND TIME

Map Unit 17

MOUND

Prepared by Mound Facility

Resource Estimate

With the data and above maps available, the total acreage contained within each contour area on each of the maps of indigenous gas was integrated and the total gas in-place in that interval was computed. The total resource for that unit was expressed on each map as TCF (trillion cubic feet).

The gas-in-place resource of the Early Marcellus is calculated as 78 TCF (Figure 158). The amount is smaller in the shallower rocks near Lake Erie and increases to the southeast to a maximum of 5 MMCF/Acre in a local rich area in the vicinity of well PA - 1. The volume of gas is about the same in the Late Marcellus unit. The distribution of the 100 TCF in this unit is shown in Figure 159. The greatest volumes of gas are contained in southeastern Pennsylvania and northern West Virginia.

The gas in the Hamilton Group (Figure 160) is estimated at 213 TCF. While the unit is not as rich in organic matter or gas as the Marcellus units below, it is much thicker, so the recoverable resource in this unit would be much smaller than for the Marcellus and other units in which the gas was more highly concentrated. The volumes of gas in this unit are very small to the southwest and increase, along with unit thickness to the northeast, reaching levels of 20 MMCF/Acre in the area of the New York wells.

The volumes of gas in the Genesee/Geneseo Unit are calculated at 242 TCF, much of its volume attributable to its thickness. The quantities increase from very low in the southeastern portion of the basin to 35 MMCF/Acre southeast of the New York wells (Figure 161).

The volume of gas in the Sonyea/Middlesex unit is 209 TCF, which is distributed similarly to the gas in the Genesee/Geneseo unit immediately below as Figure 162 shows. The high values are 25 MMCF/Acre, southeast of the New York wells.

The gas volume calculated for the Early Rhinestreet unit is 226 TCF. In this unit, the gas is concentrated in eastern Ohio (Figure 163), with values as high as 20 MMCF/Acre in the region around OH - 1. The resource in the Late Rhinestreet unit is much smaller, i.e., 63 TCF, and it too is concentrated in eastern and southeastern Ohio (Figure 164).

The resource in-place in the Middle Olentangy/Angola unit is 159 TCF. The volumes are low along the western margins of the basin, and increase eastward to levels as high as 8 MMCF/Acre in the area of WV - 7, WV - 6, and OH - 1 (Figure 165). There is 126 TCF of gas in the Upper Olentangy unit, centered in east central Ohio (Figure 166).

The early Lower Huron unit is the richest unit in terms of total indigenous gas. It contains 345 TCF which increases from east to west in the unit, reaching a high value of 18 MMCF/Acre in the area around KY - 4 and 12 MMCF/Acre near OH - 5 (Figure 167). The later Lower Huron unit is also gas-rich, particularly in northeastern Ohio, with the highest quantities, i.e., 20 MMCF/Acre near OH - 5 (Figure 168).

The Middle Huron has less gas, 120 TCF and 84 TCF in the two units, with the highest values in northeastern Ohio (Figures 169 and 170). The early and

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

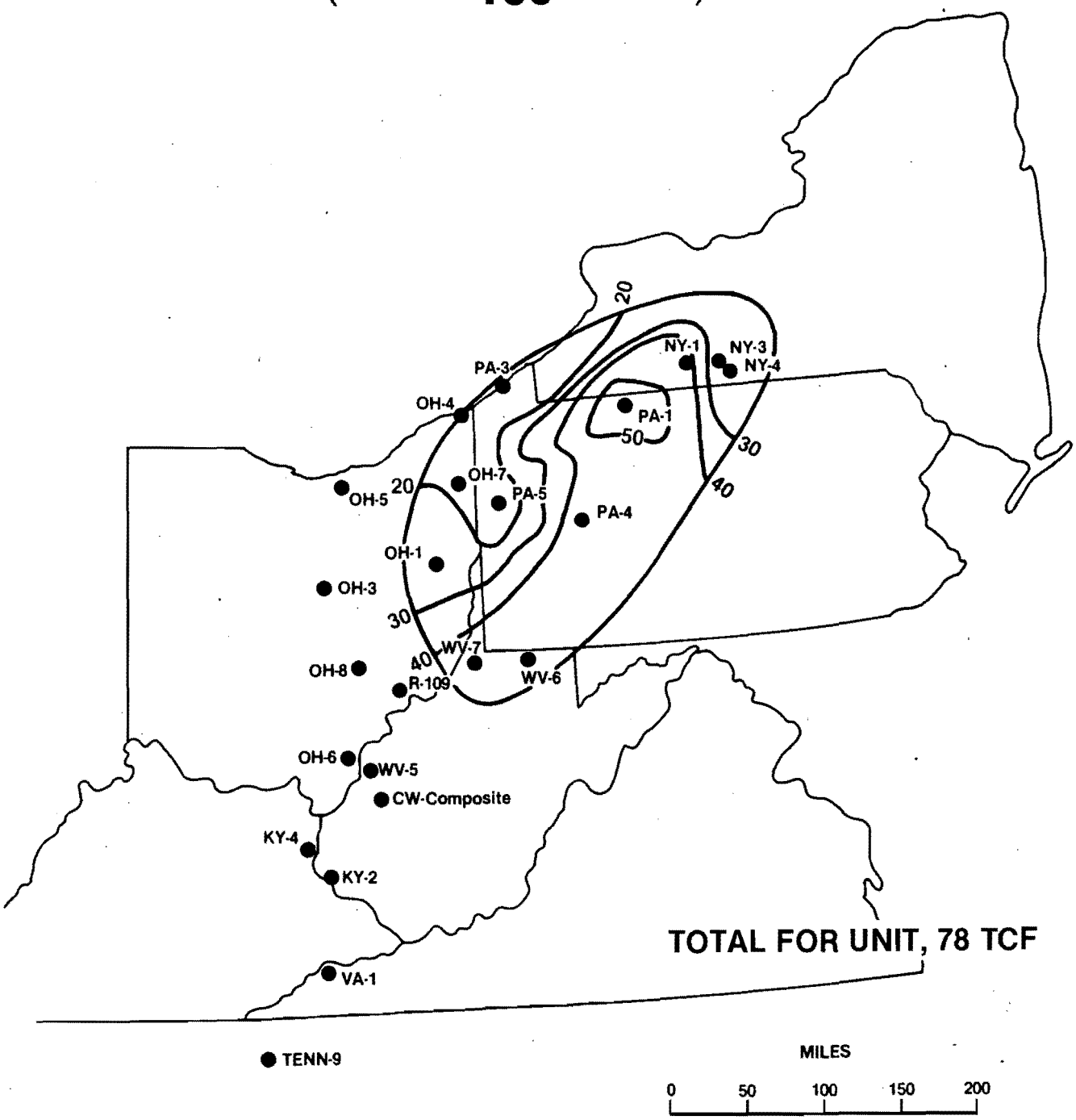


FIGURE 158

EARLY MARCELLUS TIME

MAP UNIT 1

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

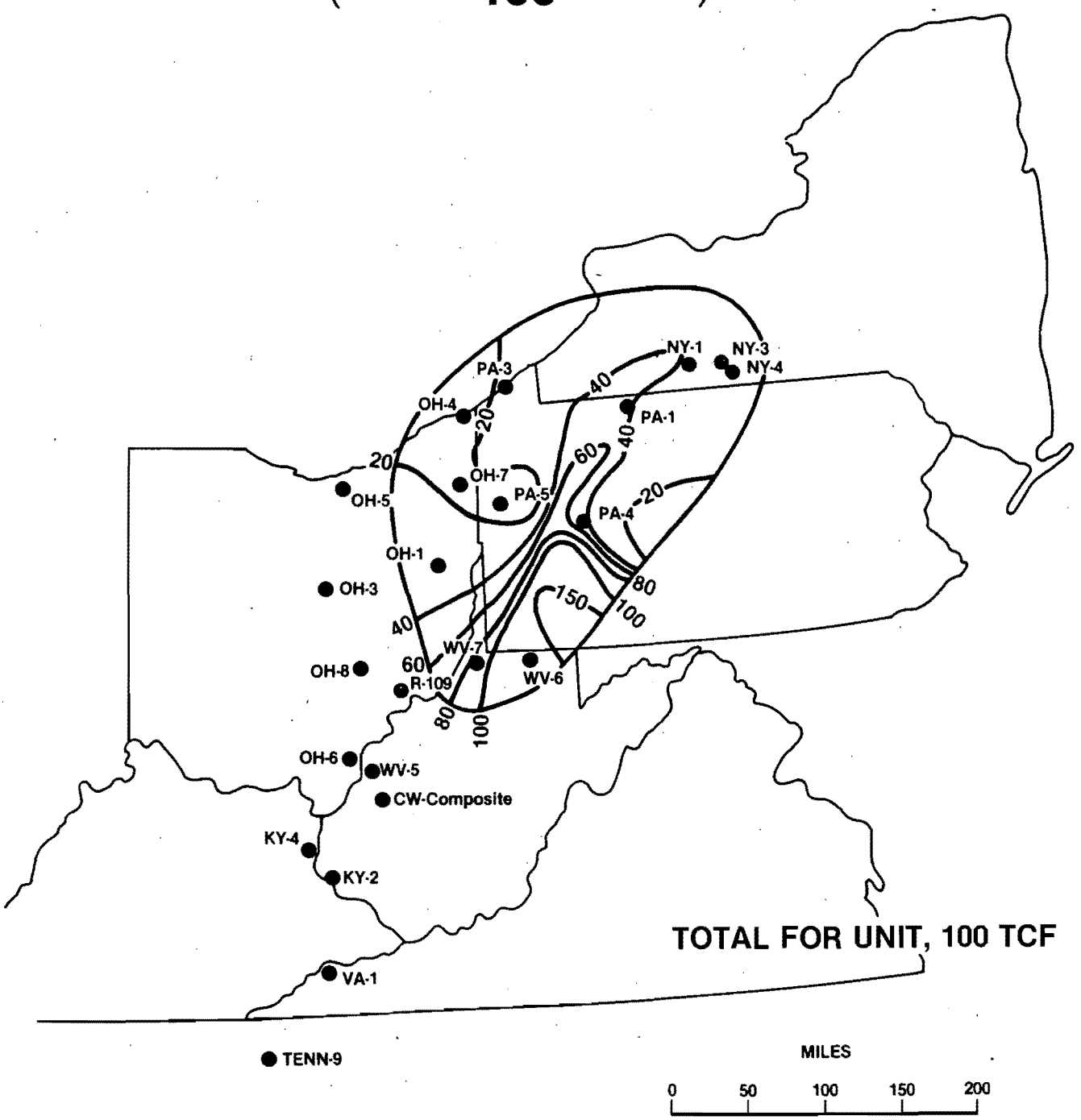


FIGURE 159

LATE MARCELLUS TIME

MAP UNIT 2

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

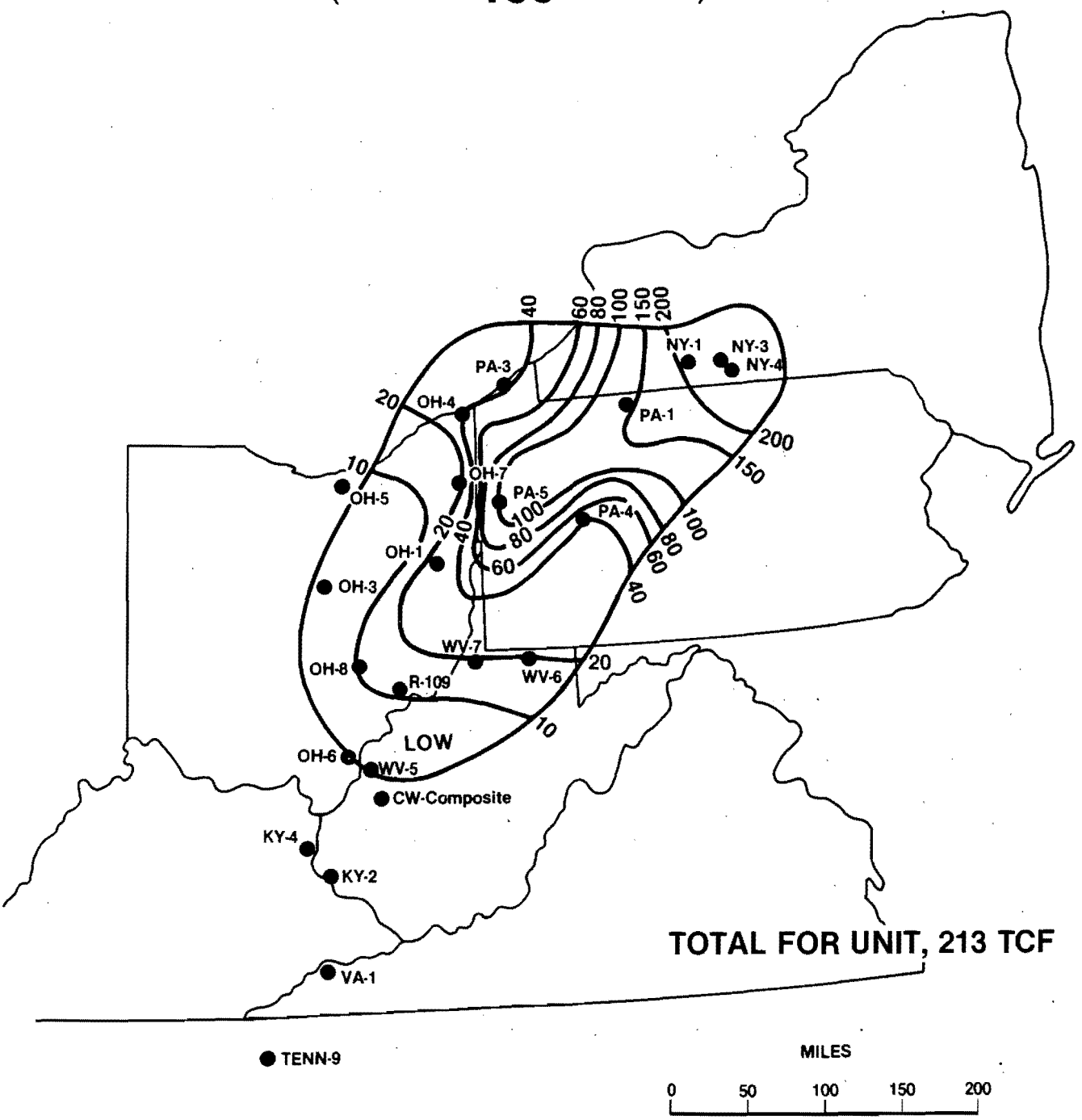


FIGURE 160

HAMILTON GROUP/POST-MARCELLUS TIME

MAP UNIT 3

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

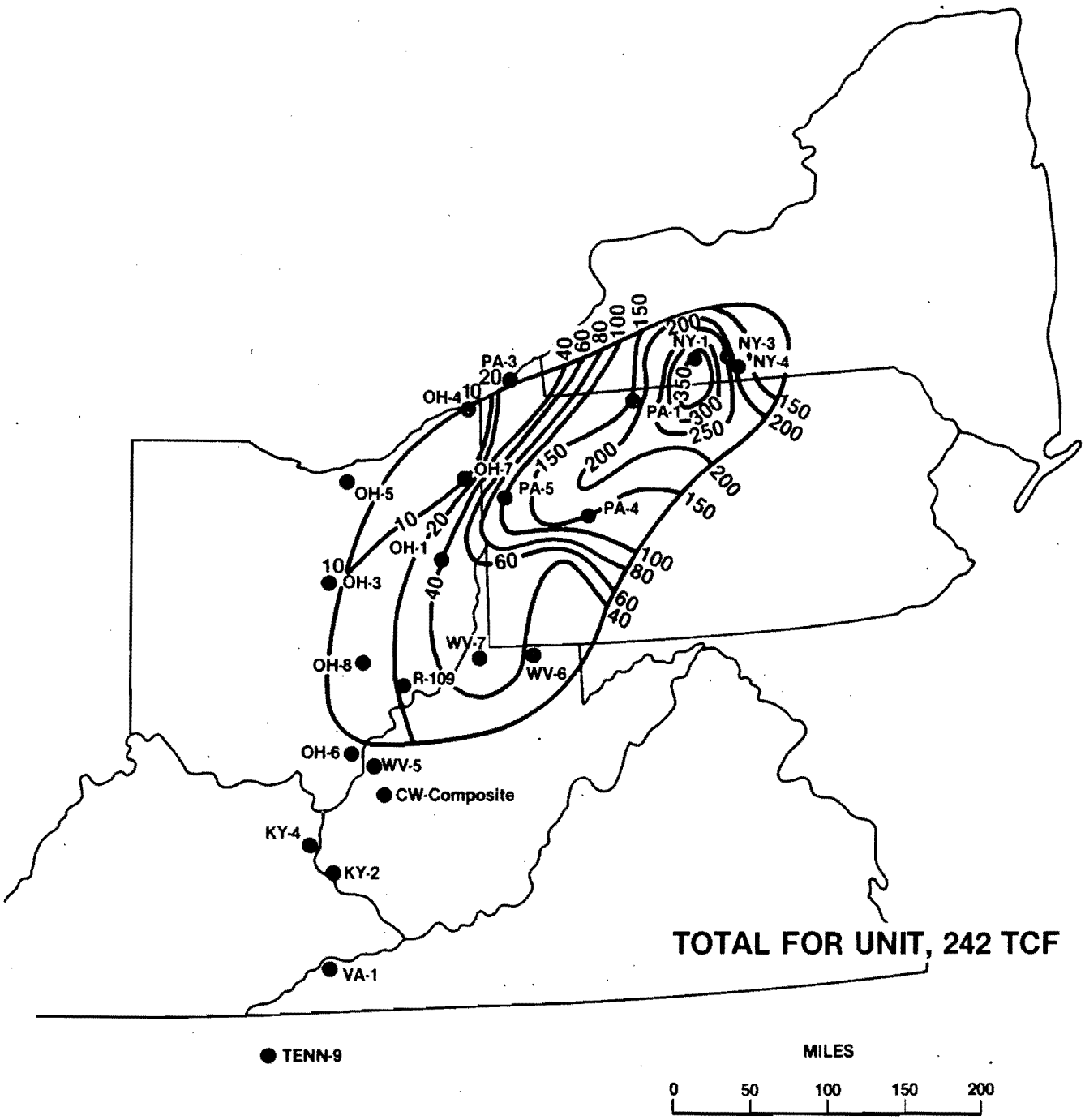


FIGURE 161

GENESEE/GENESEO TIME

MAP UNIT 4

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

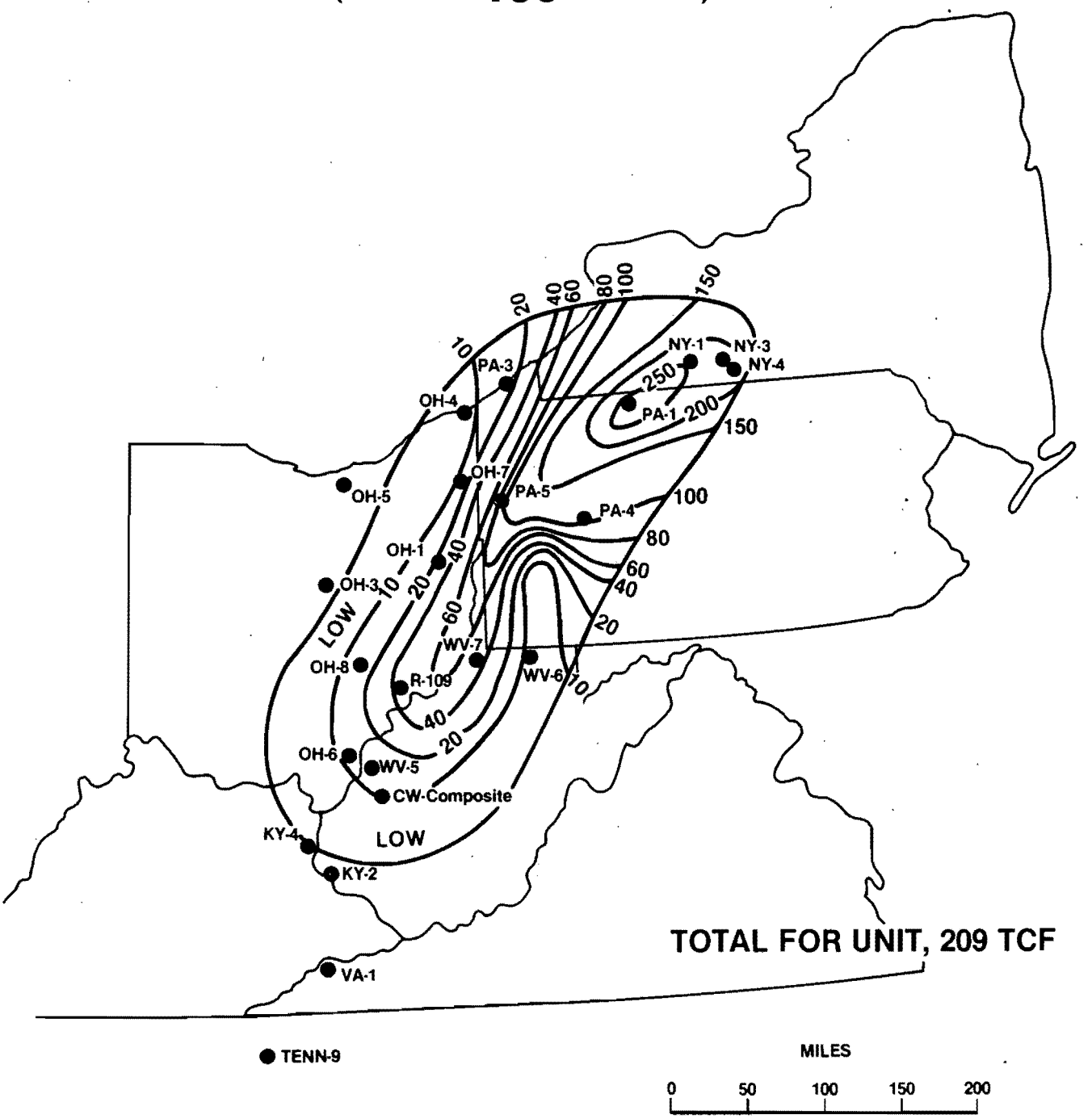


FIGURE 162

SONYEA/MIDDLESEX TIME

MAP UNIT 5

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

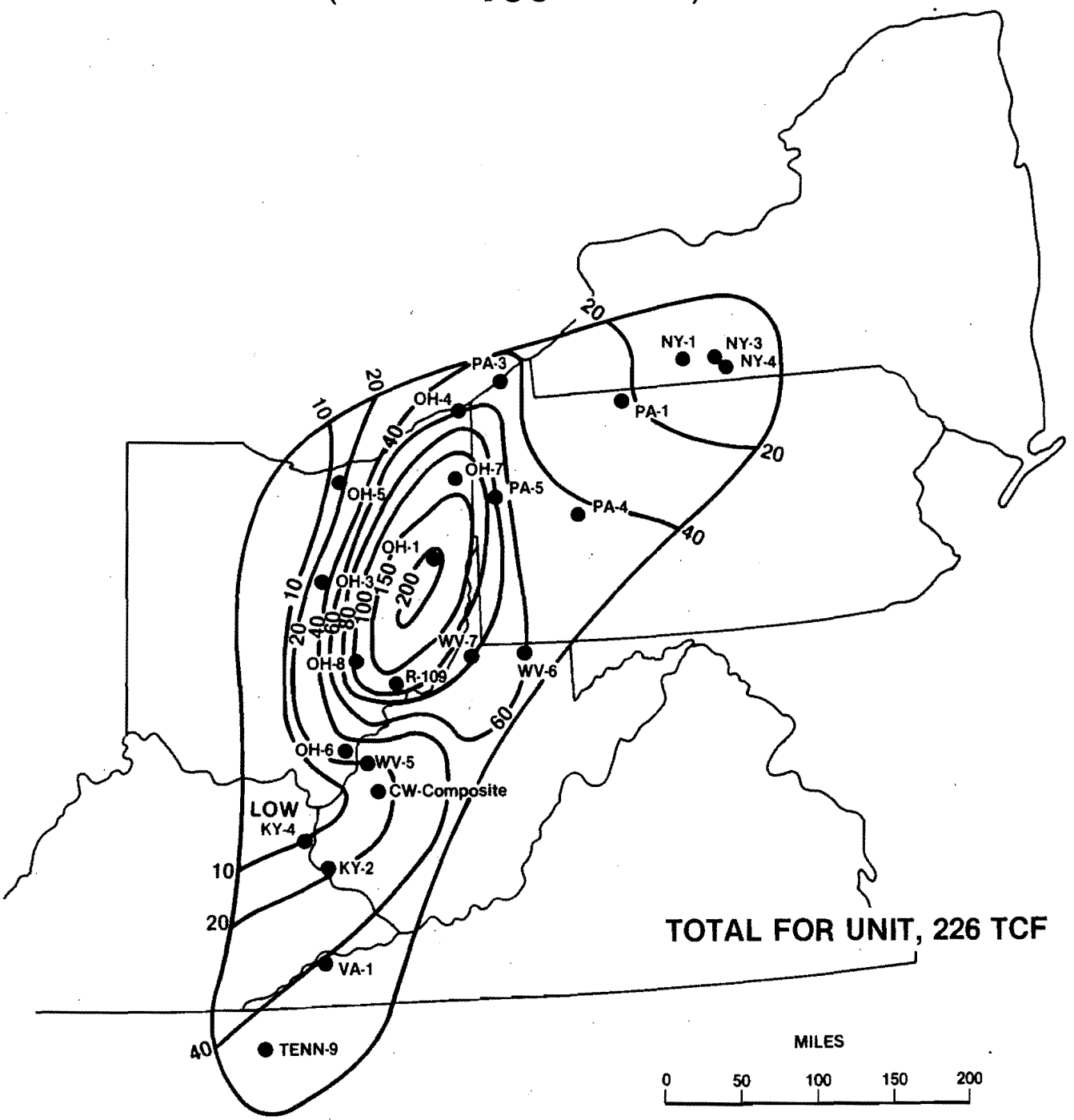


FIGURE 163

EARLY LOWER OLENTANGY/ EARLY RHINESTREET TIME

MAP UNIT 6

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

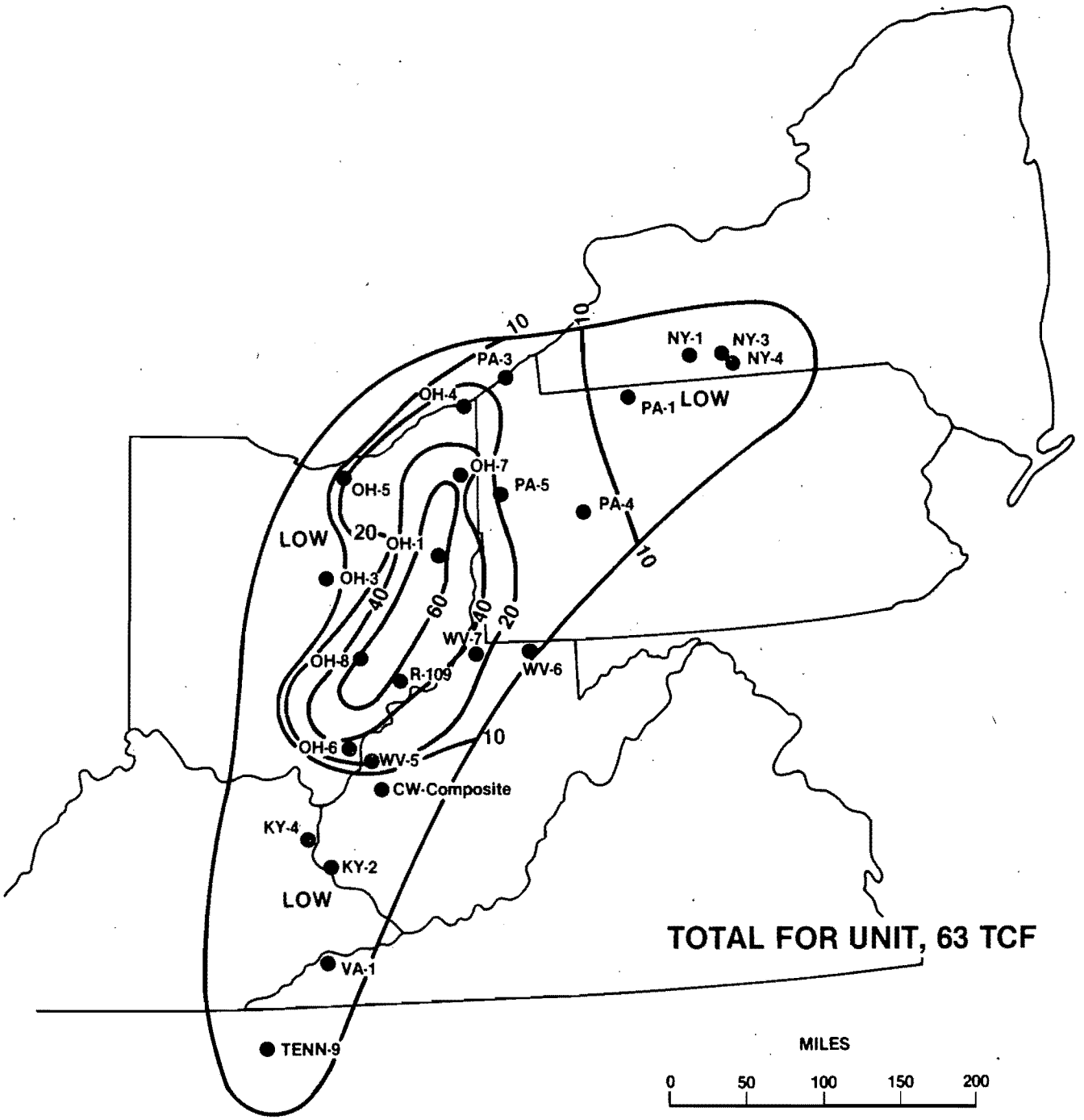


FIGURE 164

LATE LOWER OLENTANGY/ LATE RHINESTREET TIME

MAP UNIT 7

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

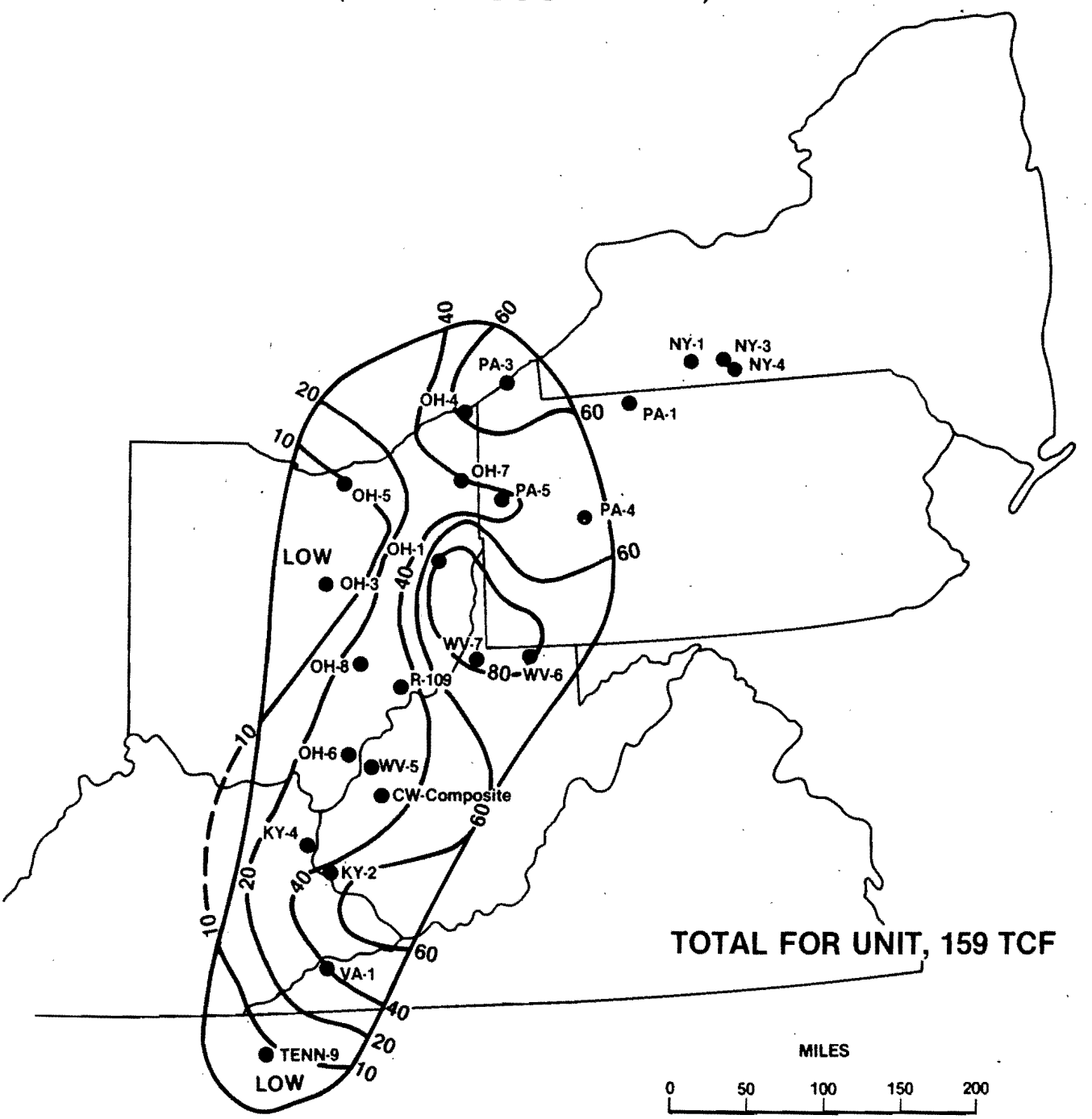


FIGURE 165

MIDDLE OLENTANGY/ANGOLA SHALE TIME

MAP UNIT 8

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

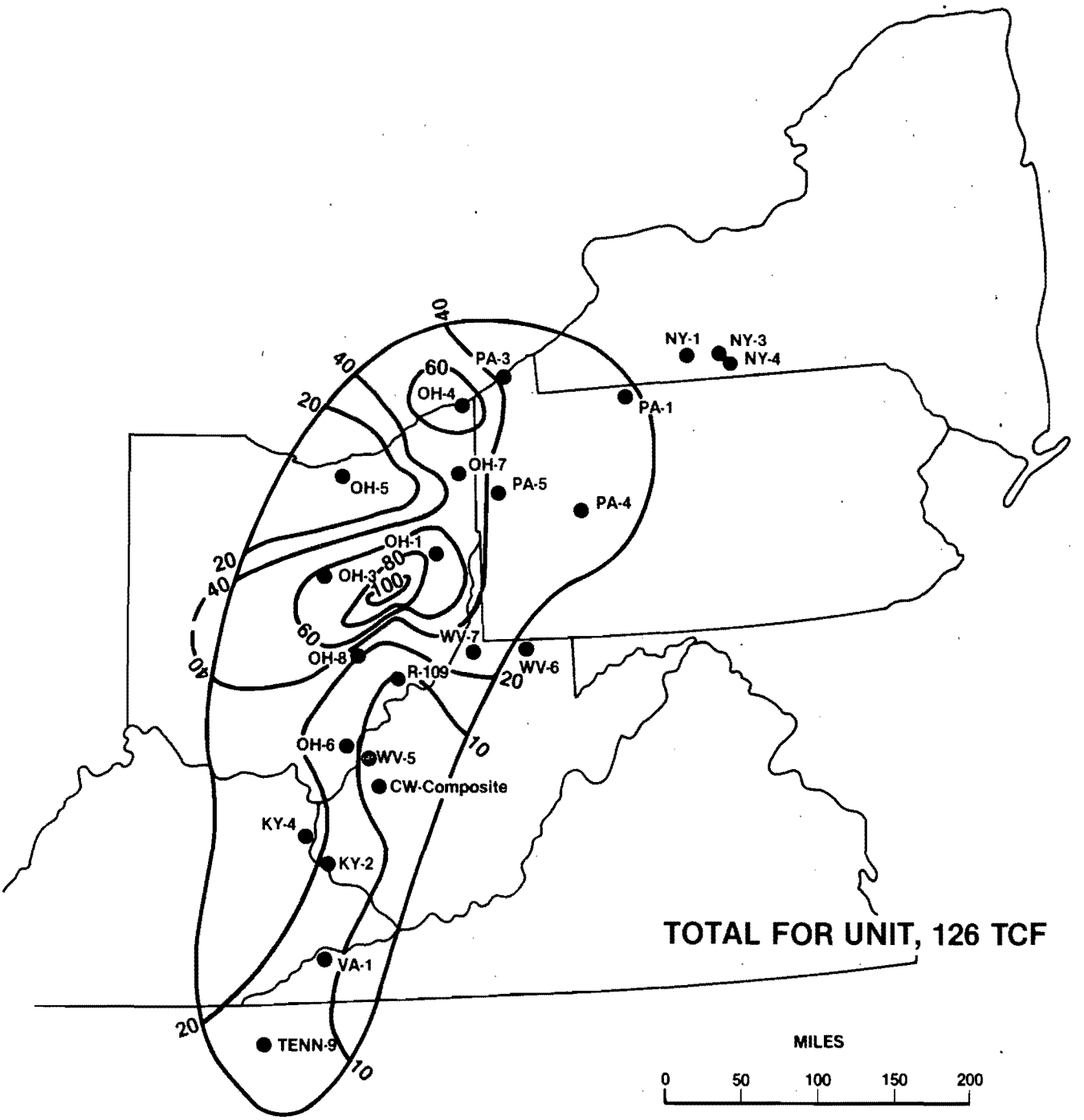


FIGURE 166

UPPER OLENTANGY/JAVA FM.
HANOVER SHALE TIME

MAP UNIT 9

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

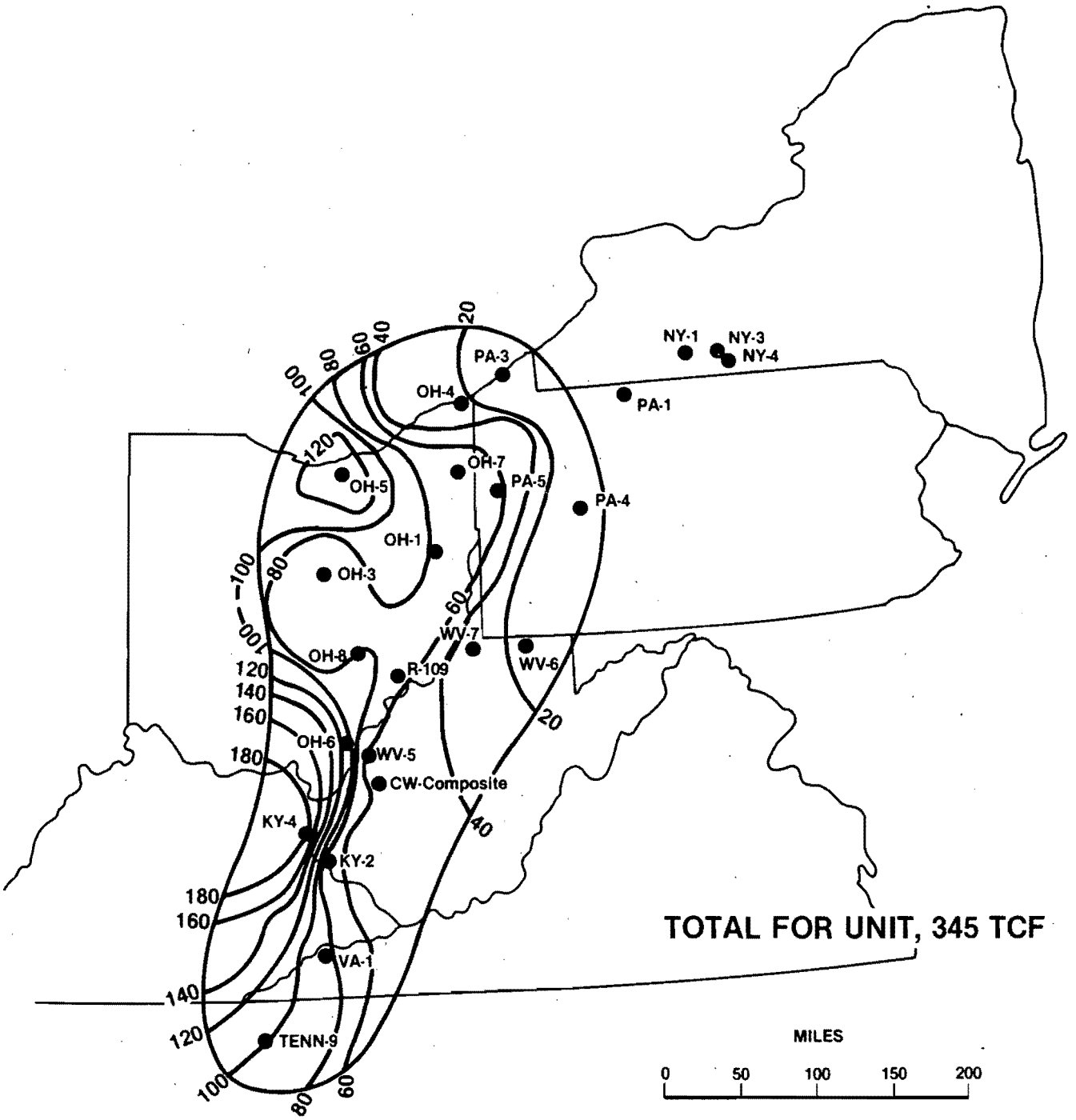


FIGURE 167

EARLY LOWER HURON/EARLY DUNKIRK TIME

MAP UNIT 10

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

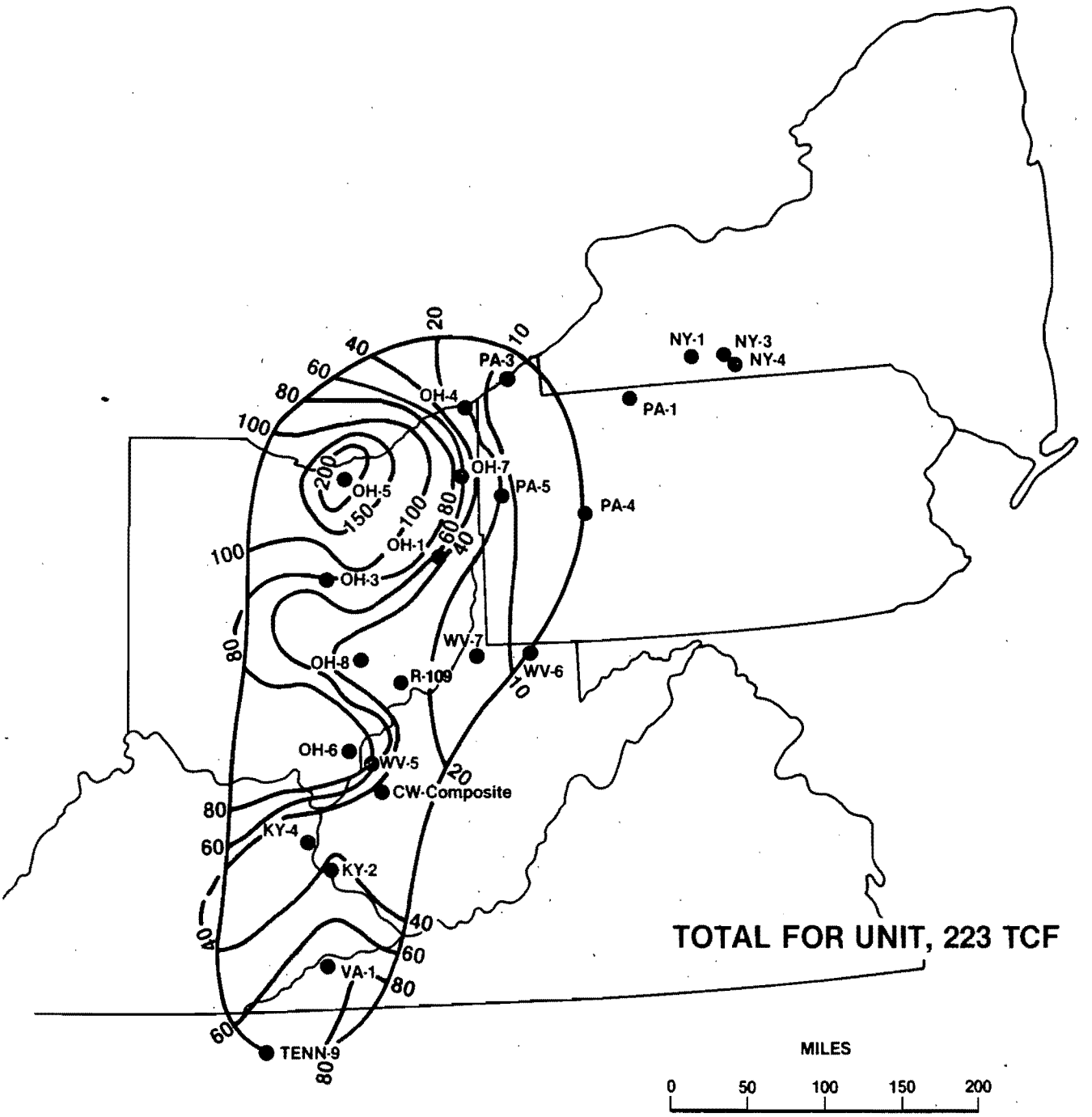


FIGURE 168

LATE LOWER HURON/LATE DUNKIRK TIME

MAP UNIT 11

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

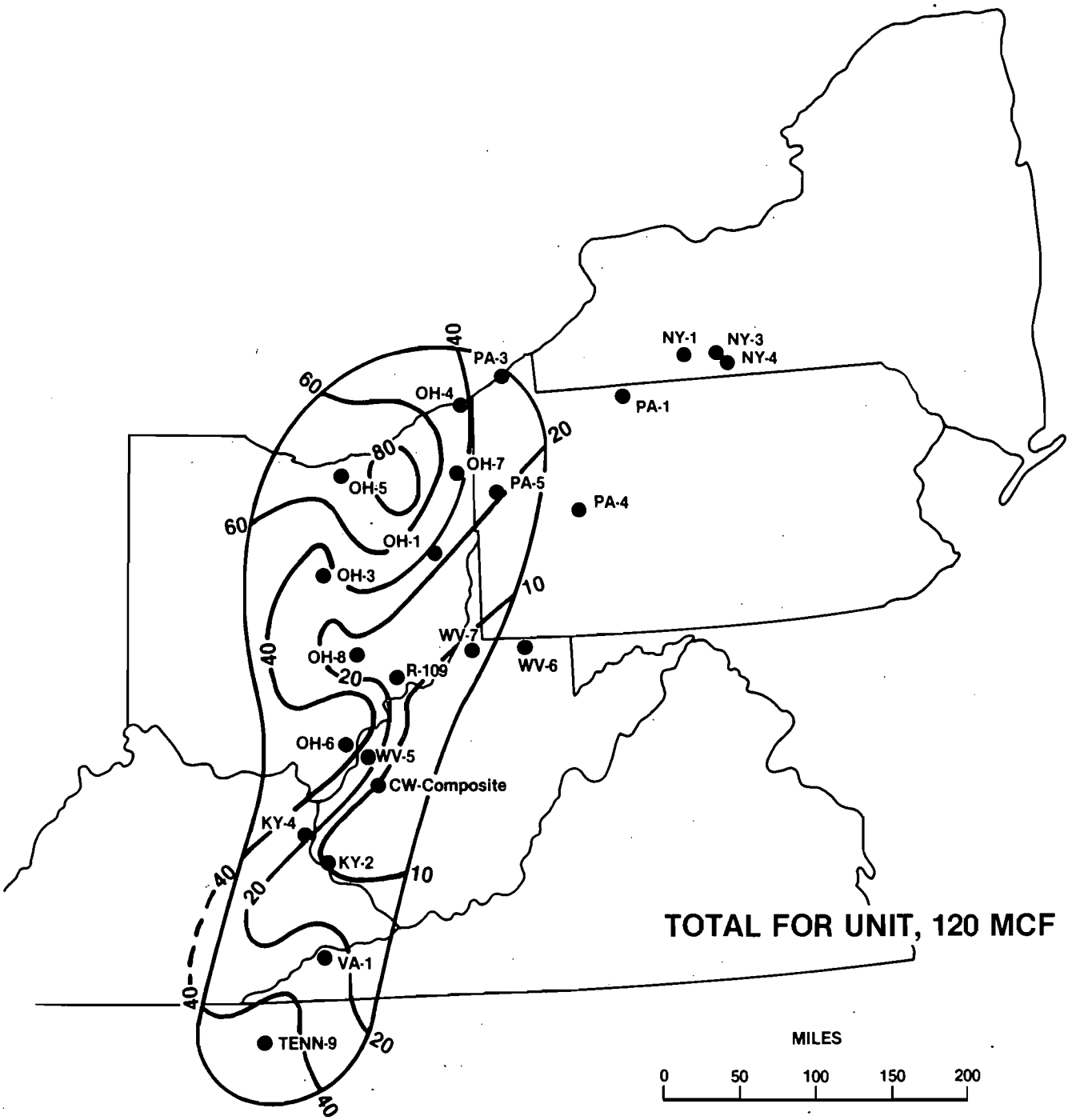


FIGURE 169

EARLY MIDDLE HURON TIME

MAP UNIT 12

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

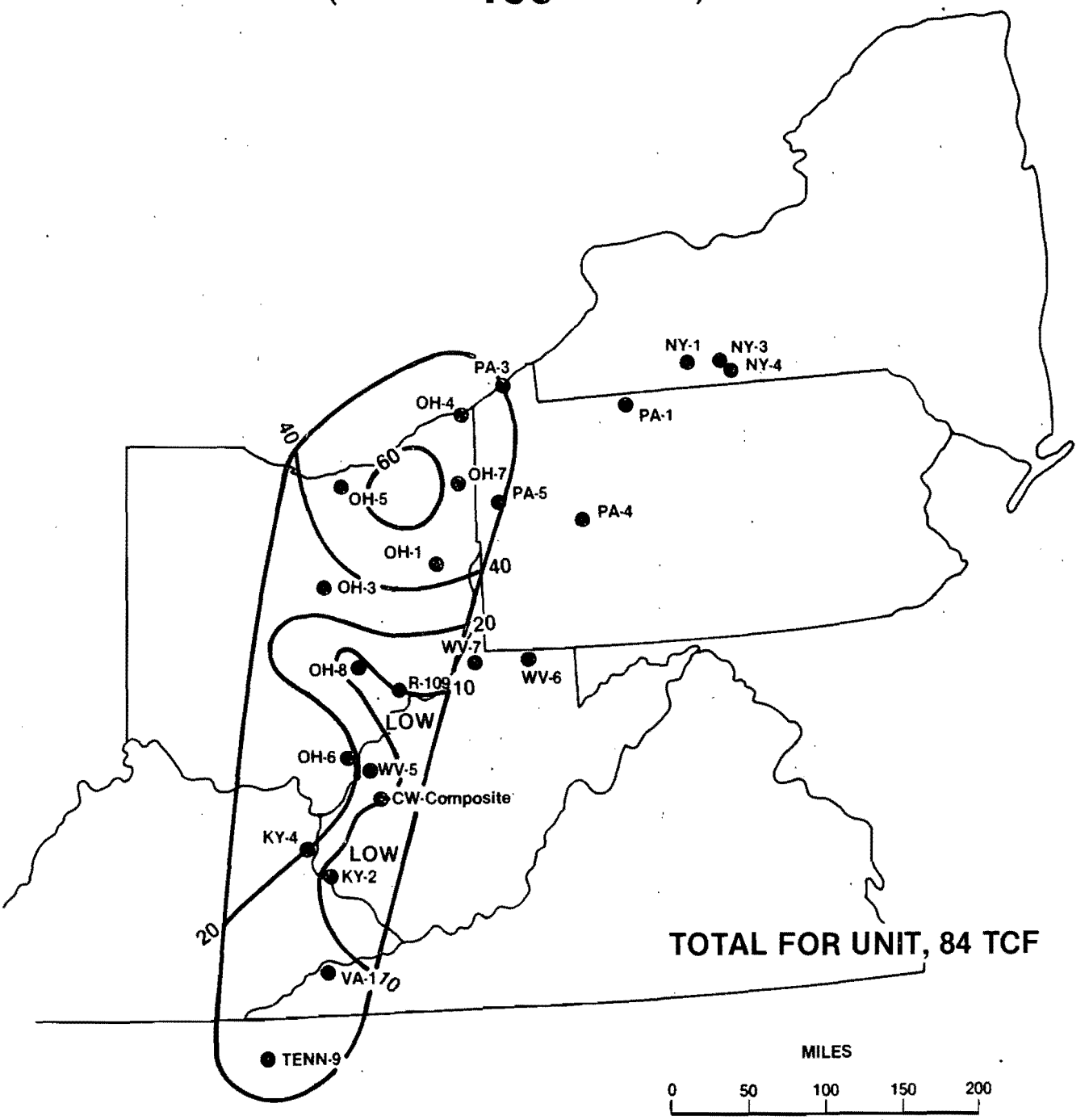


FIGURE 170

LATE MIDDLE HURON TIME

MAP UNIT 13

MOUND

Prepared by Mound Facility

late Upper Huron units (Figures 171 and 172) contain 118 TCF and 161 TCF of gas respectively, mostly in central and eastern Ohio.

The Chagrin unit contains relatively little gas, 19 TCF, because of its low content of organic carbon and its thermal immaturity (low TAI's). Most of the gas is concentrated in the junction of the boundaries of Ohio, Kentucky, and West Virginia (Figure 173). The Cleveland unit contains 94 TCF of hydrocarbon gas, mostly localized in the extreme southern portion of the basin (Figure 174).

The preceding 17 maps were the basis for the new assessment of the resource in the basin. The total resource from these units is 2579 TCF of gas. The distribution of the gas for the entire unit basinwide is shown in Figure 175. This map was prepared by summing the values on 9-mile grid lines for each of the 17 units. The matrix of totals for each of the grid intersections, over 1000 in number, were then contoured to produce the final map shown here.

The trend of greatest gas volumes is along an arcuate line extending from TENN - 9 through western Kentucky, southeastern Ohio, northwestern Pennsylvania and to the area of the New York wells. The areas with the greatest volumes of gas are in Eastern Ohio and extreme west south-central New York where gas volumes reach 80 MMCF per acre dispersed through the entire upper Devonian.

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

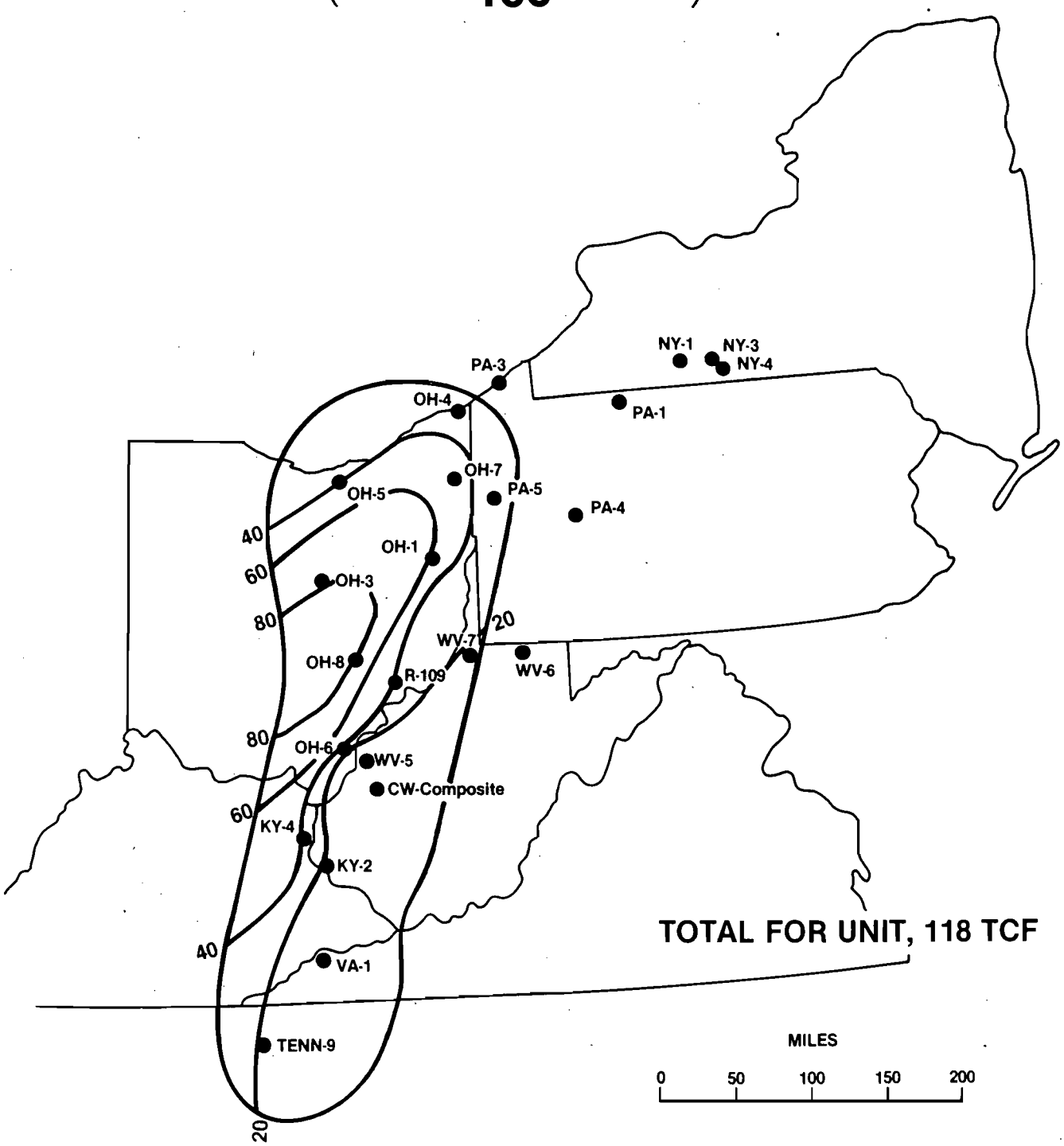


FIGURE 171

EARLY UPPER HURON TIME

MAP UNIT 14

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

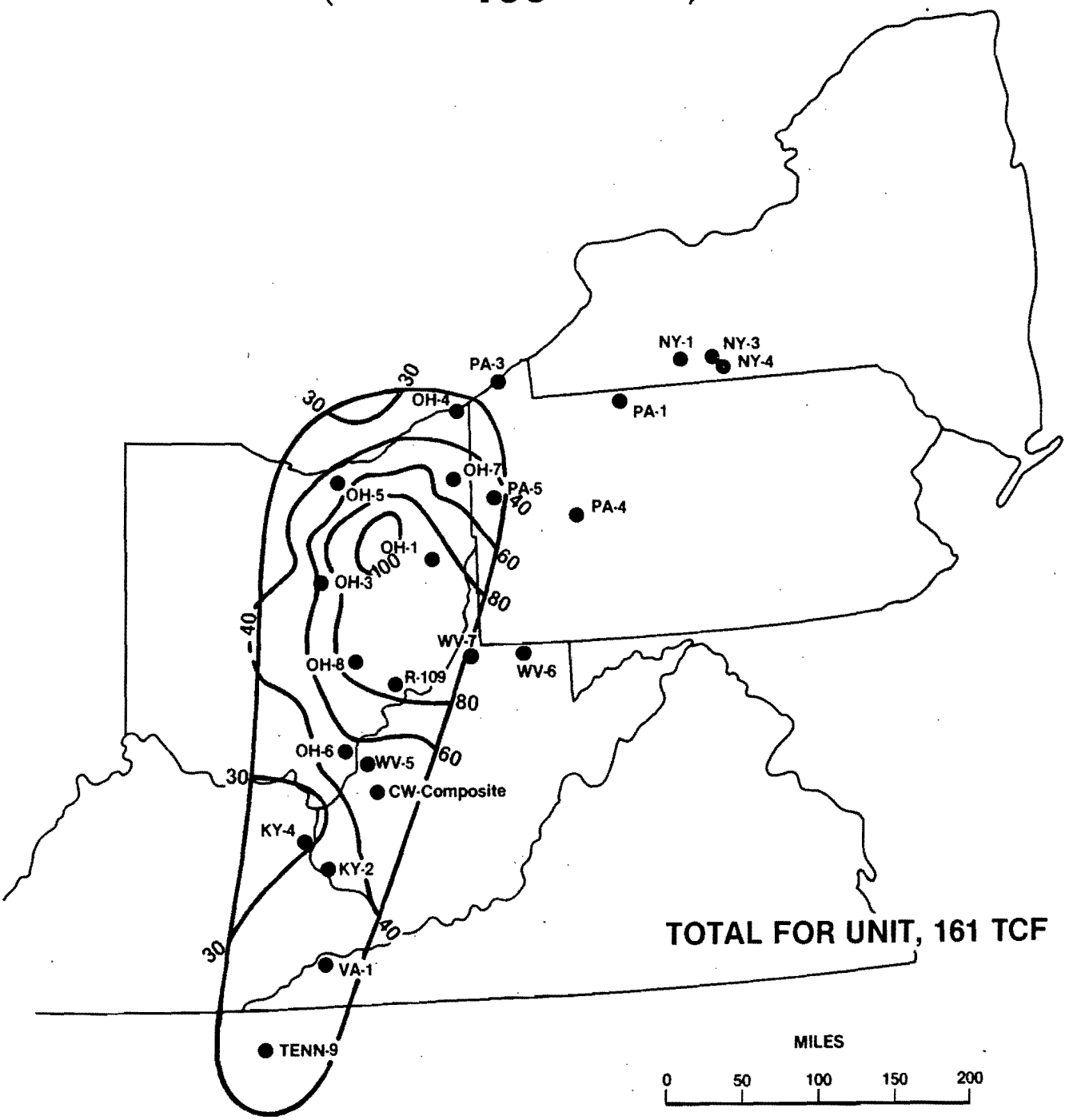


FIGURE 172

LATE UPPER HURON TIME

MAP UNIT 15

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

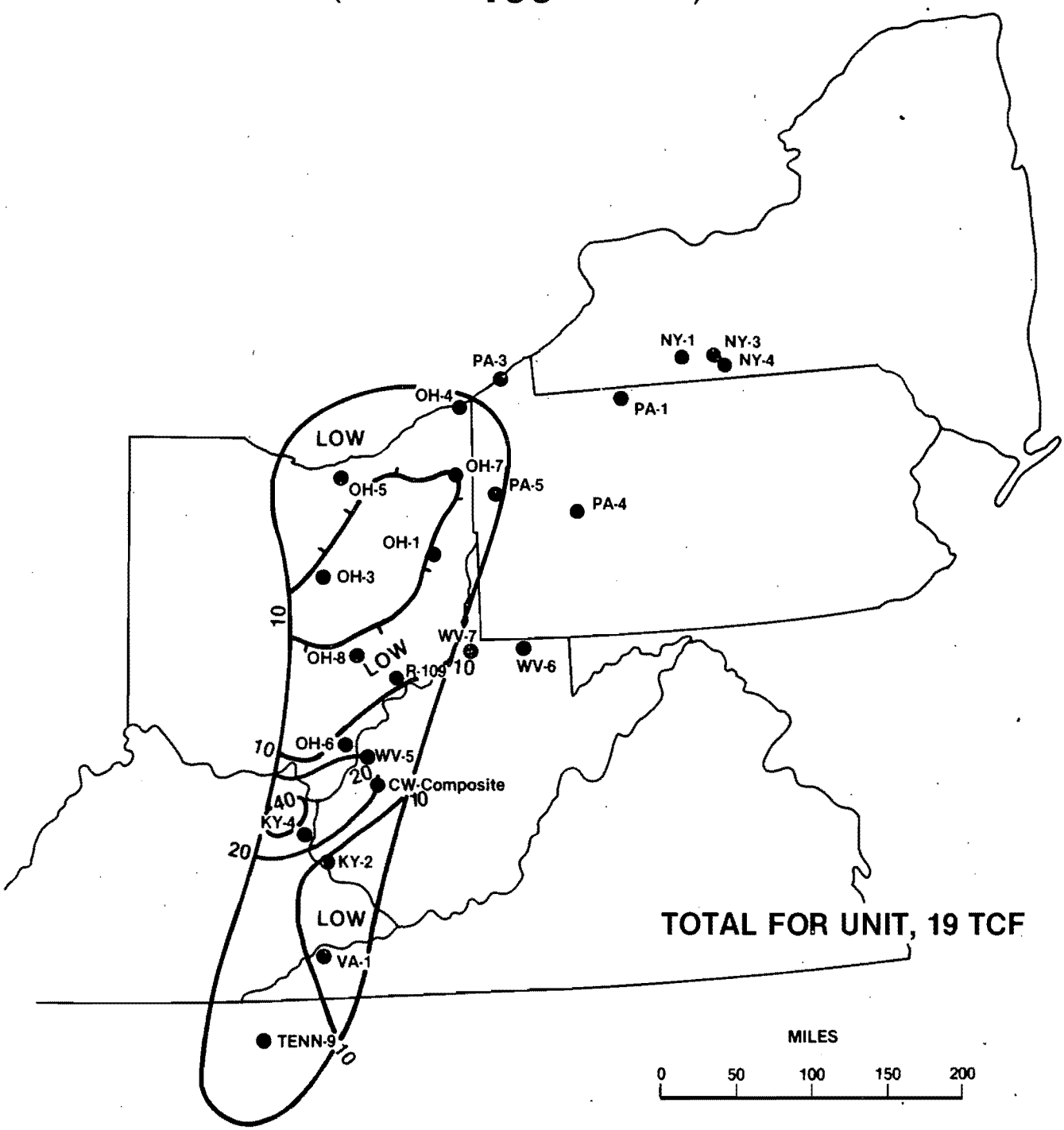


FIGURE 173

CHAGRIN TIME

MAP UNIT 16

MOUND

Prepared by Mound Facility

DISTRIBUTION OF INDIGENOUS GAS

$$\left(\frac{\text{MCF Gas/Acre}}{100}\right)$$

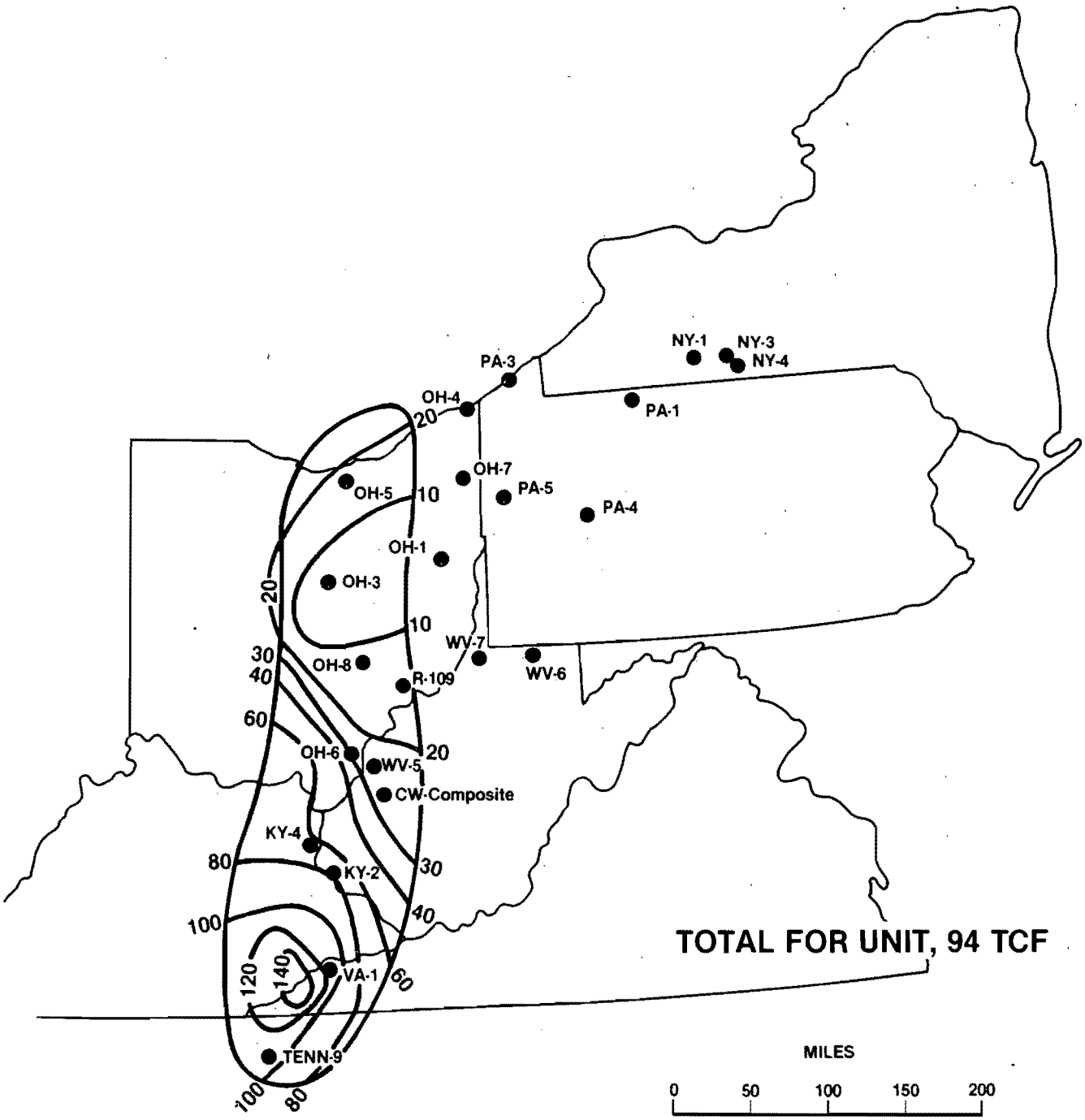


FIGURE 174

CLEVELAND TIME

MAP UNIT 17

MOUND

Prepared by Mound Facility

TOTAL UPPER DEVONIAN SHALE INDIGENOUS GAS IN PLACE

$$\left(\frac{\text{MCF Gas/Acre}}{1000}\right)$$

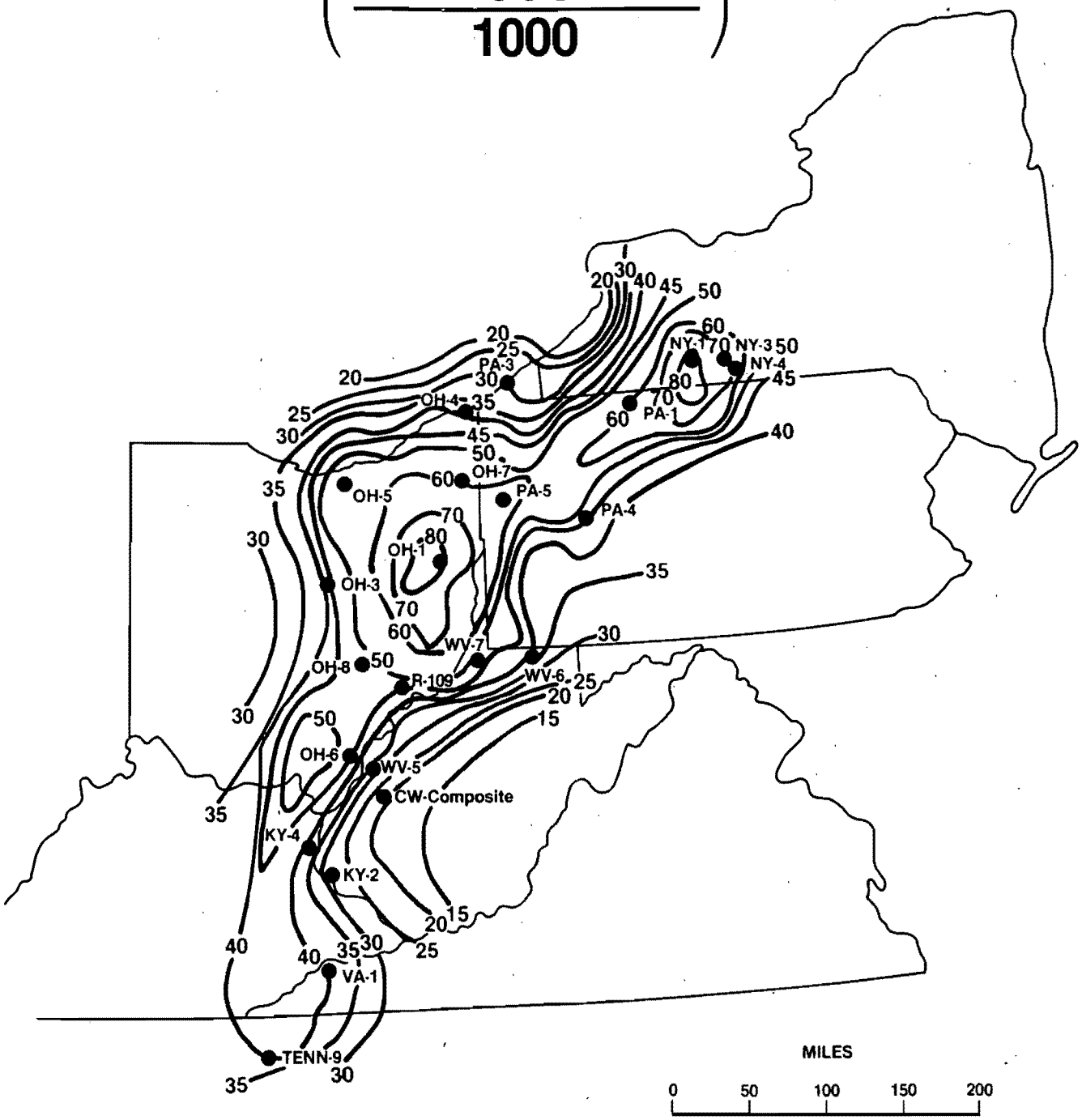


FIGURE 175

TOTAL 2579 TCF

MOUND

Prepared by Mound Facility

Discussion

The assorted gas maps constructed in this phase of the project have made it possible to calculate a new, more accurate, estimate of gas resources in the Appalachian Basin. The three critical parameters - organic carbon, organic matter type, and thermal alteration index - have been related to gas contents in each of the 17 rock units considered in the study. The resulting algorithms have then made it possible to calculate a more accurate estimate of the total gas retained in the shales than heretofore possible. The differences between the various sets of maps also make it possible to make some statements about the applicability of standard source rock criteria in the basin, as well about other, previous methods that have been used to calculate the resource contained in the Upper Devonian shales.

The first major discrepancy that needs to be explained is the one that appears to exist between the relative gas source quality as determined from the three critical organic geochemical criteria and the experimentally determined gas values. The relative source quality of each of the 17 study units was shown in Figures 56 through 72; experimentally determined gas values were shown in Figures 124 through 140. Comparisons of the two sets of maps shows little correlation.

The primary reason for this apparent discrepancy is found in the rock itself and in the sample handling methods. Because the shales have very low permeabilities, they do tend to retain most of their gas. Nevertheless, there are variations in permeability, grain size distribution (fine silt stringers) and natural fracture density, which allow more gas to escape from one sample than another. Superimposed on this is the variability in handling of the shale samples from well to well and core to core within a single well. Some samples were sealed in containers within an hour of coring, others were not sealed for several hours. Controlled off-gassing studies (30) conducted in the latter stages of the program showed that the rate of gas loss decreased exponentially with time - from some samples, over half the gas was lost within the first half hour after recovery. Therefore, the tremendous variability in sample properties and handling time reduced the values of "experimentally determined" gas so greatly and so erratically that the values can only be considered qualitative in this basin study. They do, however, establish the quantitative conservative lower limit of gas in place and "free gas".

Fortunately, enough controlled off-gassing experiments were conducted so that algorithms could be constructed to derive a more accurate value of gas generated catagenically from rocks with widely different locations, physical properties and chemical characteristics. However, a comparison of gas source quality maps in Figures 56 through 72 with values of indigenous gas contents in Figures 141 through 157, while having a much better correlation than the previously discussed sets of maps, still show some discrepancies that are important in the assessment of these rock units and in organic geochemistry.

First, the algorithms calculate greater quantities of indigenous gas in the shallow, relatively less thermally mature rocks than the conventional organic geochemical criteria would predict. This could be explained either by some relatively long distance updip migration of gas in the basin or by the retention of a significant quantity of microbially produced gas in all the organic-rich rocks regardless of their stage of thermal alteration. In all

the rocks there would be a background level, roughly proportional to the organic carbon content. Organic rich rocks would be gassy even if thermal generation, catagenesis, had not proceeded to a great extent. Both explanations probably can be called on in this case. While overall the Upper Devonian shales are generally so impermeable that little movement of gas occurs, some rocks relatively low in organic matter do have significant quantities of free gas that must have migrated from below. For example, the Hamilton Group/Post-Marcellus rocks are very poor potential source rocks (Figure 58), yet they exhibit two areas with large volumes of experimentally determined gas (Figures 143) which almost certainly migrated from the richer Marcellus rocks below. Similar examples of probable vertical migration are found elsewhere in the section, including in the Cleveland shales (Figures 72 and 157).

Units in which microbially produced methane in the shallowest (northwest) rocks of the unit, probably diluted with some updip-migrating gas, contain anomalously high gas contents for the degree of thermal alteration and include the Marcellus (Figures 56 and 141, 57 and 142), the Olentangy (Figures 63 and 131, and 64 and 149), and the Huron (Figures 66 and 151, 67 and 152, 68 and 154, and 70 and 155). Some of this microbial/catagenic gas has also migrated vertically from the Huron into the Chagrin (Figures 71 and 156).

Comparisons of the source rock criteria (as summarized in the source rock quality maps) and gas content maps suggest another important fact, as well. Organic materials that look alike from area to area in the basin have important differences, i.e., not all algal kerogens have the same potential to source hydrocarbons. In gas and oil exploration, the geochemical program should include the analysis of the component being sought. That is to say, oil and gas potential of a rock should not be estimated merely from organic carbon content, organic type and degree of thermal alteration. The quantities of gaseous and liquid hydrocarbons should also be determined. This will prevent misinterpretation that might result should good oil and gas potential be suggested from the standard criteria, but not be realized in the source rocks, and subsequently in contiguous reservoirs. Such a discrepancy between the three principle criteria and gas contents appears to exist in the southern "promising" source area in Middlesex/Sonyea Time (Figures 60, 128, and 145). Geochemical interpretations should be made with several supporting criteria. In fact, the more the better.

The advantage of developing an algorithm of calculating indigenous gas from the geochemical parameters can be seen on the overall gas source potential maps (Figures 92 and 118) and maps of distribution of indigenous gas in place (Figures 158 through 174). In general, the area of favorable source is expanded over a greater basin area to more nearly reflect the true gas source potential - the gas-in-place - particularly updip into the shallower, less mature areas. This is most apparent in the comparison of the map of overall gas source potential (Figure 120) and the map of indigenous gas in place (Figure 175) for the entire Upper Devonian section.

The maps of indigenous gas in place (Figures 158 through 175), and the composite map (Figure 175) represent the best estimates of the gas resource of each unit and in the entire Upper Devonian for several reasons. Previous estimates have generally been made based on gamma-ray logs or rock color (26, 27). As assignment of a single gas content value to every interval with

greater than 200 or 230 gamma units effectively downgrades the potential gas contents of exceptionally rich units. In such an exercise, rocks with 5 and 10 percent organic carbon, respectively, would both have gamma log readings in excess of 230 units and both be assigned the same gas contents, when the second, in fact, contains twice as much gas as the other. Moreover, the variability of gamma radiation readings with organic carbon would introduce another potential error into the calculation.

The inability of the human eye to distinguish subtle shales of color, and the virtual absence of differences in the color of rocks with greater than 3 or 4 percent organic matter, also testify to the errors that could be introduced if color were the primary criterion on which differences in gas contents were made either geographically or stratigraphically.

Ideally, the gas potential and resource in place estimates should be made from controlled off-gassing estimates of gas-in-place from the basin. This being prohibitive, time- and money-wise, subdivision into thinner units such as done in this study) and division into smaller geographic areas with gas-yield properties determined for representative samples from each sediment "cell" would give the ultimate estimate. If the cells could be reduced to county size or thereabouts, the estimate could be made with great confidence.

Based on the geochemical data, and particularly the algorithms for the calculation of in-place gas contents (which also make use of the controlled off-gassing results), a new estimate of total gas-in-place, both in matrix and porosity of the Upper Devonian shales of the Appalachian Basin, is set at 2,579 TCF. Later in this report, estimates of recoverable reserves will be addressed.

The suite of maps of indigenous gas content (Figures 141 through 157) should serve as a guide to location of stimulation research and exploitation projects. They show where the gas is most concentrated, in terms of MCF/Acre-foot, in each of the units. Combined with the indigenous gas-in-place maps and the structural and fracture maps to be discussed later in this report, these maps should also be useful in giving direction to exploration.

POTENTIAL RESERVOIRS

Background

As the preceding sections on geochemical source quality and gas distribution clearly show, the occurrence of classical reservoired gas in the Appalachian Basin is far more limited in areal extent than the distribution of potential source rocks, and far more limited in volume than the source rocks have produced. The balance of the produced gas remains in the matrix. The primary control on Upper Devonian free gas and oil occurrence is porosity - in most of the basin, if there were conventional reservoirs interbedded with or contiguous to the rich Devonian shales, the basin could be one of the giant producing regions of the world. Unfortunately, porosity is limited to relatively small volumes in the form of fracture networks and thin silt stringers, sometimes apparently interconnected. Nevertheless, in spite of their relatively small free gas volumes, Upper Devonian Shale gas and oil fields will become more and more attractive as other energy sources are exhausted or withdrawn from world and domestic markets.

As exploration for hydrocarbons in the Upper Devonian intensifies, detailed subsurface geology, careful log interpretation, and lithofacies mapping will help locate the isolated porous siltstone layers. Location of fracture porosity, on the other hand, may be approached more directly and quickly.

The most direct method is the use of aerial photographs to delineate fracture traces, their location, orientation and intersections (31). Correlation of gas occurrence as well as producing rates of individual wells with proximity to fracture traces and fracture trace intersections was the basis for the recommendation that photogeology be used as a primary tool in the location of favorable trends and individual well sites for exploitation of gas and oil in the shale.

Another method for locating fracture-controlled hydrocarbon plays in the Upper Devonian rocks emerged from one of the sub-projects of the geochemical program. In this phase of the study, the structural evolution of the basin was studied in order to determine whether the unusual patterns of Tasmanites distribution, and the distribution of the dark and gray shales were structurally controlled. While the scope of the study did not allow the resolution of that objective, a secondary benefit was realized, i.e., the recognition of areas where relatively more fractures, and hence fracture porosity, would be expected in the basin because of the stresses produced by tectonism. These favored areas were then superimposed on the geochemically favored areas to locate the best areas overall, regionally.

This regional evaluation of pre-existing and syn-depositional structural controls of sedimentation and local fracturing is an overview based on available data and literature. It is basin-wide in scope, and is not meant to be a detailed evaluation of specific structures or areas. This additional detail would require numerous closely spaced well logs and core descriptions. However, the available EGSP files do contain numerous useful summaries of these data in the form of cross sections, isopach and structure contour maps as well as maps of surface geology and interpretations of the general tectonic

evolution of the Appalachians. Other sources used in this overview of structural geology are published in U.S.G.S. and various state survey gamma-ray correlation charts, proprietary logs provided by a private source in the petroleum industry, structure contour and isopach maps of the various stratigraphic units, and other pertinent literature relevant to the tectonic evolution of the Appalachians. These sources were used to construct stratigraphic cross sections across the basin, to map structures in the surface and subsurface, to develop a historical tectonic overview for the identification of external causes for intra-basinal structures, and to identify those areas where structure has probably induced extensive fracturing in the shale units and, therefore, where the largest potential reservoirs are most likely to be found.

Structural Control of Sedimentation and Fracture Porosity

Stratigraphic Cross Sections

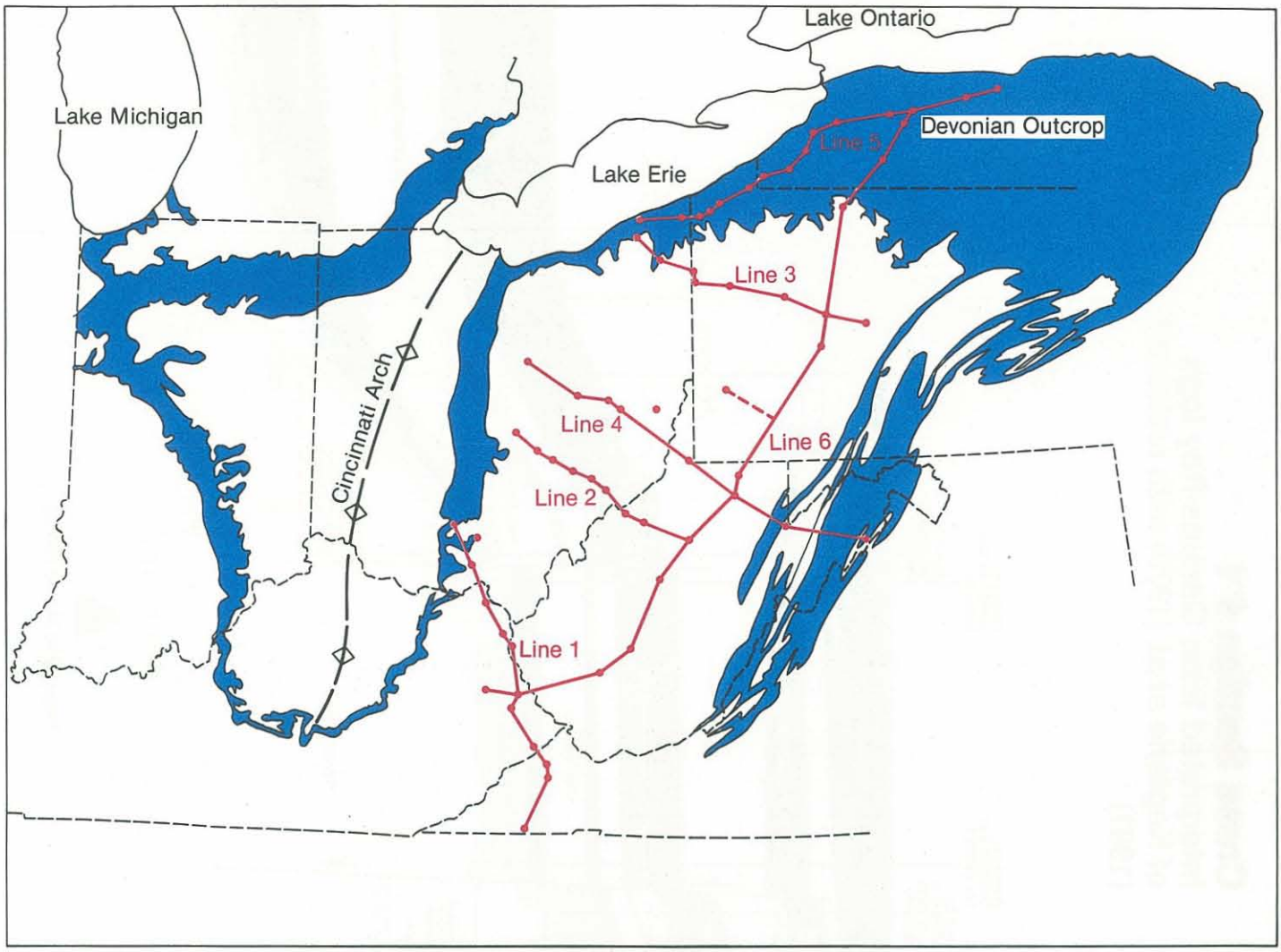
Six regional stratigraphic cross sections were constructed across the strike of the Appalachian Basin with available gamma-ray logs. The objective of this exercise was to determine areas where pre-existing or syn-depositional (contemporaneously developing) structures may have controlled lithology, biofacies, or thickness of the Upper Devonian shales. Major structures, i.e., faults and folds, that controlled sedimentation patterns would be evident on sections of this kind, and were expected to reveal thinning over anticlines, thickening in synclines and in down-dropped fault blocks. These anticipated structures were then to be more carefully studied to determine their significance.

The six cross sections, the locations of which are shown on the map in Figure 176, were constructed from the base of the Berea Sandstone - Bedford Shale sequence to the base of the Devonian shale across the strike of the basin. The locations of these sections were chosen on the basis of the availability of well logs, from which a selection was made to cover as much of the basin as possible. The wells were also selected so that the cross sections were as nearly straight as possible; however, in a few cases critical wells were somewhat off line and had to be projected into the relatively straight line of section. This, as well as genuine local thickness variations, may account for some of the local reversals in the dip of the base of the shale sequence.

Cross Sections 1, 2 and 3 (Figures 177, 178 and 179) were constructed from published U. S. Geological Survey log correlation charts (32, 33, 34) with only minor revisions and additions. Sections 4 and 5 (Figures 180 and 181) were constructed from proprietary gamma-ray logs, borrowed from a petroleum company source that wishes to remain anonymous, for wells in Ohio, West Virginia, Pennsylvania, and New York; in Section 5 (Figure 181), about half of the logs were obtained from the U.S.G.S. Oil and Gas Investigations Chart OC-8 (35). Cross Section 6 (Figure 182) was constructed to tie in several of the EGSP wells, included in the geochemical assessment, with the basin stratigraphy and structure. Logs of the EGSP core wells and published logs from West Virginia (36) and Eastern Kentucky (37) were the primary basis for this cross section.

The sections were constructed with the Berea - Bedford sequence as the datum, except for Cross Section 6 (Figure 182) in which the Pipe Creek Shale was used. In areas where the Berea - Bedford was absent or was not included in the interval logged, one or another of several widespread radioactive marker horizons was used as a local datum in the cross sections. These markers are probably related to distinct lithologic changes within the basin shales. On U.S.G.S. and state survey charts, the top of the Marcellus, the Middle Devonian unconformity, or the base of the shale sequence were generally used as a datum.

The first gross observation that is apparent from the cross sections is that the Cincinnati Arch was clearly a positive feature throughout deposition of the Devonian shale sequence. All of the shale units above the Onesquethaw and older series of rocks lap westward onto the east flank of the arch.



Sketch Map of Appalachian Basin with Locations of Section Lines and Main Devonian Outcrops

FIGURE 176

Prepared by Mound Facility

Cross Section # 1
Interpreted from Gamma-Ray logs of Kepferle *et al.* (1978) with revisions (1981)

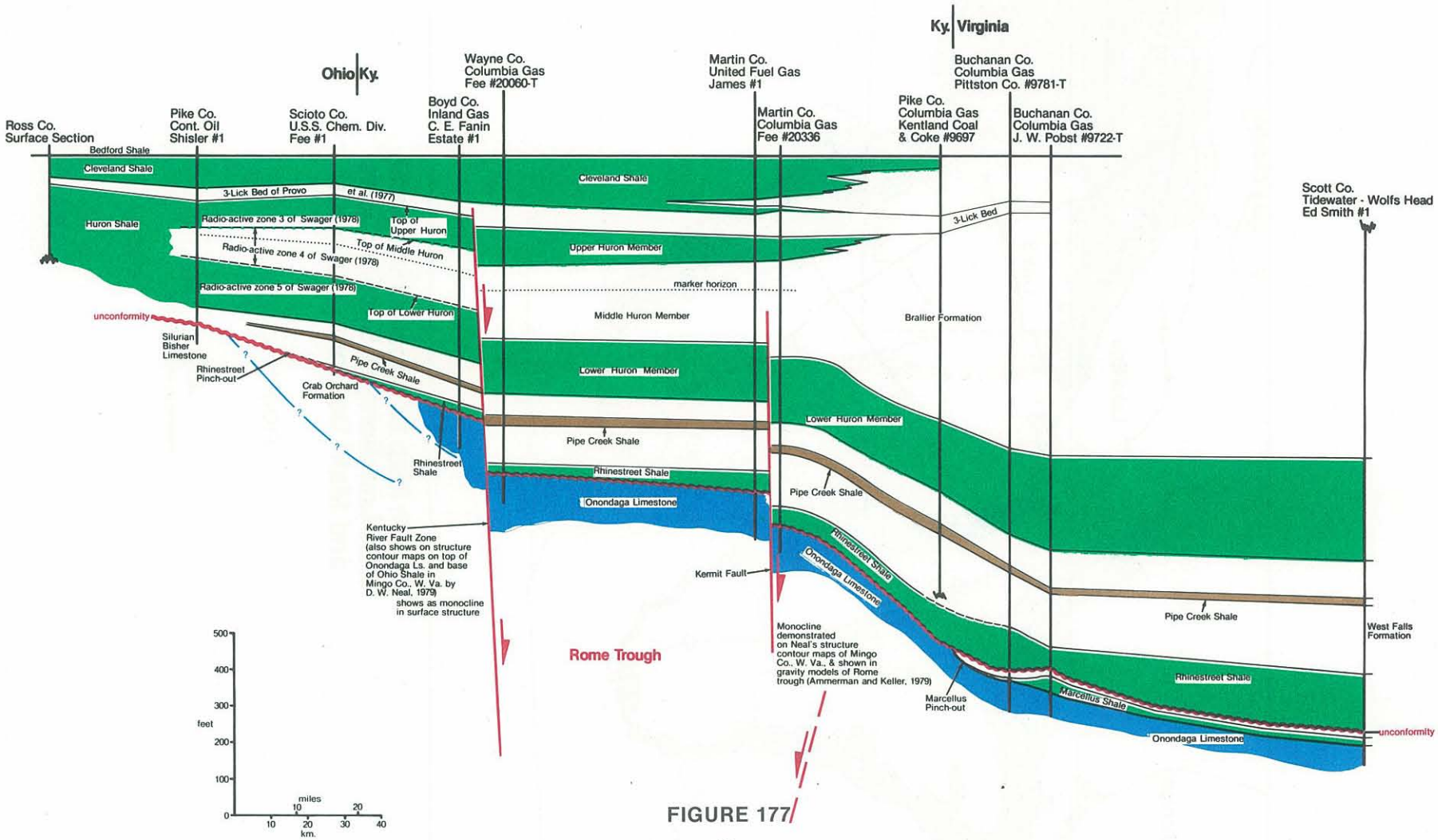


FIGURE 177

MOUND

Prepared by Mound Facility

Cross Section # 2
Interpreted from Gamma-Ray log section of Wallace *et al.* (1978) with revisions (1981)

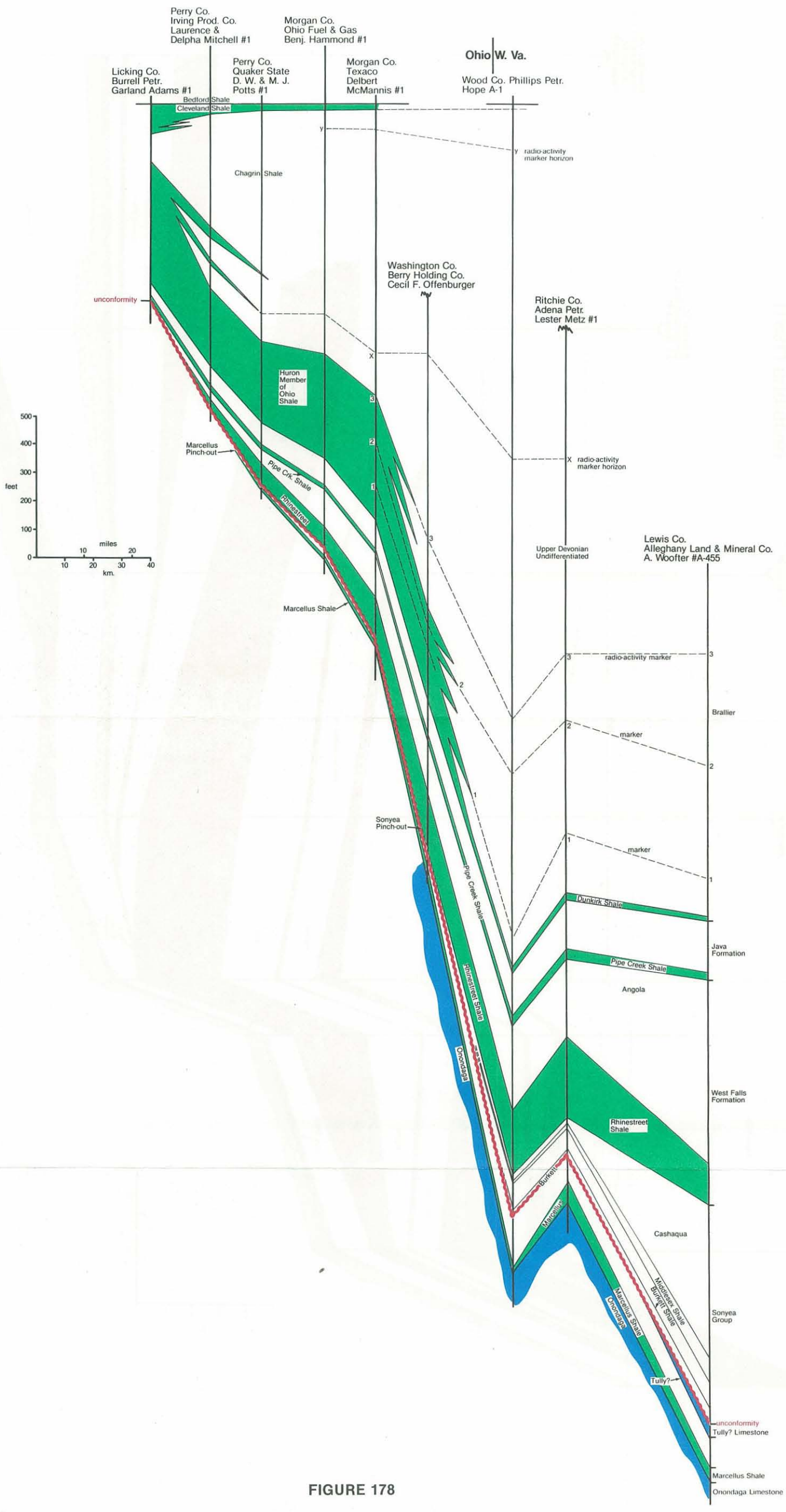


FIGURE 178

MOUND

Prepared by Mound Facility

Cross Section # 3

Interpreted from Gamma-Ray log section of Roen *et al.* (1978) with revisions (1981)

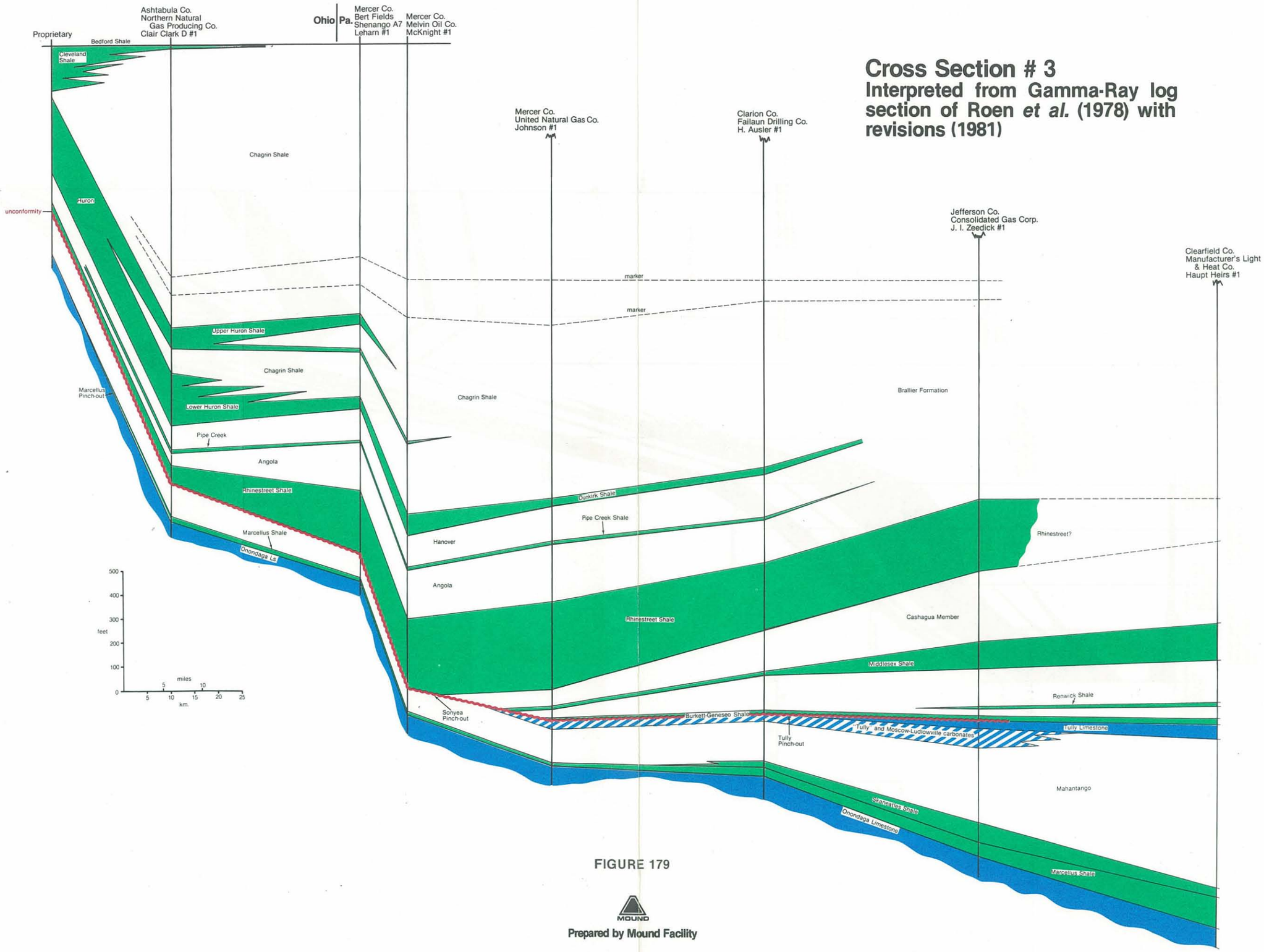
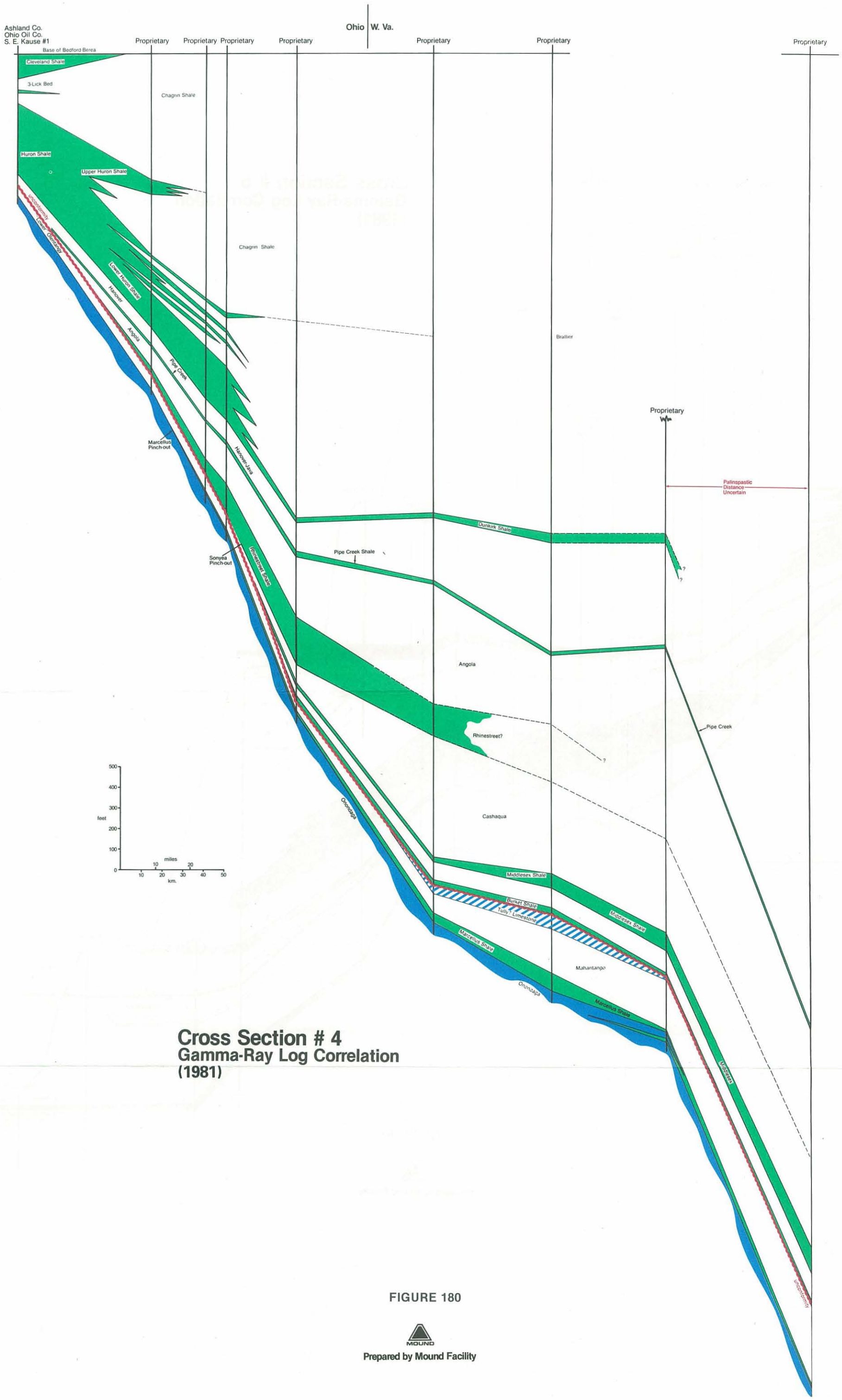


FIGURE 179

MOUND

Prepared by Mound Facility



Cross Section # 4
Gamma-Ray Log Correlation
(1981)

FIGURE 180

MOUND

Prepared by Mound Facility

Cross Section # 5
Gamma-Ray Log Correlation (1981)

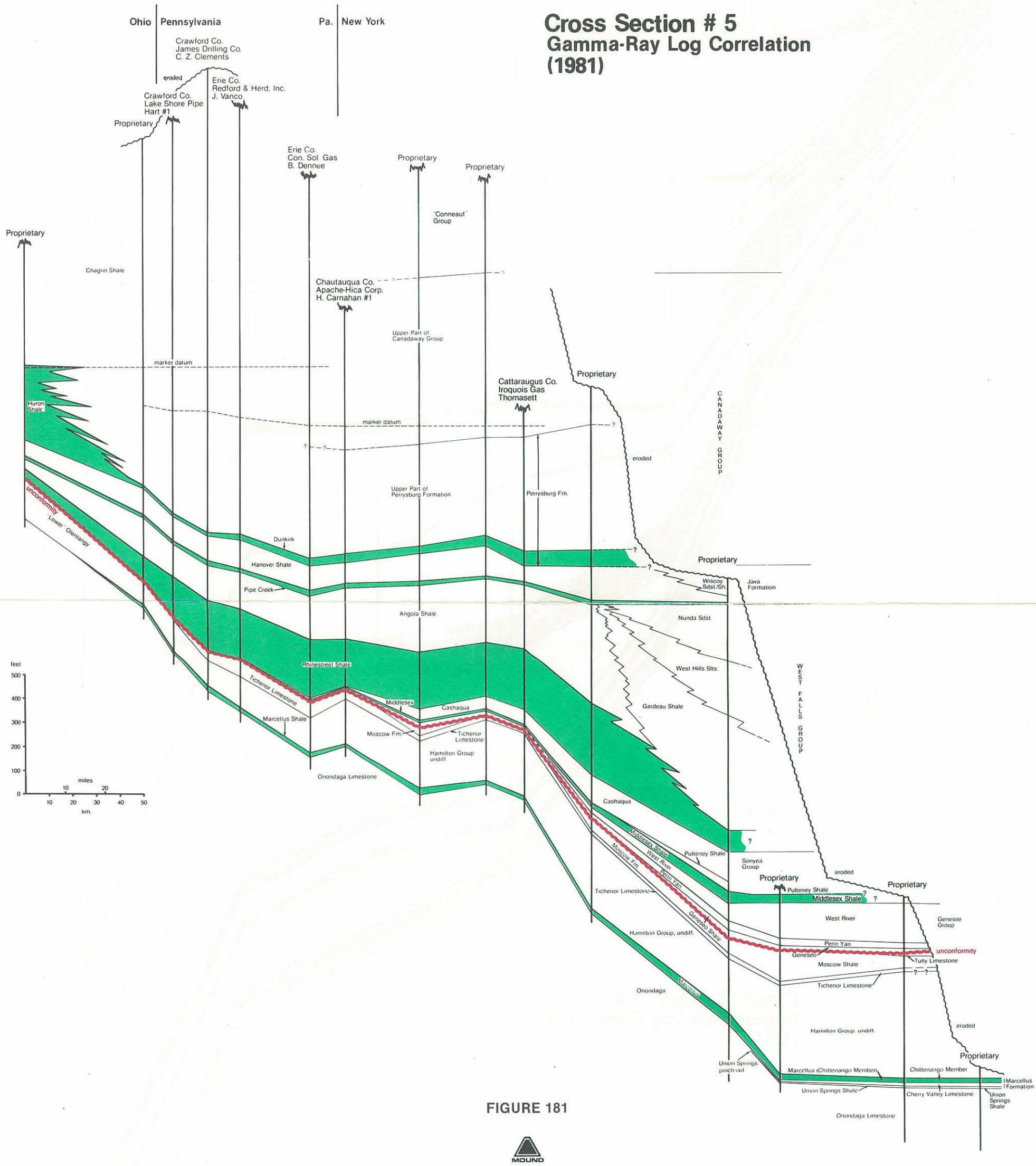


FIGURE 181

MOUND

Prepared by Mound Facility

Cross Section #6
Gamma-Ray Log Correlation
(1981)

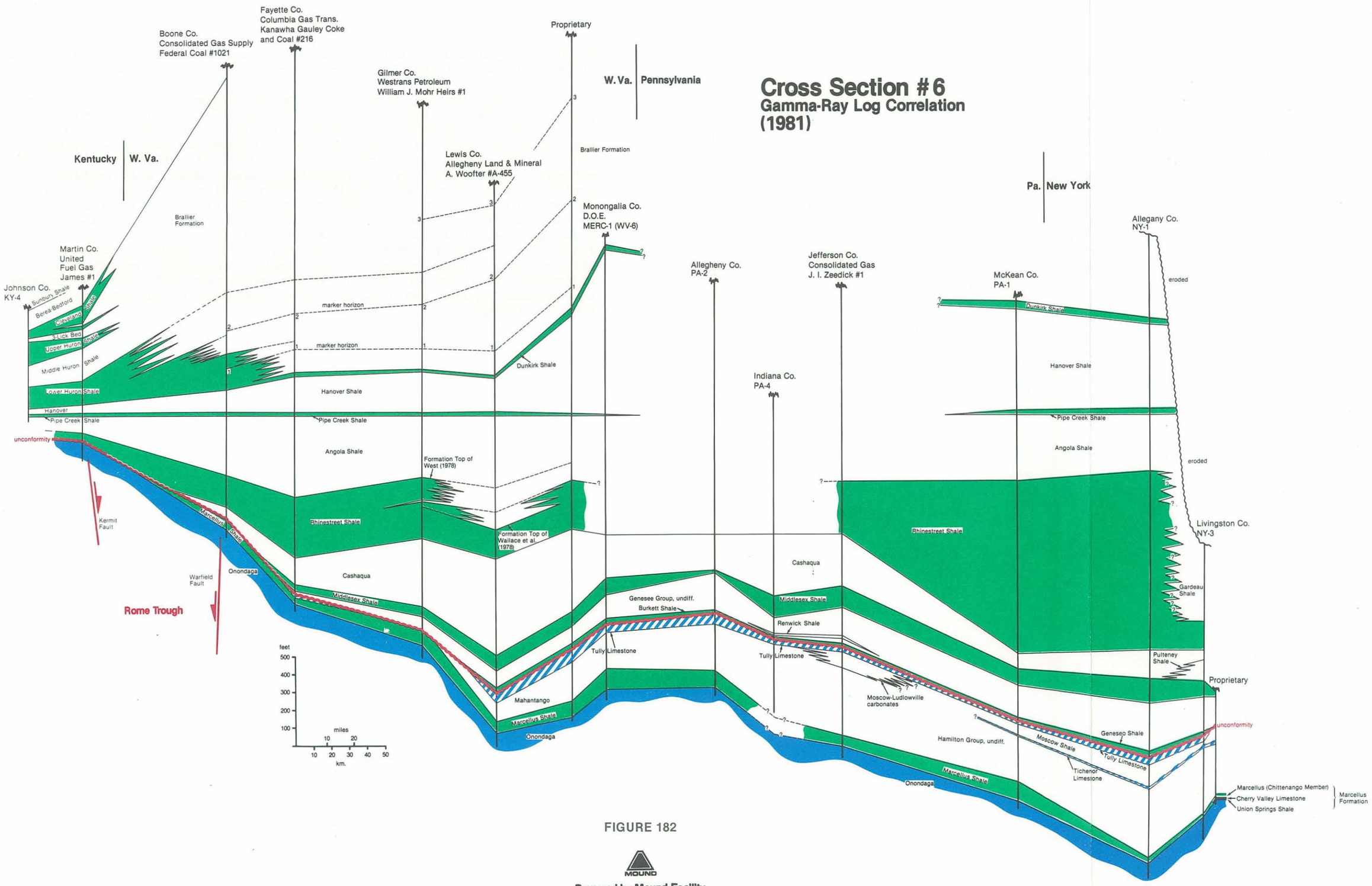


FIGURE 182

Prepared by Mound Facility

Further north in Ohio, erosion has removed the Devonian shale from the crest of the arch, so that the time of depositional overlap is more uncertain.

The second important observation from the sections is that, for the most part, except for a portion of Section 1 (Figure 177) in eastern Kentucky, they do not show any appreciable structural control on sedimentation. However, this does not imply that none existed. Information summarized below does suggest that growing or rejuvenated structures did influence sedimentation patterns. The difficulty in recognizing areas where such controls were operative is due to the wide spacing of wells on these cross sections, as well as those drawn by most other EGSP workers. The structures are too subtle to be seen on them. Schumaker et al (38) point out that the bulk of the structures associated gas production have very low structural relief at the level of the Devonian; therefore, they may not be visible on cross sections without very close control. Some subtle structural controls can be interpreted from the sections in several areas when additional information from various regional and local reports is considered in the interpretation of regional geology.

Regional Geology

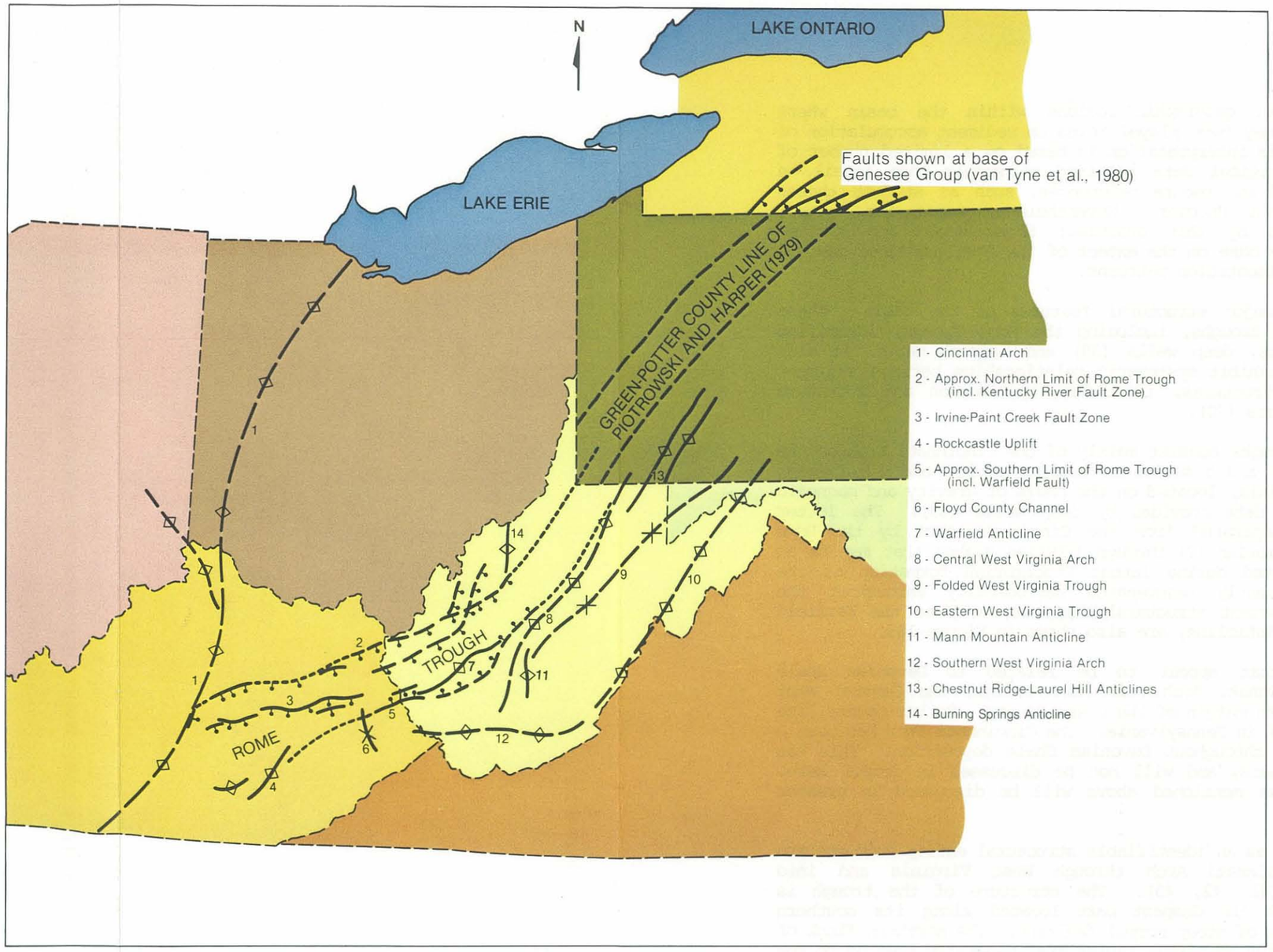
There are several major geographic regions within the basin where syn-depositional structures may have played roles in sediment accumulation of the Devonian Gas Shales. This interpretation is based on a limited number of papers and manuscripts. Critical data required to supply more detail on specific areas may be found in obscure references, such as student theses which this overview did not uncover. Nevertheless, areas for further investigation are suggested by this overview; these would add further information to the knowledge base on the extent of the involvement of control of basement tectonics on sedimentation patterns.

Figure 183 shows the major structural features of the basin. These include basement arches and troughs, including the Rome Trough, identified mainly by gravity, magnetics, deep wells (39) and isopach maps. It also includes other areas which exhibit systematic relationships between sediment thickness and individual structures, identified by isopach and structure contour maps and cross sections (20).

Basement arches and troughs consist mainly of the Cincinnati Arch on the western margin of the basin, and a series of smaller arches and intervening troughs mainly in West Virginia, located on the basis of gravity and magnetic anomalies with supplemental data provided by deep wells (39). The latter structures are spatially separated from the Cincinnati Arch by the Rome Trough, a complex late Precambrian (?) through Silurian graben that may be an aborted rift system initiated during latest Precambrian formation of the Iapetus Ocean, and subsequently rejuvenated periodically throughout the Paleozoic (40). Other important structural features, such as the Warfield Anticline and Mann Mountain Anticline, are also shown in Figure 183.

The major features that appear to be related to Devonian shale sedimentation are the Cincinnati Arch, the Rome Trough, the Central West Virginia Arch, and the eastern margin of the Green County - Potter County line of Piotrowski and Harper (20) in Pennsylvania. The Cincinnati Arch has been a positive structural element throughout Devonian Shale deposition. This has been discussed by many authors, and will not be discussed in detail here. However, the latter elements mentioned above will be discussed in greater detail.

The Rome Trough extends as an identifiable structural entity from eastern Kentucky east of the Cincinnati Arch through West Virginia and into southwestern Pennsylvania (41, 42, 43). The structure of the trough is generally asymmetrical, with the deepest part located along its southern flank, associated with a zone of steep normal faulting. The northern flank of the trough shallows by a series of normal faults that generally step up to the northwest. Harris (40) showed that the thicknesses of Cambrian through Silurian sediments are profoundly increased in the trough, while isopachs of the Devonian and younger sediments show little effect of the trough. However, as pointed out by Kulander and Dean (43), regional isopachs of the Lower Devonian Onesquethaw sediments in West Virginia do show thickening over the trough and thinning over the crest of the Central West Virginia Arch. This indicates that the trough was active at least through the early Devonian.



Major Structural Features of the Appalachian Basin

FIGURE 183

MOUND

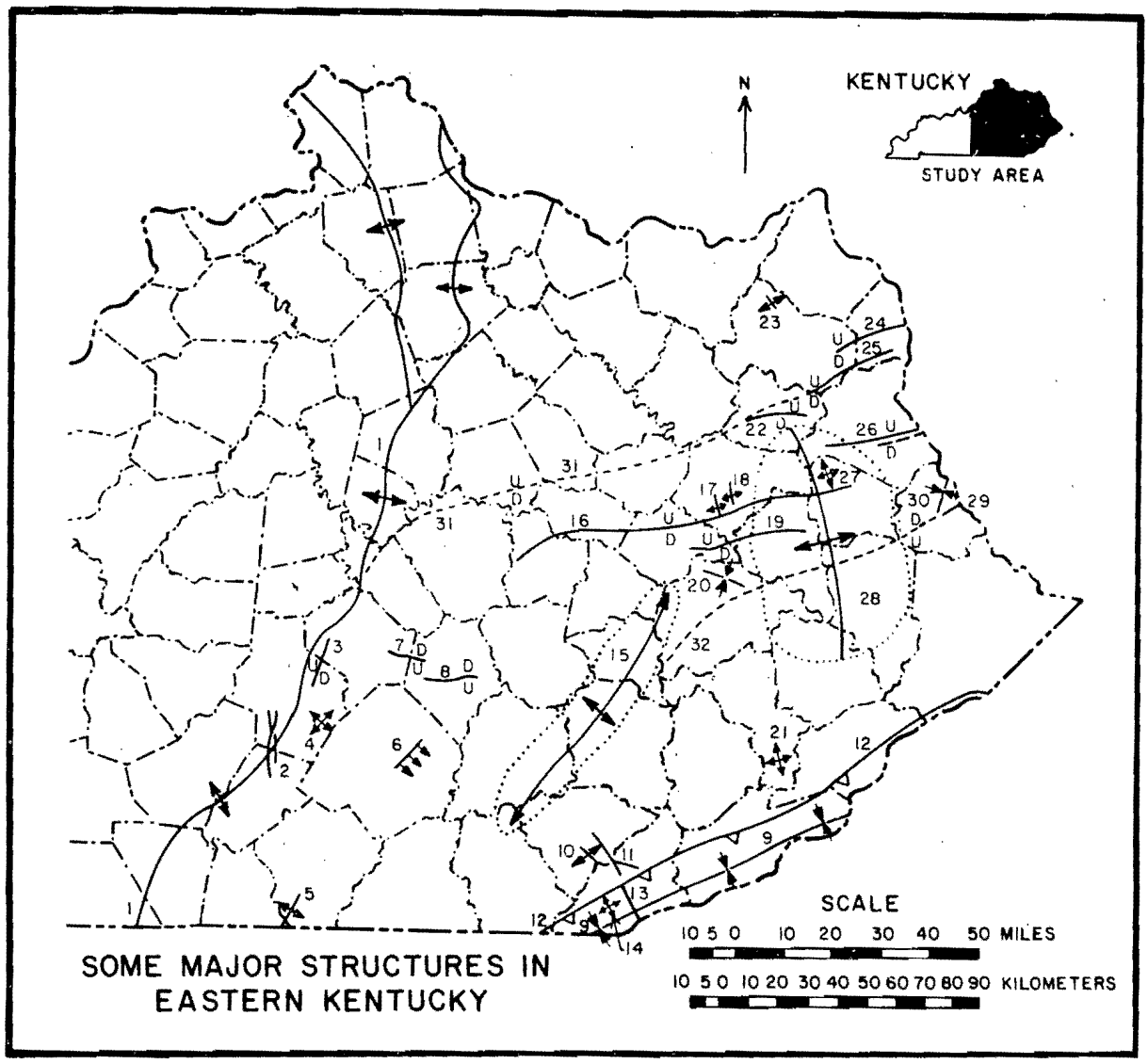
Prepared by Mound Facility

More substantial evidence for activity of the Rome Trough during the late Devonian is found in eastern Kentucky, and can be seen in Figures 177 and 184. Dillman's work (37) clearly shows increased thicknesses related to specific structures associated with the Rome Trough. In the Mavity Monocline, the Huron shale sections thicken to the south; this feature was probably a normal-faulted extension of the Kentucky River fault zone during Early Huron time. The Irvine - Paint Creek Fault zone also has increased sediment thicknesses on its downthrown side. The Kermit Fault has increased thicknesses of the Angola and Huron shales on its southern downthrown side, as well. Figure 177 shows that the Cleveland Shale achieves its maximum thickness over the Rome Trough - strong evidence that subsidence continued into latest Devonian time.

The Cleveland and Huron shales also thicken into the Floyd County Channel of Ammerman and Keller (41) south of the Rome Trough, indicating subsidence there as well (37). Horne and Ferm (44) also showed that continued faulting along these lines affected sedimentation patterns during the Pennsylvanian. Therefore, extensional stresses must have continued to operate throughout the Devonian and even later, thus rejuvenating the earlier formed structures associated with the trough.

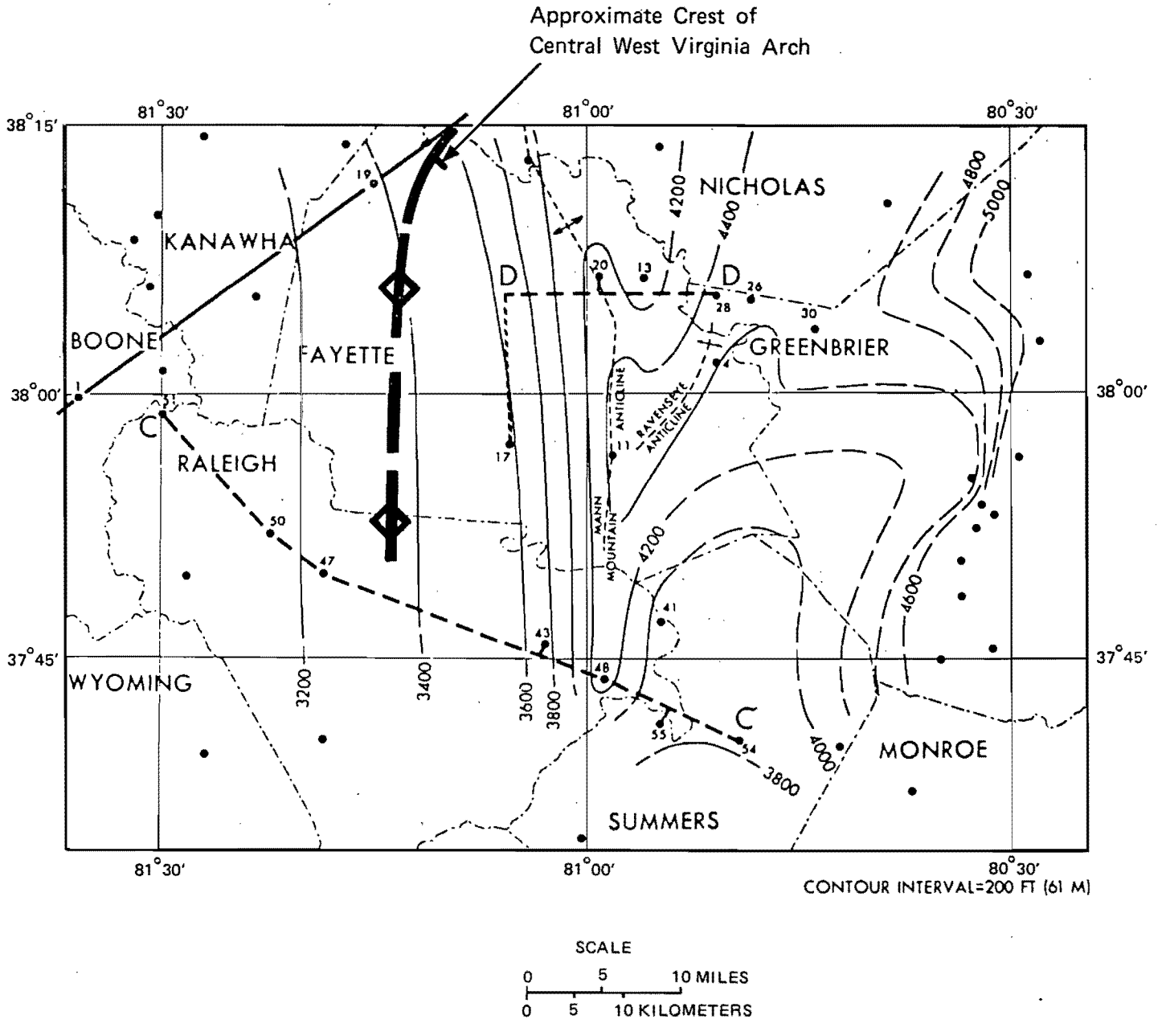
The available literature presents much less conclusive evidence for Devonian structural activity in West Virginia, although it probably did occur locally. Shaefer (45), as reported in Schumaker et al (37), showed that the Lower Huron Shale thickens northwest of the Midway Anticline, which suggests syn-depositonal growth of the structure. Several other folds are also associated with anomalies in thickness, although in these cases it is difficult to separate depositional thickening from later tectonic events. The very striking and anomalous Burning Springs Anticline has an increased thickness of Devonian shales along its northwest flank, and a quadrupled section of Lower Devonian rocks in its core (46, 47, 48, 50). However, the structural relief of the anticlinal fold extends no deeper than the Silurian. For this reason, Rodgers (48) attributed the thickening and folding to late Paleozoic thin-skinned detachment and thrust-faulting at the level of the Silurian Salina salt. The folding takes place where the detachment fault ramps upward into the Devonian from the edge of a pinch-out of the salt. Therefore, the fold is probably post depositional.

Perry (51) showed that anomalies thickening along the axis of the Mann Mountain Anticline resulted from thin-skinned detachment and thrust-faulting at the level of the Marcellus - Millsboro shales. There is no structural relief in sub-Marcellus rocks along the structure. This detachment thrusting and localization in this fold is attributed to pronounced thinning of the sub-Rhinestreet lithologies because of depositional on-lap of the Late Devonian against the Middle Devonian unconformity. The available data do not reveal whether this abrupt thinning of the sub-Rhinestreet Devonian shales is the result of a relatively positive structure existing during or after Middle Devonian shale deposition. It is of interest to note in this regard that isopachs of the Devonian shale units show a pronounced thinning over the crest of the Central West Virginia Arch in this vicinity (Figures 185 and 186). Therefore, it can be speculated that the growth of the arch could have formed a barrier to dispersal of Middle Catskill sediments. The Onesquethaw thins regionally over the arch, as reported earlier, also lending support to the view that the arch was positive in this area during Lower and Middle Devonian.



1 CINCINNATI ARCH
2 GOOSE CREEK GRABEN AND FAULTS
3 TRACE FORK FAULT
4 MINTONVILLE DOME
5 SUNNYBROOK ANTICLINE
6 SHOPVILLE MONOCLINE
7 GUM SULFUR FAULT
8 MT. VERNON FAULT
9 MIDDLESBORO SYNCLINE
10 FLAT LICK ANTICLINE
11 WHITE MTN. AND DORTON BRANCH FAULT ZONES
12 PINE MOUNTAIN THRUST FAULT
13 ROCKY FACE FAULT
14 FOUR MILE DOME
15 ROCKCASTLE RIVER UPLIFT
16 PAINT CREEK FAULT ZONE
17 STACY FORK ANTICLINE
18 WEST LIBERTY DOME
19 JOHNSON CREEK FAULT
20 TAULBEE SYNCLINE
21 OWENS BRANCH DOME
22 LITTLE SANDY FAULT
23 ROCK SPRINGS ANTICLINE
24 MAVITY MONOCLINE
25 ROSS CHAPEL MONOCLINE
26 BLAINE FAULT SYSTEM
27 LAUREL CREEK DOME
28 PAINT CREEK UPLIFT
29 WARFIELD FAULT
30 TURKEY CREEK BASIN
31 APPROXIMATE NORTHERN BOUNDARY OF ROME TROUGH ----
32 APPROXIMATE SOUTHERN BOUNDARY OF ROME TROUGH ----

FIGURE 184
(From Dillman, 1980)



(After Perry, 1980)

FIGURE 185

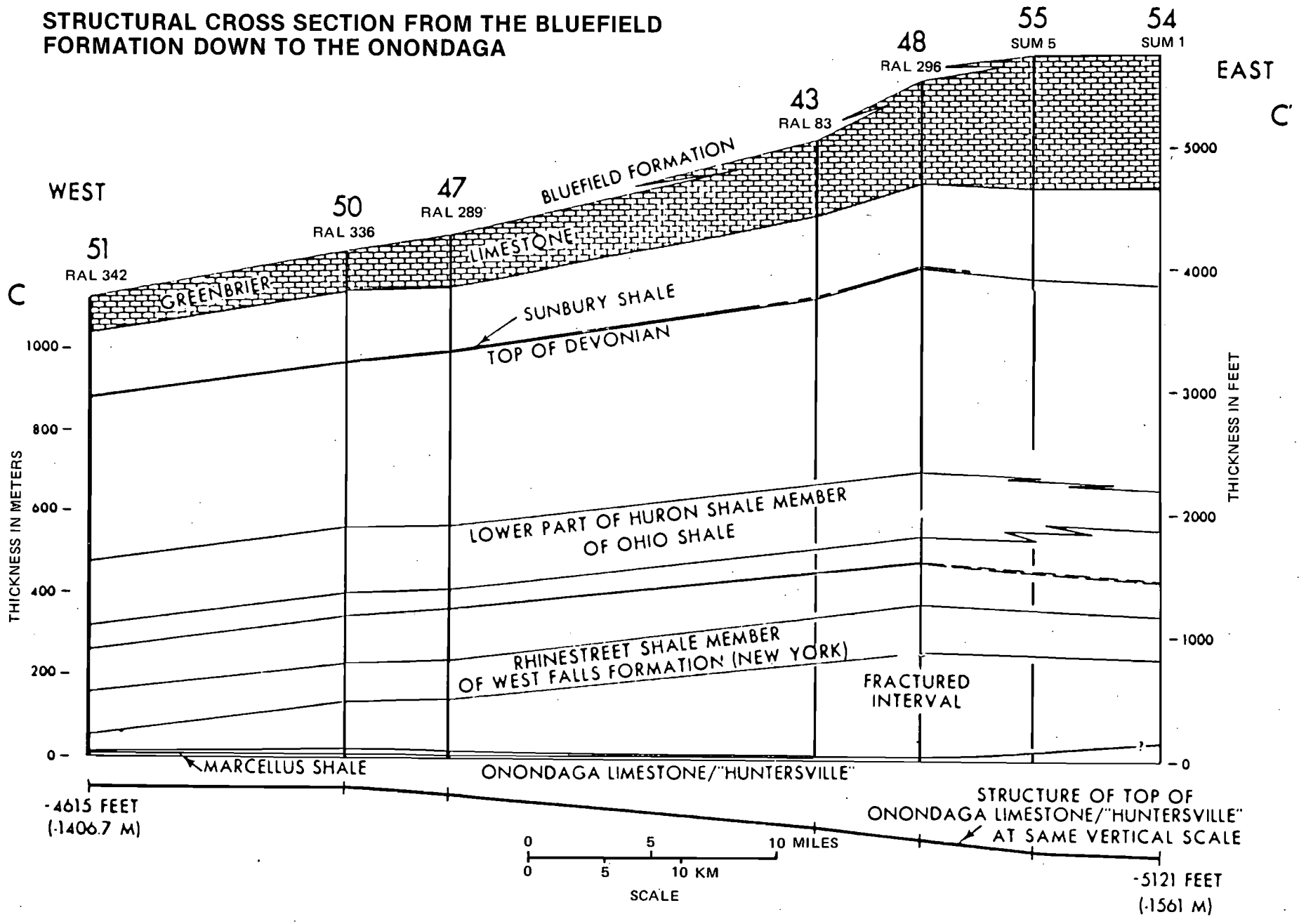


FIGURE 186
(After Perry, 1980)

Similar relations of the thickness of Middle Devonian shales, as well as other stratigraphic units, to the crest of the Central West Virginia Arch are present in northern West Virginia and along strike into western Pennsylvania (52, and Figure 180). In northern West Virginia and southwest Pennsylvania, the crest of the central West Virginia Arch is the approximate limit of the western extent of thick upper Hamilton Group (Mahantango) strata, and also coincides with the maximum thickness of the Tully Limestone in the subsurface (Figure 187). The distribution of these units may be explained if the arch restricted the westward transport of Catskill sediments and remained a positive element during Tully deposition. Subsidence east of the arch (in the folded West Virginia Trough) would act as a trap in clastic dispersal, thereby allowing Tully carbonates to develop without major drowning by turbid waters.

In southwestern Pennsylvania, subsurface data (20, 53) also indicate syn-depositional structural growth. In particular, the Chestnut Ridge Anticline and the Laurel Hill Anticline (Figure 183) lie almost directly along the strike of the Central West Virginia Arch. Piotrowski and Harper (20) show that a major northwestward thinning occurs in the Hamilton Group at or slightly west of this zone. The isopachs of total black shale in the Hamilton Group also show systematic thickening along the anticlinal crests of these and other folds along this line. The Tully interval also thickens markedly over the two anticlines and thins rapidly to either side. Piotrowski and Harper (20) explained these variations in thicknesses by syn-depositional growth of the Chestnut Ridge and Laurel Hill Anticlines which remained as high-standing areas upon which thick Tully sediments were deposited, shielded from Catskill sediments by increased basin bathymetry to the east.

These features (i.e., the eastern margin of the Green Co. - Potter Co. line of Piotrowski and Harper) follow a line which strikes northeast, paralleling the strike of Alleghenian-aged folds in the Pennsylvania Valley and Ridge province, to Potter County at the Pennsylvania - New York border. Cross section 3 (Figure 179) shows a rapid decrease of thickness of upper Hamilton Group shales in the vicinity of this line. It also shows the eastward pinch-out and interfingering of the Moscow - Ludlowville carbonates (probably included within the Tully interval of Piotrowski and Harper, 20) at about this same position between the two easternmost wells in the cross section. In addition, the Middlesex shale begins a sharp westward decrease in thickness at or slightly west of the same line. This suggests continued structural activity along this line during this time, as well. Cross Section 4, Figure 180, shows precisely the same relationship between abrupt westward thinning of the Hamilton Group strata, and the maximum thickness of carbonates at the top of the Hamilton Group along the crest of the Central West Virginia Arch. This can be seen on the cross section between the two western most wells in West Virginia.

A sharp drop in elevation of all Late Devonian units along the Ohio - Pennsylvania border, is shown in Cross Section 3, Figure 179. Several units of the Ohio Shale thicken eastward over this zone, just as they would if syn-depositional growth faulting had occurred, but there was no corroborating evidence in the available literature to support this interpretation. This possibility merits more study.

From the New York - Pennsylvania border in the vicinity of the Green Co. - Potter Co. line, maps in the literature (54, 55, 56) show a series of steep

PALINSPASTIC RESTORATION OF CONTROL POINTS PROJECTED TO MASON-DIXON LINE

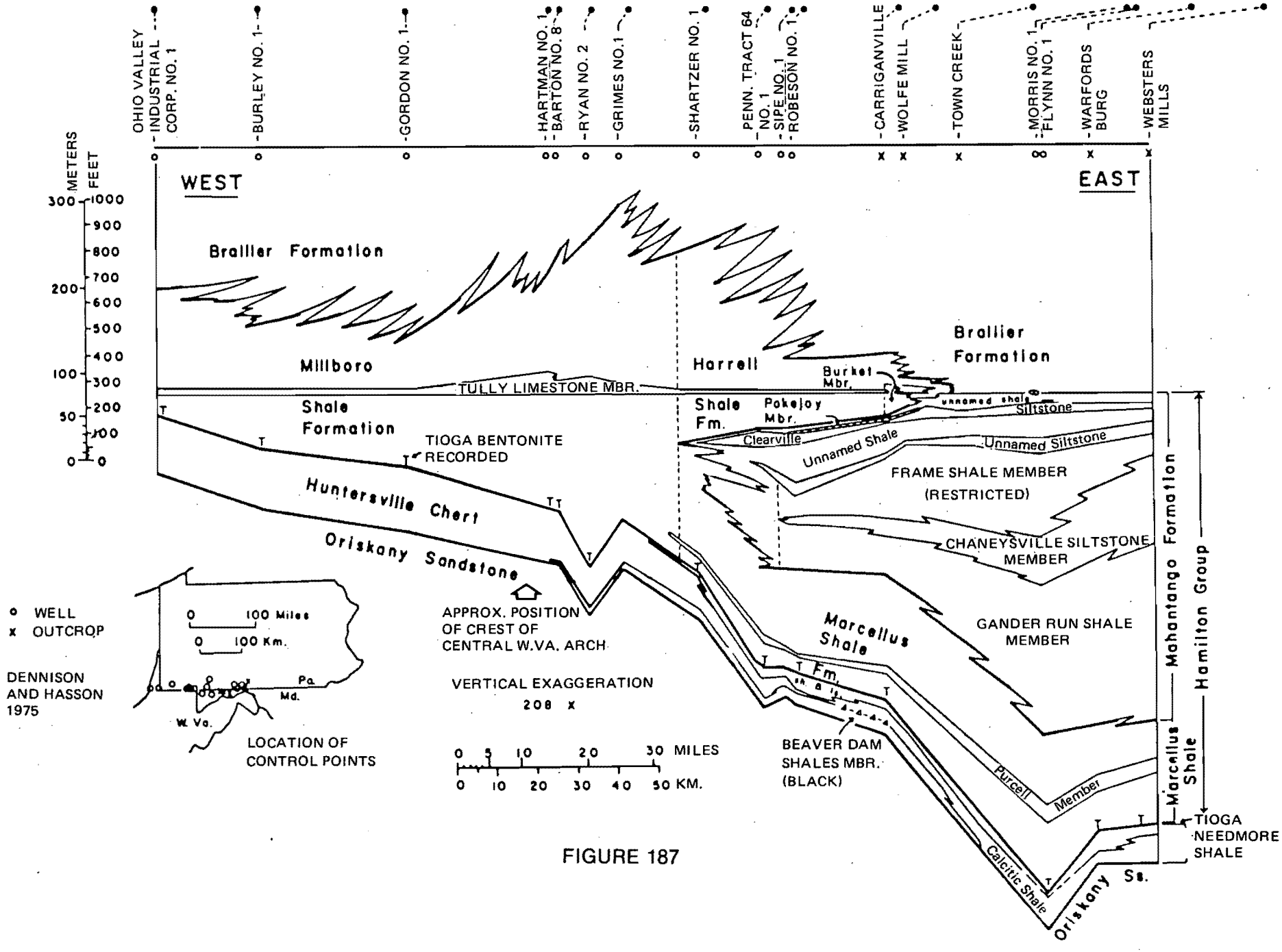


FIGURE 187

faults that strike northeastward through Alleghany and Steuben Counties. Isopach maps of black shale in various Devonian intervals (57, 58, 59) show patches and alternating belts of thick and thin black shale that may correspond to structural troughs between major sets of faults, but this interpretation is tentative. The faulting may represent the continuation of the Green Co. - Potter Co. line, but this, too is conjectural.

Cross section 5, Figure 181, which strikes more-or-less parallel to the structure contours north of the line of faults in New York, shows a gently southeasterly dipping sequence. In this region, the basin slope was to the south, roughly perpendicular to the line of section. Apparent structural relief beneath the Middle Devonian unconformity in Pennsylvania and western New York is merely a function of the position of the wells with respect to the basin margin. Those wells situated farther south (more basinward) encountered thicker intervals of Hamilton Group sediment, thus creating apparent "decapitated" folds beneath the unconformity. Those portions of the cross section that strike parallel to the basin margin show no structural relief beneath the unconformity.

Tectonic History

Basin models advanced to explain Devonian shale deposition nearly all advocate the same basic elements: an actively rising Cincinnati Arch to the west, and a relatively deep (100 to 300m) shale basin that was alternately subjected first to anoxic and "starved" basin conditions and then to relatively aerobic conditions during which sediment-laden currents deposited muddy sediments as turbidites from an eastern prograding plexus of nearshore deltaic and other strandline deposits of the Catskill "Delta", all in response to the Acadian Orogeny (11, 60, 61, 62). The following interpretation of tectonic history of the Appalachian Basin draws largely upon those previous studies, but also emphasizes that basement related syn-depositional structures also had profound effects on Devonian shale sedimentation patterns. However, even though the objective of this phase of the project was to determine whether the deposition of the organic-rich shales might be controlled by structures, this work indicates that is probably was not, although conceivable organic matter deposition could have been influenced by local subsidence effects. Much of this interpretation is preliminary and deserves more extensive study, but in overview, this study did show how the basin evolved.

The primary features of Lower-Middle Devonian sedimentation in the Appalachian Basin involve the deposition of shallow-water carbonates (Onesquethaw) across a wide area, coupled to the east with deposition of the Needmore shale in a foreland basin west of the earliest Catskill deltaic sediments. During this time, carbonate sedimentation kept pace with differential subsidence in the Rome Trough. Thinning of the Onesquethaw over the Central West Virginia Arch suggests that minor uplift may have occurred along this axis. Each of the arch-Onesquethaw sediment units, eg, the Onondaga Huntersville) interfingered with the deeper shales deposited in a basin low formed by subsidence in response to the early phases of Acadian deformation.

Westward progradation of early Catskill sediments (Hamilton) was coupled with widespread subsidence and development of anoxic "starved" basin conditions under which the Marcellus shale was deposited above the Onondaga carbonates over a wide area of the Appalachian Basin. At this time, the Central West Virginia Arch and the eastern margin of the Green Co. Potter Co. line may have served as a positive submarine barrier or as a hinge line. West of that line only a very thin Marcellus section was deposited, while continued subsidence to the east (in the Folded West Virginia Trough), much of it perhaps due to sediment loading, maintained the bulk of the Hamilton Group shales and did not allow major westward progradation of the Catskill sediments, so that Hamilton Group sediments did not accumulate to any appreciable thickness west of the barrier. Starved basin conditions abated with progradation toward the arch.

At the end of Hamilton time, near-starved basin conditions were restored, and these fluctuated with relatively oxygenated, clear-water conditions during deposition of the Tully Limestone and its equivalents. Long-continued starved basin conditions led to the deposition of thin black shaly zones in the Tully or, in the more western areas, phosphatic and pyritic horizons (Leicester pyrite lenses) and shell lags or zones during periods of submarine non-deposition (63). Clear-water, more oxygenated

conditions alternated with short episodes of muddy and fossiliferous carbonate deposition, the upper parts of which interfinger with the succeeding Burket-Geneseo black shales. The increased thicknesses of Tully strata along the West Virginia - Pennsylvania line suggest that this barrier was still effective well into Middle Devonian time.

Continued subsidence east of this line, or eustatic sea-level rise may have been responsible for the conditions of non-deposition that generated this submarine uncomformity. Heckel (63) also suggests that contemporaneous structures east of the site of Tully deposition may have cut off the clastic influx. Farther west and south, especially near the Cincinnati Arch, uplift and erosion may have occurred. This was probably not widespread throughout the basin, however, as the unconformity in the central part of the basin appears to have been entirely submarine and lacks any shoal-water deposits that could have been derived from laterally emergent and actively eroding areas.

After the diastemic conditions of the Middle Devonian, progradation of Catskill sediments again spread shale (Burket-Geneseo-Middlesex) westward into large areas of the Appalachian Basin. The extent to which the West Virginia-Pennsylvania barrier inhibited progradation is not certain, but it probably had some effect, because in several areas the Genesee-Sonyea intervals thin over its crest.

By the time of the deposition of the West Falls unit, however, shallow-water sedimentation had been established along the crest of the barrier so that the main locus of black shale deposition lay to the west, above the Rome Trough and against the east flank of the Cincinnati Arch.

The distinction between the Eastern and Western black shale belts (64, 65) clearly outline the segregation of thick Middle Devonian and Late Devonian Black shales. Harris et al (64) suggested that the two belts represented times of greater stillstand, first developed in the east, and then to the west, separated by a time of more rapid progradation across the intervening area between them. If the barrier model presented here is correct, then the two areas are the result of a tectonic sill that was overtopped by the Late Devonian, allowing the distal basin milieu to shift westward. Recurrent subsidence in the Rome Trough, revealed by the thickened West Falls and Huron sections, allowed the basin axis to shift rapidly westward so that the Late Devonian black shales were deposited adjacent to the east flank of the actively rising Cincinnati Arch. Sediment transport of the clastic wedge was dominantly east-west, as shown by paleocurrent studies (66). Locally, patterns of thickness are complex, and show a series of thickened black shale depocenters that are probably separated by actively prograding lobes of turbidite sediments (64). Black shale finally deposited over the top of the arch during Middle Huron time.

While numerous workers studying the Devonian Shales have attempted to outline basin evolution in terms of stratigraphic and tectonic elements within the basin, few have attempted to place this within the framework of a plate-tectonic model that links events in the Devonian foreland with deformation within the Acadian Orogen (proposed by Robinson and Hall, 67) itself. Ettensohn and Barron (62) used a model for plate geometry proposed by McKerrow and Ziegler (68), later amplified by Dewey and Kidd (69), to

explain the Acadian, but they did not try to relate the kinematic evolution of the orogen to events in the foreland.

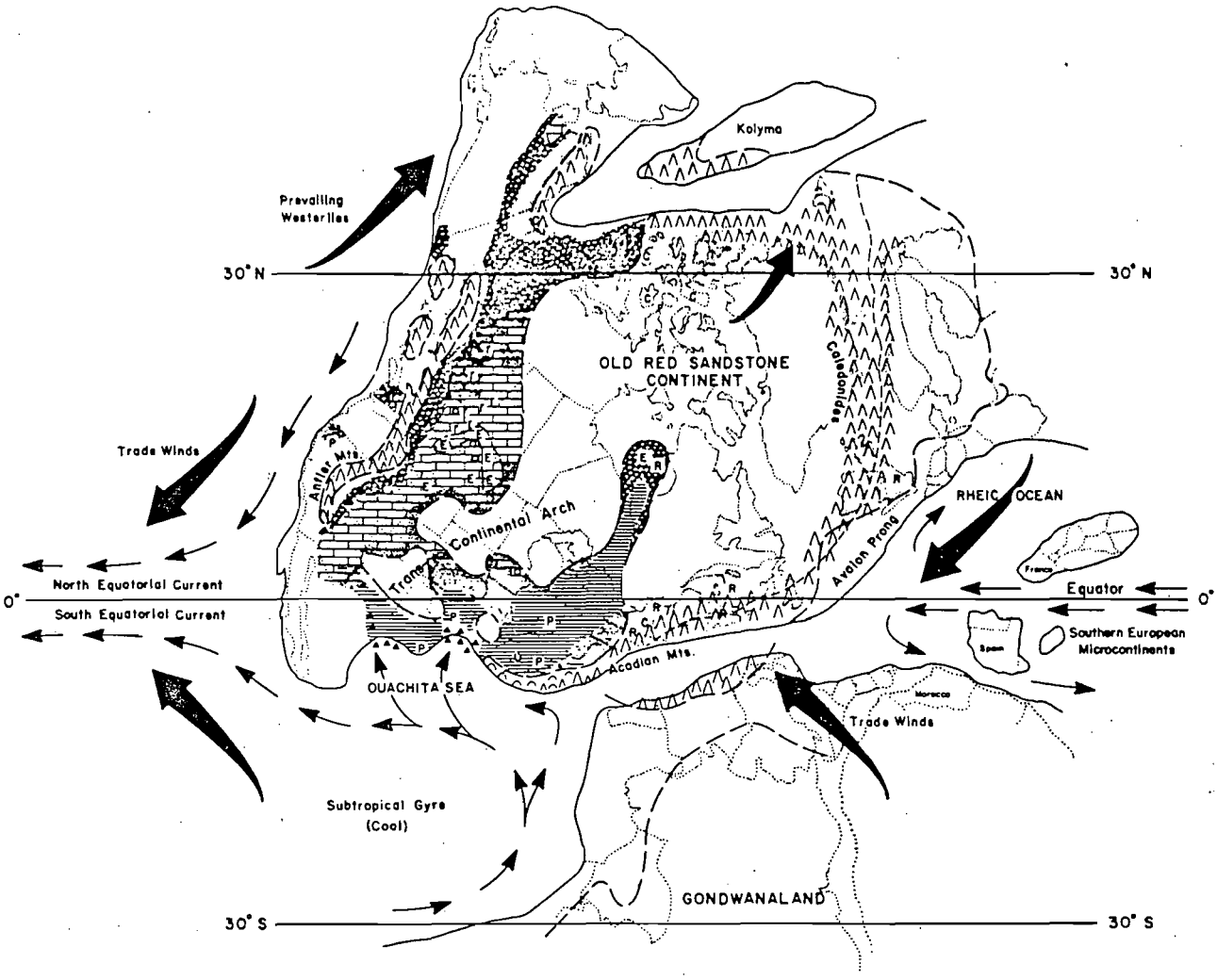
According to the authors just mentioned, the Taconic Caledonide Orogen of the Ordovican and early Silurian resulted from the collision of the Baltic Shield and assembled fragments making up the Avalon Prong with the North American Craton (Figure 188). Two studies (68, 169), indicated that the Avalon Prong suture with the New England Appalachians was incomplete until Middle Devonian time, when South America (as part of Gondwana) drove the Avalon Plate against North America to create the Acadian event. Paleomagnetic data (70) and paleographic maps of plate configurations (71, 72) suggest strike-slip motion or oblique subduction prior to and during the Devonian collision. Left-lateral Motion along a convergent zone accommodates the paleomagnetic data for the Avalon Plate (70). The final configuration is shown in Figure 188 which is modified from Ettensohn and Barron (62).

Robinson and Hall (67) summarized the major kinematic events that occurred in the New England Appalachians during the collisional event. They reported that the axial portion of the orogen (the Bronson Hill Anticlinorium) underwent an early phase of westvergent nappe development, followed by an eastvergent kinking or backfolding of the nappes. Backfolding was accompanied by the emplacement of mantled gneiss domes in the Bronson Hill Anticlinorium and eastward-vergin cataclastic zones that ultimately developed into a thrust belt in eastern Connecticut and Massachusetts (i.e., the Honey Hill, Clinton-Newsberry, Bloody Bluff and related faults) along the lines of strikeslip motion required by the paleomagnetic data of Kent and Opdyke (70). Robinson and Hall invoked the "flake" tectonics of Oxburgh (73) for the Avalon Prong to account for the observed kinematic sequence.

An alternate scenario to that of Robinson and Hall (67) is suggested by the data: oblique impingement of the Avalon Prong on the North American continent involves transmission of compressive stresses across a left-lateral convergent zone to the North American Craton, as shown in Figure 189. This compressive stress caused epeirogenic uplift of the Cincinnati Arch and the Central West Virginia Arch and the Green Co. Potter Co. Line in Pennsylvania, along with initial eastward asymmetric subsidence of the foreland beneath the advancing Avalon Prong. In Figure 189A which shows the configuration during Late Early Devonian, impingement of the Avalon Prong has begun. Compressive stresses have generated epeirogenic basements arches in the North American cratonic interior. Subsidence of the Needmore-Marcellus basin axis of shale depositions was generated by isostatic loading of the edge of the North American plate during west-vergent nappe folding and the compressive component of Avalon Prong motion. This produces the initial "rain shadow" effect required by Ettensohn and Barron () to account for Marcellus black shale deposition. Progradation of the earlier portions of the Catskill Delta initially kept pace with subsidence of the Marcellus basin axis but could not overtake it, and eventually declined with widespread subsidence and basin water stagnation during Tully time.

In Figure 189B, backfolding (74, 75, 76) began as an adjustment to plate convergence in which the more buoyant North American Plate refused to be subducted beneath the smaller Avalon Prong during the Middle Devonian. Uplift along the Acadian Highlands generated rainshadow conditions, tectonic

A VIEW OF APPALACHIAN BASIN EVOLUTION



LEGEND

probable edge of continental mass	o ooids	sandstone
modern political boundaries	▲ chert	carbonate
probable land	C coal	green to gray shale
tectonic suture	R redbeds	black shale
limit of thick evaporites	r reefs	mixed carbonate - shale
probable mountains	E evaporites	carbonates with interbedded siltstones, sandstones, and shale
oceanic currents	P phosphate	

FIGURE 188

(From Ettensohn and Barron, 1981)

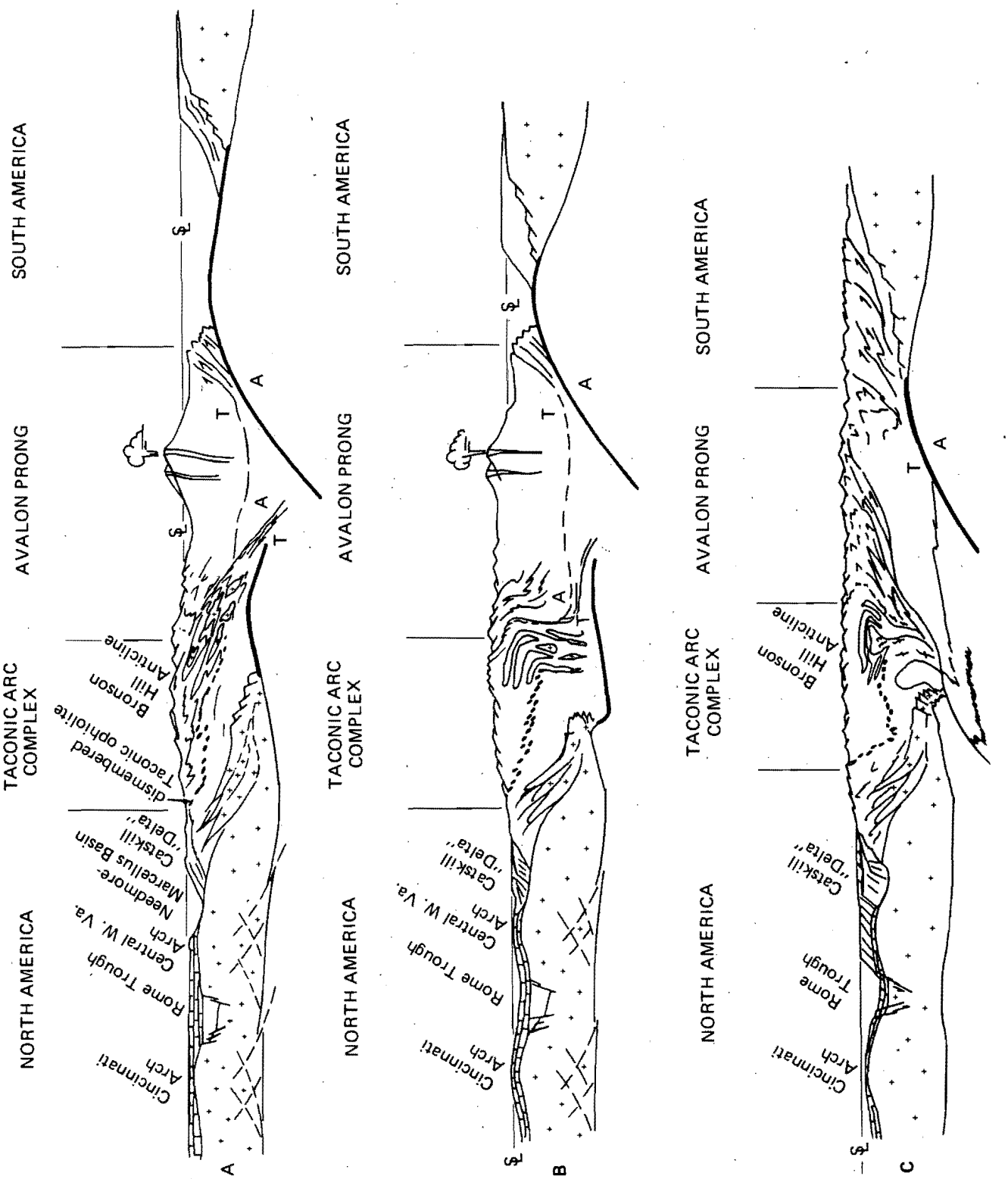

THE TECTONIC VIEW OF THE EASTERN U. S.
DURING DEVONIAN TIME
NORTH AMERICA
TACONIC ARC COMPLEX
AVALON PRONG
SOUTH AMERICA
Cincinnati Arch
Rome Trough
Central W. Va. Arch
Needmore-Marcellus Basin
Catskill "Delta"
disembered Taconic ophiolite
Bronson Hill Anticline
A
T
A
B
C

FIGURE 189

thickening and loading of the edge of the North American plate caused basin subsidence during Tully time.

Continued transmission of compressive stresses to the North American plate maintained the Cincinnati and West Virginia Arches. In Figure 189C, gneiss dome emplacement and retrocharriage (74), or backthrusting, along the east side of the Bronson Hill Anticlinorium returned plate convergence to stable buoyant conditions in the Late Devonian. Release of compressive stresses in the North American plate interior reactivated the Rome Trough as a growth-fault system on the east flank of the Cincinnati Arch. Progradation of the Catskill deltaic wedge shifted the site of black shale deposition westward across the now inactive West Virginia Arch to the east flank of the Cincinnati Arch, causing the arch to be overtopped by black shales during Huron time.

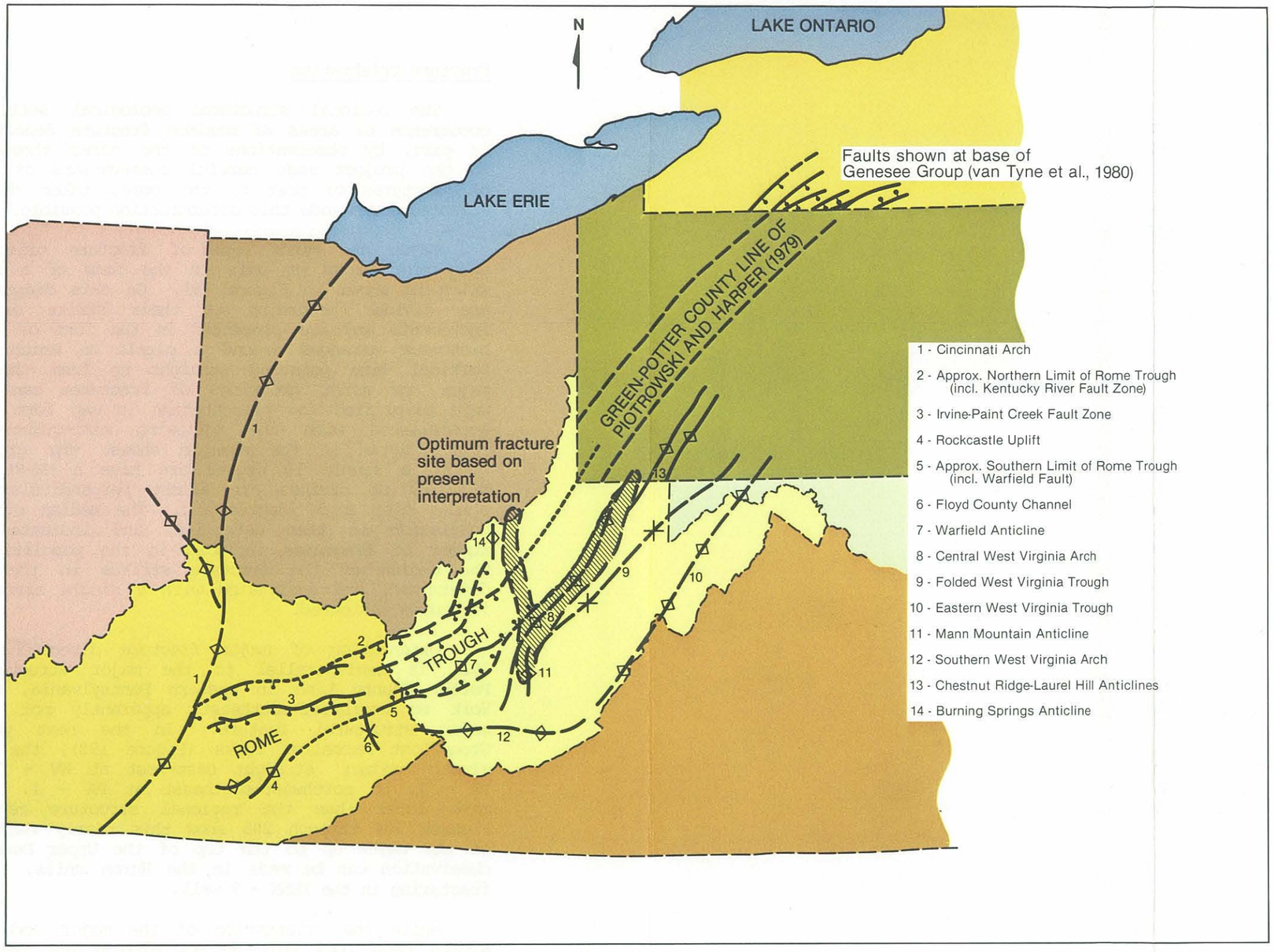
Favored Exploration Areas

The possibility that the Central West Virginia Arch controlled sedimentation patterns in the Devonian shales suggests that structural considerations may provide a rationale for predicting optimum reservoir sites in future exploration of the basin. The Plateau Province east of the arch contains numerous folds produced by decollement thrusting in the Paleozoic section. The style of deformation suggests that the core zones of these folds may contain sections of Devonian shale thicker than the regional trend, because of shale flow and fault imbrication above decollement thrust faults, such as may be the case in the Burning Springs and Mann Mountain anticlines.

The cores of folds should also be the sites of increased fracture porosity. If the locus of thrusting and tectonic thickening in Middle Devonian shales of the Hamilton Group is the result of abrupt depositional thinning over the crest of the arch, then the crest should be the optimum site of fracture development associated with folds having structural relief at the Marcellus level. Small anticlines with less than 300 feet of structural relief do coincide with the crest of the arch along a zone beginning in Clay County, West Virginia, and extending through Braxton, Lewis, Harrison, Taylor, and Monongalia Counties to the Pennsylvania state line (47), but whether this structural relief extends to the Marcellus level is uncertain. Nevertheless, these folds are potential exploration targets because they may be the sites of porosity development in areas where the shales have the potential to source both oil (paraffinic) and gas, as discussed earlier in this report.

The zone of optimum fracture porosity may also be extended along a fairly straight zone connecting the Burning Springs Anticline, a site of recent hydrocarbon discoveries, to the Mann Mountain Anticline. This zone lies along the line which Rodgers (48) argued may be the wedge-out of Silurian salt, which is the level of detachment associated with the Burning Springs structure.

Based on structural considerations, the favorable areas which are potential sites for the occurrence of reservoir rocks, because of the development of fracture porosity, are shown as the V-shaped area outlined on the map in Figure 190.



Favored Exploration Areas Based Upon Structure

FIGURE 190

Prepared by Mound Facility

Fracture Orientation

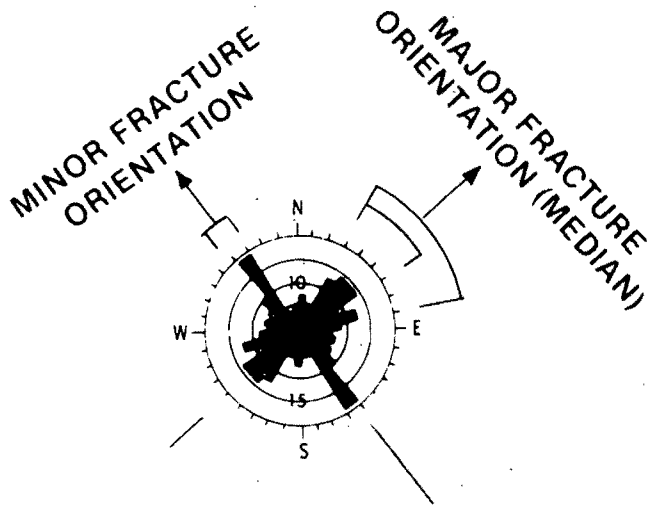
The regional structural geological setting and the prediction of occurrence of areas of maximum fracture density are amenable to testing, in part, by observations of the cores themselves. Geologists attached to the project made careful observations of the density and orientation of fractures of most of the cores taken during the program. Cutting oriented cores made this determination possible.

Major and minor axes of fracture orientation were presented for each rock group or unit in the form of a rose diagram, an example of which is shown in Figure 191. On this diagram, the number of fractures are divided according to their strike orientations into 10 degree increments and are presented in the form of a rose diagram, which is a histogram arranged around a circle on which north is represented by a vertical line pointing straight up from the central point, etc. The major and minor groupings of fractures can be discerned visually, but were simplified for presentation in map form for this report. This was accomplished with the following semi-quantitative procedure. As the rose diagram in the example shows, the greatest number of fractures within a single 10 degree arc have a NW-SE orientation. However, the majority of strikes are almost perpendicular to this orientation, but spread over a 50 degree arc. The median orientation of this the major population is then determined and indicated as a single arrow, the number of fractures included in the population is placed by the arrow. The median of the fracture strikes in the minor population is also determined, and designated with a single arrow, again with the number of fractures indicated.

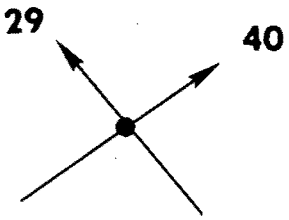
Orientation of major fracture directions in the Marcellus (Figure 192) is semi-parallel to the major structural feature, the Green - Potter County Line in western Pennsylvania, but changes abruptly in New York to northwest-southeast, apparently not under the control of any major structural feature. In the next younger unit, the Hamilton Group/Post Marcellus rocks (Figure 193), the orientation appears to be almost random: straight east-west at WV - 7 to southwest-northeast at PA - 4, to northwest-southeast at PA - 1. The controls must be much more local than the regional structure mapped earlier (Figure 190). Figures 194 through 205 show this nearly random orientation in the rest of the units up to the top of the Upper Devonian. One very interesting observation can be made in the Huron units, i.e., the relatively intense fracturing in the TENN - 9 well.

While the orientation of the major and minor fracture populations within each rock unit do not display any regularity nor any correlation with regional structural geology, the intensity of fracturing recorded in the cores appears to have considerable importance. To demonstrate this, the number of fractures recorded in all the cores were totaled for each well, and the number of fractures was placed beside each well on Figure 206. If fifty fractures per well is selected as the dividing point between high fracture and low fracture density, the basin can be divided into the poorer and better regions for exploration for naturally fractured reservoirs. Such a favorable area is suggested beginning in the area of the TENN - 9 well, through extreme southeastern Kentucky,

EXAMPLE OF A ROSE DIAGRAM OF NATURAL FRACTURES AS MAPPED BY PERSONNEL OF CLIFF MINERALS INC.



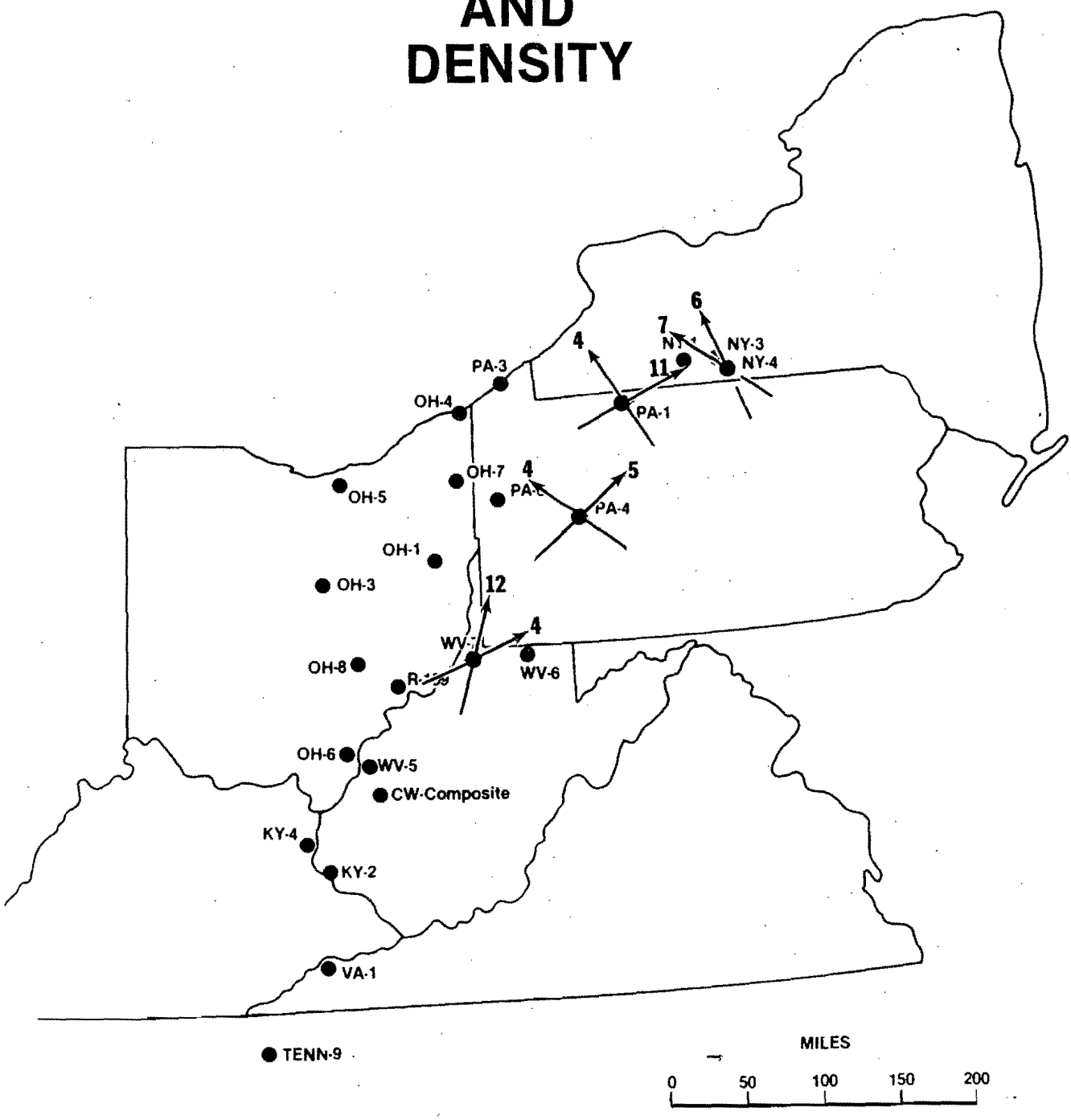
SIMPLIFIED DIAGRAM FOR MAPPING PURPOSES



DISTRIBUTION OF NATURAL FRACTURES IN CORE FROM MAP UNIT 10, TENN-9 WELL

FIGURE 191

FRACTURE ORIENTATION AND DENSITY



MARCELLUS TIME

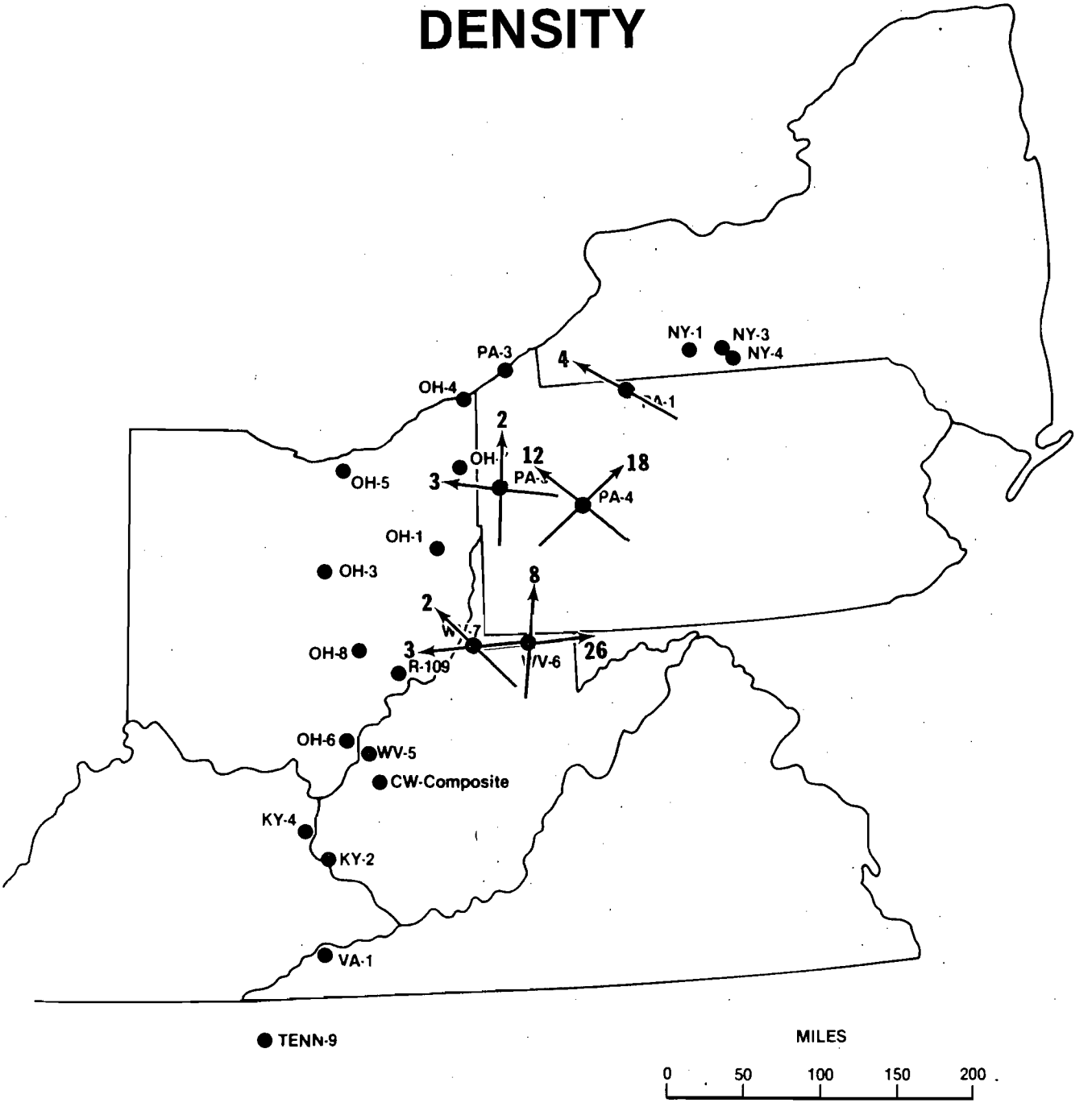
Map Units 1 & 2

FIGURE 192

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



HAMILTON GROUP/POST MARCELLUS TIME

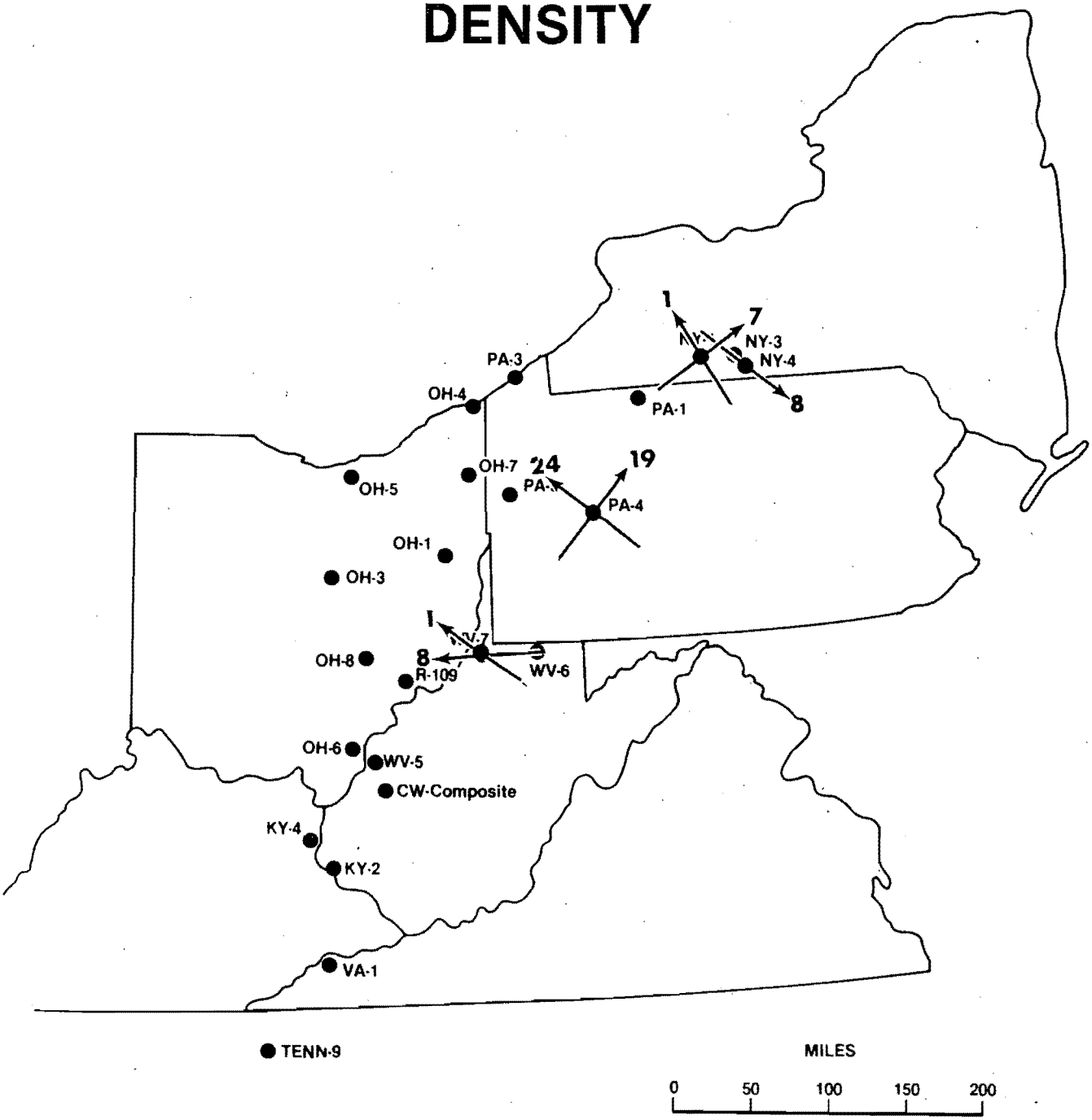
Map Unit 3

FIGURE 193

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



GENESEO/GENESEE TIME

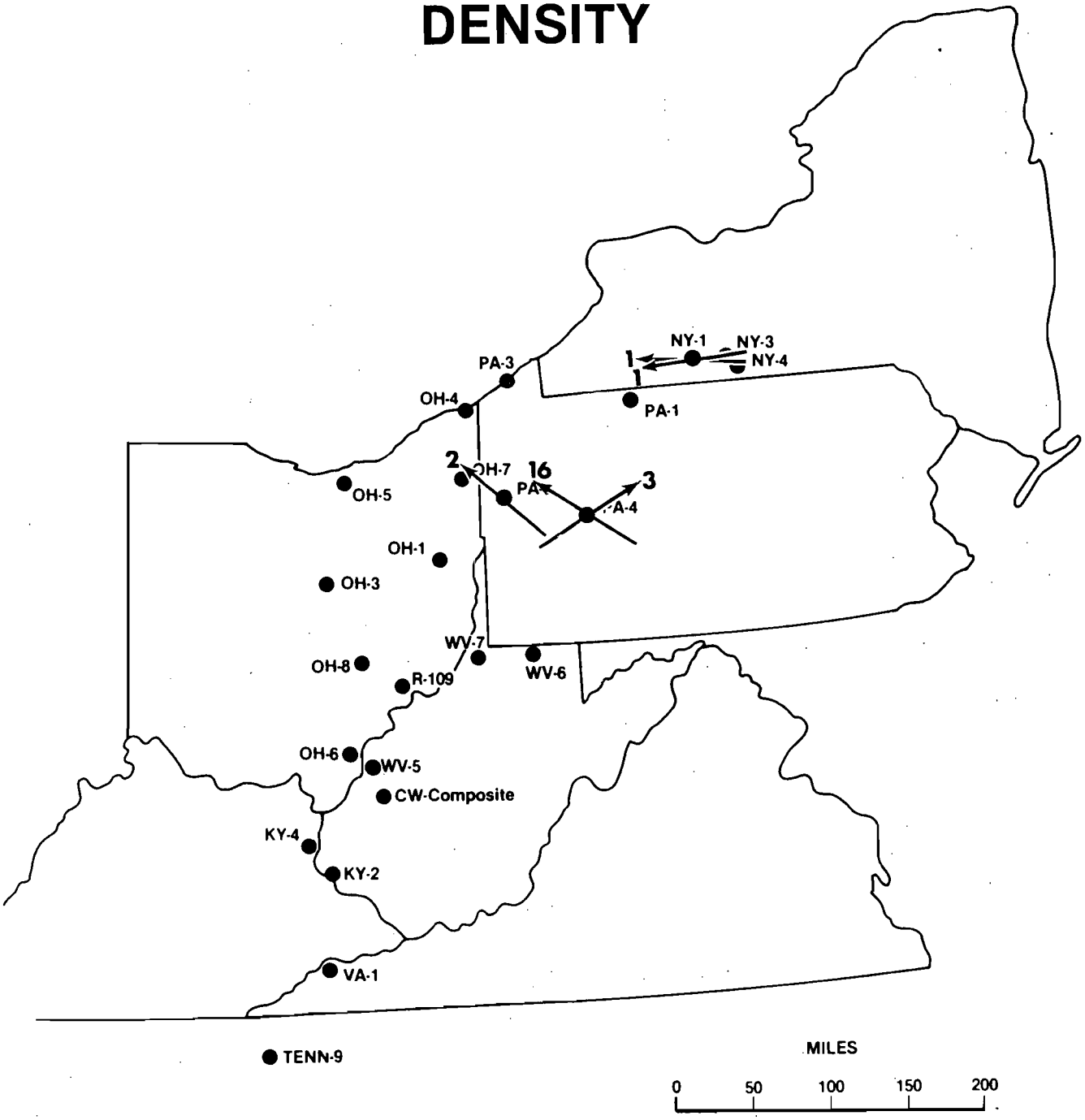
Map Unit 4

FIGURE 194

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



SONYEA/MIDDLESEX TIME

Map Unit 5

FIGURE 195

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY

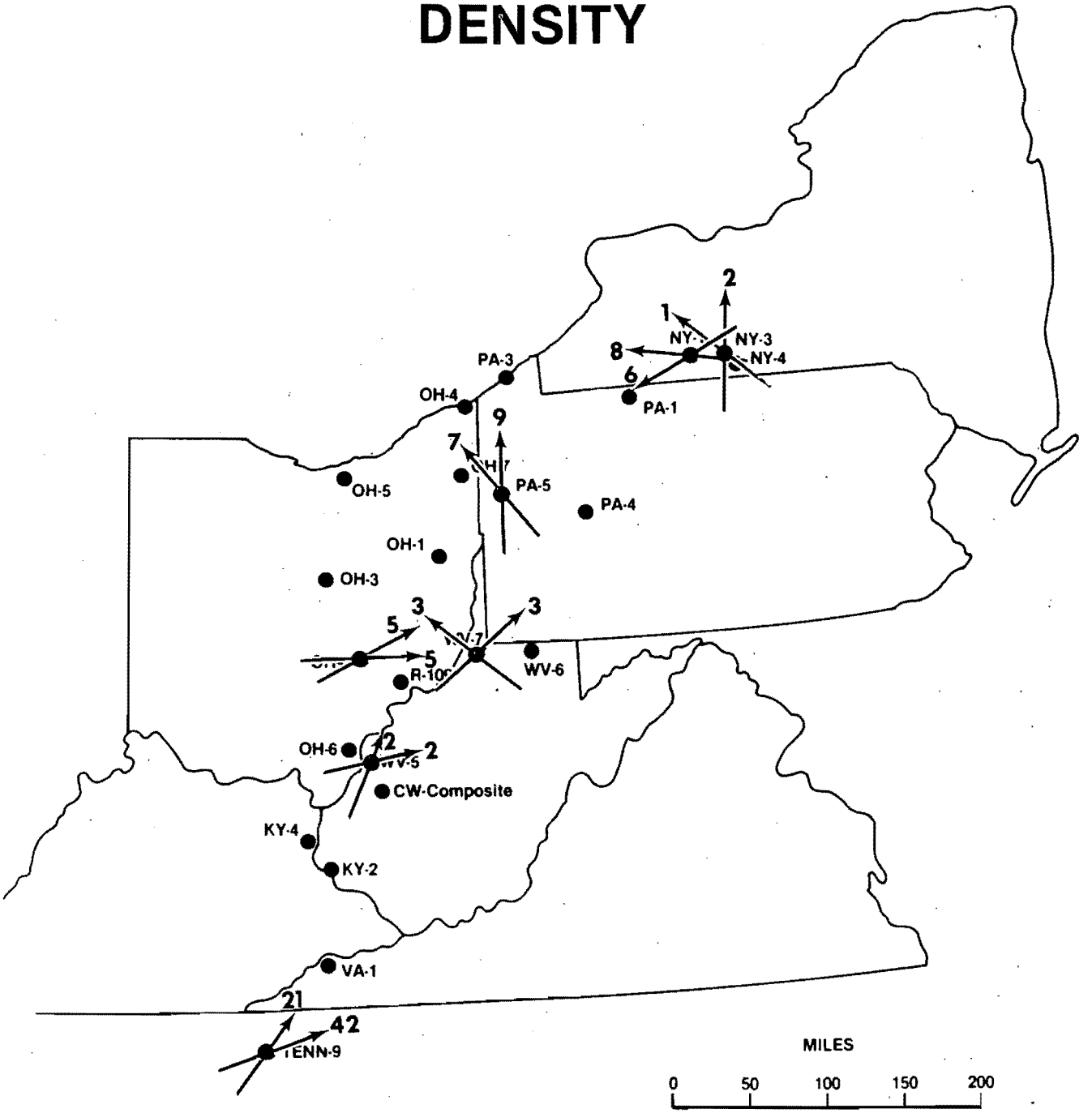


FIGURE 196

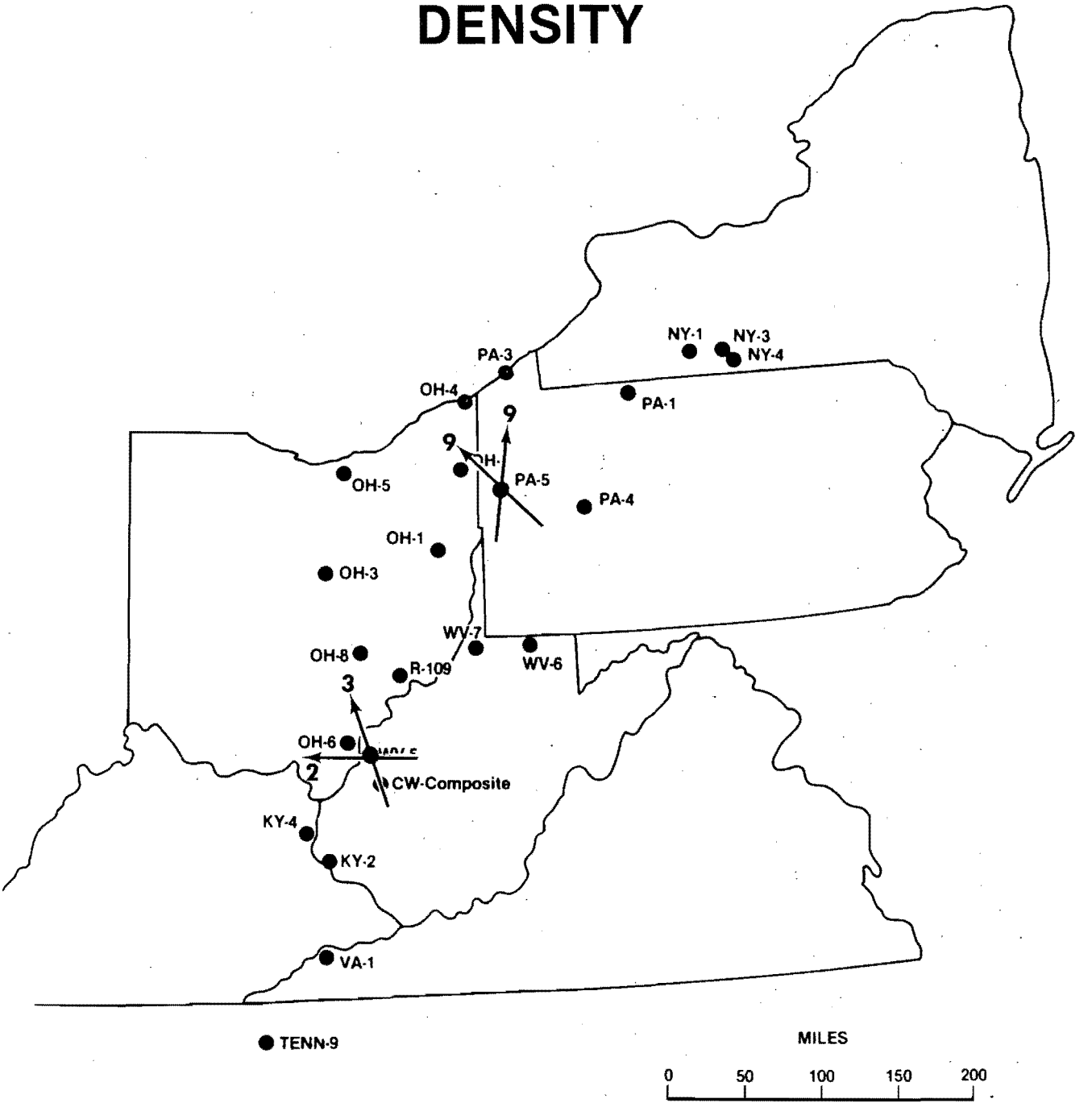
LOWER OLENTANGY/ RHINESTREET TIME

Map Units 6 & 7

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



MIDDLE OLENTANGY/ANGOLA SHALE TIME

Map Unit 8

FIGURE 197

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY

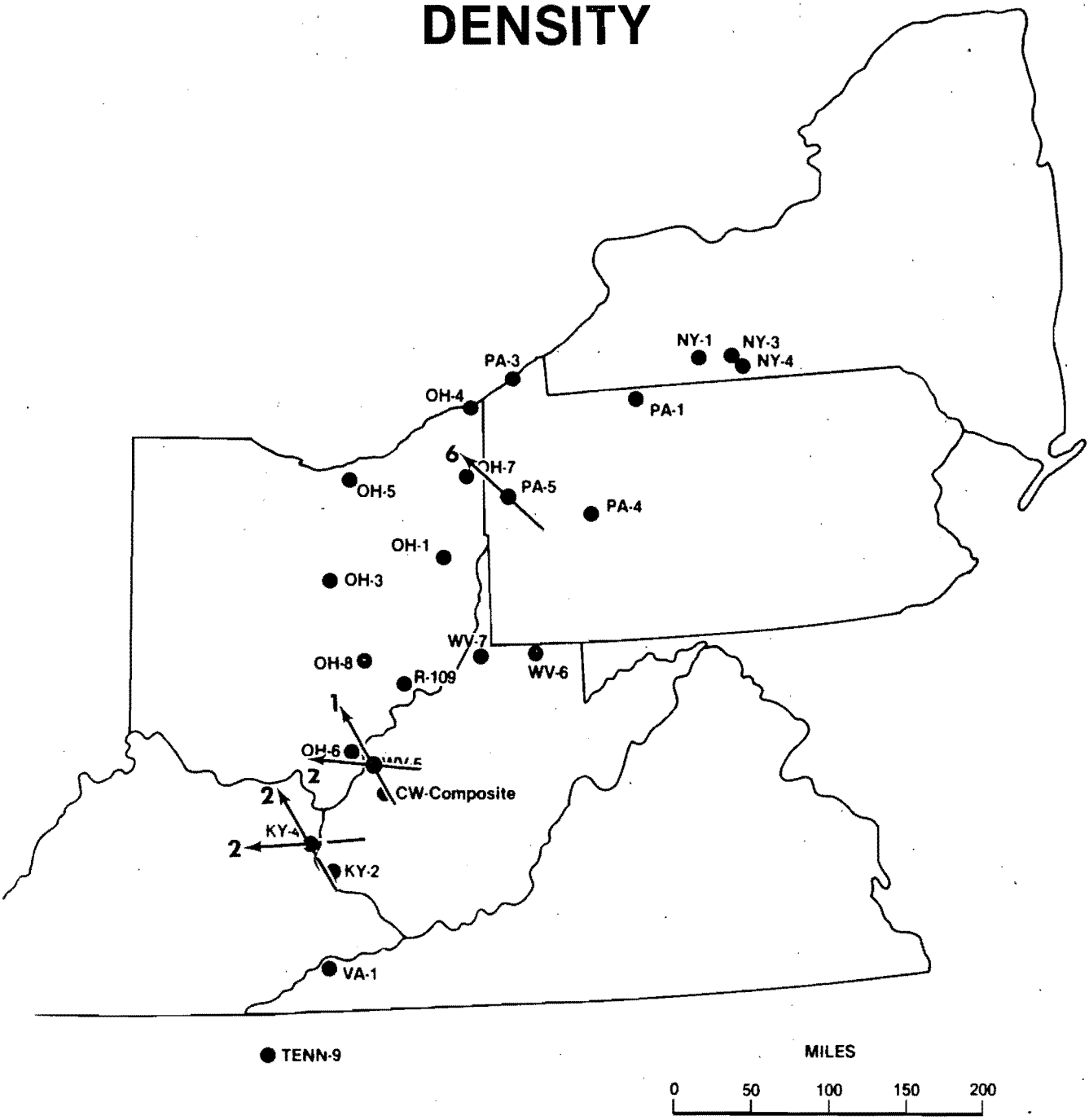


FIGURE 198

UPPER OLENTANGY/JAVA FM. HANOVER SHALE TIME

Map Unit 9

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY

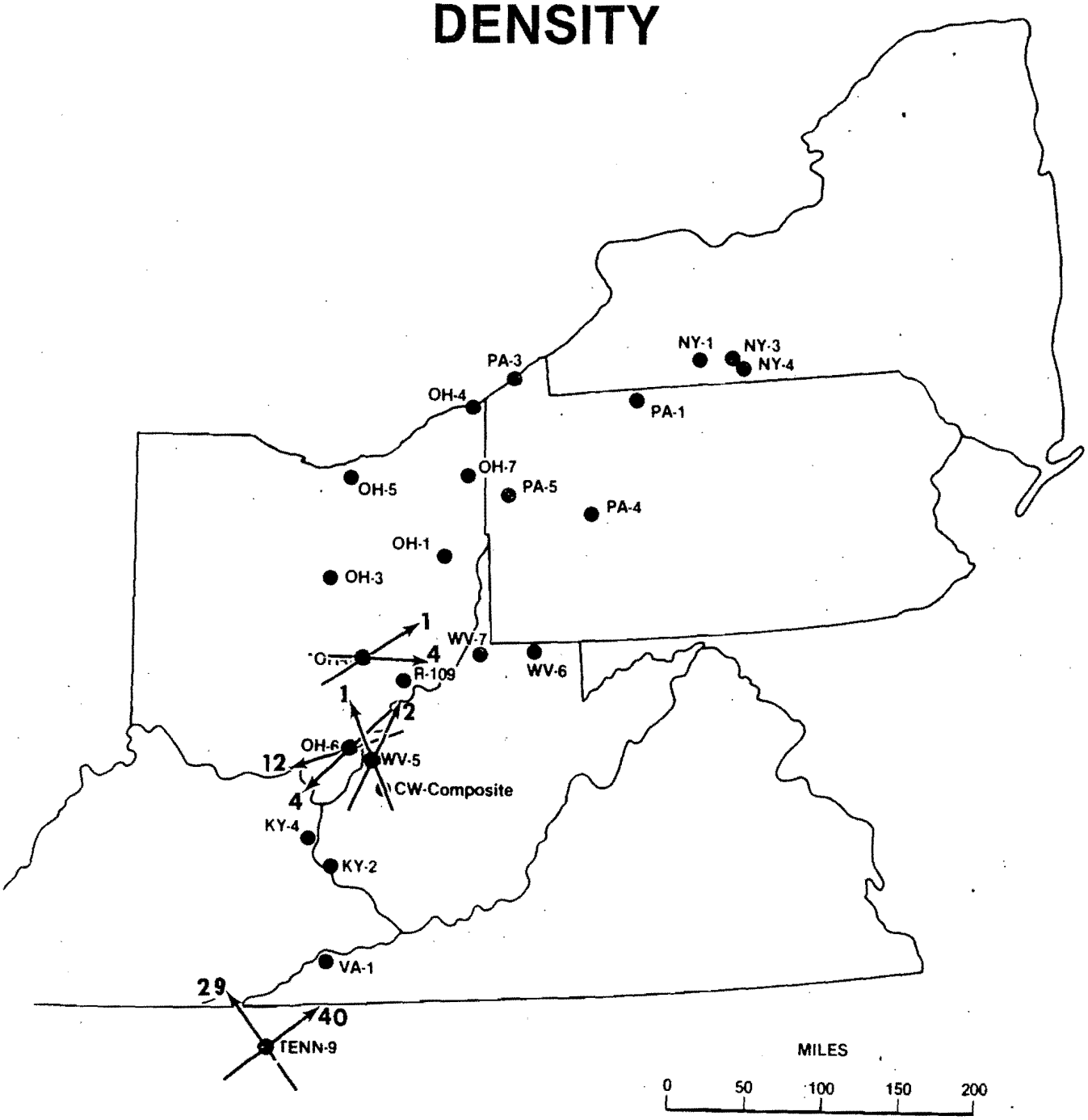


FIGURE 199

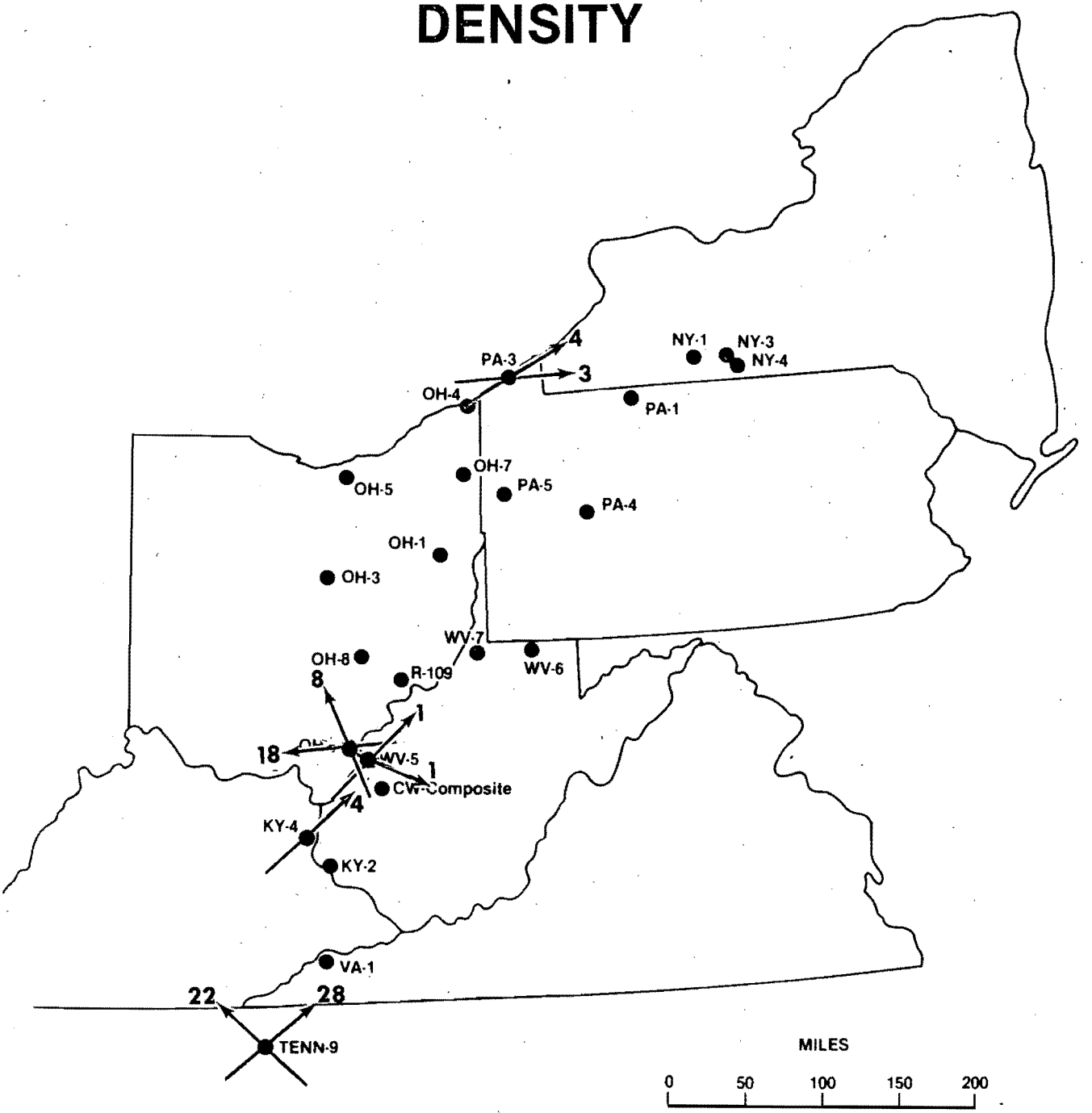
EARLY LOWER HURON/ EARLY DUNKIRK TIME

Map Unit 10

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



LATE LOWER HURON/LATE DUNKIRK TIME

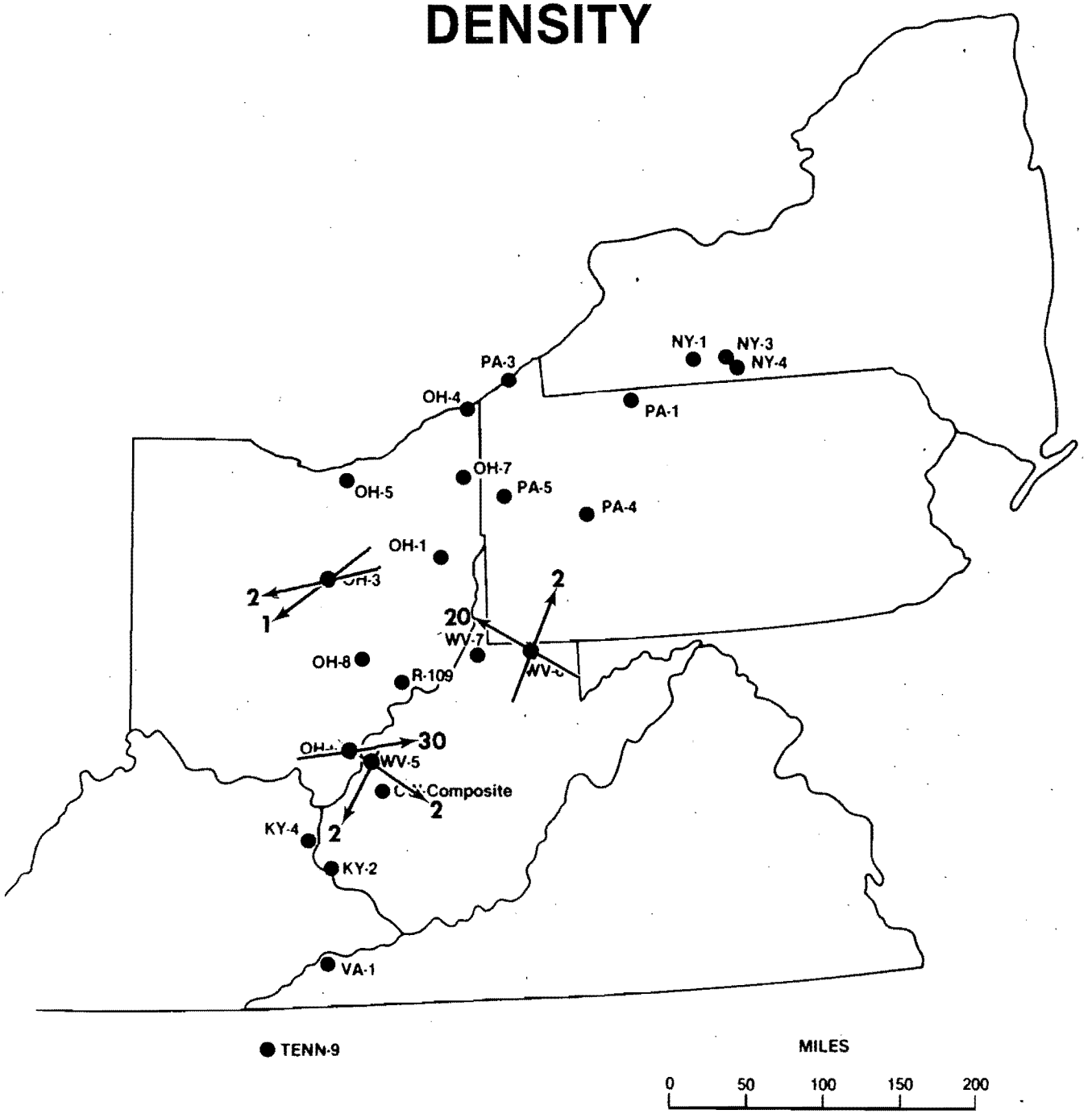
Map Unit 11

FIGURE 200

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



EARLY MIDDLE HURON TIME

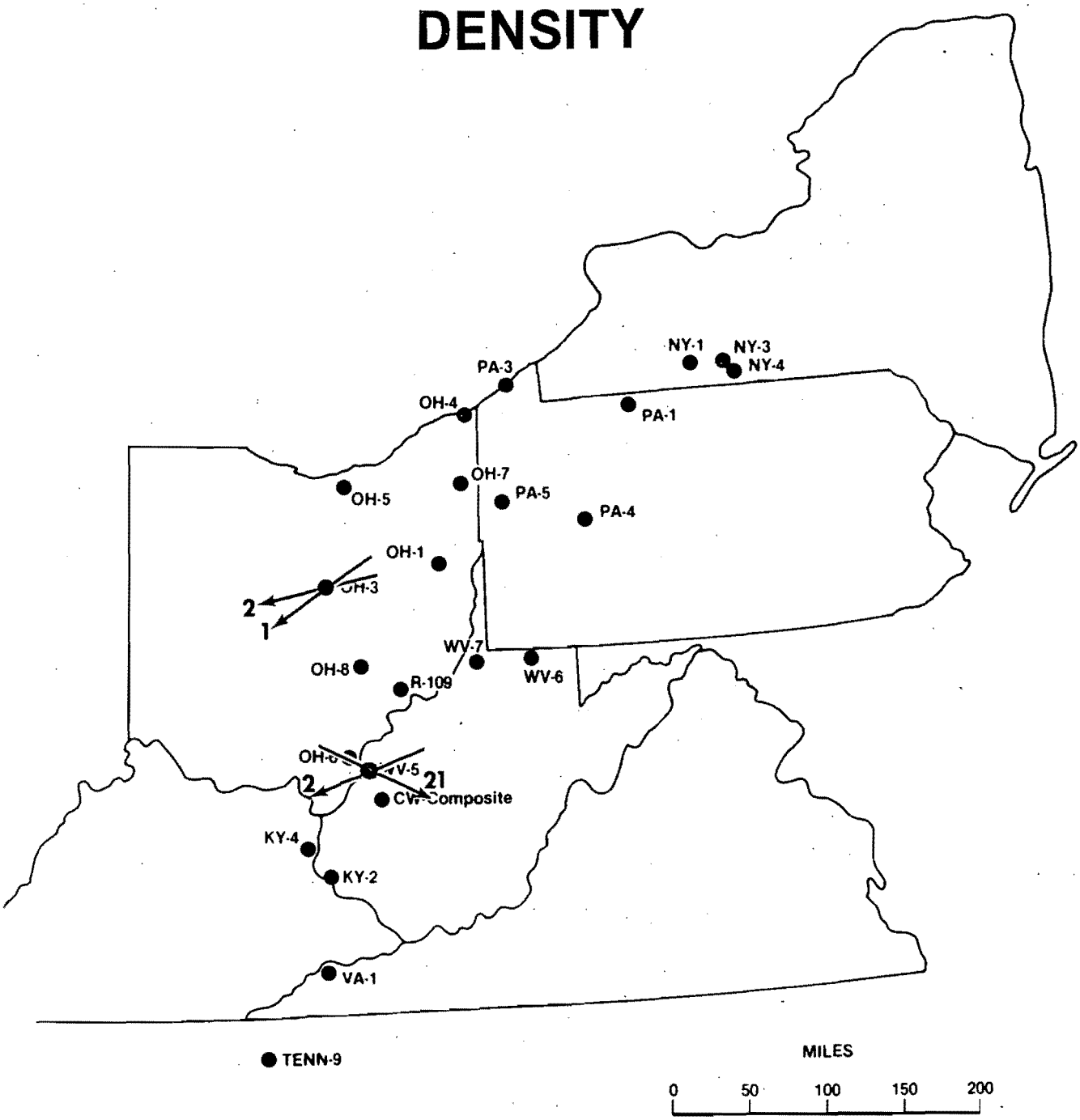
Map Unit 12

FIGURE 201

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



LATE MIDDLE HURON TIME

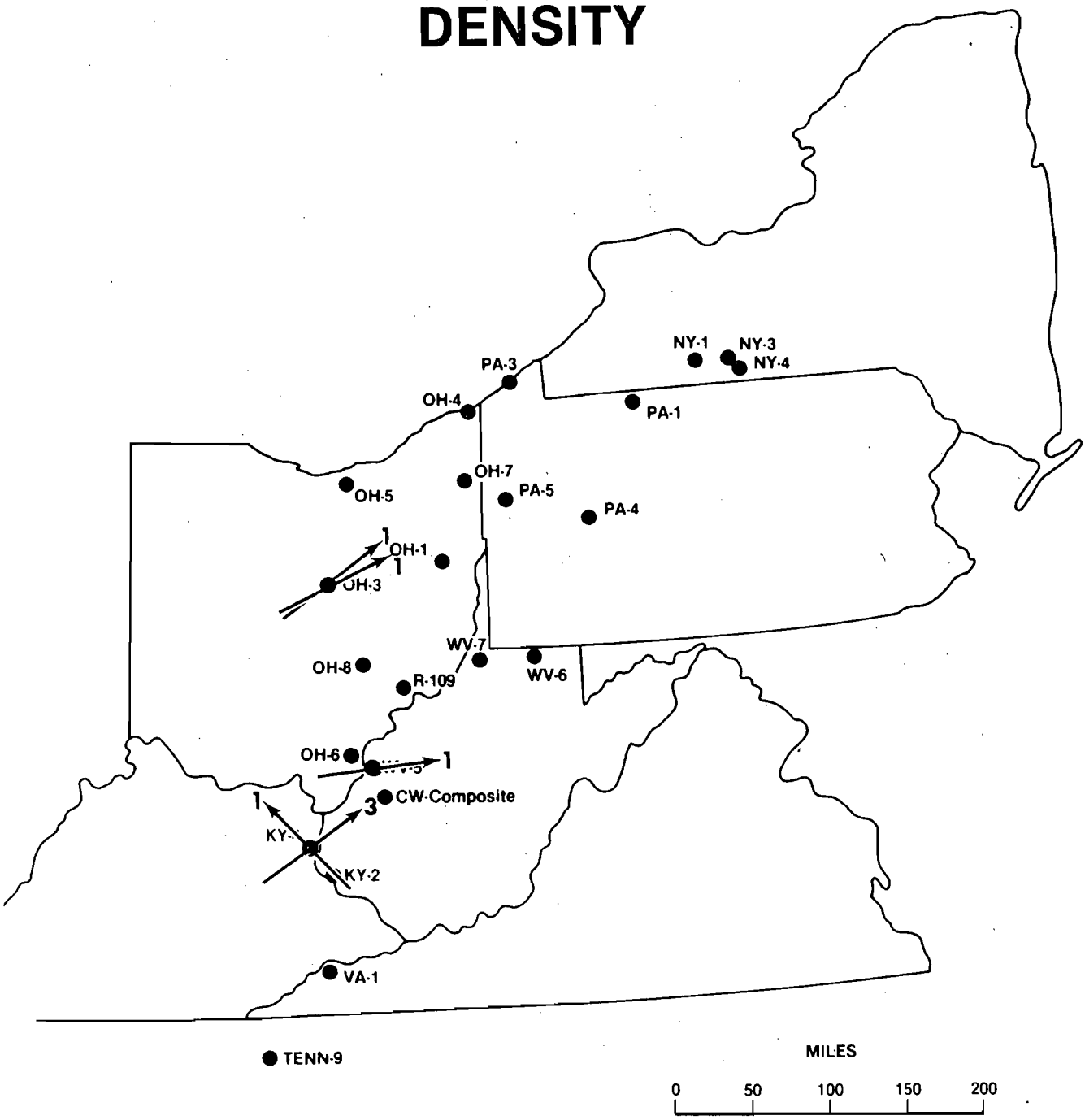
Map Unit 13

FIGURE 202

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



EARLY UPPER HURON TIME

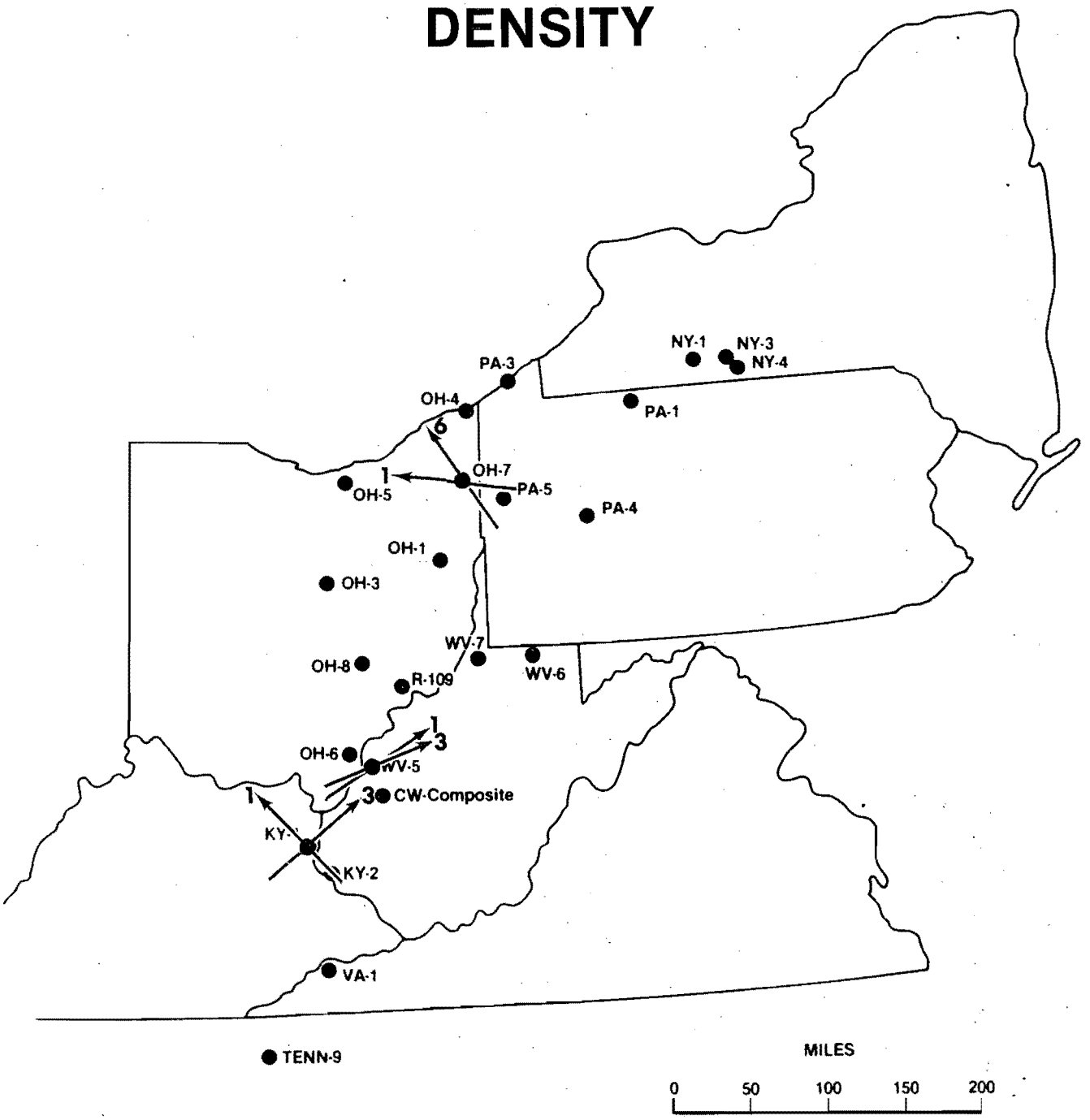
Map Unit 14

FIGURE 203

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



LATE UPPER HURON TIME

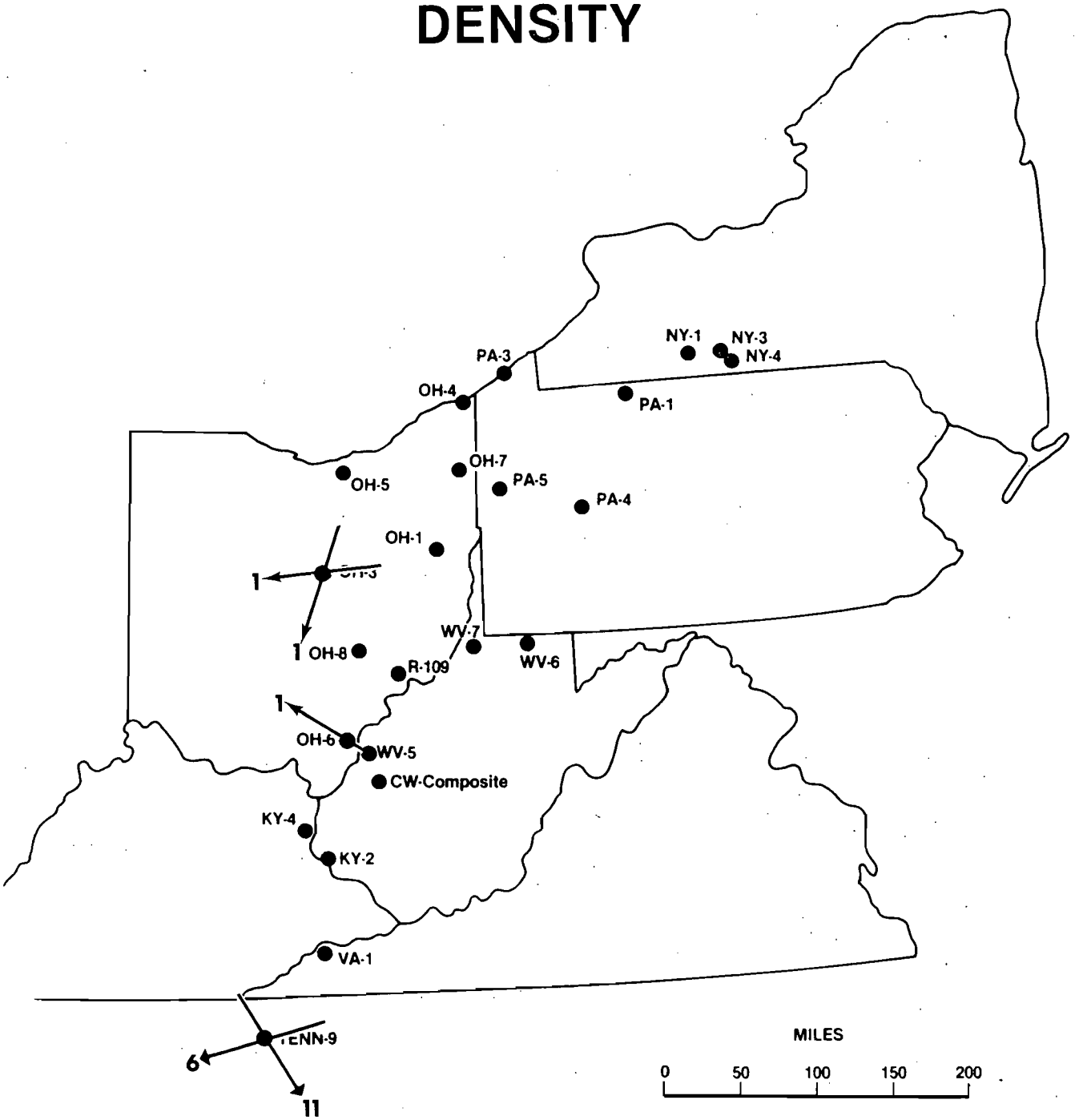
Map Unit 15

FIGURE 204

MOUND

Prepared by Mound Facility

FRACTURE ORIENTATION AND DENSITY



CHAGRIN-CLEVELAND TIME

Map Units 16 & 17

FIGURE 205

MOUND

Prepared by Mound Facility

NUMBER OF FRACTURES IN CORES FROM EGSP WELLS

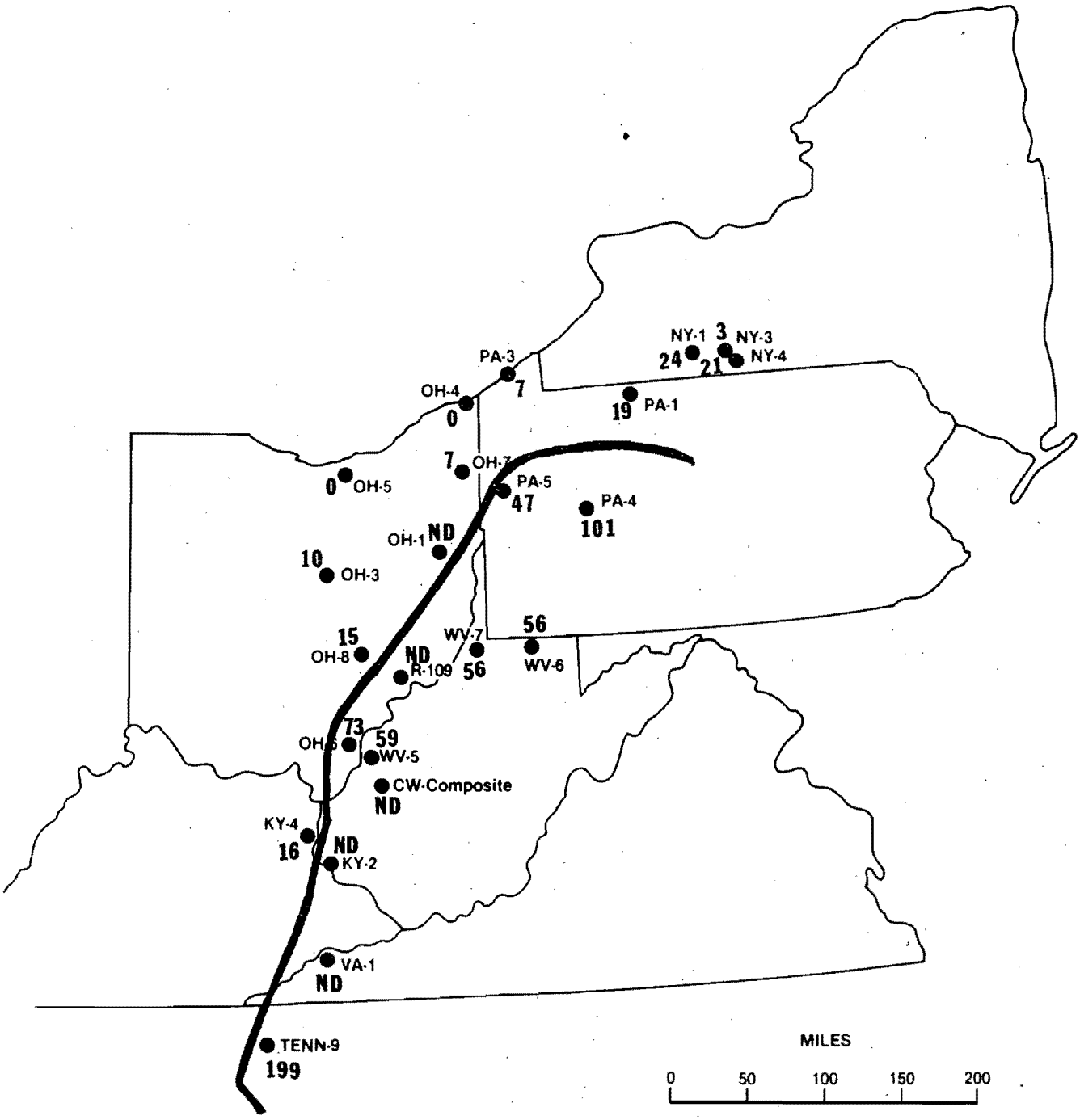


FIGURE 206

Prepared by Mound Facility

along a strip 50 miles either side of the Ohio - West Virginia boundary, and into central-western and west-central Pennsylvania. This is west of the more favored zone indicated from structural studies (Figure 190), and suggests that the "Y"-shaped favored zone is but the core for a broader favored area that lies east of the broad line in Figure 206. Where this coincides with the better geochemical facies, exploration emphasis should be placed. Note, too, that in the southern end of the Appalachian Basin the more highly fractured cores come from an area where stress ratios are in the range 0.3 to 0.5 (77). However, the fracture data from cores suggests that natural fractures will be more concentrated along and up to 50 miles west of the Rome Trough (on either side of the Ohio - West Virginia line), into central western Pennsylvania, rather than northward west of the Ohio - Pennsylvania line as suggested earlier from stress ratios (78).

Porosity and Permeability

From the previous discussion on organic geochemistry, the organic matter in the eastern Devonian Shales has been described as organically rich, oil prone kerogen which in some areas has not matured sufficiently to realize its peak potential but in other areas catagenesis should have occurred to a sufficient degree that significant quantities of liquid petroleum should have been generated. The fact that these huge reservoirs of petroleum do not exist in the shales is a dilemma of significant consequences.

Classical petroleum source rocks are typically fine-grained sediments rich in clay minerals. Originally these rocks had high porosity and as a consequence of age and greater depth of burial their porosity was gradually reduced. This compaction as it reduced pore volume forced from the rock the substances capable of fluid movement and thus primary migration occurred. This phenomena is essential for the formation of petroleum and is the process that distinguishes a true oil source rock from a potential source rock. In a true oil source rock as more and more of the newly formed oil migrates from the source rock a non-equilibrium process is in effect and as new hydrocarbons are formed from the kerogen they continue to migrate as long as a channel for movement exists. Once the migrating oil droplets reach a permeable zone, secondary migration occurs as the petroleum coalesces and moves as a continuous phase in response to buoyancy or hydrodynamic gradients. When the channel is eliminated the petroleum generation process still occurs, however, since there is no possibility for movement the petroleum and gaseous hydrocarbons remain in place causing an increase in in-situ pore pressure and a concurrent decrease in process kinetics until a quasi-equilibrium condition occurs. At this stage, because of the over-pressure condition, a significantly larger amount of energy is required to produce petroleum than can be supplied by the overburden pressure and in-situ temperature. At this point in the process the rate of compaction and consequently the overburden pressure and in-situ temperature rates of increase are reduced to such a degree that no new product is formed. If tectonism occurs and the matrix becomes fractured, the existing product migrates out and additional hydrocarbons are formed. If a tectonic event does not occur, the trapped product inhibits further production or slows it to an infinitesimal rate.

In calcareous sediments, primary migration probably does not occur or only involves short distances. In these sediments the initial oil forming process occurs but the hydrocarbons essentially remain in the already cemented rock. As the trapped hydrocarbons are refined into low molecular weight liquids and hydrocarbon gases, the hydrocarbon gases have a higher possibility of migrating through the low porosity and if migration does occur more material is available for gas formation and thus an oil prone kerogen becomes a prodigious gas source. If the migration of the gaseous product is inhibited because of the low porosities and permeabilities of the source rock a quasi-equilibrium

type condition is again set up where the isolated porosity essentially becomes overpressured and little if any additional generation occurs.

The identification of the depositional environment is an important factor in determining the true source potential and reservoir capacity of the shales. The depositional environment can provide important information concerning the distribution and continuity of porosity and permeability. The information concerning the depositional environment is that which is used to analyze the response of certain geophysical logs and once the correlations are reasonably fixed, depositional environments can be deduced for wells from log responses. Unfortunately, because of program constraints, detailed sedimentary analyses were not performed on all core samples. However, a sufficient number of analyses were performed to provide an overview picture of the basin.

The texture of the sediment is the first factor that needs to be characterized. Particle size and sorting are the most useful attributes of texture.

Particle size of sediments is usually classified according to the Wentworth-Krumbein Scale (Figure 207). Samples from a number of shale cores were subjected to particle size analysis. Analyses were performed on three different groups of samples: Inorganic particles, kerogen, and composite samples. For these analyses both settling velocity and microscopic techniques were employed.

These analyses indicated that the kerogen particles ranged from 210 μm to 0.1 μm in size, while the inorganic particles ranged from 120 μm to 0.75 μm. The composite sample plot is shown in Figure 208. For comparative purposes a plot of the particle size distribution from a sandstone reservoir is also shown in the Figure. This comparison dramatically illustrates the difference in particle sizes for a classical reservoir compared to the Devonian Shales.

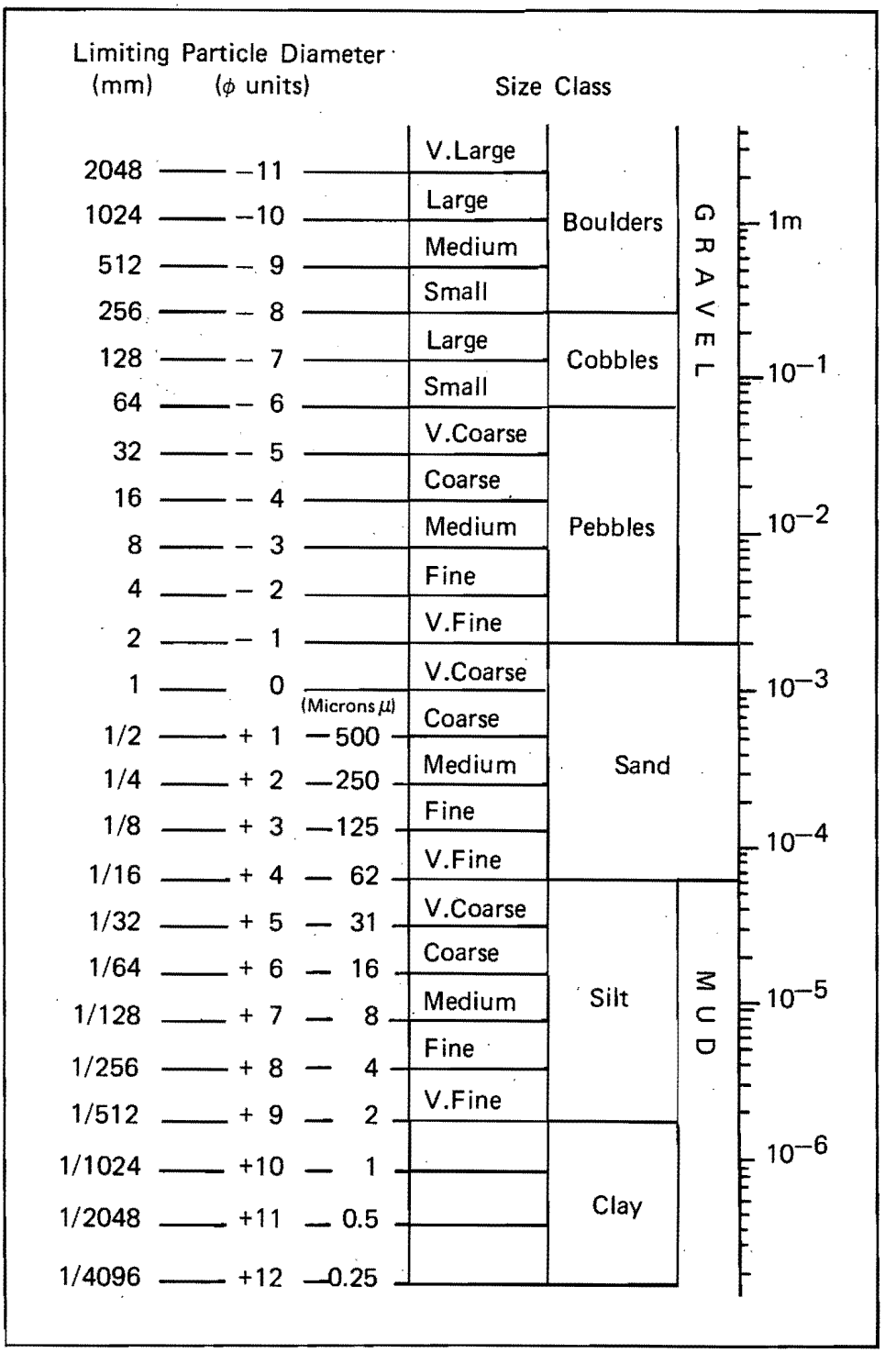
The sorting coefficient, S_o, for the Devonian Shales can be determined by:

$$S_o = \sqrt{\frac{P_{25}}{P_{75}}}$$

where P_{25} and P_{75} are the particle sizes at 25% and 75% respectively. The sorting coefficient, S_o, is 1.70 for the Devonian Shales.

The median particle size is 6.9 μm and the standard deviation is 1.41 μm.

A sorting coefficient of 1.70 would be classified as moderate sorting of particles. A value of 3.00 would be classified as poor sorting, this category is not atypical for other shales.



Modified Wentworth-Krumbein Sediment Scale

FIGURE 207

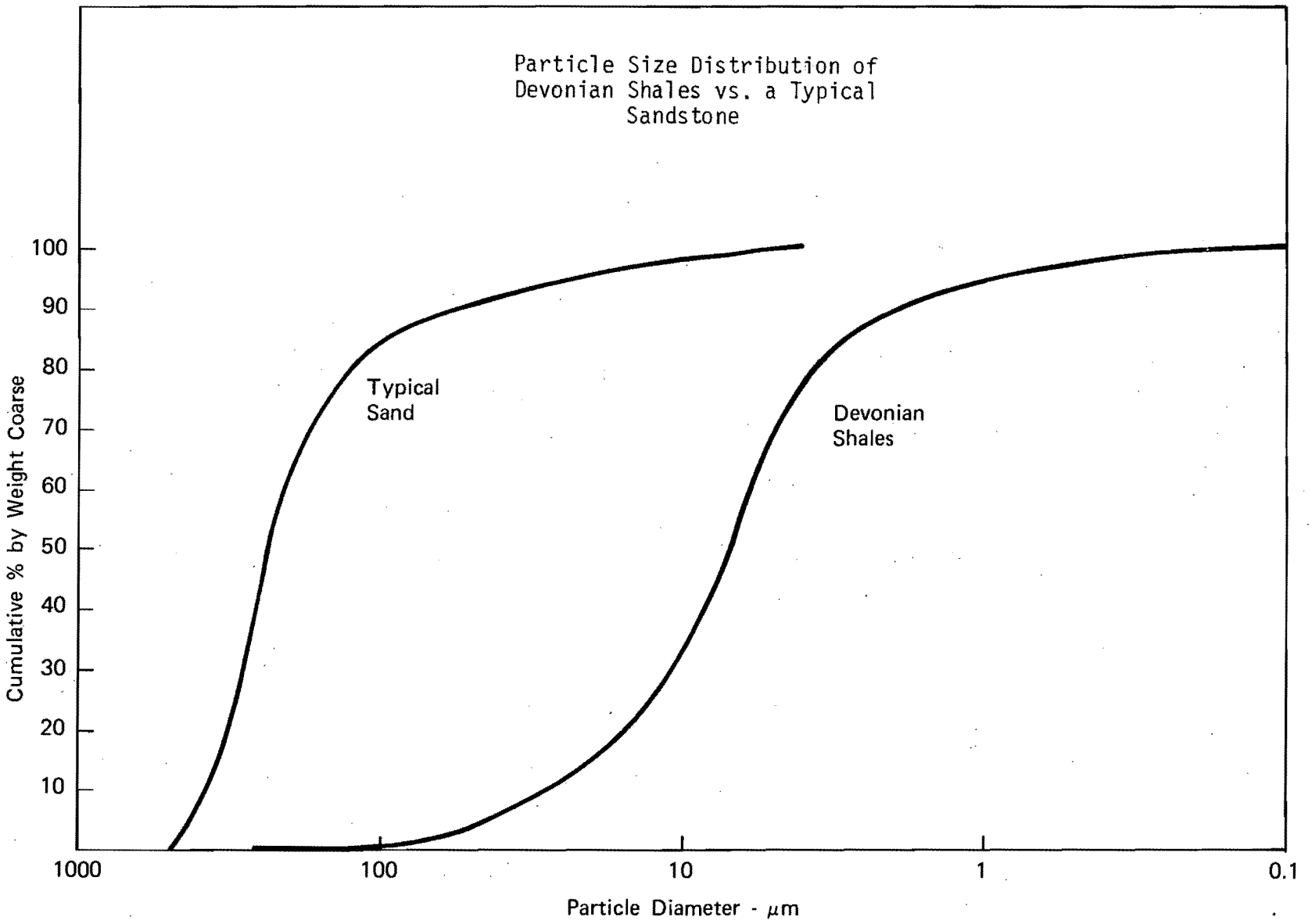

Particle Size Distribution of
Devonian Shales vs. a Typical
Sandstone
Cumulative % by Weight Coarse
100
90
80
70
60
50
40
30
20
10
Typical
Sand
Devonian
Shales
1000
100
10
1
0.1
Particle Diameter - μm

FIGURE 208

With the particle size being so small in a shallow sea such as the Devonian was, plane bed sedimentary structures would be common, and this is indeed what the cores indicate. The core samples exhibit predominantly horizontal laminae which would indicate sediment settling with little or no movement, essentially a low energy state of deposition.

The initial porosity, pore geometry and permeability of a sediment are controlled primarily by grain-size distribution. Other textural properties such as grain shape, packing and orientation have minor influence on initial porosity and permeability. Beard and Weyl (79) have shown that initial porosity is dependent almost entirely on sorting and is essentially independent of grain size. Initial permeability, on the other hand, is a function of both grain size and sorting.

Beard and Weyl also performed a series of experiments to determine the porosity and permeability of artificially mixed wet and packed sand of different sizes and sortings. Figure 209 is a modified presentation of their results. If the Devonian shale information is interpreted in light of this Figure, it can be concluded that at initial deposition the porosity of the sediment was large ($42\% < \phi < 44\%$) while the permeability was low (~ 18 millidarcies). A mathematical treatment of Beard and Weyl's data would indicate a permeability of 21 millidarcies for a mean grain size of 6.9 μm in the Devonian Shales. This indicates that while the shales had high initial porosity most of it was isolated.

This situation would result in a condition where diagenesis and catagenesis would occur but would be restricted in degree because primary migration would be restricted due to the low initial permeability. This situation is further enhanced by compaction and cementation. In the Devonian Shales carbonate forms a pore-filling cement (66) which would effectively reduce the porosity and the primary effect of compaction is the reduction of porosity.

The ultimate effects of compaction and cementation on the Devonian Shales are shown in Figure 210. This Figure is a cross plot of the effective porosities and in-situ permeabilities parallel to bedding of the Devonian Shales core samples that had no fractures or mineral filled lenses as determined by X-ray analysis. The Figure indicates that initial porosities and permeabilities are significantly reduced. When the data from Figure 210 are compared with that from Figure 211, which represents a cross-plot for a typical sandstone reservoir, the differences (orders of magnitude) put into perspective why the Devonian Shales are an unconventional, "tight" reservoir - little or no migration can occur through the Devonian Shale matrix.

The permeability perpendicular to bedding was determined to be two to three orders of magnitude less than in the parallel direction, so that no upward migration of hydrocarbons was possible in the tight unfractured matrix.

In the core samples that had natural fractures or mineral lenses present, permeabilities ranged from 10^{-2} to 10^{-4} darcies. This is the

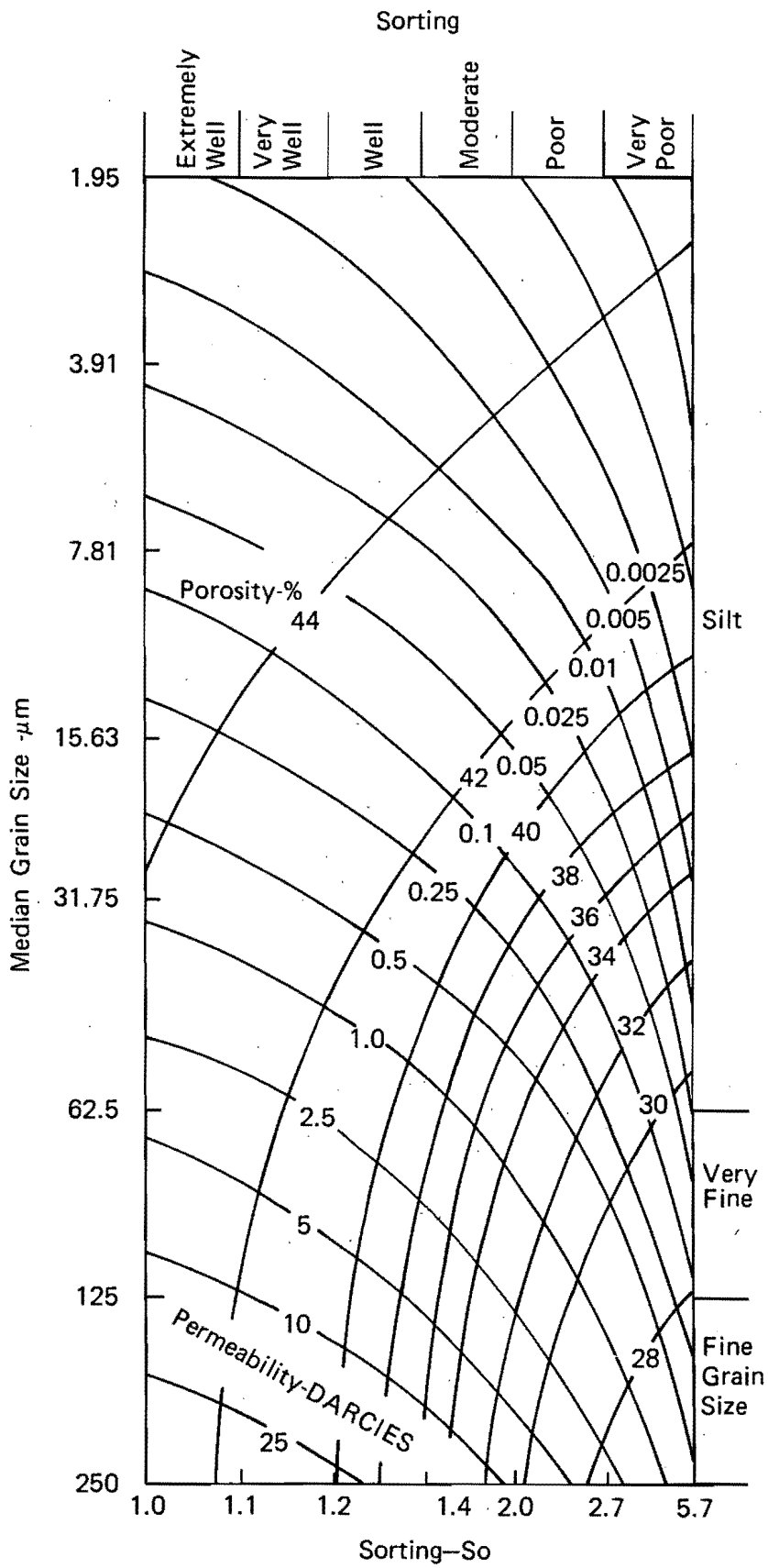
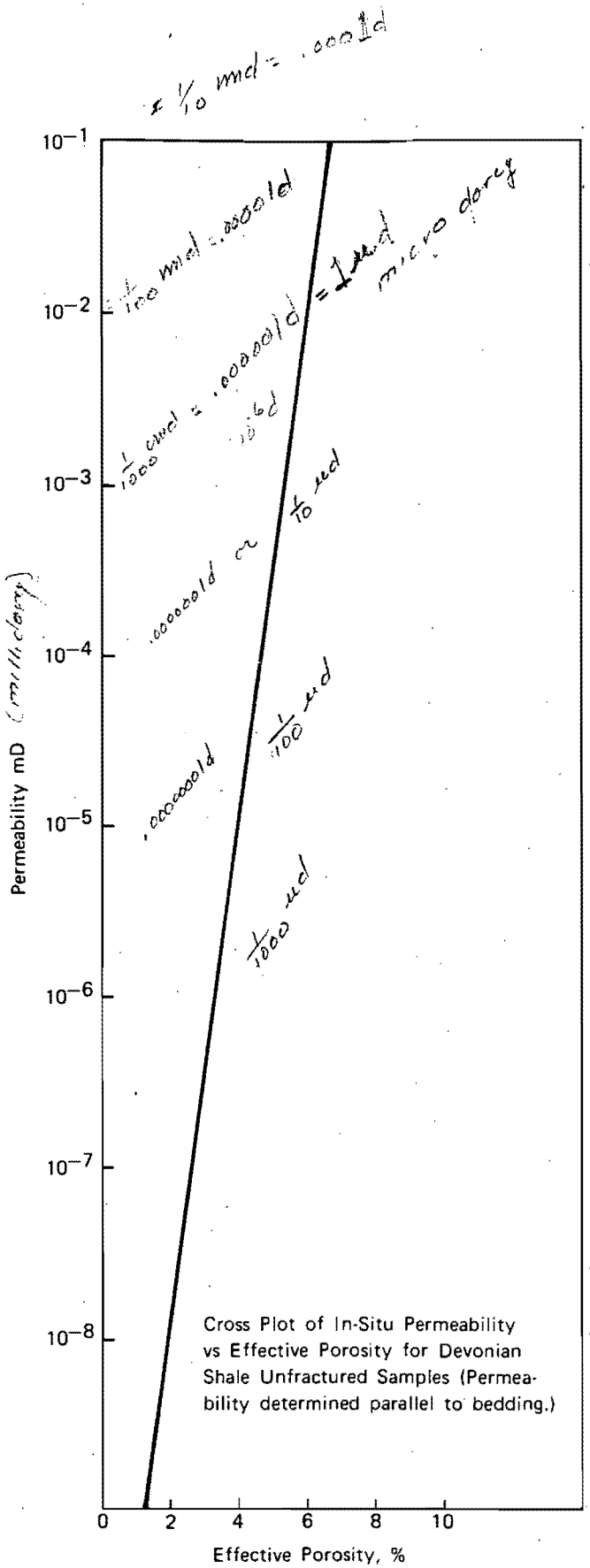

Sorting
Extremely Well
Very Well
Well
Moderate
Poor
Very Poor
1.95
3.91
7.81
15.63
31.75
62.5
125
250
Median Grain Size -μm
Porosity-%
44
42
40
38
36
34
32
30
28
25
0.0025
0.005
0.01
0.025
0.05
0.1
0.25
0.5
1.0
2.5
5
10
Permeability-DARCIES
Silt
Very Fine
Fine Grain Size
1.0
1.1
1.2
1.4
2.0
2.7
5.7
Sorting—So

FIGURE 209



Cross Plot of In-Situ Permeability vs Effective Porosity for Devonian Shale Unfractured Samples (Permeability determined parallel to bedding.)

FIGURE 210

Cross Plot of Permeability vs Effective Porosity for a Classical Sandstone Reservoir

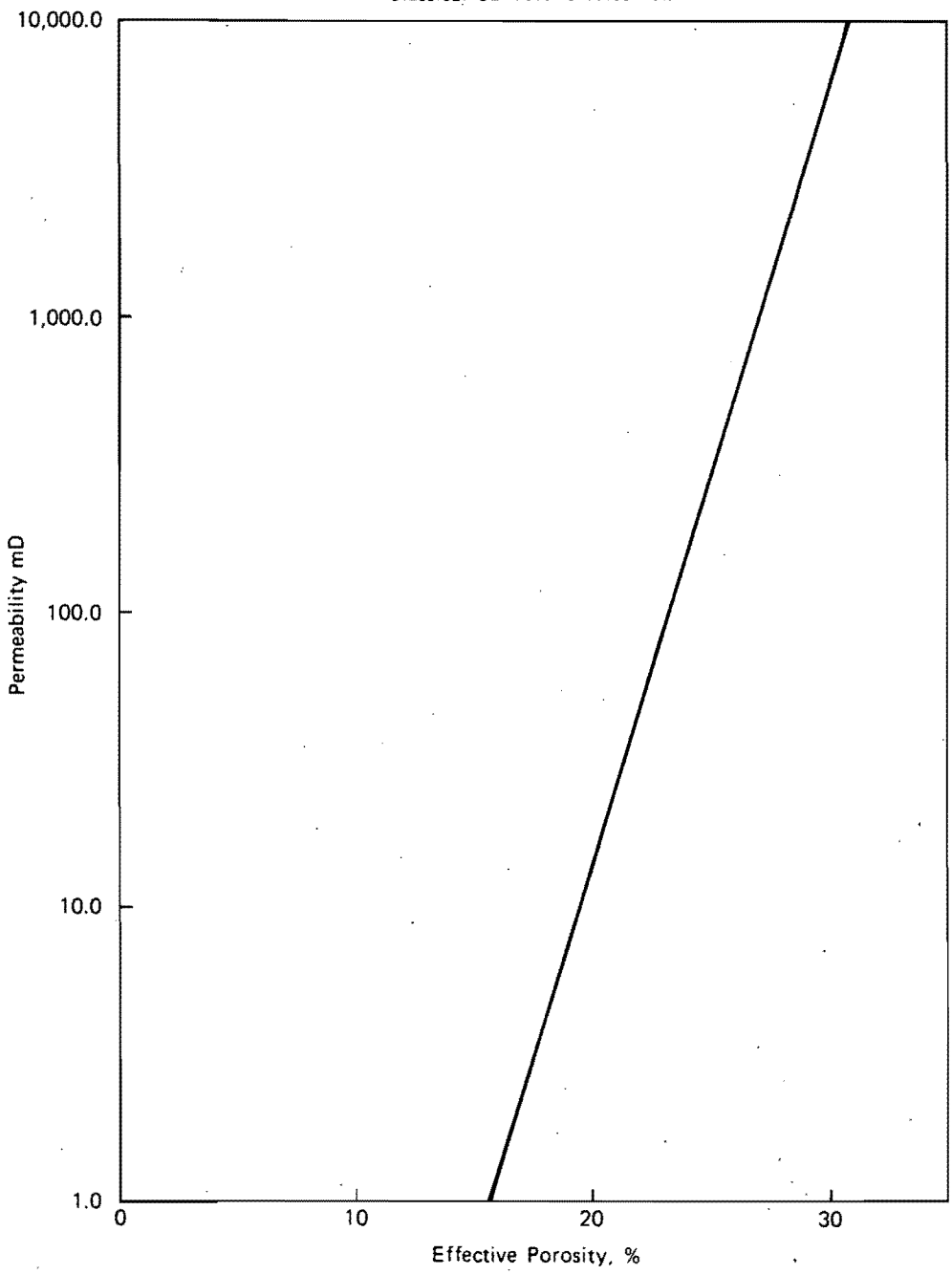


FIGURE 211

reason why the naturally fractured zones in the shale must be located to maximize production.

In summary, the sedimentary pattern of the Devonian Shales set up a very atypical situation where source and reservoir are essentially synonymous. Because of the extremely low permeability and porosity of the shales, even though hydrocarbon generation was occurring it occurred at a more reduced rate than common in other source rocks because migration was impeded. This resulted in several geochemical anomalies.

These anomalies would include: the scarcity of liquid hydrocarbons; the significantly large quantities of hydrocarbon gas in immature sediments; the lack of reservoirs in the classical sense; and the shifting of standard geochemical interpretations.

These anomalies can be addressed by the following explanation:

The nature of the hydrocarbon product which will ultimately be produced by any unit volume of the shale is determined by the organic assemblage it contains. The make-up of the organic matter is controlled by the environment of deposition and the biofacies. Algal and amorphous kerogens have the capacity to produce a higher proportion of liquid hydrocarbons (oil) than does herbaceous kerogen. This in turn has a greater capacity to generate oil than does woody or coaly varieties, with which frequently only gas is found. Moreover, there is a progressive change from naphthenic petroleums with amorphous-algal kerogens, to more paraffinic oils as the proportion of terrestrial (herbaceous and woody) organic matter increases.

In conventional source rocks, production of the potential products proceeds progressively - from very early microbial gas, to early catagenic gas, to light liquid hydrocarbons (condensate) and more gas, to heavier liquids (oil) and more gas, and finally to dry methane gas - as the temperature of the rock increases or as the length of exposure of the rock to the heat increases. The combined effects of time and temperature, sometimes referred to as the time-temperature integral, are revealed by the coloration of components of the kerogen and is expressed as the Thermal Alteration Index (TAI). The hydrocarbons associated with a rock at a given TAI are almost always those products that would be generated at the corresponding point in the normal progression if the hydrocarbon products had steadily migrated away from their site of formation and maintained a non-equilibrium condition. This is almost always the case with more permeable, conventional source shales.

In the very impermeable Upper Devonian Gas Shales, it appears that the removal of products from the reaction sites was not accomplished as rapidly as necessary to allow the progressive formation of gas-oil-gas to keep pace with the time-temperature integral. In some instances even the very early microbial gas was immobilized to bring the organic system to near equilibrium. In other areas, combinations of relatively more permeable , interbedded silts, and fractures, allowed some of the hydrocarbons to escape so that the breakdown of the kerogen and other organic detritus proceeded to some degree toward the product mix anticipated for that particular TAI in the non-equilibrium situation.

Therefore, in any given volume of Devonian Gas Shale of the Appalachian Basin, the Thermal Alteration Index is not an absolute indicator of nature of the hydrocarbons that will be associated with the source rocks. Rather, it describes the limiting mixture of hydrocarbons that would be expected in that area if matrix hydrocarbons had continuously migrated out of the sources during catagenesis, compaction, lithification, etc. Because this migration has been retarded to some degree in most locations, the indigenous and associated hydrocarbons would be of a composition normally associated with less mature rocks.

Therefore, where the TAI is under 2, the source rocks have not produced significant quantities of either oil or gas via catagenesis; any significant gas or oil nearby would have to have migrated from more mature sources deeper in the basin. Where the TAI's are in the range 2 to 3, the products could range from exclusively gas (from microbial and very early catagenic processes) where the rocks have been virtually impermeable since shortly after deposition, to gas with condensate where there has been slow migration, to oil with gas where migration has kept up with hydrocarbon generation in the source. Of course, if the kerogen is predominantly Tasmanites, any oil would be of a naphthenic nature; if herbaceous or coaly, much more paraffinic.

Where the rocks are very mature, i.e., with TAI's at or near 4, the energy supplied to the mixture of organic types is probably so intense that the equilibrium retardation of the breakdown to methane is overridden. The restoration of non-equilibrium conditions and effects is accelerated as the pressure of the gas in the pores rises above lithostatic and the gas moves out of the rock laterally and upward. Even in the relatively impermeable shales of the Upper Devonian, it is doubtful that any significant gas or gas-generating potential remains after the Thermal Alteration Index of the host rocks rises above 4.

As can be seen from this explanation, in the Devonian Shales, classical geochemical criteria must be modified because of the overwhelming influence of the atypical sedimentary situation. Typically, the anomalously low permeability of the shales restricts the generation of hydrocarbons from a rich oil-prone kerogen at the appropriate temperature, to a disproportionately small amount of gas. Therefore, while organic geochemistry has characterized the Eastern Gas Shale as a potentially super-prolific oil and gas source, the majority of this potential, particularly that for oil, has not been realized because the uniquely low permeabilities and porosities have severely limited migration, which in turn has drastically restricted the chemical conversion of solid kerogen and asphaltenes into light liquid and gaseous hydrocarbons.

However, even with this severe reduction in realization of hydrocarbon-generating potential, the resource that was formed is still very large. It remains for the explorationist to locate the areas with natural fractures and with siltstone partings and fractures where relatively more migration from the source has allowed somewhat more of that potential to be realized. Once these sites are located and confirmed by drilling, effective stimulation treatments must be designed

to link natural fractures and silt stringers with induced fractures to form a well base for maximum production.

Discussion

While sedimentation was controlled in large part by large-scale plate tectonics and mountain building during much of the Upper Devonian time, the sought for link between organic geochemistry and structural geology did not emerge from these studies. Structure played only a secondary role in the control or organic facies. The contrasts in relief between the highlands and the basin determined sedimentation patterns and the volume of sediment by which the organic detritus was diluted. Apparently, some of the sedimentary material from the growing Appalachian Mountains had a profound effect in inhibiting the growth of the algae, Tasmanites. On the other hand, it can be speculated from the distribution of the facies, that conditions near the Cincinnati Arch, or perhaps even nutrients from the arch itself, favored the growth of Tasmanites.

While there appears to be no tie between structure and organic geochemistry, structure, obviously, was an important factor in controlling fracture distribution. The superposition of fractures, or of fracture-favoring trends, with the most favorable hydrocarbon source rocks should optimize the search for reservoired petroleum. On this basis, the combined results indicate the probability that the greatest frequency of new large naturally fractured gas accumulations in the Eastern Gas Shales will be discovered in northwestern and northern West Virginia, and southeastern Ohio, i.e., where the eastern edge of the better source rocks (and those thermally mature enough to have realized a significant fraction of their potential) overlaps the western edge of the more structurally disturbed shale. However, as the section on tectonic history discussed, the structural evolution of this basin was very complex, and there was a great deal of local tectonism superimposed on the regional events; therefore, local fracturing due to localized stress will have created many possible hydrocarbon-collecting fracture networks outside the most favored areas as well. Therefore, exploration should focus on the location of structures, however subtle, as the sites of greatest fracturing.

Of course, fracturing is the result of processes other than folding and bending of rock strata. Another cause is the stresses imposed upon the removal of overburden by erosion. When this overburden is removed and the sediments are unloaded, they expand and the incipient weaknesses in them become fractures and joints. The preceding stratigraphic studies showed the presence of a number of uncomformities and the possibility of many more throughout the Basin. These too could account for reservoirs scattered throughout the basin, many of which will continue to be encountered by chance.

Fracturing is also the result of compaction. As the volume of rocks is reduced with burial, their diagenesis involves the loss of water together with mineralogical conversions. Heterogeneities in the shale, with accompanying differentials in volume loss, would induce fracturing. In many cases, this kind of fracturing is characterized as irregular or conchoidal in form. This type of fracturing probably will not play an important role in alone creating potential reservoirs, but will add to the porosity networks created by the other two processes.

Moreover, these would also contribute to fracture networks created by stimulation projects, as well.

Future exploration will undoubtedly reveal a host of reservoirs of various sizes in the Upper Devonian Shales. Explorationists can improve their chances of discovering such accumulations by directing their attention to the many well known structural features of the basin and to more subtle, local structural features where fracturing would have been favored. The Big Sandy Field is an example of a continuum of fractures spread over large area in the shales. Other widespread networks are possible elsewhere in the basin. If they coincide with even more favorable organic facies, in areas of adequate thermal maturity, large reserves of gas, or even oil, would be possible.

After a potential structurally controlled prospect has been outlined, fracture trace delineation from aerial photographs is probably the best method to optimize the prospect. If surface fractures or fracture traces are abundant on or near the site, then the likelihood that there are subsurface faults is increased. Other things equal, a prospect with surface fracture traces would be more favorable than one without. Moreover, one with a series of intersecting traces would be preferrable to one with only parallel ones.

RECOVERABLE RESOURCE

Introduction

The objective of all studies of this type is to produce a value of recoverable resource. In fact the key objective of the DOE Program are to not only develop accurate estimates of gas-in-place but also a value of recoverable resources. In this light then, an attempt was made to establish a value of recoverable resources.

To put the problem in perspective, the recent studies by the National Petroleum Council (NPC) (26), and Science Applications, Inc. (SAI) (80) were reviewed. Both of these studies reported gas-in-place values and based upon production histories of Devonian Shale Wells projected values for economically recoverable resource.

Gas-In-Place

The NPC study determined that approximately 1,861 TCF of gas was in place in the Appalachian Basin's Devonian Shales, while SAI reported a maximum of 900 TCF was in place. Both of these estimates were principally based on off-gassing data accumulated early in the Eastern Gas Shale Program. The current study employed the most complete set of geochemical data available and evolved a value of 2579 TCF of gas-in-place in the Appalachian Basin's entire shale interval.

The NPC study further qualified its information by considering "available drilling area". In this phase of the study, the actual reserve area of the Appalachian Basin that could be drilled was reduced by 44 percent because of urban area restrictions and other non-available lands. Once this restricted area was estimated, the study multiplied the estimated in place resource value by 56 percent (the amount of land that could be drilled) to arrive at a revised in place resource estimate of 1,040 TCF.

In the current study, the estimates of "available drilling area" derived by NPC were utilized on a county basis and since an estimate of the amount of gas present in each county was known, each county was considered individually and a revised estimate of in place resource was made. This estimate considering only "available drilling area" is placed at 1,440 TCF or again at approximately 56 percent of the total gas in place.

The area not available for drilling is restricted because of institutional, cultural, topographic and other "discouraging" factors, however, these variables can be modified by the degree of demand and price incentives. Therefore, the 56% is a conservative lower limit and as price and demand increase, significant portions of "non-drillable" area can become "available drilling area". This is especially true since the "non-drillable" area contains a significant amount of in-place resource.

Recoverable Gas (Past Studies)

Having estimated the amount of gas in place the next logical step is to estimate the amount of economically recoverable resource. Since shale production mechanisms are not yet well defined and no generic reservoir model exists, the only basis for determining recoverable resource is the review of past production histories.

In their attempts to address recoverable resource both the NPC and the SAI study reviewed the production records of a large number of shale wells and because "shooting" technology is the dominant stimulation technology which has been employed in the shales, the production histories predominantly represent "shot" wells.

In shooting, the well is completed as an open hole and approximately 10 pounds of 80-percent nitroglycerin is used for each foot of shale section. Shooting as a technique is known to create small induced fractures but it can also potentially cause healing of existing fractures and some skin damage. The results of shooting are hopefully an increase in fracture density, however, there is no guarantee of a concurrent increase in fracture surface area. In the shales with their low porosities and permeabilities, the fracture surface area is the dominant factor that will influence long term production. Shooting therefore represents a base case technology.

Without the availability of an appropriate reservoir model for the shales, both the NPC and SAI rely on empirical equations to fit the existing data. Empirical equations do not necessarily include all of the factors affecting past, present or future performance. When this type of equation is extrapolated to either a new location or a future time, it is assumed that all of the factors affecting performance (except those variables in the equation, itself) have exactly the same cumulative effect at the new location or a future time. If a large enough data base is developed, then this type of approach could evolve patterns that may be qualitatively correlated with identifiable reservoir characteristics. However, there are some external influences that can result in significant impacts on this type of analysis. Operating policy, the market, production techniques and workover treatments are major factors affecting production histories especially in Devonian Shale wells. If a well is shut in for a number of months during a year, the total production for that year will be significantly different than the total production of a well that was produced for the entire year. This situation is best illustrated by Figure 212. This Figure represents the results of a study of the production histories of forty shale wells located in Lincoln and Wayne Counties, West Virginia. The annual production of the forty wells was monitored for fifteen years and the production for the wells was totaled by year. The variability that was observed by year was the result of external influences. The degree of variability is shown in the Figure. If this sensitivity is not applied to the analysis of the cumulative production of the wells, erroneous conclusions will result. This is why measured production rates are more important than cumulative production for analysis purposes. If a well is produced against a back pressure as opposed to one that is not or another that is produced against a different back pressure, then production rates as well as cumulative production will be different. If a well is worked over as opposed to one that is not, different production rates and cumulative

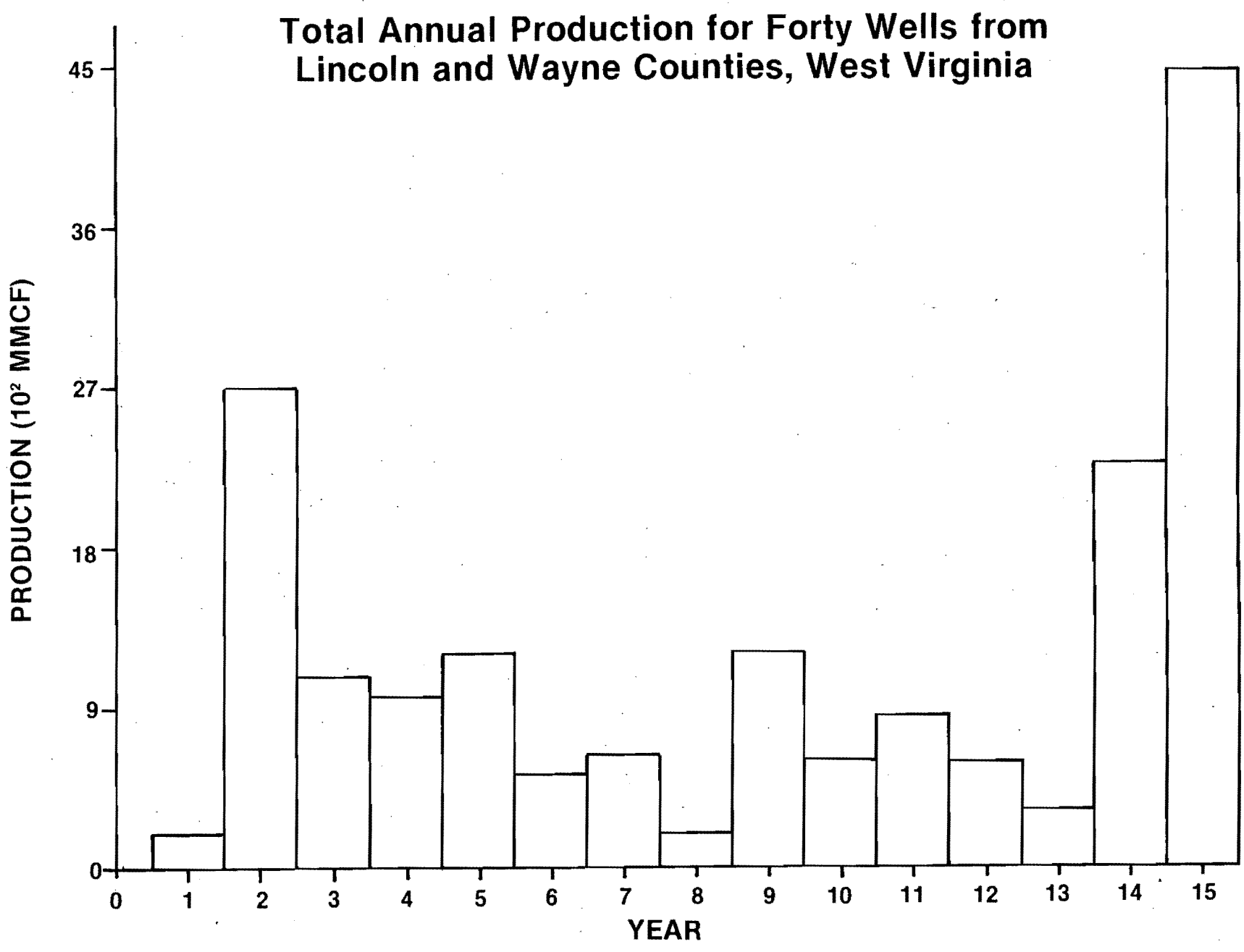

Total Annual Production for Forty Wells from
Lincoln and Wayne Counties, West Virginia
PRODUCTION (10² MMCF)
45
36
27
18
9
0
0
1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
YEAR

FIGURE 212

productions will result. All of these scenarios can also result in physical changes to the reservoir which will have long term effects.

For the above reasons then, it becomes obvious that any rigorous treatment of production data to define or extrapolate to recoverable resource must address all the variables that affect production for each well and there is a danger in extrapolating production curves indiscriminantely over either the long term or widely separated geographic areas.

Following the determination of gas-in-place, the NPC study then proceded to review Existing Production Technology to accumulate a resource base on production for Devonian Shale wells by county.

Their production rate or decline curve analysis utilized a hyperbolic equation:

$$\text{Production Rate (PR)} = C_1 \left[1 + \left(\frac{C_3}{C_2} \right) t \right]^{-1/C_3},$$

(MCF/D)

where PR is the production rate in MCF/D and t is the time in years. C_1 represents the initial production rate in MCF/D at time (t) = 0. C_3 is a dimensionless constant and C_2 is a constant with the dimension of years.[3]

The intent of the study was to characterize the average well decline curve for each county by developing a set of values of C_1, C_2, and C_3 for each county. However, as they reported, "All county decline curves could be reasonably represented by common values of C_2 and C_3 held at 3 and 2.5, respectively." When this was done the Production Rate Equation became:

$$PR = C_1 \left[1 + \left(\frac{5}{6} \right) t \right]^{-2/5},$$

and the average decline curve for each county could be characterized by a single parameter, C_1.

The study then pointed out that an attempt was made to correlate C_1 with physical parameters of the shale and the only correlation found was that with the thickness of the black shales as determined by the gamma-ray logs. The correlation was:

$$\bar{C}_1 = (0.213)\ (T_{avg} - \text{of black shale from } \gamma\text{-log}).$$

In this study, there was no attempt to quantify the organic richness of the black shale and all thicknesses with a gamma-ray radiation greater than 230 API units were considered in the total thickness.

The NPC study also calculated a table of cumulative productions for years based upon the single parameter C_1. This table was assumed to be calculated in the following manner:

10 year cumulative production (MMCF) =

$$C_1 \left[1 + \left(\frac{5}{6}\right) (10) \right]^{-2/5} (365 \text{ D/yr}) \ (10 \text{ yr}) \left(\frac{\text{MMCF}}{10^3 \text{ MCF}} \right).$$

The equation yields a 10 year cumulative production (MMCF) = 1.494 C_1. The calculated multiplier of C_1 is significantly different from that reported by NPC. Table 4 lists the NPC reported multipliers and those calculated using the reported equation. As the table shows a significant deviation exists between the reported values and the values that the equation actually produces. The significance of this discrepancy whether it is a result of the determination of the values of the constants in the equation or simply a mathematical error cannot be addressed without a complete review of the NPC data. Since the equation was used as the basis for extrapolation in the NPC study, it is important to identify any changes that might result.

In evaluating the NPC study several comments need to be made. First, the NPC study derived an equation that is quite different than that commonly used for estimating hyperbolic decline and its insensitivity to physical parameters should be addressed. Hyperbolic decline curves appear to be applicable to gas production decline in the Devonian Shales (81) and the classical equation governing this type of decline can be expressed as:

$$PR_t = (PR_o) \ (1 + n \ D_o t)^{-1/n},$$

where $0<n<1$. In this equation PR_t is the production rate at time t, PR_o is the initial flow rate, t is time in months, D_o is the initial rate of decline, month^{-1} and n is the exponent which controls the decline curve and is an implicit function of the composite operating porosity, permeability, resource potential, and local geology.

The value of n has to be determined for each reservoir. One way to obtain this value is through computer reiteration of the data until a value for n is determined. To avoid the use of the computer, Bass (81) has constructed a series of hyperbolic curves for various values of n. In order to determine n, production data are plotted on the curves until a straight line is obtained, then the value of n is fixed for that reservoir. Once this value is determined, D_o can be calculated:

$$D_o = \left[\left(\frac{PR_o}{PR_t} \right)^n - 1 \right] \Big/ (nt).$$

Cumulative production can now be calculated by:

$$CP = \left[\frac{PR_o}{(n-1) \ D_o} \right] \left[\left(\frac{PR_o}{PR_t} \right)^{n-1} - 1 \right],$$

for $0<n<1$, or

$$CP = \left(\frac{PR_o}{D_o} \right) \ln \left(\frac{PR_o}{PR_t} \right),$$

for $n=1$.

TABLE 4

Relationship of C_1 to Cumulative Production from NPC Study

X Cumulative Production (MMCF)	Y C_1
1st yr. cumulative production (MMCF)	= 0.32 C_1
10 yr. cumulative production (MMCF)	= 2.06 C_1
20 yr. cumulative production (MMCF)	= 3.36 C_1
30 yr. cumulative production (MMCF)	= 4.43 C_1

Calculated Relationship of C_1 to Cumulative Production

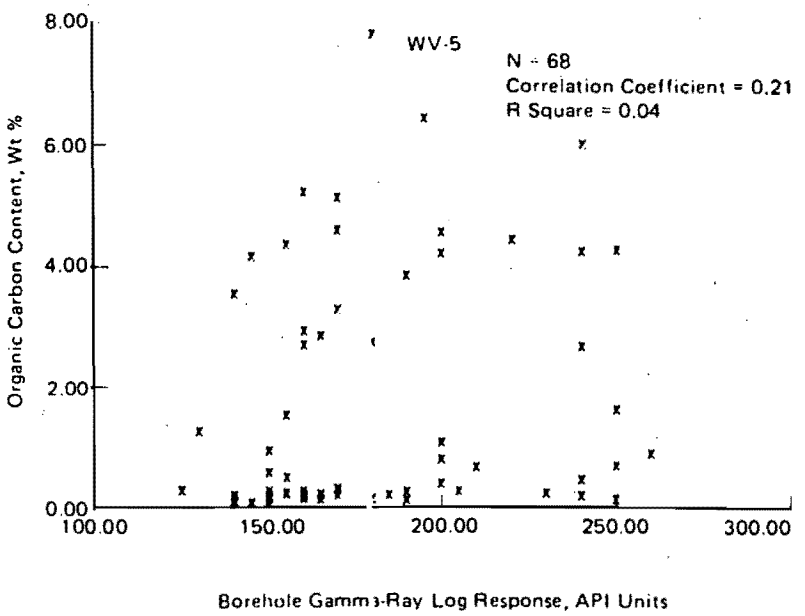
X Cumulative Production (MMCF)	Y C_1	Deviation from NPC
1st yr. cumulative production (MMCF)	= 0.286 C_1	-10.6%
10 yr. cumulative production (MMCF)	= 1.494 C_1	-27.5%
20 yr. cumulative production (MMCF)	= 2.315 C_1	-31.1%
30 yr. cumulative production (MMCF)	= 2.975 C_1	-32.8%

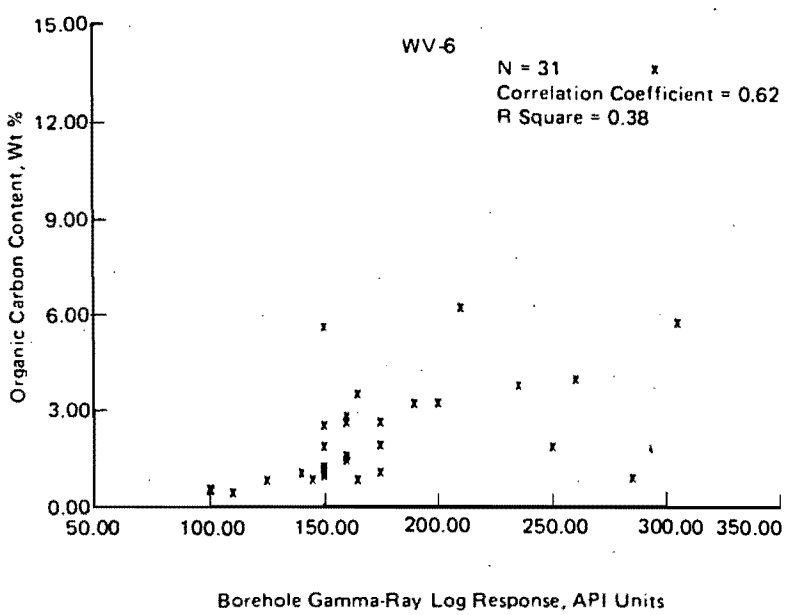
Aquilera (81) has pointed out that decline curves are not generally used for evaluating gas reservoirs; however, the hyperbolic decline curve with n=1 seems useful for evaluating Devonian shales. This comment apparently was based upon the examination of a limited set of data from some West Virginia wells. Caution must be used in simply extrapolating this comment to other portions of the basin where source, potential, richness, porosity, permeability, geology and especially the natural fracture systems are different.

The NPC observation that C_1 was related only to black shale thickness also merits some comment. In some early studies performed for the EGSP, no correlation was found between gamma-ray log response and either the organic richness of the shales or the gas content (Figures 213 and 214). The gamma-ray log does not indicate organic matter type or maturation and consequently does not indicate potential. The fact that C_1 correlated with black shale thickness had to do with the selection of the variables for examination: black shale thickness as determined by gamma-ray logs, total shale thickness, sample black shale thickness and depth. From these variables only black shale thickness as determined by gamma-ray logs was the closest indicator of potential albeit a poor one and if the sample data set was large enough black shale thickness would correlate with initial production by default.

The most interesting point of the NPC study was that after performing the analysis on a county basis, it was found that the entire basin could be represented by one equation. Since all the production data for a large number of wells, assumedly representing the entire basin, were analyzed, it would be safe to assume that these wells had different geological, resource potential and production histories (dictated by policy and market) and yet they all seemed to converge into one empirical equation. This could have been serendipity or it could have a very important physical explanation. Since the greatest majority of wells analyzed were shot wells, the statistics for these wells should dominate the analysis. The singular fit of the data could be attributed to the basic nature of a shot well. In such a well, as stated above, the number of fractures and not necessarily the fracture area is increased. Following an initial high production rate through the fracture system, production should decline to a lower, more consistent rate. (This is essentially the basis of hyperbolic decline.) This long term, low production rate is influenced by the porosity and permeability of the matrix. Hydrocarbon gas must diffuse to the fracture surface where it can then be desorbed into the well bore. Since the porosity and permeability of the matrix are inherently low, as was shown above, production is then diffusion controlled.

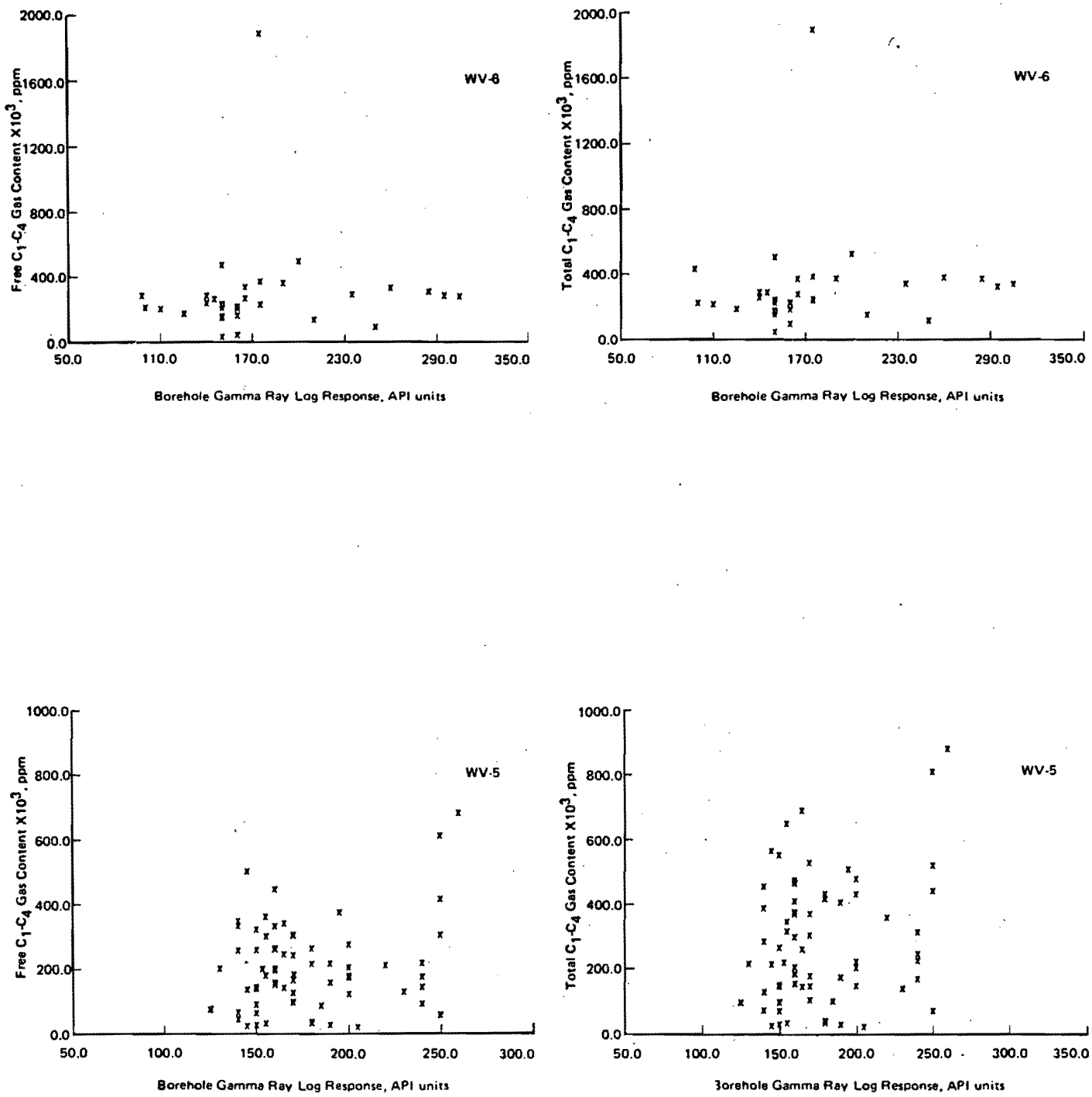
The fact that the depositional history of the shales was quite uniform, implies that the original matrix porosity and permeability values of the shale should be relatively consistent throughout the basin and therefore gas production dominated by only these parameters should be consistent. The NPC data, if they are indeed representative of production across the entire basin, have confirmed this. Using the depositional history of the shales and from that and along with the implications of the NPC study, then close well spacings can significantly improve production from the shales under a shot well strategy. Furthermore, spacings on the order of 80 or even 40 acres





ORGANIC CARBON CONTENT VS GAMMA RAY LOG RESPONSE FOR DEVONIAN SHALE WELLS

FIGURE 213



Hydrocarbon Gas Content vs Gamma Ray Response for Devonian Shale Wells

FIGURE 214

should be considered if it can be determined that the natural fracture system is such that no well to well interference would result.

In contrast to the NPC study, the study performed by SAI utilized a statistical approach to address economically recoverable resource. The first phase of this study involved the grouping of the counties of the Appalachian Basin into 10 clusters. The variables used for clustering purposes included: radioactive shale thickness, conodont alteration index (CAI), drilling depth, and stress ratio. Following the clustering, it was assumed that the distribution of production per well would be the same for all wells drilled anywhere in the cluster and then data were extrapolated to address production for the entire cluster. In order to determine recoverable resource, the study considered well spacing, data on the mean and variance of production and the success ratio in each cluster. Production data were available for only five clusters, for the other five clusters, the Delphi method was used to obtain estimates of the mean production. The Delphi method was also used to obtain estimates of the success ratio for all ten clusters.

The study assumed a lognormal distribution as the representative probability model for cumulative well productivity in each cluster and summed the results by cluster for the entire basin to obtain a value for total recoverable gas. This value was assumed also to be the economically recoverable gas.

The concept of clustering is a very viable approach if a complete set of effective variables is considered. For a Devonian Shale reservoir these should include organic matter type, organic richness, thermal maturity, porosity and permeability, and natural fracture systems, not averaged over the entire shale column, but only for the high potential zones or at least weighted by these zones if a per well value is to be produced.

As mentioned previously, radioactive shale thickness, conodont alteration index (CAI), drilling depth and stress ratio were taken as the effective variable by SAI. The choice of radioactive shale thickness was made on the basis that: "The National Petroleum Council (NPC), in their study of Devonian shales, found correlations between RST and initial open flows, and between initial open flow and cumulative production." This statement followed: "No definitive relationship has been established between radioactive shale thickness and gas production." As has been shown above the relationship that NPC found was heavily biased by their choice of variables and in fact there is no definitive evidence to show a correlation between RST and production.

The conodont alteration index (CAI), is one method of assessing the thermal maturation of a material. If it is a weighted average for the productive shale sections, it should indicate the diagenetic history of the shale.

The drilling depth and stress ratio could be inferred reflections of the geology and natural fracture systems present in the shale zone. The problem with the choice of these specific variables is that drilling depth does not reflect the actual stratigraphic system present and consequently does not reflect the thickness of the high potential zones. The stress ratio (the ratio of minimum horizontal stress to vertical stress) has only actually been determined for a small number of counties and for the purposes of this study

was extrapolated throughout the basin. Whether or not this extrapolation is valid can only be evaluated as more data become available.

Since the influence of three of the four principal variables, chosen by SAI, have no documented relationship to gas production; and since the fourth variable, maturity, without organic matter type and richness cannot imply potential, the results of the cluster analysis study are open to discussion.

Following the establishment of ten clusters, SAI proceeded to plot histograms of cumulative production for the clusters. As it turned out, the 1780 well-data set that SAI used consisted of wells from five of the identified clusters, the values for the other clusters were obtained by the Delphi method.

When looked at individually the production data from the five clusters on a county basis did not always indicate a log normal distribution visually nor more importantly, mathematically. Also in the analysis of the data, some clusters were approximated on the basis of data from only one county.

While their approach was sound, in actuality, SAI did not address the variables that influence gas-in-place and ultimately production, nor did they account for production influences such as market and policy. Since such a detailed analysis was probably beyond the scope of their study, but must be considered to achieve a reasonably accurate assessment of recoverable reserves, the merits of their study results cannot be assessed at the present time.

In summary then, the analysis of recoverable resource is not an easy task. The two recent studies performed on this subject, while sound in approach, did not consider the major influencing variables and consequently do not form a sound foundation for the estimation of recoverable resource.

Such a detailed study, necessary to assess recoverable resource, is not only beyond the scope of the current study but the data used by NPC are not available for review or analysis. The current study is also hampered by the lack of complete data and therefore only another gross estimate of the recoverable resource will be made.

The fact that the results of the NPC study were insensitive to region and that the entire basin could be characterized by one equation differed from the results of the SAI study which approximated production on the basis of different clusters. The SAI study did establish a log-normal distribution of cumulative production for the entire basin which in effect forced the same conclusion as the NPC study: All wells in the basin can be considered in one qualitative, empirical model.

Recoverable Gas (Current Study)

Since the NPC data were not available for review, but the SAI data were, the SAI data were reviewed from several different aspects to try to find correlative influences. This review was performed on the basis that all wells were drilled on 160 acre spacing. A correlation that evolved was production per area. The data available from the SAI study spanned fourteen counties located in Ohio, Kentucky and West Virginia. In Table 5, the county, the production per area and the resource in place per area are listed. From the Table, a correlation by state is obvious. The counties from Kentucky produced an average of 2.3×10^{-3} TCF/mi^2, while those from Ohio produced an average of 0.7×10^{-3} TCF/mi^2, and those from West Virginia produced an average of 1.5×10^{-3} TCF/mi^2. These production rates are apparently independent of resource in place. While it is important to note that as in the previously discussed studies no attempt was made to qualify these data by production practices, it also appears significant that the data can be correlated by state. If upon a more detailed study (beyond the scope of this report) it can be shown that production practices have not forced this relationship then the data appear to be a significant factor in assessing recoverable resource.

Recalling that these data represent production histories primarily for shot wells and assuming that no bias was built into siting the wells using remote sensing techniques, the production histories reflect the basic nature of the shales. Following the initial release of gas from fractures, production is controlled by the matrix porosity, permeability, and fracture connectivities of the shales and what is observed is production controlled by these parameters. Since permeability is somewhat independent of gas-in-place, no correlation between production and gas-in-place would be expected in the long term where ultimate recoverable resource would be influenced by the total in place resource. Only the rates of recovery are affected by these variables.

The fact that porosity and permeability influence production from shot wells was inferred in the NPC study which allowed the basin to be considered as a whole since the approach was insensitive to the small yet significant differences in the physical parameters. This fact was addressed in the SAI study which produced a value for recoverable gas as a function of well spacing.

Since the two recent studies and further analysis of the data from one of the studies indicate that production from shot wells is diffusion controlled over the long term (>10 yrs), then cumulative production should directly reflect the controlling production parameters. If this is true and if the production per area values can be verified as being consistent for larger sample sets than those currently available, then a base case recoverable value can be estimated. From the data that are now available, the gross assumption can be made that they represent the controlling production parameters for the individual states and if this is true then the recoverable gas based upon 160 acre spacing for the states of West Virginia, Ohio and Kentucky can range from 30 to 50 TCF. Since no data were available for New York and Pennsylvania, no estimate can be made for these states.

Ignoring new technology and assuming only shot well production and the fact that over the long term production from these wells is diffusion

TABLE 5
Production Histories
for "Shot" Devonian Shale Wells

State	County	Number of Wells	Production (TCF/mi^2)	Resource (TCF/mi^2)
Kentucky	Floyd	232	2.7×10^{-3}	2.14×10^{-2}
	Knott	72	2.1×10^{-3}	2.86×10^{-2}
	Martin	224	2.0×10^{-3}	1.93×10^{-2}
Ohio	Lawrence	29	1.1×10^{-3}	3.14×10^{-2}
	Licking	19	0.5×10^{-3}	2.69×10^{-2}
	Meigs	19	0.4×10^{-3}	3.23×10^{-2}
West Virginia	Boone	16	1.5×10^{-3}	1.21×10^{-2}
	Cabell	20	1.7×10^{-3}	2.14×10^{-2}
	Jackson	26	1.4×10^{-3}	2.14×10^{-2}
	Kanawha	10	1.8×10^{-3}	1.22×10^{-2}
	Lincoln	337	1.5×10^{-3}	1.42×10^{-2}
	Logan	121	1.1×10^{-3}	1.43×10^{-2}
	Mingo	206	1.5×10^{-3}	1.57×10^{-2}
	Wayne	156	1.3×10^{-3}	1.79×10^{-2}

controlled and that the porosity and permeability values of the matrix are low, then closer well spacings seem extremely advantageous. If the well spacing was set at 80 acres, the recoverable resource could be doubled up to the limit of gas in place in the area.

Again caution should be used in considering these values as quantitative estimates. They are subject to the same constraints as those imposed on the other studies and should be used with the realization that all the factors that concern potential and production were not integrated into the analysis. If a quantitative number is required, then a very detailed analysis of well histories is required. The Gas Research Institute (GRI) is currently formulating a well history data base for Devonian Shale wells, once this data base includes a representative set of wells for the entire basin, then detailed analysis considering all factors of potential and production can be performed and more realistic quantitative estimates of recoverable resource can be made.

The analyses made to date in all three studies include only shot wells that were randomly sited. To improve the recoverable value for a well, two technologies should be investigated. The first is remote sensing technology. Since ultimately production from a shale well is controlled by matrix diffusion and desorption from the free fracture surface area of the shale, if areas with a great degree of natural fracturing can be located, these would present the ideal locations for wells. A well sited in such a location would not only have a higher initial production rate because of the drainage of the fracture system, it would also produce more gas during the long term since increased fracture surface area would allow desorption of the gas that diffused to a greater free space (larger surface area) to occur at a higher rate. Thus, production would be enhanced since the flux rate of the gas would be larger because of the increased surface area.

The other technology that needs to be investigated is the improvement of stimulation technologies. Since fracture surface area is perhaps ultimately more important than number of induced fractures, techniques that result in the increase of fracture surface area will lead to increased production. The physical reason for this is that even though production is ultimately controlled by the diffusion of gas from the matrix to a free surface, the larger the surface area, the greater the flux of gas from the free surface to the well head, and consequently the greater the production rate. Techniques such as foam fracturing, tailor pulse loading, nitrogen gas frac, and hybrid technology do hold great promise for improving the gas recoverable rate from the shales.

These techniques are beginning to find more acceptance in the shales. A gross example of the value of these techniques and their improvement on recoverable gas can be demonstrated by the examination of a small set of production histories for stimulated wells. Five year production histories were available for six wells from Kanawha County, West Virginia. These wells were stimulated using water frac, aleogel, gelled water, methanol and gelled water, CO_2:LPG:Methanol, and nitrogen gas frac and the five year recovery rate for the wells was $3.5 \times 10^{-1} \pm 1.5 \times 10^{-1}$ TCF/mi^2, as opposed to 1.8×10^{-3} TCF/mi^2 calculated for the shot wells in this same county. So the new technologies should markedly improve gas production from the shales. The

estimate of quantitative improvement, however, cannot be evaluated at the present time.

One of the key issues that still remains in the assessment of the Eastern Gas Shales is the definition of gas production from the shales. Until that issue is adequately addressed. there can be no generic production model or consistent fracture analysis models. Since this issue has defied quantification from laboratory studies and from an examination of actual production data, it remains as one of the key goals of an Eastern Gas Shale Program. Because it has not been solved or adequately addressed by secondary methods, it must be addressed directly. The Eastern Mineback Program is idealy suited to solve this issue along with providing actual in-situ evaluation of fracture treatments and the effects of other variables on an actual reservoir. Only after the completion of this type of directed effort will a generic shale reservoir model be available as well as fracture analysis models so that the most effective recovery techniques can be applied to the shales.

Discussion

An evaluation of the recent NPC and SAI reports has identified shortcomings in the approach of both studies to produce a quantitative value of recoverable resource. The current study is also subject to those same shortcomings. There is the indication that production from shot wells is diffusion controlled and because of this, closer well spacings should be considered to improve recovery. The fact that the resource in-place number is so great would indicate that ultimate recovery would be improved by the closer well spacings.

The influence of natural fracture systems and the area of fracture surface on the production of gas from shale is very important to production rates and overall recovery. To address these issues remote sensing techniques and new stimulation technologies must be adequately investigated.

There exists no accurate generic reservoir model for the shale and this is an important shortcoming. To address gas production mechanisms, effects of other variables on gas production, and the effects of stimulation technologies on gas production in an effective manner in the near term, in-situ experiments must be performed since the interaction of all important variables on these parameters cannot be adequately addressed by secondary laboratory experiments and unqualified production data.

The estimate of minimum recoverable resource has been established at 30 to 50 TCF. While these numbers are qualitative at best, they do serve to fix a minimum value. It is hoped that the balance of this study will serve to increase the success ratio for new wells. Also if well spacings are reduced in areas that are not highly fractured and remote sensing techniques are utilized to identify naturally fractured areas, the quantity of recoverable resource can increase significantly. New stimulation techniques can also result in enhanced production. It is important to remember that the in-place resource is tremendous and that improved engineering technology can only help to maximize recovery of this resource from the shales.

OTHER DATA

Gross Mineralogy

During the course of the analytical program,mineralogical analyses were performed on a select group of samples. This program did not allow for mineralogical analysis of every sample, but a sufficient number of analyses were performed to provide for representative cross sections across the basin.

The first observation that can be made concerning these data is that the compositional range is very broad even when the data are categorized by the same seventeen map units used in the other portions of this study. The data presented by map unit are listed in Table 6A. Table 6B lists the map unit terminology for reference purposes.

An examination of the data showed no well-defined regional trends even within singular map units. An important observation was that none of the samples contained montmorillonite; however, the mixed layer clays ranged from 0 to 24%. The iron rich minerals, ankerite and chlorite, also varied widely in composition, 0-10% and 0-12%, respectively.

No correlation could be made between mineral composition and either gas content or the organic geochemical factors.

The mineralogy results, however, do have application to drilling, completion and stimulation technology.

In a matrix where porosity and permeability are very low, formation damage must be minimized. This is especially true in shales where effective completions can be a problem, even in naturally fractured areas.

Acidizing treatments, if not planned to match formation mineralogy, can effectively damage the formation and destroy even natural permeability. This damage can be the result of fines plugging, precipitation, CO_2-gas saturation, or any combination of the three.

If CO_2-gas saturation is responsible for a loss in permeability, then as the gas is removed the formation permeability should eventually return, to its original value.

Since iron is a constituent of some of the minerals found in the shales and the concentration range varies widely, it is important to design proper field practices to avoid the precipitation of iron from spent acid solutions. This type of precipitate is an amorphous gel.

In the Devonian shales, the iron bearing minerals are ankerite, siderite, pyrite and chlorite. The iron in these minerals is in the form of the ferrous ion (Fe^{++}). These minerals will react with HCl and generate soluble iron. The minerals ankerite and siderite dissolve rapidly in HCl to release the ferrous ion into solution with CO_2 being a by-product. This reaction will proceed until the acid is consumed and equilibrium with the mineral is reached. No precipitates are formed. Pyrite will decompose very

TABLE 6A
Mineralogical Composition Ranges for the Devonian Shales

Mineral	MAP UNITS 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
Quartz	27-29*	31	17-33	N.D.**	23-37	43-44	29-43	9-34	31-42	28-50	30-40	8-32	31-40	37	32-53	24-27	48-59
Potassium Feldspar	0	0	0		0	0	0	0	0	0-1	0	0	0	0	0	0	0
Sodium Feldspar	0-4	3	0-7		0-4	0-9	0-13	0-13	0-9	0-15	4-12	0-9	4-9	0-11	0-11	5-11	11-19
Calcite	38-48	3	0-33		0-38	0	0-15	0-24	0-9	0-1	0-7	0	0	0	0	0	0
Dolomite***	4-10	0	0-9		0	0-9	0	0-3	0-6	0-1	0-7	0	0-12	0-4	0-6	0-6	0-6
Siderite	0	0	0		0	0	0	0-14	0-6	0-5	0	0-77	0	0	0-4	0-5	0
Pyrite	5-8	13	3-13		4-19	4-9	6-13	0-24	0-7	4-26	0-12	0-13	0-22	11	0-13	3-19	5-6
Montmorillonite	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0
Illite	9-11	34	22-43		16-28	26-28	28-31	24-38	25-37	23-31	20-30	10-45	24-43	31-35	19-32	28-42	13-23
Mixed Layer	1-4	7	0-11		11-16	5-15	0-13	4-20	10-24	2-16	5-21	5-14	6-18	3-9	0-21	6-14	2-5
Kaolinite	0	0	0		0	0	0	0-1	1-2	0-2	0-2	0-2	1-3	1-2	0-2	0-1	0-3
Chlorite	0-1	4	3-10		3-5	3	3-6	3-7	3-5	2-12	2-6	1-4	2-5	2-4	1-6	4-9	1-2
Gypsum	0-4	6	0-7		0	0	0	0	0	0	0	0	0	0	0	0	0

*All values are expressed in whole rock %.

**Not Determined

***Includes Ankerite

TABLE 6B
Correlation of Map Units with Time

Map Unit	Time or Its Equivalent
1	Early Marcellus
2	Late Marcellus
3	Hamilton Group/Post-Marcellus
4	Genesee/Geneseo
5	Sonyea/Middlesex
6	Early Lower Olentangy/Early Rhinestreet
7	Late Lower Olentangy/Late Rhinestreet
8	Middle Olentangy/Angola Shale
9	Upper Olentangy/Java FM./Hanover Shale
10	Early Lower Huron/Early Dunkirk
11	Late Lower Huron/Late Dunkirk
12	Early Middle Huron
13	Late Middle Huron
14	Early Upper Huron
15	Late Upper Huron
16	Chagrin
17	Cleveland

slowly in HCl to yield the soluble ferrous ion and H_2S. Again, pyrite comes to equilibrium with the HCl and no precipitates are formed.

Chlorite minerals behave differently. They do not dissolve completely in HCl. With these minerals, the iron as well as the magnesium and aluminum are leached from the matrix and a hydrated silica residue is left. This leaching process is very slow and normally would be expected to have a minor effect on the formation.

The iron precipitate problem becomes acute only if there is another mineral present in the formation that will cause the HCl to be completely spent. The most common mineral of this type is calcite. Calcite can neutralize the acid and increase the pH of the spent acid sufficiently to result in iron mineral precipitates. The calcite concentration in the Devonian shales ranges from 0 to 48% so there is the possibility of precipitation in the formation. If the pH of the spent acid rises above 1, the ferric ion (Fe^{+++}) will precipitate as iron hydroxide which is a hydrated gel which can be very damaging to near well bore permeability.

If HF is used, chlorite is rapidly dissolved and essentially all the iron is released into solution. The best use of HF is as a subsequent treatment to a HCl preflush. This preflush can dissolve the carbonates and prevent complete spending of the HF-HCl mixture. The fluoride ion has a great affinity for dissolved ferric ions and the resulting iron fluoride complex will prevent hydroxide formation until very high pH values, $\gtrsim 6$, are reached.

However, even with the use of HF, the penetration distances are small ($\leq$12 inches). The actual distance is very dependent upon the concentration of the non-quartz constituents in the formation.

Clays and Feldspars react with HF and during the reaction HF is consumed and silicate minerals are dissolved. When the HF concentration is reduced, silica precipitates from the spent acid. This precipitate is a hydrated colloid which can severely restrict the permeability of the formation.

Large afterflush treatments can minimize silica precipitation, if the afterflush is sufficient to displace spent acid immediately after treatment.

Stimulations performed with aqueous solutions can also be a problem in Devonian Shale wells. This is true not only because of the mineralogy but also because water invasion into the low porosity requires very high pressures and long clean up times to remove.

While no montmorillonite was observed in the core samples, the concentration of mixed layer clays ranged from 0 to 24%, and mixed layer clays also contain water-sensitive materials.

There are two types of mixed layer clays: regular mixed layer and random. The regular mixed layer type can be: a chlorite composed of a regular alternation of mica and brucite layers; allevardite which is a mica type mineral with layers of water separating double mica layers; rectorite which contains a continuous pyrophyllite layer and a vermiculite layer; and corrensite which is a regular interstratification of chlorite and swelling

chlorite. The random type is composed of an irregular interstratification of layers in which there is no uniform repetition.

Not only are mixed layer clays sensitive to aqueous solutions but they also contain either chlorite or vermiculite, which contains ferrous iron. This fact also has further implication concerning effective acidification.

Reiterating the fact that completions in shales can be a serious problem, even in naturally fractured areas, there exists one more problem that is worth mentioning. Even if the procedures are properly designed using all the information available concerning the localized mineralogy, in a calcareous material using a fluid as a stimulation material fine clay and silt can be loosened from the matrix and can plug the fractures during cleanup if they are not propped. If the proppant is a small-size sand the mobile fines can fill the voids in the propped zone and consequently reduce the permeability. If a larger size sand (20-40 mesh) is used exclusively, the possibility of plugging the porosity in the propped zone is minimized.

Surfactants can also be used in the fracturing fluid to aid in the removal of the fines. While these do help they do not completely remove all of the fines; however, the use of surfactant and a large sand proppant (20-40 mesh) can in most cases effectively minimize plugging due to fines.

In summary, while the mineralogical data do not bear any observable relationships to the organic geochemistry factors and consequently to gas production, and while specific compositions cannot be ascribed to stratigraphic zones or regions; the random variability of the concentrations is important. This variability implies that caution must be exercised in designing completion and stimulation treatments. As a consequence, it would not be prudent to assume that a treatment that works effectively in one area could be used without reservation in another area or region of the basin. To effectively stimulate and complete a well, all specific factors about that well must be considered. Since the service companies are well equipped to analyze the mineralogy of the formation from the well cuttings, and perform this as a routine service in the design of treatments, this service should be utilized for all Devonian Shale wells. Minor modifications in treatments based on local mineralogy could make the difference between a good well and a dry hole.

Another alternative would be the complete elimination of the use of acid and aqueous solutions. This can be accomplished by the use of a hybrid stimulation in which Tailor Pulse Loading can be used to break down the formation and create the initial fracture pattern. This can be followed by a pure nitrogen treatment which would create the effective drainage pattern.

Oil and Gas Yield by Thermal Recovery

In several areas, some intervals within the Upper Devonian have been considered as a potential source of feed stock for retorting, a process in which oil would be destructively distilled from the rock kerogen. Samples from a number of locations have been subjected to conventional retorting procedures to determine the yield of hydrocarbons from various units with the purpose of determining potential yield and the possible economics of mining and retorting to recover a significant portion of the kerogen as a useful liquid feed stock for refineries. Some yields as high as 23 gallons of oil per ton of rock have been reported (82); however the range for most of the rocks subjected to this type of assessment fell within the 0 to 10 gallon/ton range, or far below what is considered economic by currently available technology.

It was obvious that the pessimistic picture painted by these low values is inordinately discouraging because only the liquid hydrocarbons are determined by the standard method (83). Gas and light liquid hydrocarbons are lost in the standard process. But they could represent a significant increase in BTU recovery from a unit volume of shale were they determined as part of the retorting step. How significant has been a matter of conjecture.

For these reasons, a modified retort method was developed to determine all the liquid and gaseous products, and the organic carbon before and after analysis. While the results have not been correlated with conventional retorting, they do present a total picture of the fate of the organic carbon, and other species during heating. It was also hoped that the data would correlate with the degree of thermal diagenesis the rock has experienced up until the present time.

Table 7 lists the results of recovery of products from thermal processing of Eastern Gas Shale, from the seventeen subdivisions arbitrarily set apart for this report. Not only is oil yield listed, but so also are organic carbon before and after pyrolysis, and yields of water, hydrocarbon, hydrogen, hydrogen sulfide, and carbon dioxide. The relative amount of gases heavier than methane (gas wetness) is also shown.

The organic matter in the samples varies widely in its susceptibility to pyrolysis. In some samples, the kerogen is virtually inert; in others as much as 46% of the organic carbon is converted to other products. The greatest yield of oil is slightly over 8.2 gallons per ton in the Dunkirk shales in Southeastern Ohio and eastern Kentucky. Overall, the highest oil yields were in Kentucky, and in rocks of Cleveland and Huron age, which was no surprise.

A cursory look at the relative quantities of oil and gas show that all of these shales, or at least their kerogens, are oil-prone. One cubic foot of gas per cubic foot of rock would be equivalent to approximately 0.05 gal oil/ton. In most cases, the hydrocarbon gas would increase BTU recovery by about 5 to 10%, with a few notable exceptions. In a few cases (eg, in Zone 10, the sample from KY-4; in stratigraphic zone 11, two samples from the same well; and in stratigraphic zone 17, two more KY-4 samples), samples with relatively (for this area) high oil yields had BTU yields enhanced by 25 to 40 percent by the generation of hydrocarbon gas. Additional BTU's would be

TABLE 7
Mass Balance Assay Results
For Thermal Evolution Studies

Map Unit	Well	Organic Carbon (wt %) Pre Test	Organic Carbon (wt %) Post Test	Carbon Transfer Ratio	Oil Yield (Gal/Ton)	API Gravity	Water Yield (Gal/Ton)	Total Hydrocarbon Gas Yield (CF/Ton)	Gas Wetness (%)	H_2 Gas Yield (CF/Ton)	H_2S Yield (CF/Ton)	CO_2 Yield (CF/Ton)
1	PA-2	5.00	5.00	-	< 0.50	-	2.20	37.04	14.53	27.52	-	197.05
		4.70	4.70	-	< 0.50	-	2.00	25.98	21.25	2.96	84.23	124.10
	WV-6	10.40	10.40	-	< 0.50	-	4.65	46.46	11.11	24.02		
		5.80	5.80	-	< 0.50	-	2.75	22.20	97.33	23.41		
2	WV-6	3.70	3.70	-	< 0.50	-	4.52	6.31	80.00	24.99	5.70	89.64
		6.50	6.50	-	< 0.50	-	5.59	14.56	26.09	24.99	28.87	236.54
		7.10	7.10	-	< 0.50	-	4.41	26.56	13.95	24.38	64.29	243.09
		6.60	6.60	-	< 0.50	-	3.88	17.59	21.43	24.87	40.27	196.38
3	WV-6	7.70	7.10	7.79	< 0.50	-	1.23	1.21	87.50	5.82	0.24	25.23
		0.78	0.70	10.26	< 0.50	-	1.73	1.21	70.00	5.58	0.24	25.72
		2.00	1.92	4.00	< 0.50	-	2.14	1.21	87.50	6.43	1.09	20.01
		0.42	0.39	7.14	< 0.50	-	1.61	1.21	87.50	5.70	0.24	29.96
		0.81	0.74	8.64	< 0.50	-	2.73	1.21	85.00	6.67	0.24	45.73
		1.11	1.10	0.90	< 0.50	-	3.49	1.21	85.00	6.31	0.24	20.50
		3.10	3.10	-	< 0.50	-	4.13	6.19	40.00	24.50	12.74	74.84
		4.10	4.10	-	< 0.50	-	4.63	10.67	39.39	25.72	40.64	103.11
4	WV-6	2.80	2.80	-	< 0.50	-	3.58	2.55	42.50	6.07	1.46	33.24
	PA-1	4.40	4.40	-	< 0.50	-	4.00	159.17	31.34	0.86	98.56	197.74
	NY-1	0.70	0.40	42.86	1.00	-	1.00	7.25	70.00	5.68	8.58	20.79
		0.40	0.40	-	< 0.50	-	1.40	11.24	76.29	5.44	7.98	24.78
		1.00	1.00	-	< 0.50	-	1.40	29.14	78.15	5.44	18.86	29.26
5	NY-1	0.70	0.60	14.29	< 0.5	-	2.20	28.53	85.00	5.56	21.88	22.25
	WV-6	1.20	1.10	8.33	< 0.5	-	2.65	1.58	56.00	6.07	1.46	43.79
	OH-1	0.50	0.50	-	< 0.5	-	1.80	104.75	36.43	4.99	8.89	33.62
		0.87	0.67	19.80	< 0.5	-	2.90	7.67	38.72	4.99	15.96	41.17
		0.62	0.44	9.70	< 0.5	-	2.70	4.51	36.43	4.99	6.82	51.64

TABLE 7 (Continued)
Mass Balance Assay Results
For Thermal Evolution Studies

Map Unit	Well	Organic Carbon (wt %) Pre Test	Organic Carbon (wt %) Post Test	Carbon Transfer Ratio	Oil Yield (Gal/Ton)	API Gravity	Water Yield (Gal/Ton)	Total Hydrocarbon Gas Yield (CF/Ton)	Gas Wetness (%)	H_2 Gas Yield (CF/Ton)	H_2S Yield (CF/Ton)	CO_2 Yield (CF/Ton)
6	OH-1	6.84	4.70	30.10	5.7	33.00	2.70	126.92	43.36	54.93	119.00	34.23
	KY-2	2.63	1.78	32.32	1.4	31.89	2.97	31.29	42.30	15.65	53.96	61.97
7	OH-1	3.43	2.42	31.40	2.9	37.00	2.40	61.02	48.30	30.45	90.01	13.64
8	KY-2	3.14	2.50	20.38	1.34	31.89	5.98	45.46	40.40	25.75	83.16	63.32
		1.17	0.89	23.93	0.24	-	6.54	13.55	45.90	5.05	4.93	17.99
		0.12	0.12	-	0.16	-	4.51	1.60	78.30	31.79	0.37	537.64
		0.16	0.14	12.50	0.19	-	4.88	0.86	69.20	4.93	4.93	65.67
		0.64	0.47	26.56	0.36	-	5.07	8.99	35.20	5.30	0.86	65.05
	WV-5	2.60	1.30	26.92	4.00	34.20	4.00	48.48	58.29	42.92	98.41	28.29
		0.70	0.60	14.29	< 0.50	-	2.50	1.33	87.50	7.01	7.01	79.43
		0.27	0.19	20.63	< 0.50	-	3.80	2.30	54.29	7.62	8.95	38.33
		0.07	0.07	-	< 0.50	-	3.80	1.33	87.50	7.01	0.24	54.51
		0.67	0.55	17.91	< 0.50	-	4.40	13.54	52.05	11.49	42.56	24.30
		0.07	0.06	14.29	< 0.50	-	3.90	1.57	88.01	7.98	8.34	47.39
		0.09	0.08	11.11	< 0.50	-	4.30	0.97	86.67	4.84	0.24	61.17
		3.90	2.40	38.46	4.00	26.6	3.80	77.74	48.70	70.24	54.65	48.48
		0.44	0.30	31.82	< 0.50	-	4.30	6.29	53.13	8.22	22.49	57.31
9	WV-5	0.12	0.12	-	0.5	-	3.60	0.36	85.00	7.13	8.95	29.02
		0.45	0.36	20.00	0.5	-	3.70	7.13	41.82	7.50	33.54	13.78
		0.28	0.28	-	< 0.5	-	3.70	5.20	48.73	7.13	26.72	25.54
		0.14	0.13	7.14	< 0.5	-	4.00	0.97	86.67	4.96	0.24	62.38
		0.25	0.17	32.00	< 0.5	-	5.30	2.30	44.29	4.96	3.51	15.72
	KY-2	0.10	0.07	30.00	0.70	31.89	3.73	0.74	78.30	4.93	0.12	81.44
	R-109	3.18	2.05	35.50	2.60	36.00	3.00	46.50	46.57	27.61	44.82	18.16
		0.31	0.31	-	< 0.5	-	3.20	5.03	27.84	5.03	0.98	15.58

TABLE 7 (Continued)
Mass Balance Assay Results
For Thermal Evolution Studies

Map Unit	Well	Organic Carbon (wt %) Pre Test	Organic Carbon (wt %) Post Test	Carbon Transfer Ratio	Oil Yield (Gal/Ton)	API Gravity	Water Yield (Gal/Ton)	Total Hydrocarbon Gas Yield (CF/Ton)	Gas Wetness (%)	H_2 Gas Yield (CF/Ton)	H_2S Yield (CF/Ton)	CO_2 Yield (CF/Ton)
10	R-109	2.60	2.30	11.54	<0.5	-	2.80	58.41	45.41	28.83	65.15	13.99
	KY-2	5.45	3.17	41.83	4.63	30.03	3.78	93.14	40.80	47.56	70.59	74.91
		4.70	3.09	34.26	3.91	31.89	3.73	87.10	44.00	50.88	11.14	49.28
		4.77	3.34	29.98	2.72	31.89	4.70	99.55	40.70	51.25	127.39	38.56
		0.65	0.64	1.54	0.25	31.89	4.29	3.82	32.50	5.05	0.62	110.02
		3.05	2.15	29.51	2.43	34.50	3.58	66.77	43.40	35.24	65.91	50.76
	KY-4	6.90	4.20	39.13	7.54	23.10	3.20	655.74	62.11	11.91	153.72	90.31
	WV-5	0.17	0.17	-	0.50	-	3.20	2.90	43.33	6.65	0.24	51.26
		3.29	2.10	36.17	3.00	28.40	3.60	75.93	48.10	46.91	88.38	28.53
		4.70	2.80	40.43	5.00	26.20	3.40	108.69	49.16	61.78	84.63	26.24
		0.35	0.34	2.86	0.50	-	3.00	6.53	53.00	5.32	16.93	28.05
		0.12	0.12	-	1.10	-	2.80	1.33	87.50	6.77	6.89	18.74
	VA-1	0.24	0.24	-	<0.5	-	1.60	0.99	79.31	6.16	0.25	100.41
		5.65	5.27	6.73	<0.5	-	1.70	32.04	20.62	10.76	87.89	76.29
		2.81	2.60	7.47	<0.5	-	2.00	12.81	19.54	6.16	34.62	51.50
11	R-109	2.85	2.22	22.10	1.50	37.00	2.50	59.75	48.18	25.52	32.27	22.21
		4.29	3.28	23.50	2.80	37.40	2.40	77.79	46.65	32.64	77.67	19.88
		0.45	0.38	15.60	0.15	-	5.14	5.30	35.90	4.68	0.12	91.04
		1.11	0.68	38.70	0.56	31.89	3.44	13.43	42.80	4.80	7.39	56.80
		6.70	3.80	43.28	8.20	-	2.80	303.21	51.50	2.18	127.84	189.59
		0.31	0.31	-	<0.5	22.80	3.80	13.83	41.90	28.18	0.64	168.45
		8.00	5.00	37.50	8.27	22.30	2.50	704.68	52.80	26.77	419.02	469.49
		6.20	3.80	38.71	6.96	23.30	3.10	732.48	50.90	27.32	339.47	493.83
		5.24	3.10	40.84	6.40	25.7	2.80	6.89	52.80	66.25	67.22	62.63
		1.87	1.00	46.52	1.80	-	3.50	103.13	50.71	22.12	40.74	21.16
		4.12	2.40	41.75	4.80	28.6	3.20	115.34	51.87	47.51	66.01	37.24
		3.03	1.70	43.89	4.30	27.3	2.90	71.33	51.74	38.57	52.35	29.26
		4.39	3.79	13.67	<0.5	-	1.80	17.25	15.31	38.81	55.56	45.83

TABLE 7 (Continued)
Mass Balance Assay Results
For Thermal Evolution Studies

Map Unit	Well	Organic Carbon (wt %) Pre Test	Organic Carbon (wt %) Post Test	Carbon Transfer Ratio	Oil Yield (Gal/Ton)	API Gravity	Water Yield (Gal/Ton)	Total Hydrocarbon Gas Yield (CF/Ton)	Gas Wetness (%)	H_2 Gas Yield (CF/Ton)	H_2S Yield (CF/Ton)	CO_2 Yield (CF/Ton)
12	WV-5	0.50	0.38	24.00	0.50	-	4.30	104.82	65.91	10.03	9.91	21.40
		5.43	3.30	39.23	6.20	27.30	3.00	11.61	52.18	65.41	86.32	40.74
	VA-1	0.63	0.60	4.76	< 0.5	-	3.50	1.72	42.31	6.04	1.72	27.93
		2.27	2.09	7.93	< 0.5	-	3.20	4.44	25.37	6.04	12.81	22.30
	KY-2	0.27	0.22	18.52	0.14	31.89	2.21	2.34	50.00	9.24	0.37	87.23
		0.85	0.63	25.88	0.19	31.89	4.06	10.47	42.80	5.05	15.65	59.26
	R-109	1.64	1.60	2.44	0.50	-	2.80	26.14	46.84	14.72	10.31	9.94
13	R-109	0.29	0.29	-	< 0.5	-	3.00	3.07	30.11	5.03	0.25	38.65
		0.21	0.21	-	< 0.5	-	2.30	1.96	48.28	5.03	0.25	26.63
	KY-2	0.55	0.54	1.82	0.13	31.89	5.51	5.79	47.00	11.21	1.85	102.75
		3.30	1.99	39.70	0.82	36.31	4.46	54.08	46.70	30.18	110.39	31.79
14	KY-2	1.70	1.18	30.59	1.01	31.89	4.70	26.00	47.40	11.83	39.79	42.01
		1.90	1.25	34.21	1.11	31.89	4.54	27.60	48.10	12.44	53.10	34.00
	OH-3	3.20	2.10	34.38	3.23	-	6.20	145.14	51.30	0.90	82.62	212.26
	WV-5	0.80	0.60	25.00	0.50	-	3.55	76.53	65.95	8.34	35.91	9.07
15	OH-1	4.23	2.59	38.77	4.00	32.30	3.30	73.57	46.72	43.00	122.53	11.21
	WV-5	3.71	2.00	46.09	4.10	27.7	2.70	73.63	53.07	45.10	95.39	30.83
		4.96	2.70	45.56	4.80	27.1	4.20	97.08	54.14	59.97	148.10	37.72
	KY-2	1.91	1.48	22.51	0.33	-	4.11	32.89	42.50	22.79	73.55	14.04
		0.25	0.23	8.00	0.12	-	3.84	1.23	44.70	4.93	0.12	34.25
		3.98	2.72	31.66	2.87	-	3.74	63.69	44.70	36.47	84.76	36.59
		4.72	3.19	32.42	3.90	-	4.17	80.70	46.30	46.94	111.99	47.19
		4.06	2.49	38.67	3.11	-	4.26	65.54	45.30	38.68	97.20	56.92
		3.50	2.20	37.14	2.39	-	7.00	129.61	48.80	1.23	123.69	119.38

recovered in the form of free hydrogen and hydrogen sulfide, but these values are small relative to the BTU's recovered in the form of hydrocarbon gases.

The results show conclusively that material balance retorting with recovery and analysis of all products will give a much more accurate, and encouraging assessment of the products of retorting; and will allow a much more accurate economic analysis to be made.

The quantities of hydrogen sulfide and carbon dioxide were also somewhat of a surprise. The variability of hydrogen sulfide yields may reflect the variable pyrite contents of the samples; the carbon dioxide could be both organic and inorganic in origin.

From the standpoint of maturation, the volumes of the products did not correlate well with degree of organic maturity. For example, the few samples from Ohio would have been expected to give much higher yields of both liquid and gaseous hydrocarbons; the samples from VA-1 would not have been expected to give up as much hydrocarbon gas.

This work may be considered a pilot study that merits additional effort. Detailed data on mineralogy, geology and geochemistry need to be correlated with the results of this new material-balance retort method.

CONCLUSIONS AND RECOMMENDATIONS

This study has served to establish the fact that the Devonian Shales of the Appalachian Basin are organically very rich and should, on the basis of commonly accepted first principles, be a prodigious hydrocarbon source. In fact, from classical geochemistry, the Devonian Shales should be one of the more prolific oil sources of the world. However, the unusual history of the Devonian Shales precludes the application of classical organic geochemical interpretations.

The rocks are rich in gas and have a relative paucity of liquid hydrocarbons. The unique history of the rocks has not only affected the source potential but significantly influenced resource production. Unfortunately there is no known analog for the Devonian Shales of the Appalachian Basin and any information useful to the solution of the dilemma of the shales must come from the shales themselves.

This study has shown that three parameters are the most diagnostic in describing the source potential of the shales. These reveal the quantity of hydrocarbon generated by the source and whether it is gas or oil prone. The parameters include: organic carbon, thermal maturity, and the origin of the organic matter. The interrelationship of these parameters control the production of hydrocarbons in the shales.

These factors were integrated together and for seventeen stratigraphic zones, maps were created to identify high potential areas. The seventeen stratigraphic zones represent a subdivision of the major stratigraphic units on the basis of consistent data for each subdivision.

Following the assessment of the high potential areas of the basin, the sensitivities of the organic matter type were employed to yield information on whether the hydrocarbon potential was oil or gas prone. The majority of the kerogen sourced in the basin is oil prone but without the proper maturity or sufficient initial porosity and permeability, liquid hydrocarbon sourcing is remote.

In areas where all standard organic geochemical factors would imply prodigious liquid hydrocarbons, little or none have been observed and this is a major dilemma from the standpoint of classical organic geochemistry. This dilemma is the result of the fact that the natural open porosity and permeability of the shales, because of their depositional history, are such that primary migration of the liquid hydrocarbon progenitor cannot occur. This situation consequently affects the kinetics of hydrocarbon generation and classical assumptions must be modified. Only in those areas where sufficient initial porosity and permeability existed via natural fractures or siltstone lenses is classical geochemistry applicable. In the other areas more thermal energy must be expended to produce comparable products.

Gas contents of the shales were examined and, because of the comprehensive organic geochemical program and the application of the pressure core barrel and controlled off gassing techniques, it was possible to derive algorithms to more directly address indigenous gas. This phase of the study had an advantage over previous estimates of gas-in-place because it was a

direct consequence of the experimental program. Previous studies were based upon secondary indicators that in themselves were averaged over broad areas and ignored the inherent variability of the shales. The estimated indigenous gas was determined for the same seventeen stratigraphic zones for which the experimentally determined organic geochemical factors were available. The total indigenous gas value of the Devonian Shales in the study area was estimated at 2579 TCF, a tremendous resource by any standard. This number was modified downward by the consideration of "available drilling area". this revision resulted in a value of 1440 TCF of gas-in-place.

Problems were encountered in trying to estimate the recoverable resource since sufficient data do not exist to adequately address this issue. However, a preliminary estimate of 30 to 50 TCF recoverable evolved for the states of West Virginia, Ohio and Kentucky. This estimate is for shot wells on 160 acre spacings and it is thought that closer well spacings and improved stimulation technologies can significantly increase recoverable resource. However, because basic data are not available for the shales, no statistically relevant value can be put forth for improved stimulation technologies since the number of assumptions that would have to be made would immediately qualify the value to such a degree that a random guess would be just as good. Suffice it to say that a tremendous resource does exist in the shales and it is left to direct research and technology development to maximize recovery of that resource.

Structural evolution of the basin was also studied in an attempt to fix the depositional controls of the organic matter types. While this was not possible, this phase of the study did serve to help delineate, on a regional basis, those areas where fracture porosity might be favored.

Complete sets of maps and cross sections were prepared to aid the explorationist to determine probable regional favorability from a geochemical and fracture porosity point of view by means of standard geochemical analyses and photogeology respectively. While this study does have regional applicability, the explorationist should employ local confirmation prior to actual drilling. This can be accomplished with a minimum of effort from a geochemical and fracture porosity point of view.

After the detailed examination of the data was completed, it was obvious that some of the objectives of the study were satisfied, namely the delineation of the most favorable regional geochemical trends, the discrimination of the most useful criteria to assess shale sections locally, characterization of the regions where fracture porosity is most likely, and a new estimate of gas-in-place in the basin based on actual geochemical data. Values of minimum recoverable gas were also quantified. On the other hand, the problems of effective recovery of the gas, once discovered, and elucidation of the behavior of the gas moving through and from the rock, and the development of a more representative reservoir model, were not addressed. Data to address these problems will not come from the geochemical or geological parameters collected thus far. Applicable data can only come from gas-release data from shales still resident in the subsurface, i.e., where stimulations can be carried out and gas release can be observed <u>in-situ</u>.

Therefore, if the maximum recovery of the tremendous potential resource of the dark Devonian shales of this basin is to be realized in the near-term, a program similar in scope and design to the proposed Mineback Program will be

required. This type of program will allow the elimination of numerous assumptions required thus far in modeling production and stimulation. It will permit the interaction of the numerous variables to be observed and quantified. Only through successful completion of such a concerted effort will shale-gas recoveries be increased upward from the recent two percent to a value that will stimulate industry activity and consequently result in more gas being made available to the consumer.

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APPENDIX A

WELL LOCATIONS

Detailed Description of EGSP Appalachian Basin Core Well Locations

Mound Well	Well Name	State	County
7239	Kentucky-West Virginia Gas Co./ Nicholas Combs #7239	Kentucky	Perry
KY-2	Columbia Gas Transmission Corp./ Columbia Gas #20336	Kentucky	Martin
KY-4	Ashland Oil Co./ Skaggs-Kelley Unit #3-RS	Kentucky	Johnson
NY-1	National Fuel Gas Supply Corp./ #5213 (Jo) EGSP NY #1	New York	Allegany
NY-3	Arlington Exploration Co./ Ambrose Scudder Unit No. 1	New York	Steuben
NY-4	Arlington Exploration Co./ Valley Vista View, Inc. #1	New York	Steuben
NY-5	Gustavson & Associates	New York	Steuben
OH-1	Canton Oil & Gas Co./ Glen-Gery #5-74S	Ohio	Carroll
R-109	River Gas Company/ Florence L. House #R-109 (OH-2)	Ohio	Washington
OH-3	Thurlow Weed & Associates/ Louise Beckholt #1	Ohio	Knox
OH-4	Monsanto Research Corp./Bessemer and Lake Erie Railroad Co. #3	Ohio	Ashtabula
OH-5	Columbia Gas Transmission Corp./ D. M. Wakefield #10148-7	Ohio	Lorain
OH-6-1	Mitchell Energy Corp./#1-5 Carpenter	Ohio	Gallia
OH-6-2	Mitchell Energy Corp.	Ohio	Gallia
OH-6-3	Mitchell Energy Corp./L. McCombs #1-6	Ohio	Gallia
OH-6-4	Mitchell Energy Corp./#1-8 straight	Ohio	Gallia
OH-6-5	Mitchell Energy Corp./Carter #1-9	Ohio	Gallia

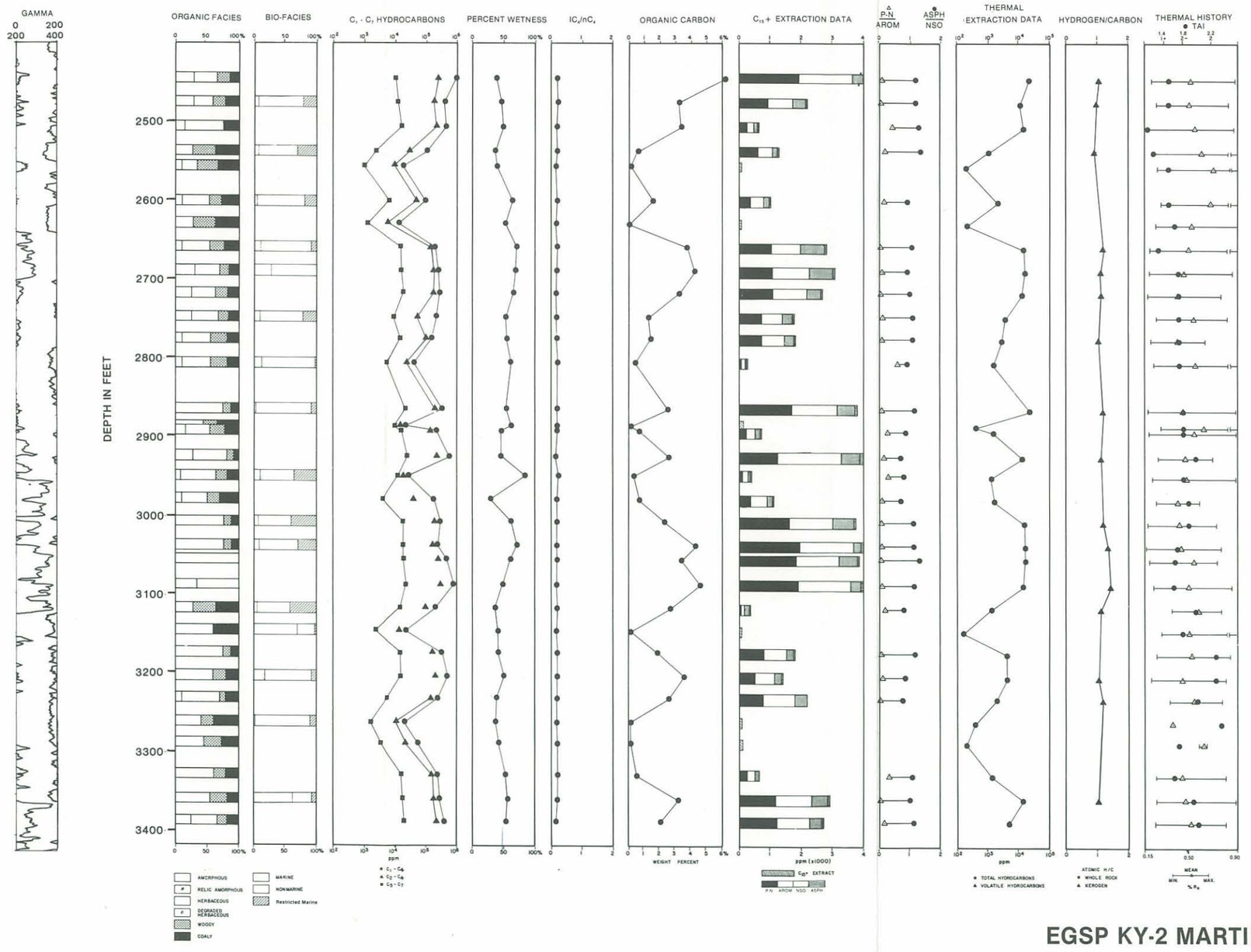
Mound Well	Well Name	State	County
OH-7	Columbia Gas Transmission Corp./ Anna Meleski #20143	Ohio	Trumbull
OH-8	Donohue, Austey & Morrill/Schockling #1	Ohio	Noble
OH-9	Gruy Federal, Inc./DOE/Columbia Gas Co. #10056-A	Ohio	Meigs
PA-1	Minard Run Oil Co./ Minard Run Exploration #1	Pennsylvania	McKean
PA-2	C. E. Power Systems/ C. E. Power Systems #1	Pennsylvania	Allegheny
PA-3	Monsanto Research Corp. Pennsylvania DER/Presque Isle State Park #1	Pennsylvania	Erie
PA-4	Gruy Federal, Inc./DOE/Glen McCall #5	Pennsylvania	Indiana
PA-5	Peoples Natural Gas/C. Sokevitz #1	Pennsylvania	Lawrence
TENN-9	Gruy Federal, Inc./DOE/Gruy Federal #1	Tennessee	Grainger
VA-1	Columbia Gas Transmission Corp./ Penn Va. Corp. Farm Well #20338	Virginia	Wise
11940	Consolidated Gas Supply Corp./ L. A. Bales #11940	West Virginia	Jackson
WV-5	Reel Drilling Co./ D/K Farm #3	West Virginia	Mason
WV-6	U. S. Dept. of Energy MERC #1	West Virginia	Monongalia
WV-7	Mobay Chemical Corp./ H. Emch & A. Pyles Unit #1	West Virginia	Wetzel

APPENDIX B

GEOCHEMICAL CROSS SECTIONS

EGSP KY-2, MARTIN CO.

Well: Columbia Gas #20336

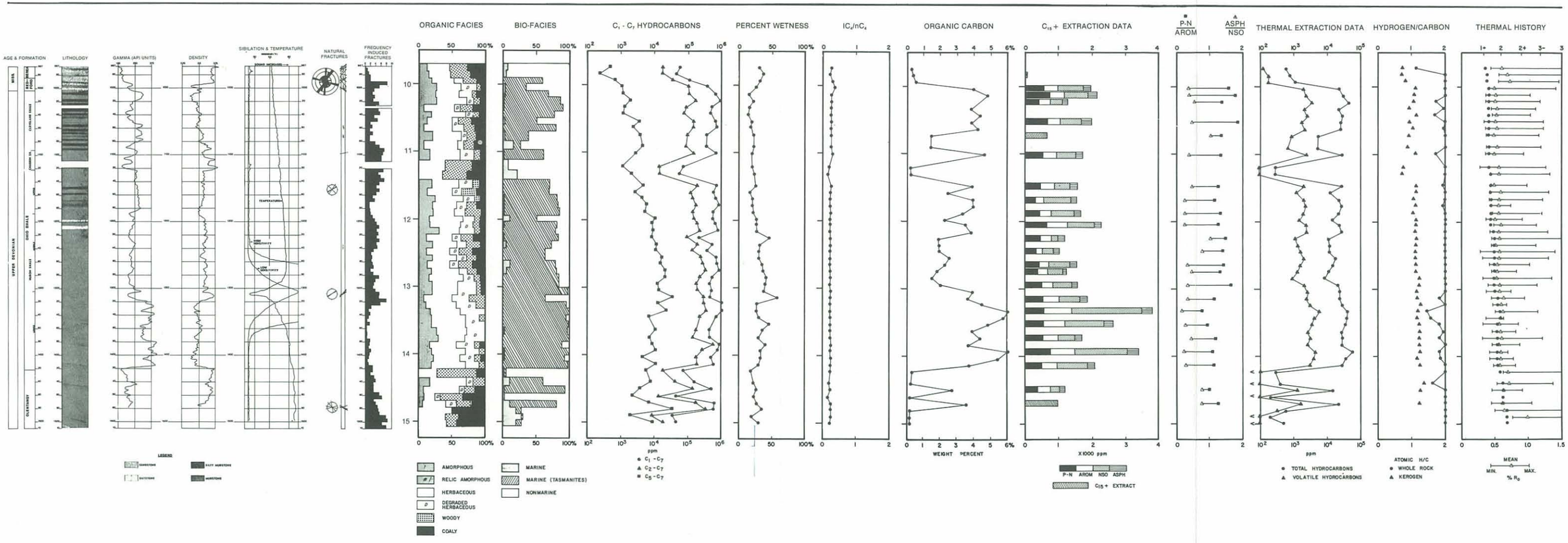


EGSP KY-4, JOHNSON CO.

Well: 3-RS

A.P.I.No. 16-115-33985

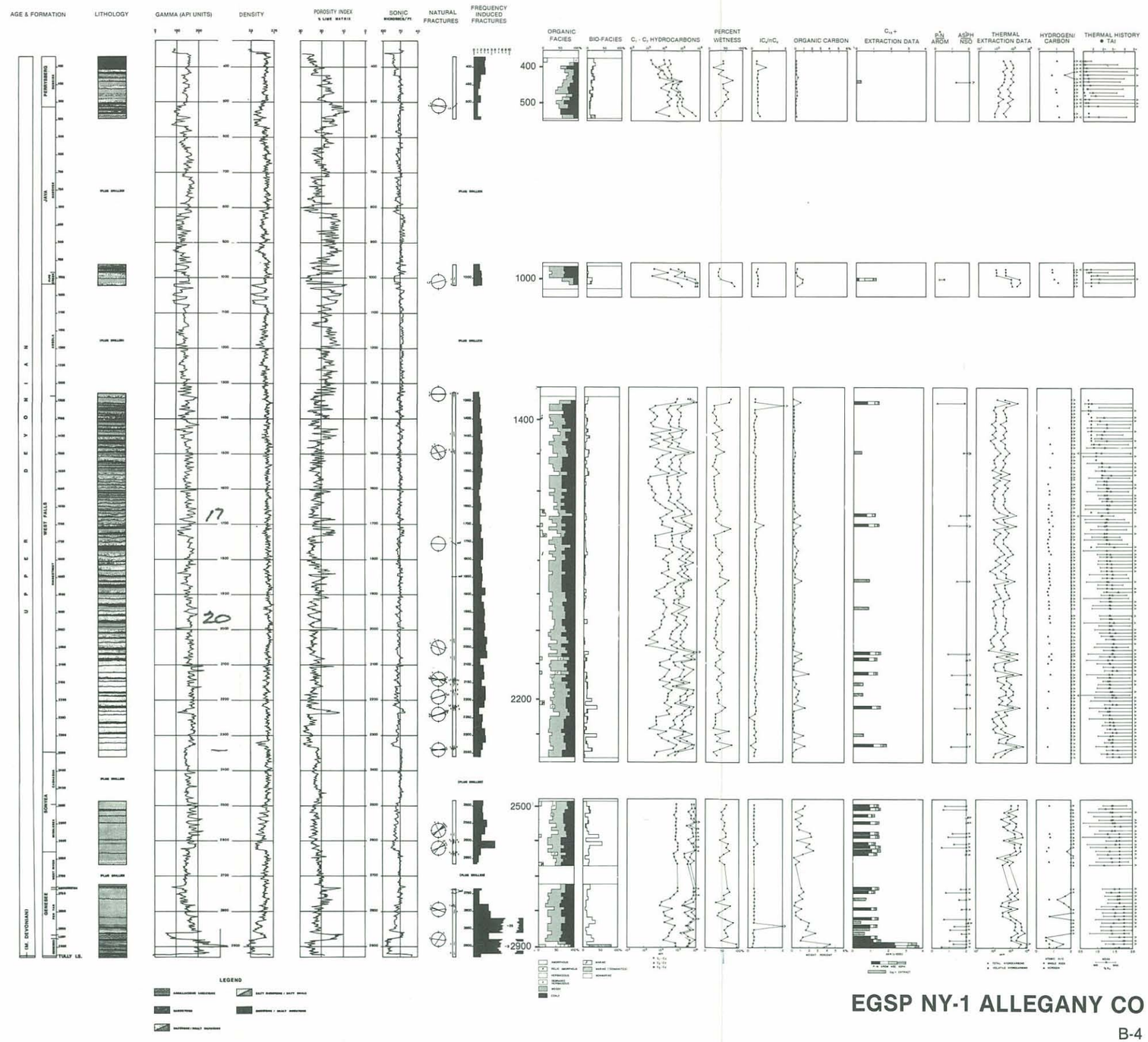
Drilling Completed: December 1978



EGSP NY-1, ALLEGANY CO.

Well: 6213 (JO) A.P.I. No. 31-003-13549

Drilling Completed: October 20, 1978

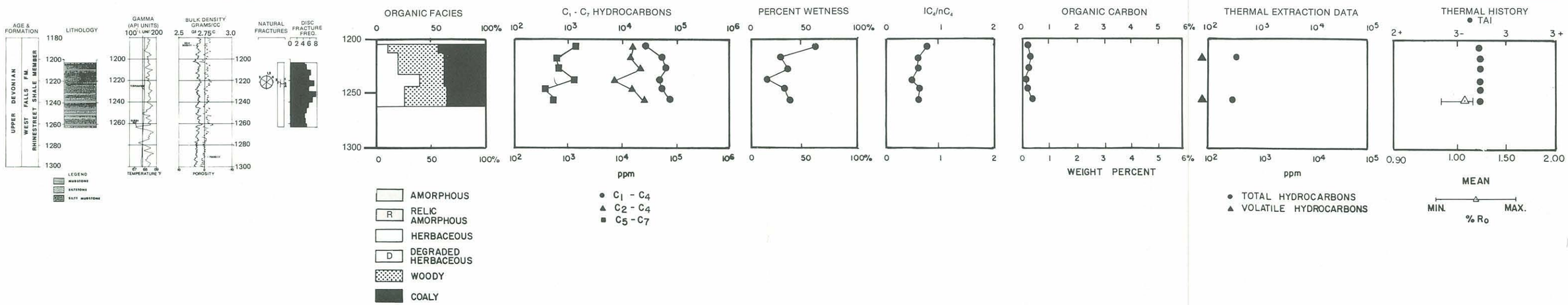


EGSP NY-1 ALLEGANY CO

EGSP-NEW YORK #3, STEUBEN COUNTY

Well: Ambrose E. Scudder Unit No 1 A.P.I. No. 31-003-15382

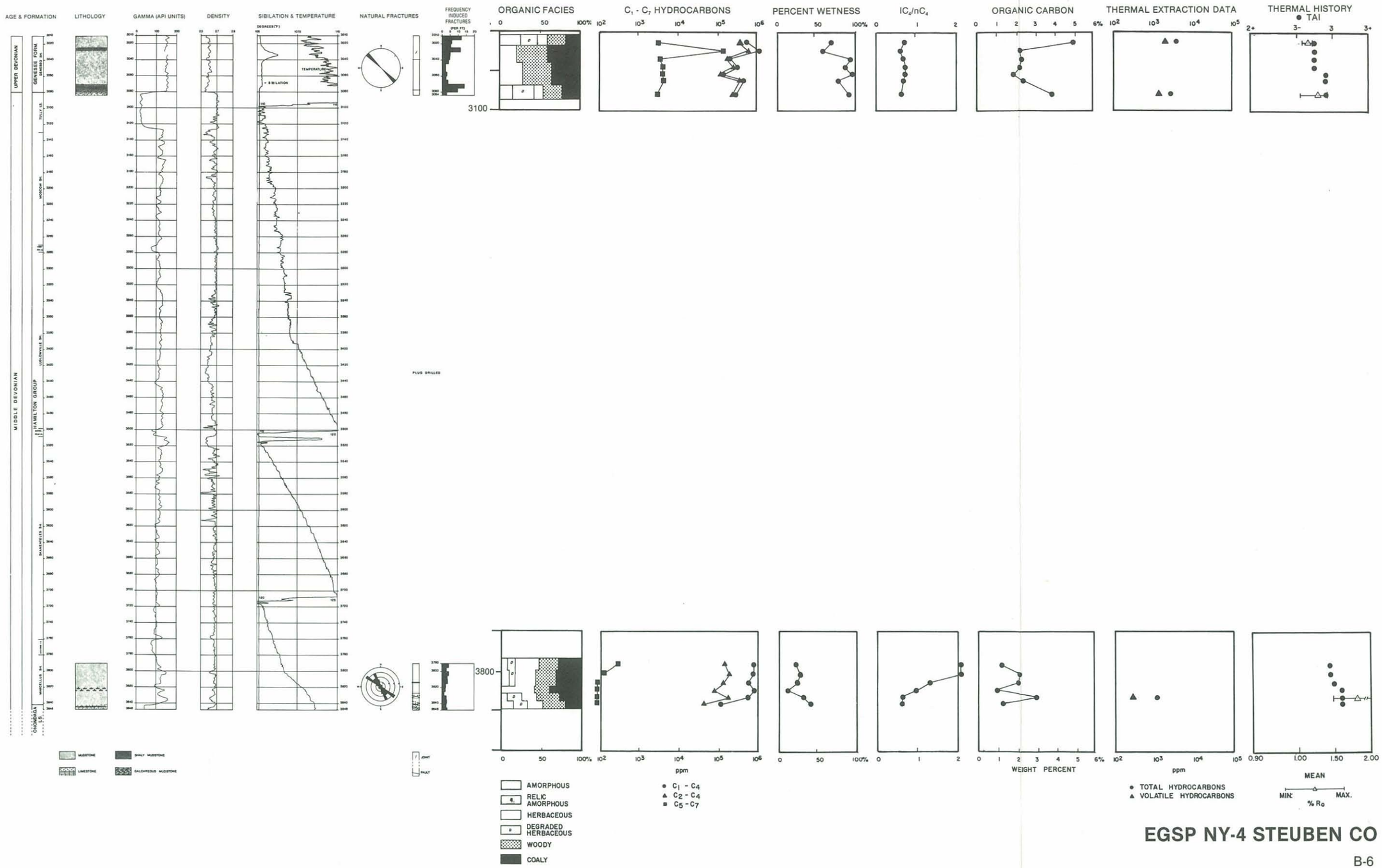
Drilling Completed: July 26, 1980



EGSP-NEW YORK 4, STEUBEN CO.

Well: Valley Vista View #1 A.P.I. No. 31-010-15268

Drilling Completed: July 29, 1980

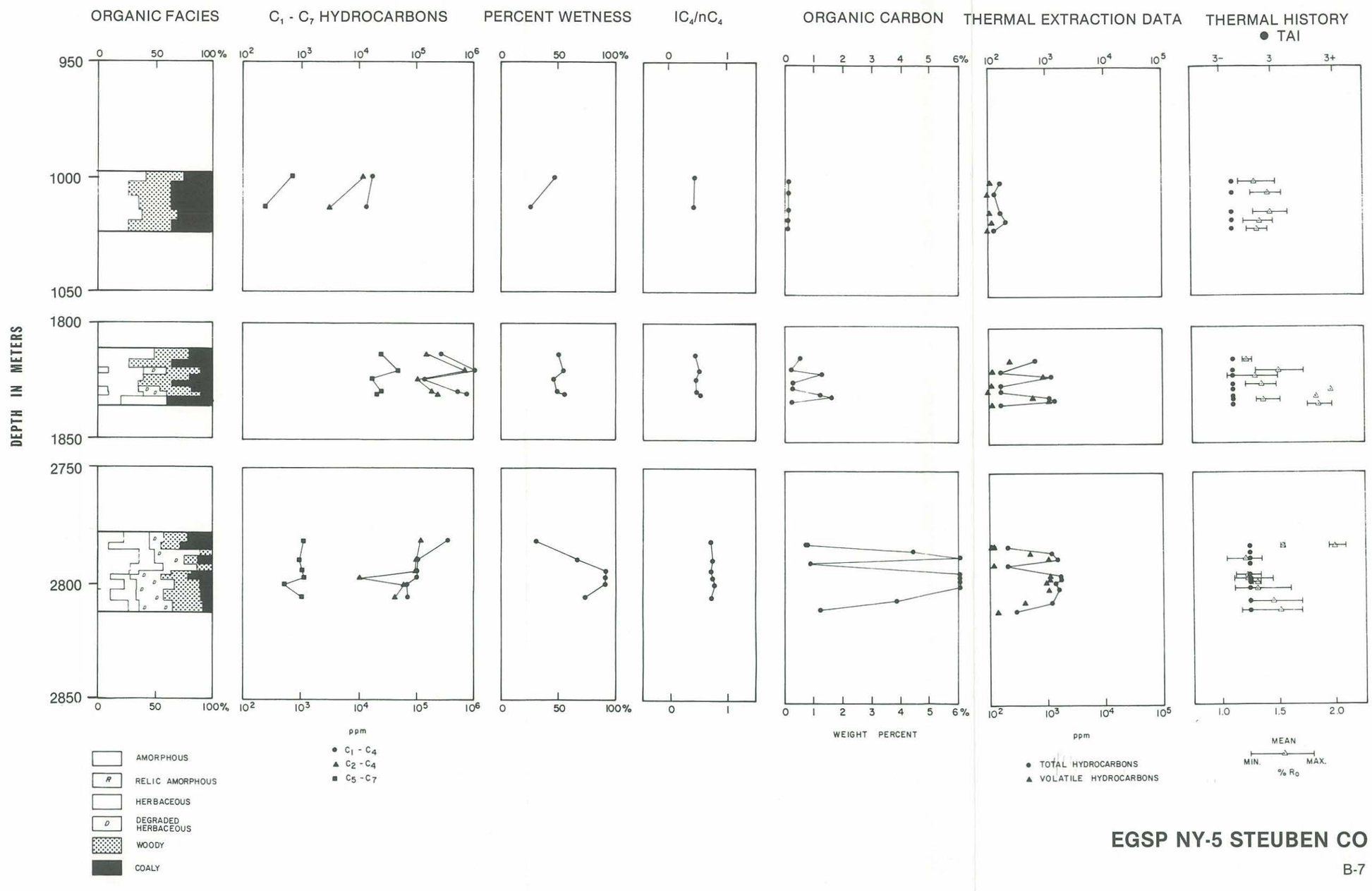


EGSP NY-4 STEUBEN CO

EGSP NY-5, STEUBEN CO.

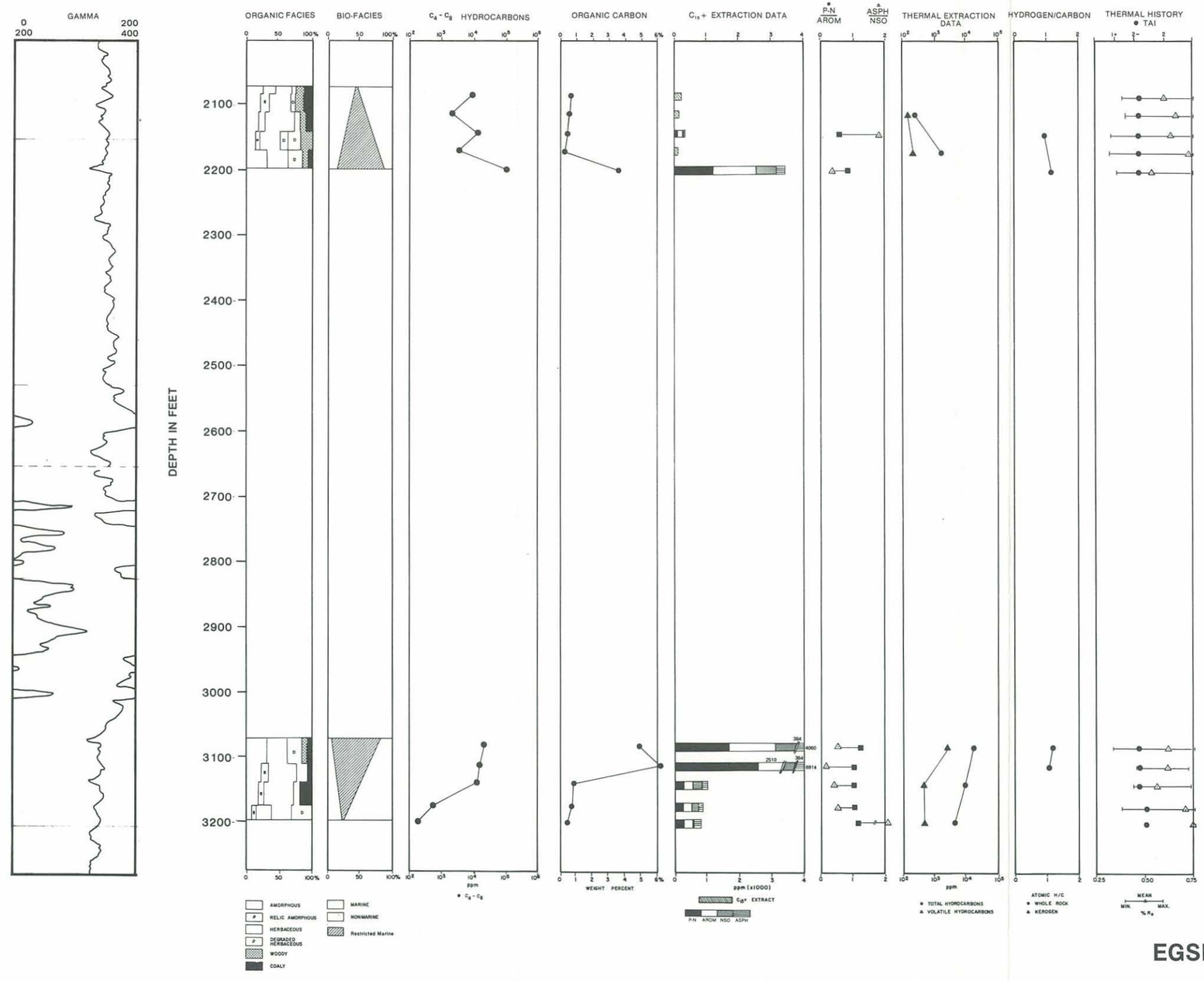
Well: Fee #1 A.P.I. No.

Drilling Completed: March 7, 1981



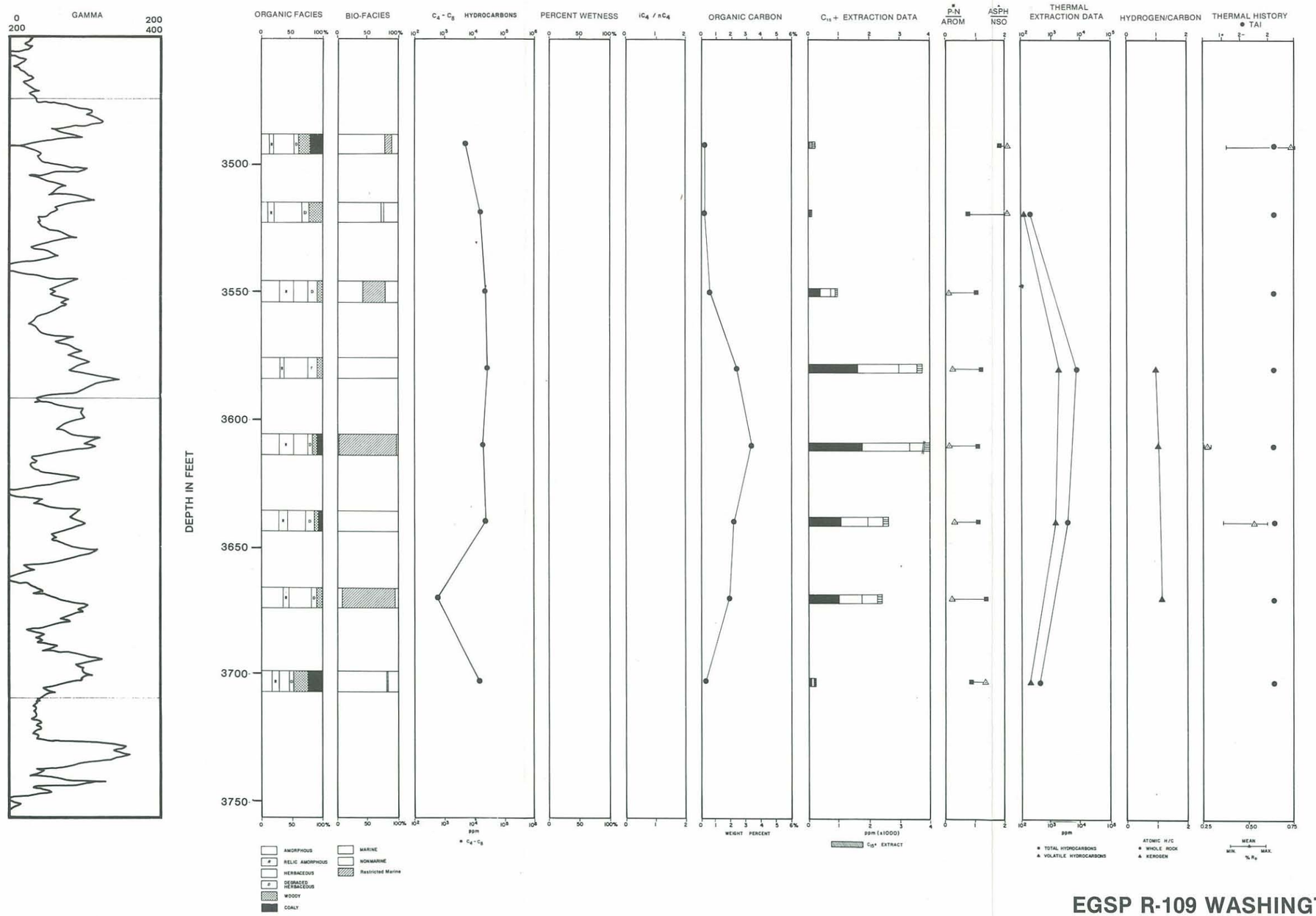
EGSP OH-1 CARROLL CO.

Well: Glen-Gery #5-74S



EGSP R-109 WASHINGTON CO.

Well: Florence L. House #R-109 - EGSP OH-2

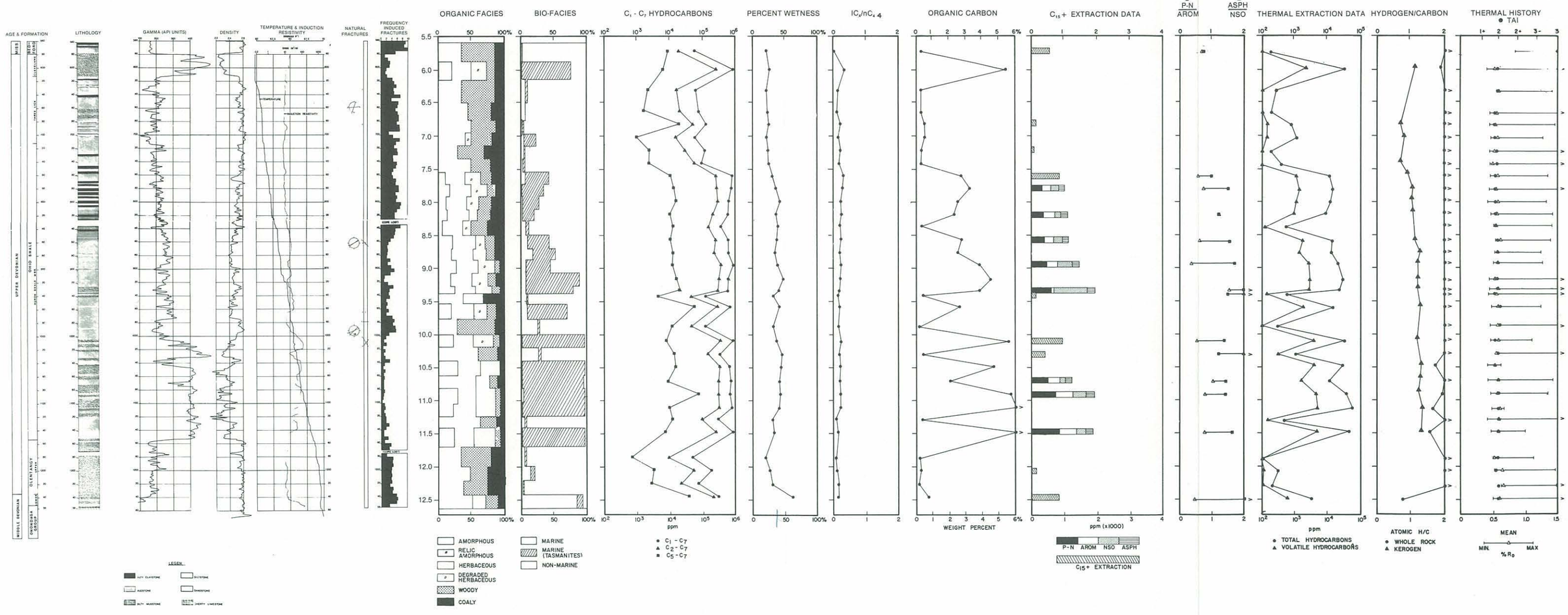


EGSP R-109 WASHINGTON CO

EGSP OH-3, KNOX CO.

Well: Louise Beckholt #1 A.P.I. No. 34-083-225 99

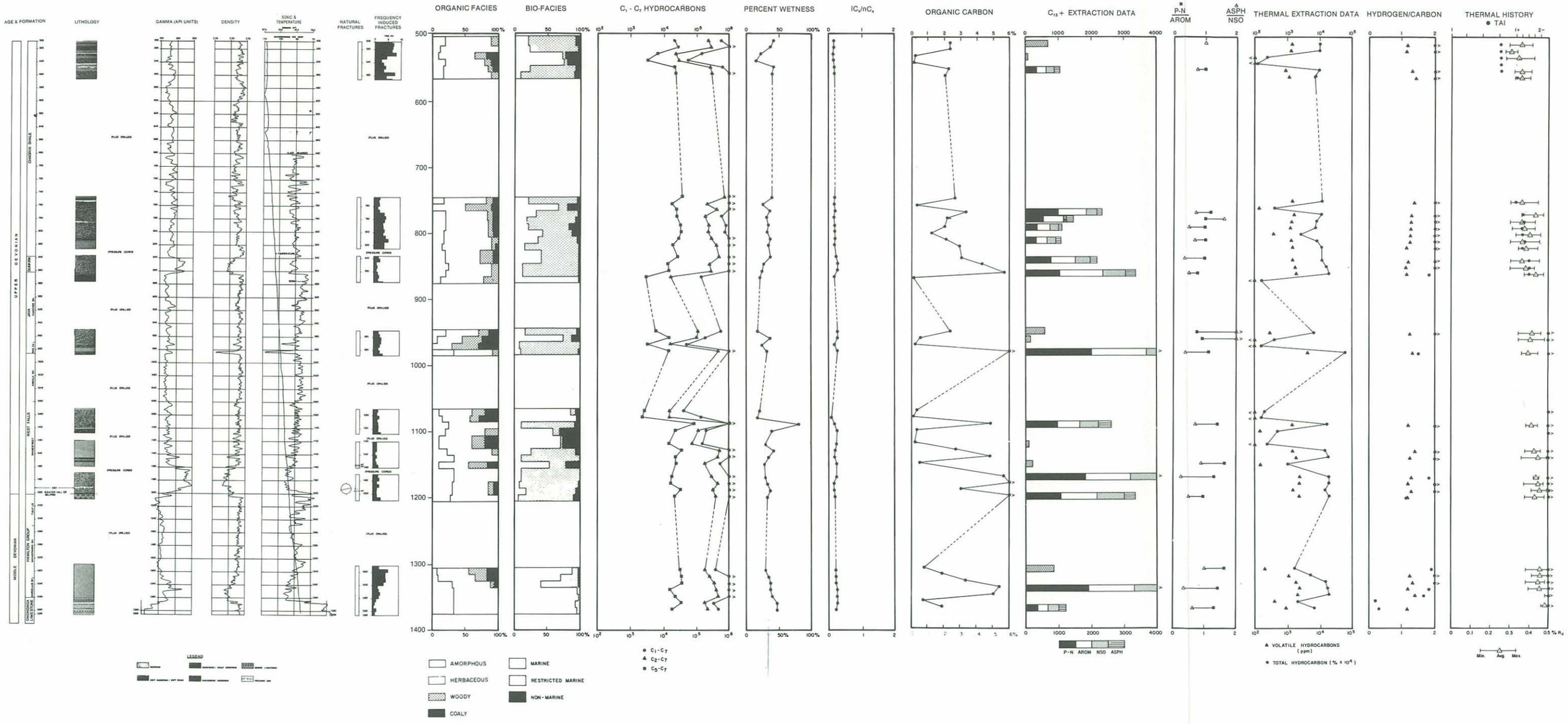
Drilling Completed: April 1979



EGSP OH-4, ASHTABULA CO.

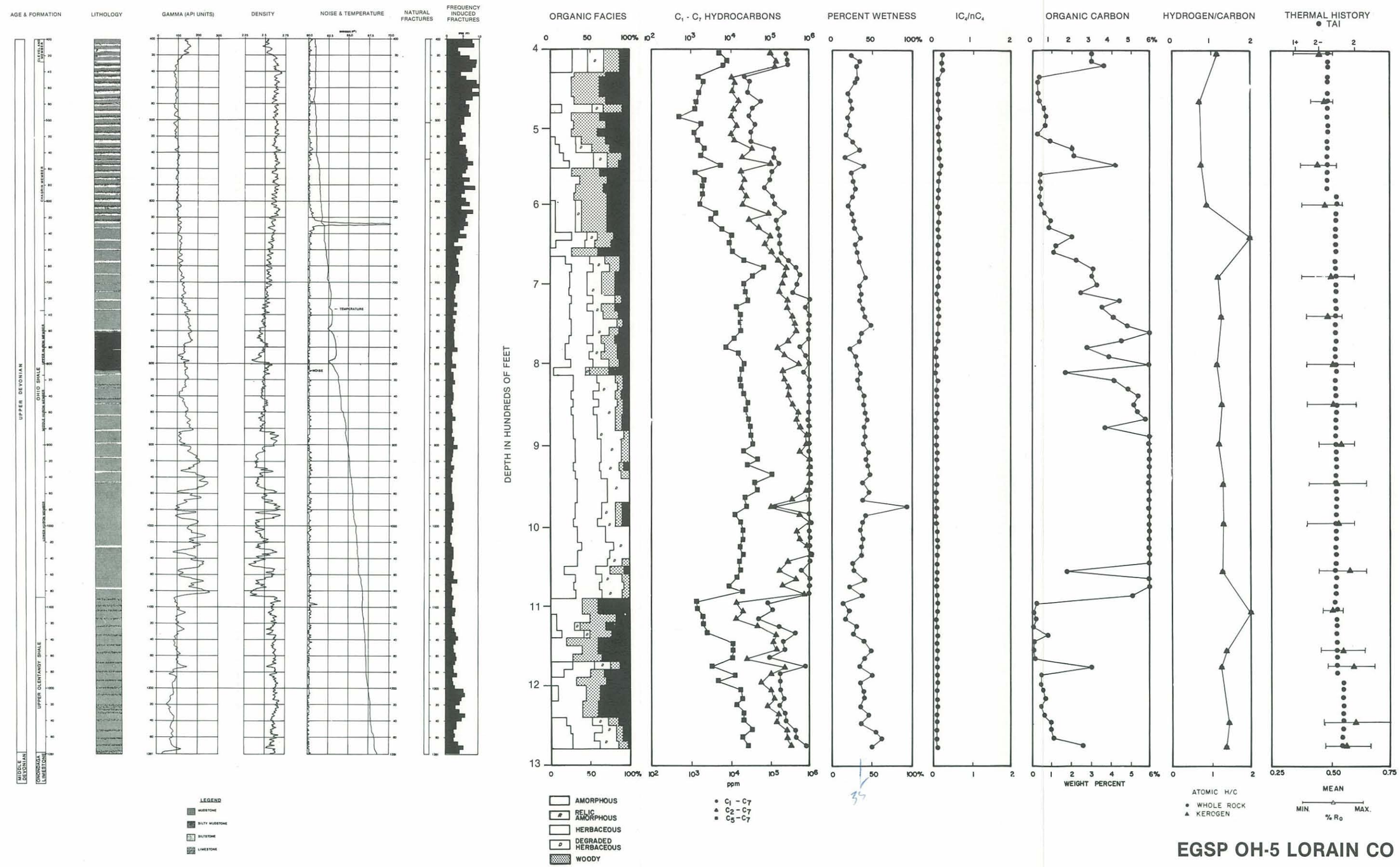
Well: Ohio #4 A.P.I. No. 34-007-21087

Drilling Completed: August 12, 1979



EGSP OH-5, LORAIN CO

Well: B&R McGuire 20149-T A.P.I. No. 34-093-21103
Drilling Completed: September 11, 1979

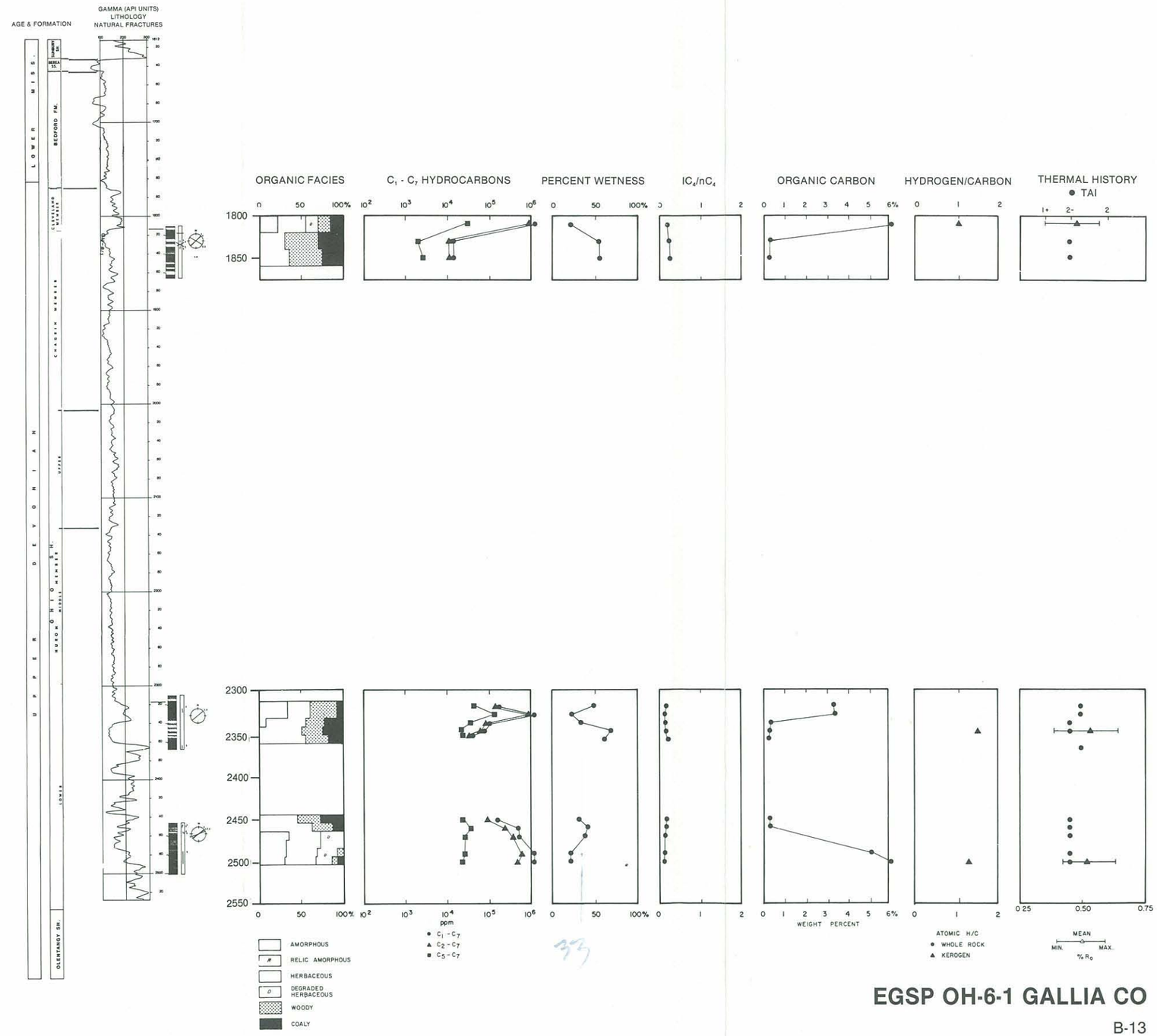


EGSP OH-5 LORAIN CO

EGSP OH-6 SERIES, GALLIA CO.

Well: OH-6/1 [Carpenter #1-5] A.P.I. No. 34-053-20482

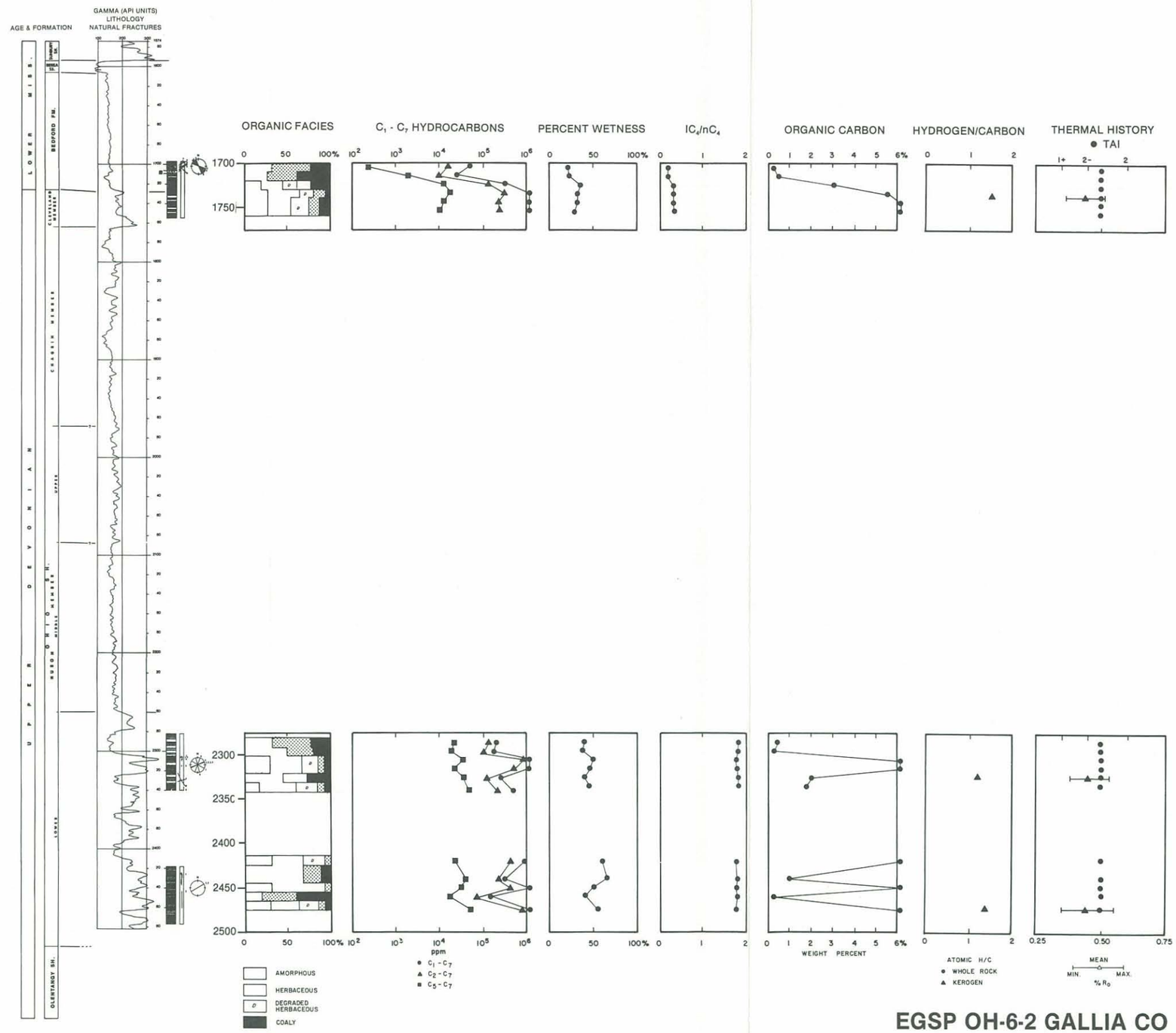
Drilling Completed: December 5, 1979



EGSP OH-6-1 GALLIA CO

EGSP OH-6 SERIES, GALLIA CO.

Well: OH-6/2 [White Price Newberry Unit #1-7] A.P.I. No. 34-053-20479
Drilling Completed: December 5, 1979

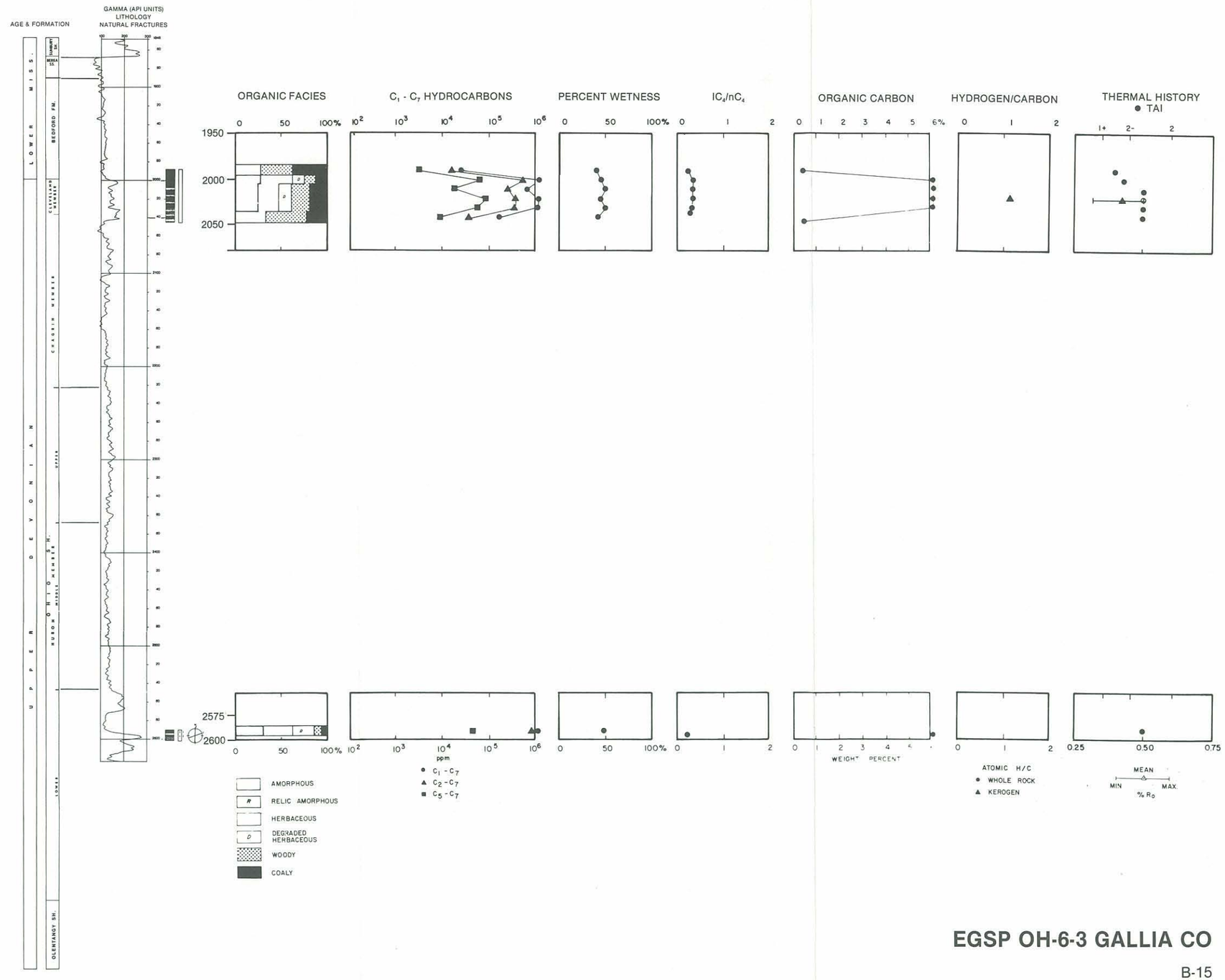


EGSP OH-6-2 GALLIA CO

EGSP OH-6 SERIES, GALLIA CO.

Well: OH-6/3 [L. McCombs #1-6] A.P.I. No. 34-053-20474

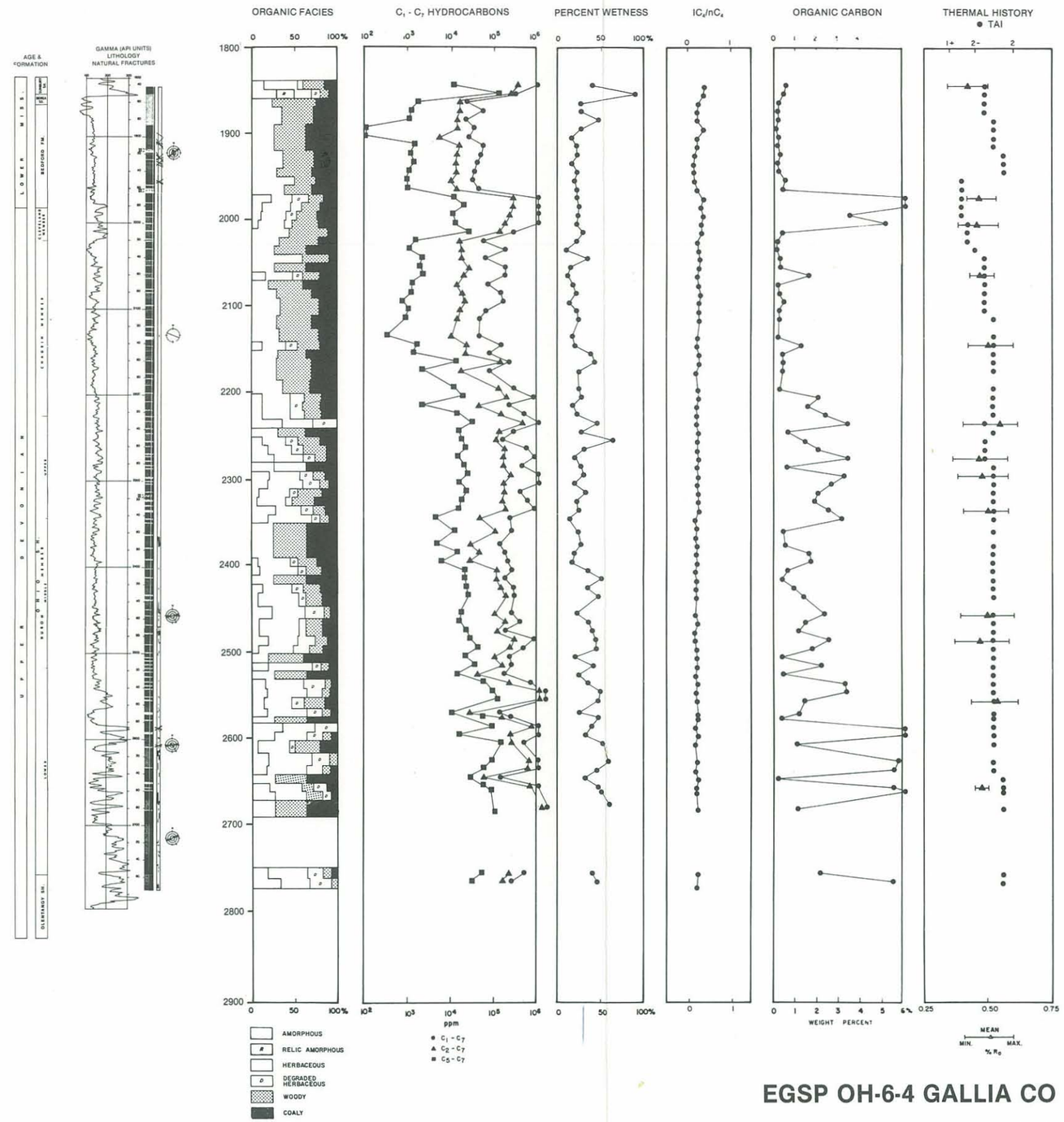
Drilling Completed: December 5, 1979



EGSP OH-6-3 GALLIA CO

EGSP OH-6 SERIES, GALLIA CO.

Well: OH-6/4 [Straight-Wisemandle Unit #1-8] A.P.I. No. 34-053-20477
Drilling Completed: December 5, 1979

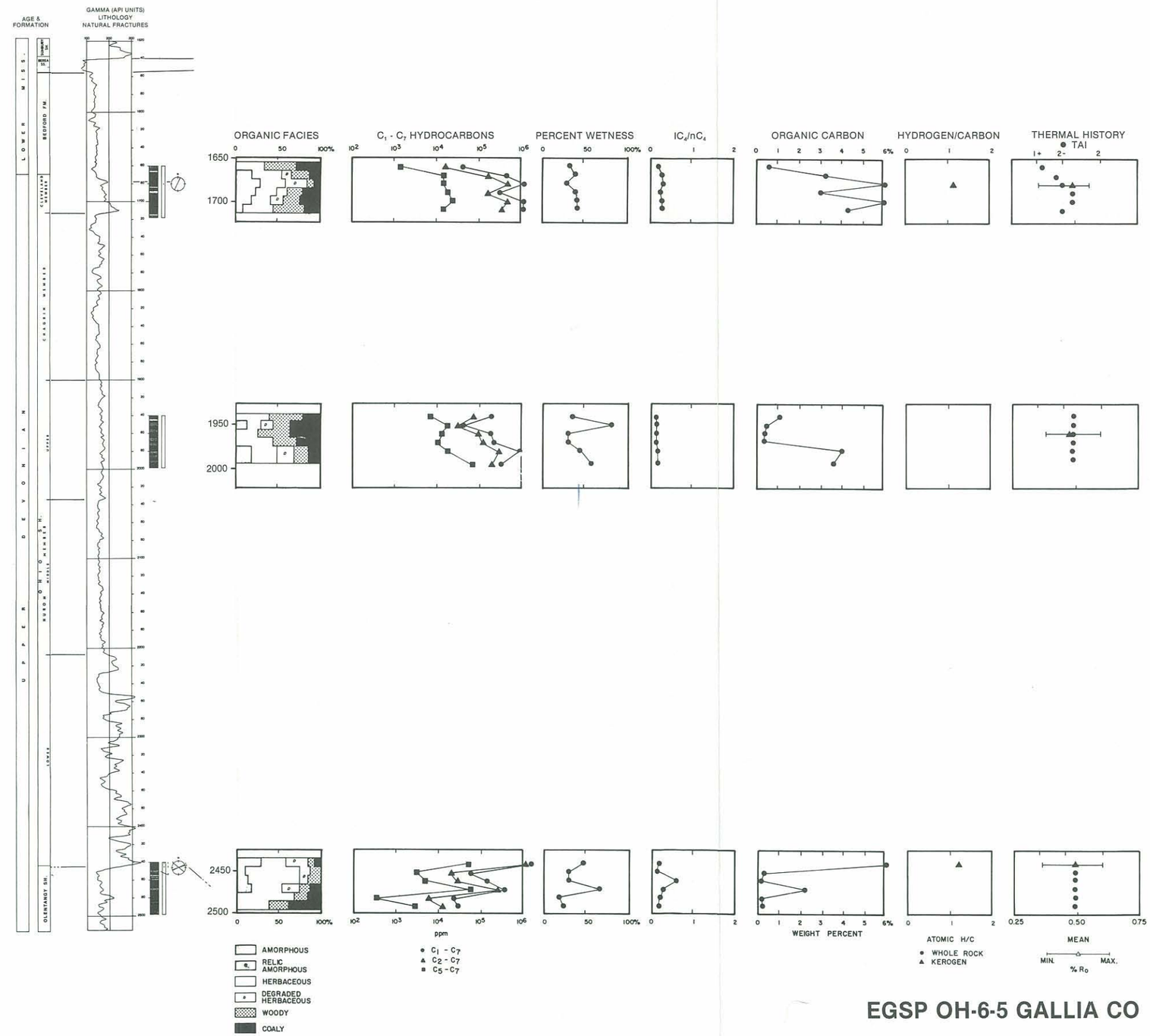


EGSP OH-6-4 GALLIA CO

EGSP OH-6 SERIES, GALLIA CO.

Well: OH-6/5 [M. Carter #1-9] A.P.I. No. 34-053-20478

Drilling Completed: December 5, 1979



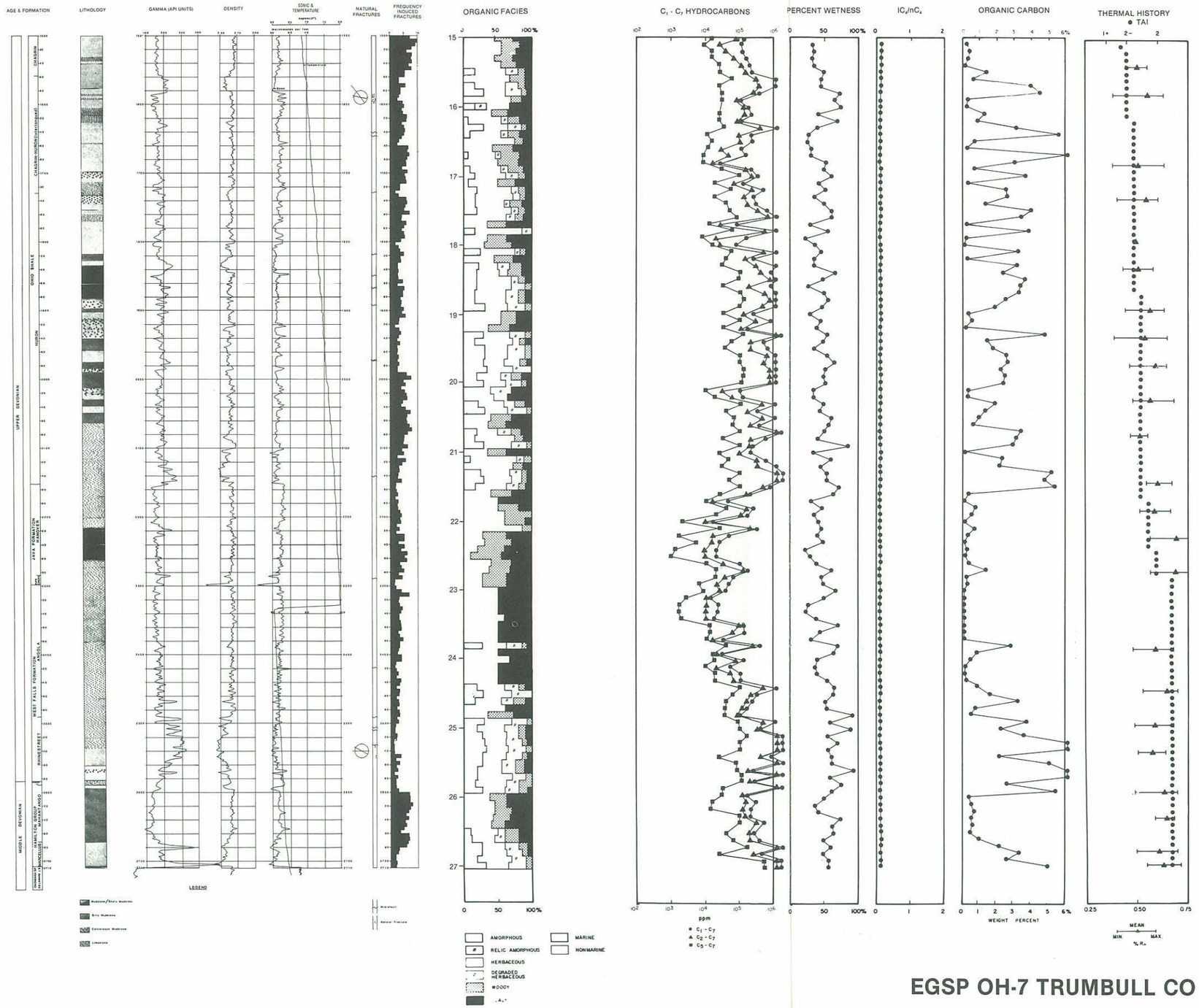
EGSP OH-6-5 GALLIA CO

EGSP OH-7 TRUMBULL CO.

Well: Ohio-7

A.P.I. No. 34-155-21238

Drilling Completed: October 3, 1979



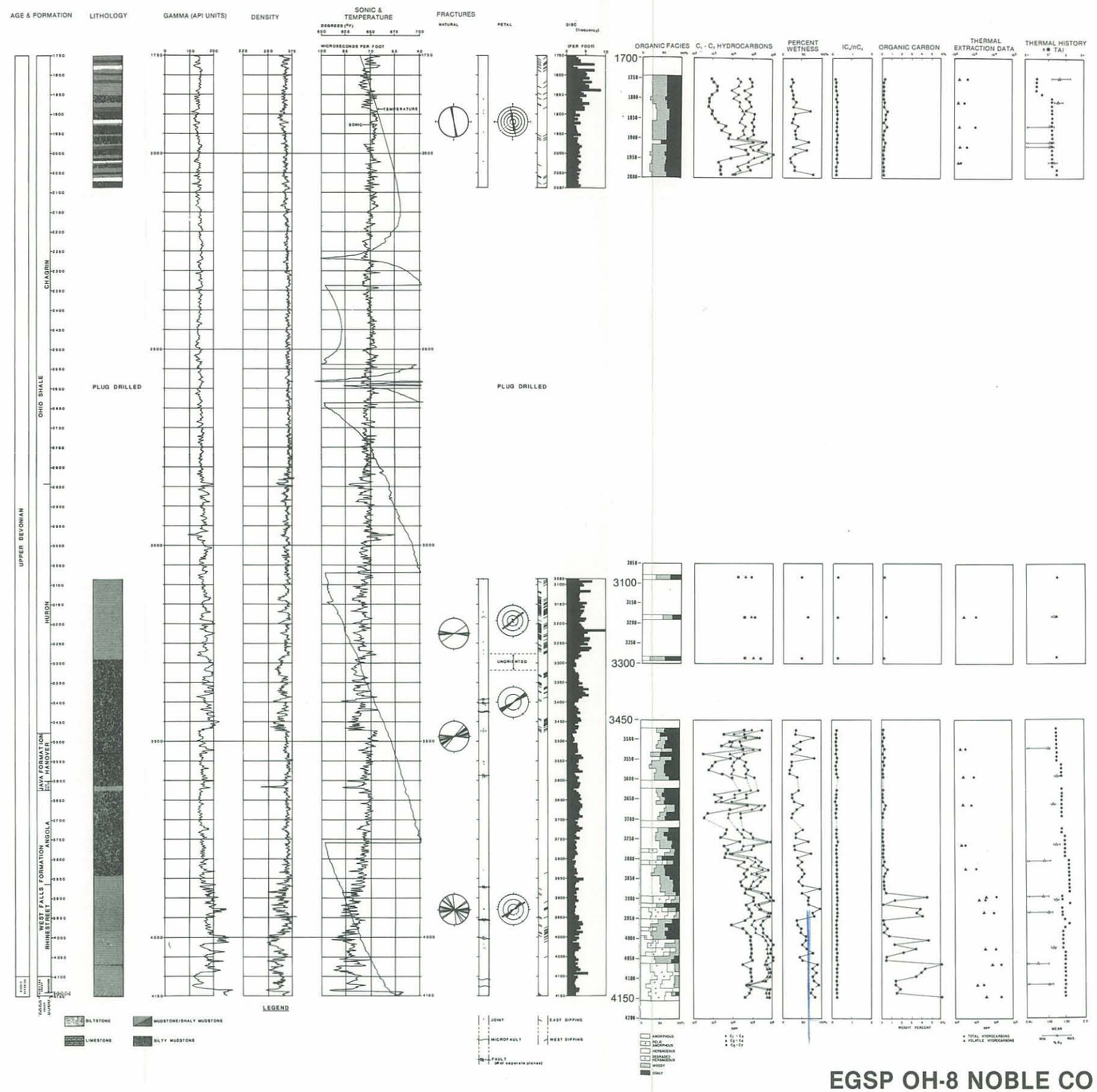
EGSP OH-7 TRUMBULL CO

EGSP-OHIO #8, NOBLE CO.

Well: Schockling #1

A.P.I. No.34-121-22255

Drilling Completed: March 1980

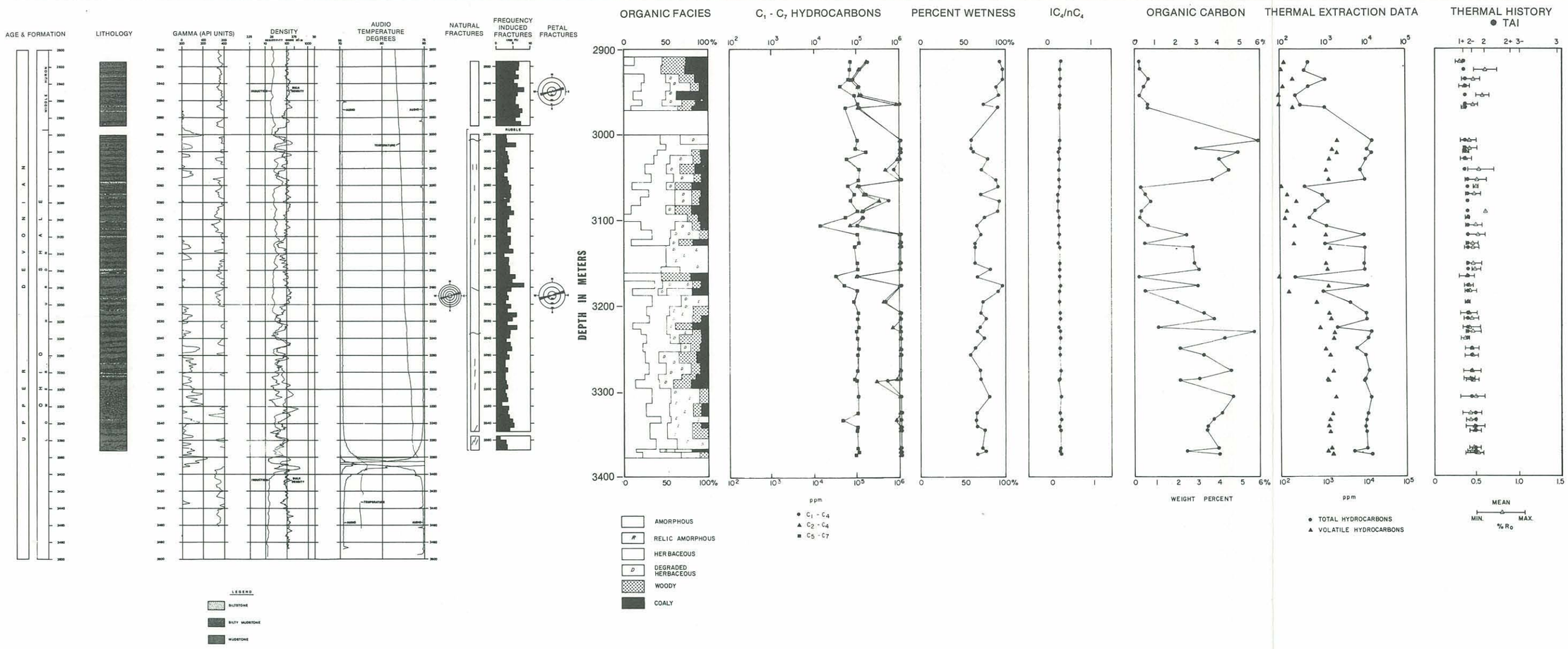


EGSP OH-8 NOBLE CO

EGSP OH-9, MEIGS CO.

Well: Columbia Gas #10056-A A.P.I. No. 34-105-22058

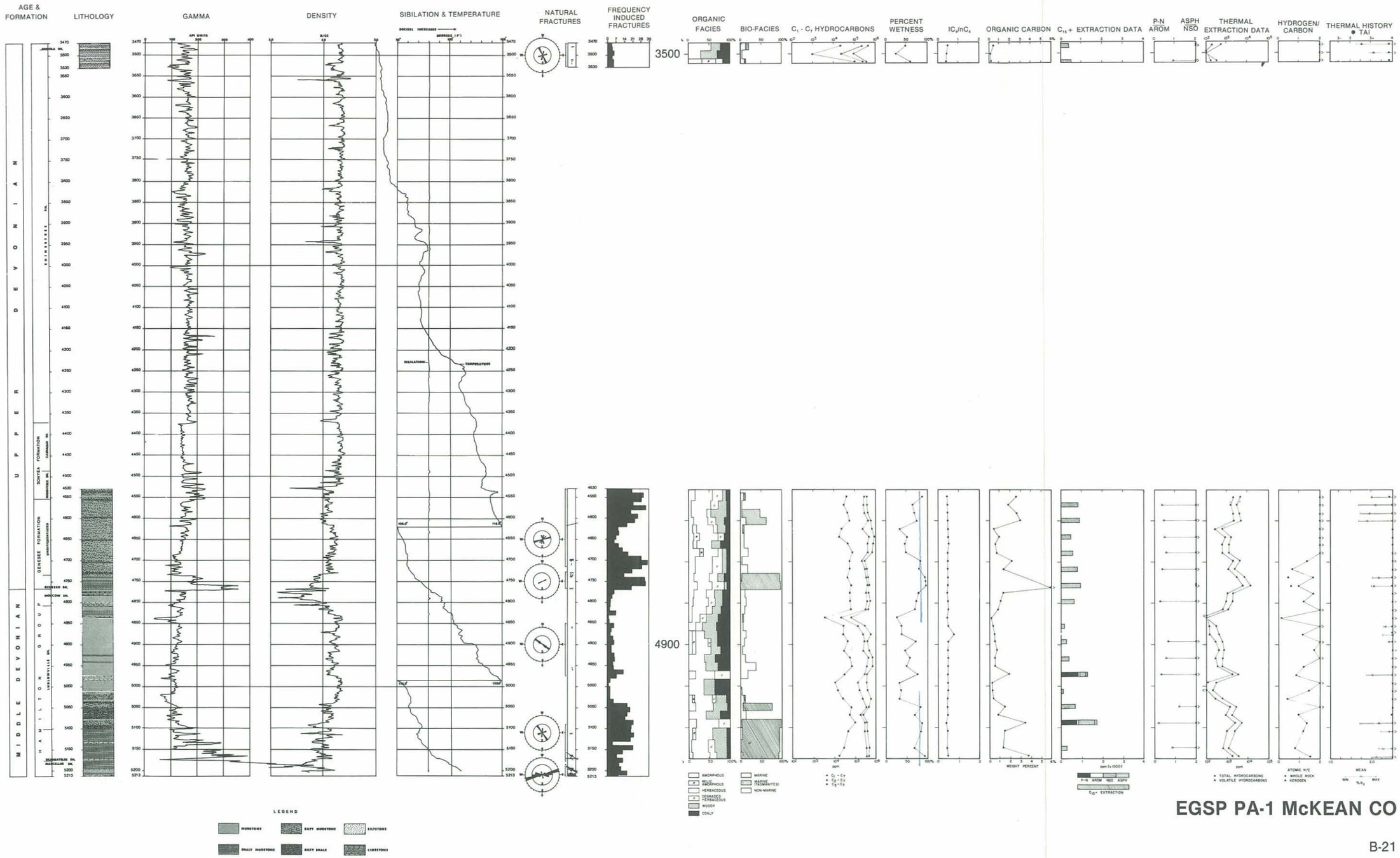
Drilling Completed: February 10, 1981



EGSP PA-1, MCKEAN CO.

Well: M.R. Ex. #1 A.P.I. No. 37-083-37291

Drilling Completed: February 22, 1979

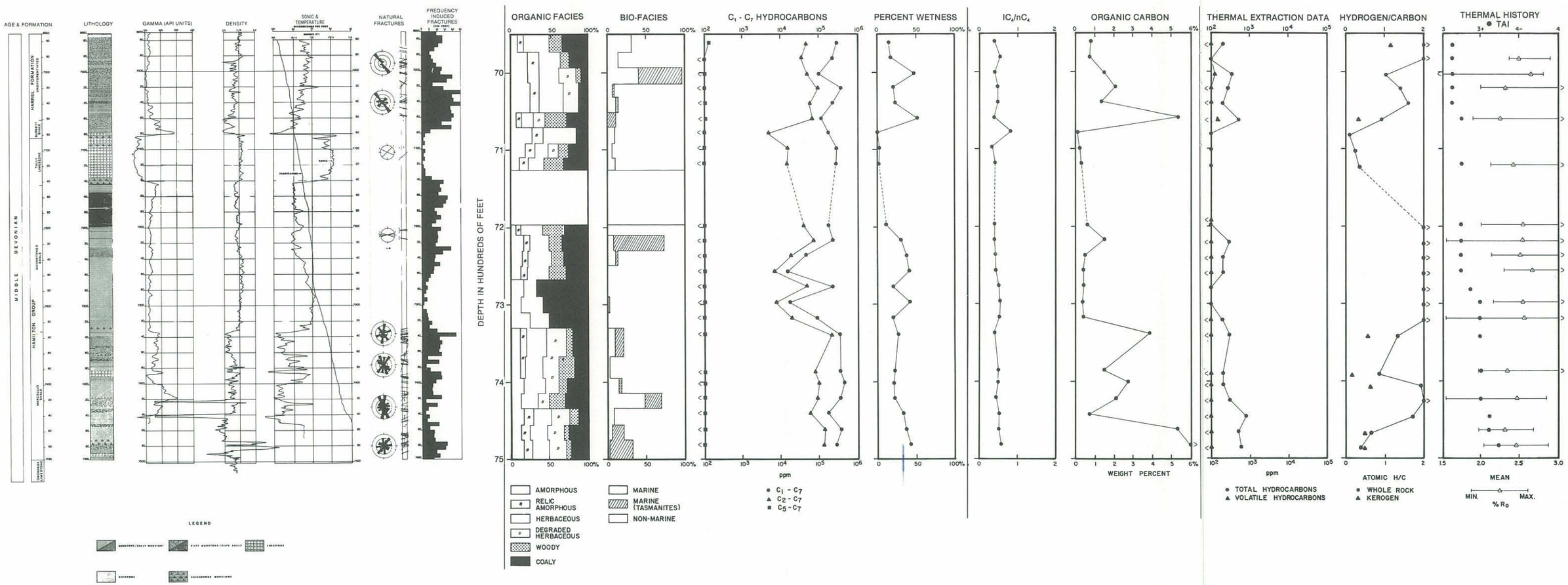


EGSP PA-1 McKEAN CO

EGSP PA-2, ALLEGHENY CO.

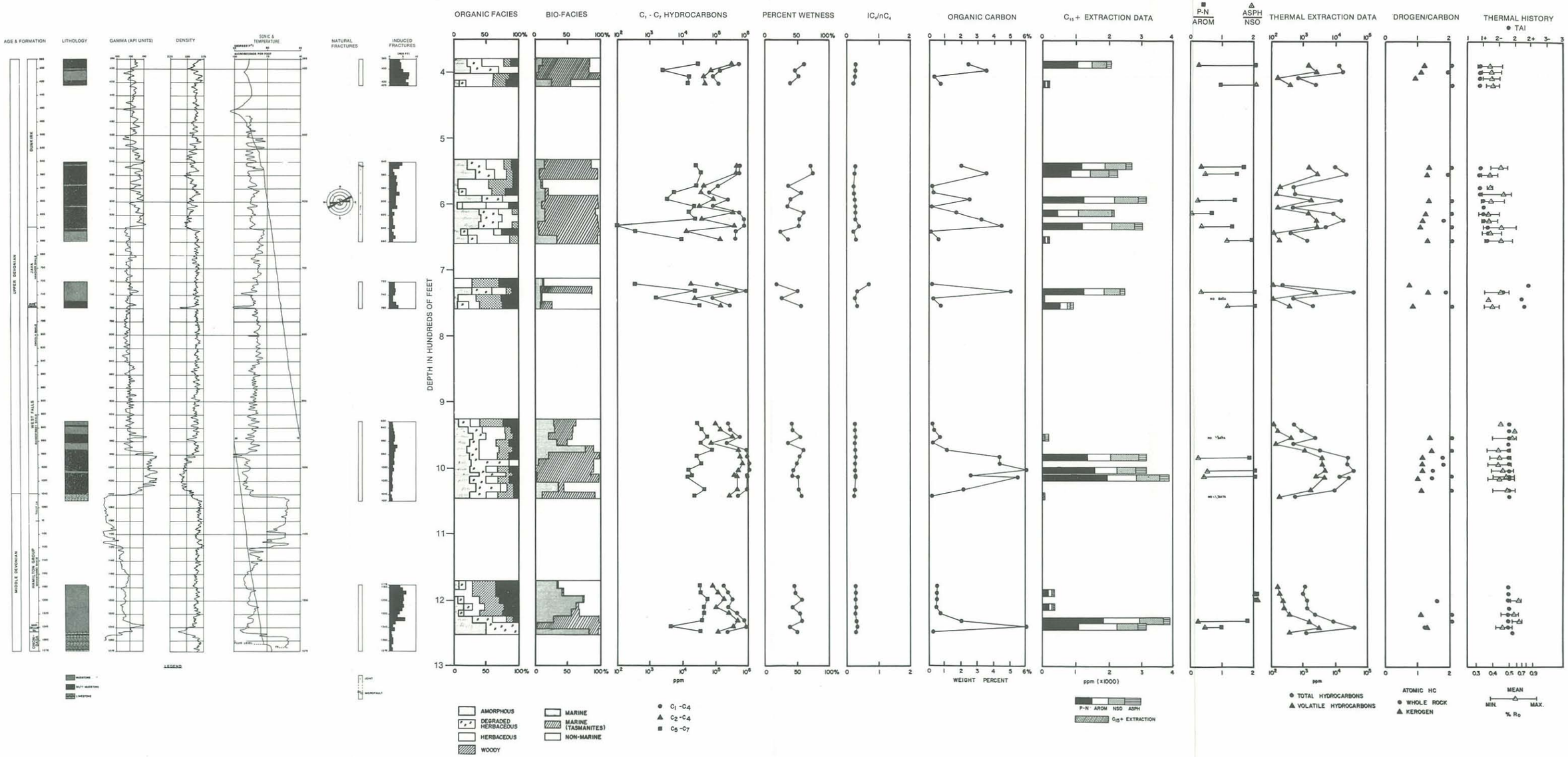
Well: C.E. #1 A.P.I. No. 37-003-20980

Drilling Completed: March 1979



EGSP-PENNSYLVANIA 3, ERIE CO.

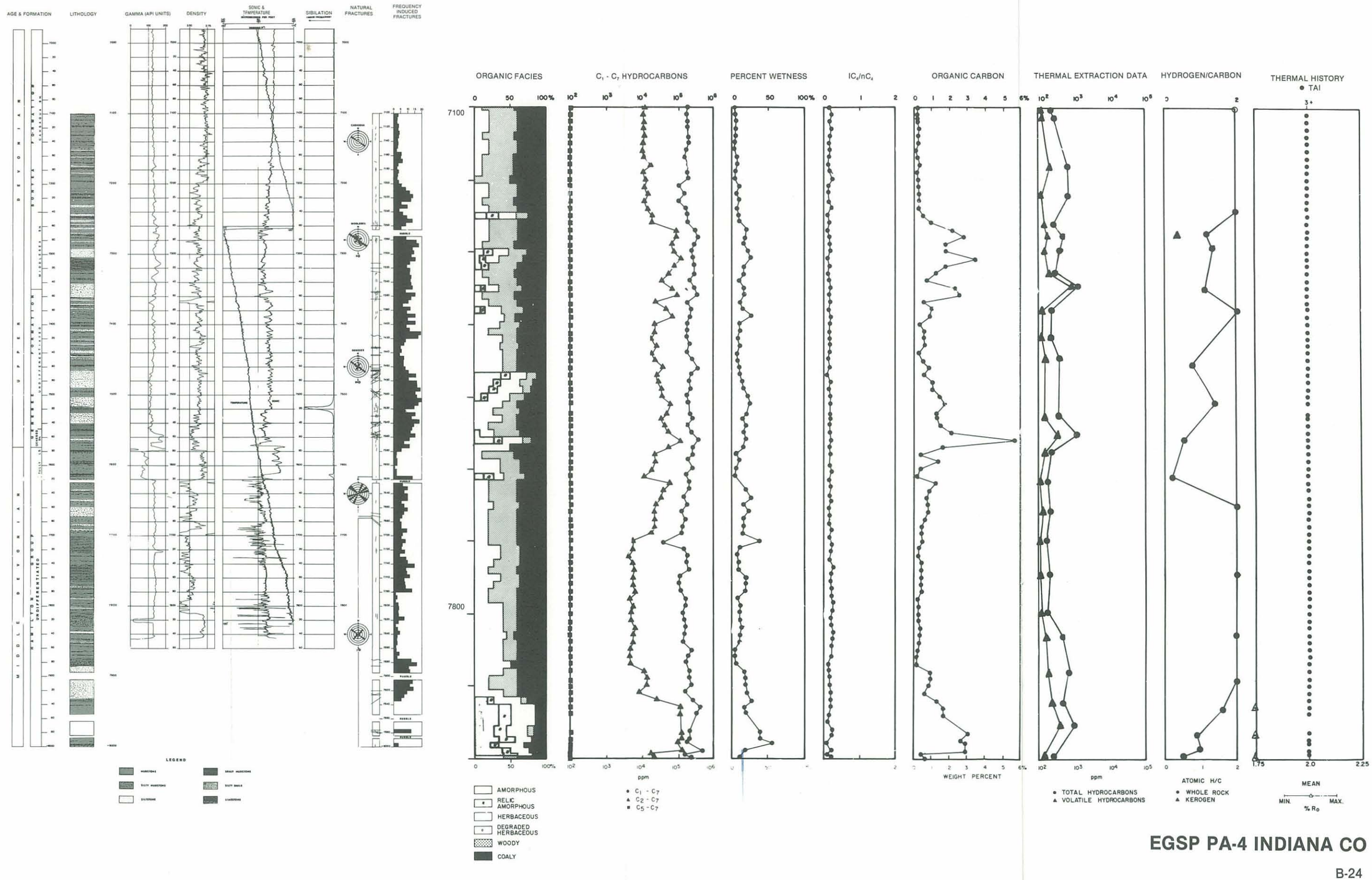
Well: Presque Isle State Park #1 A.P.I. No. 37-049-20846
Drilling Completed: October 1979



EGSP-PENNSYLVANIA NO. 4, INDIANA CO.

Well: Glenn McCall #5 A.P.I. No. 37-06d3-25073

Drilling Completed: November 20, 1979

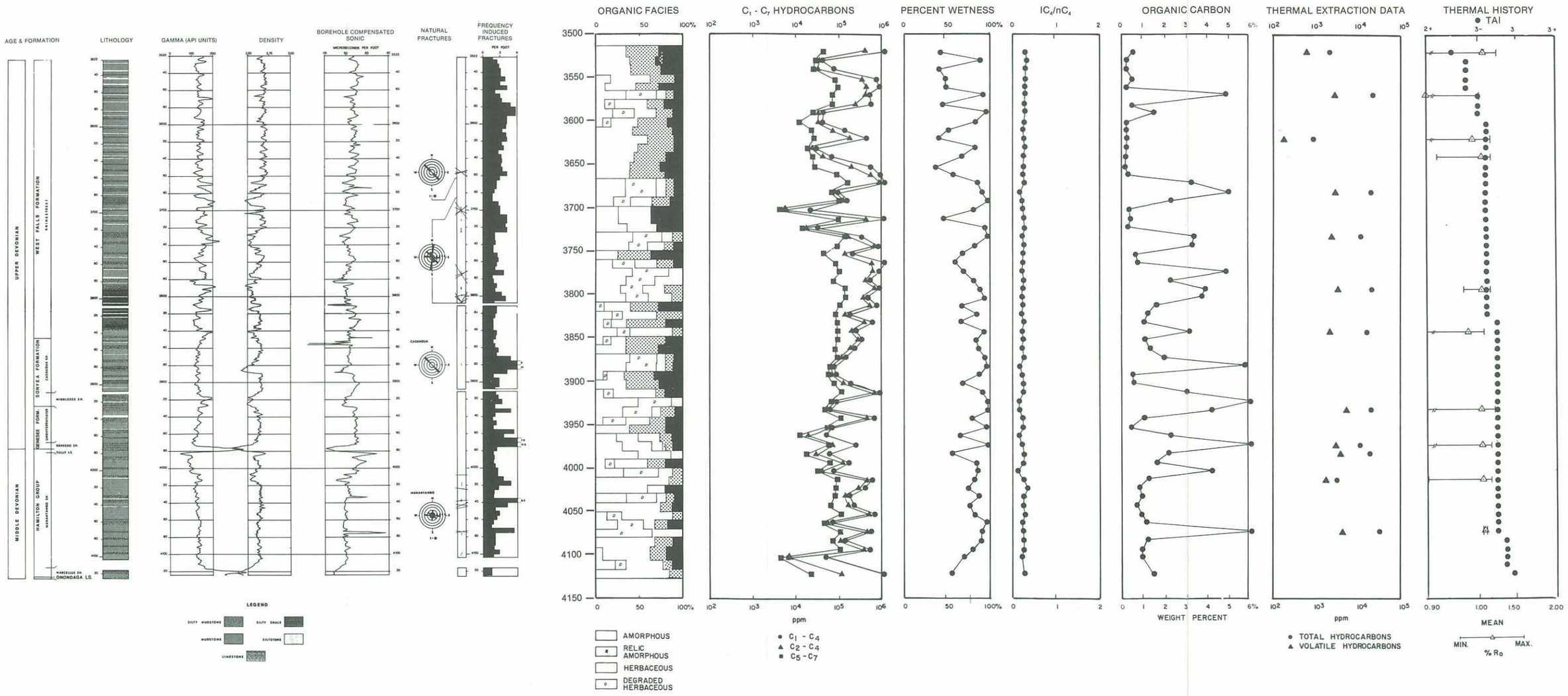


EGSP PA-4 INDIANA CO

EGSP-PENNSYLVANIA NO. 5, LAWRENCE CO.

Well: C. Sokevitz No. 1 A.P.I. No.: 37-073-20022

Drilling Completed: December 14, 1979

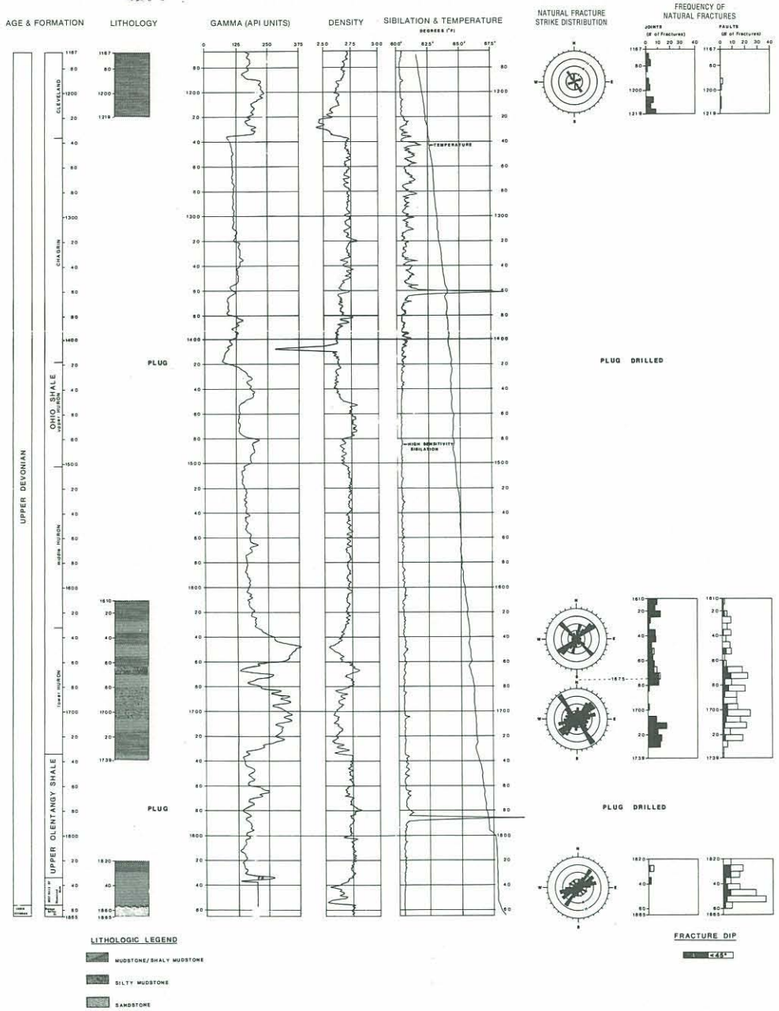


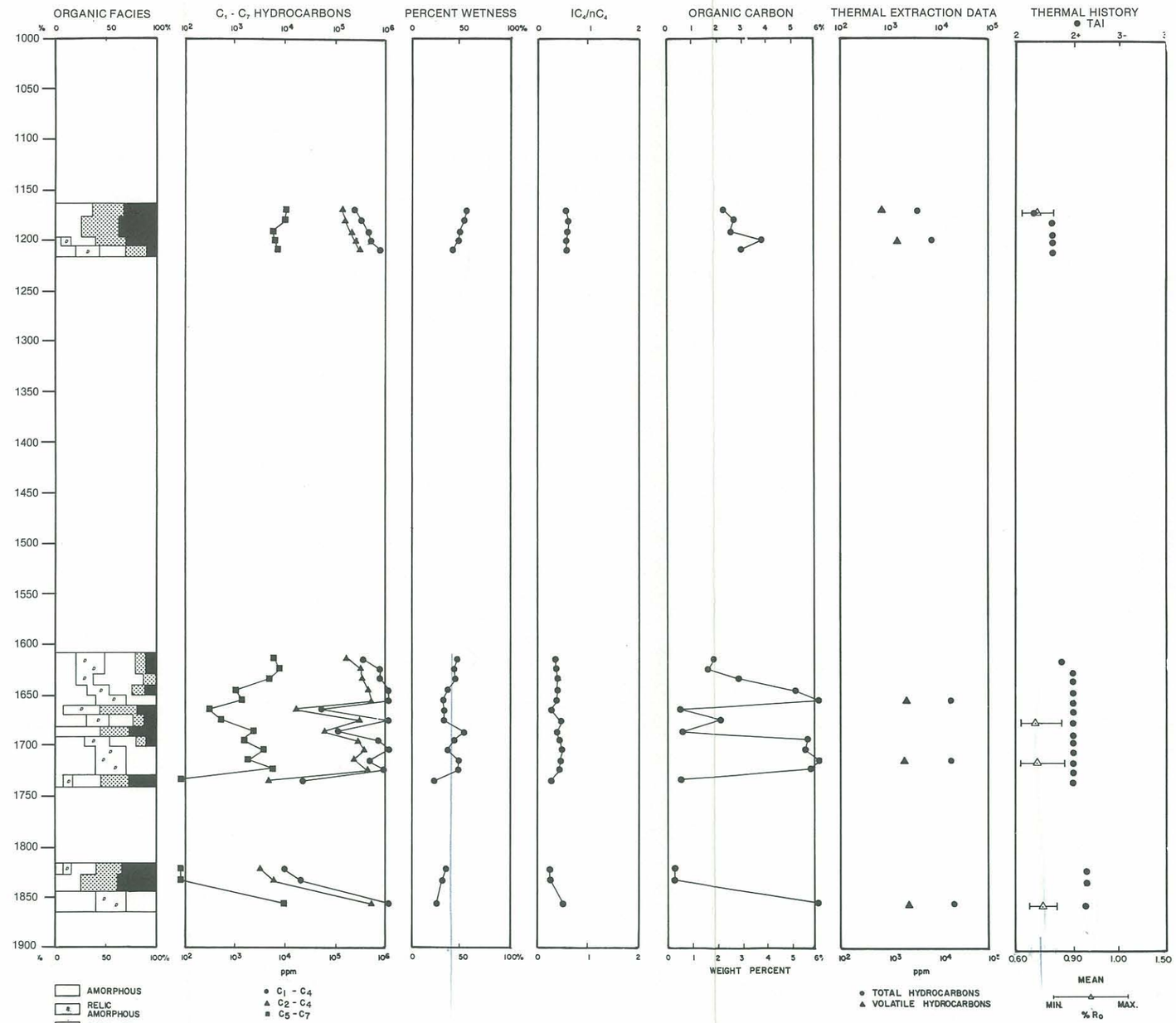
EGSP PA-5 LAWRENCE CO

EGSP TENN-9, GRAINGER CO.

Well: Gruy Federal #1

Drilling Completed: Jan. 1, 1980

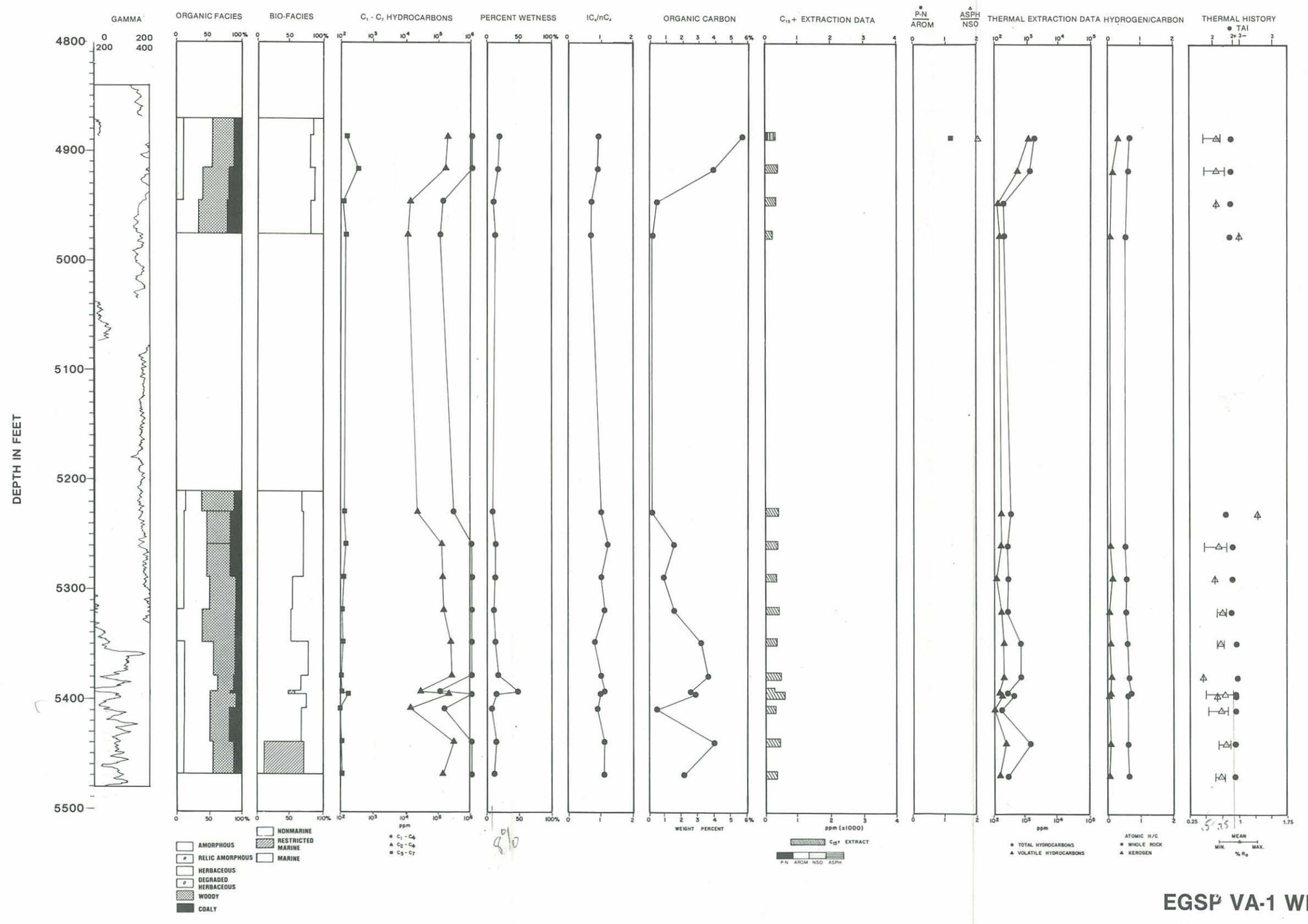




EGSP TENN-9 GRAINGER CO

EGSP VA-1 WISE CO.

Well: #20338

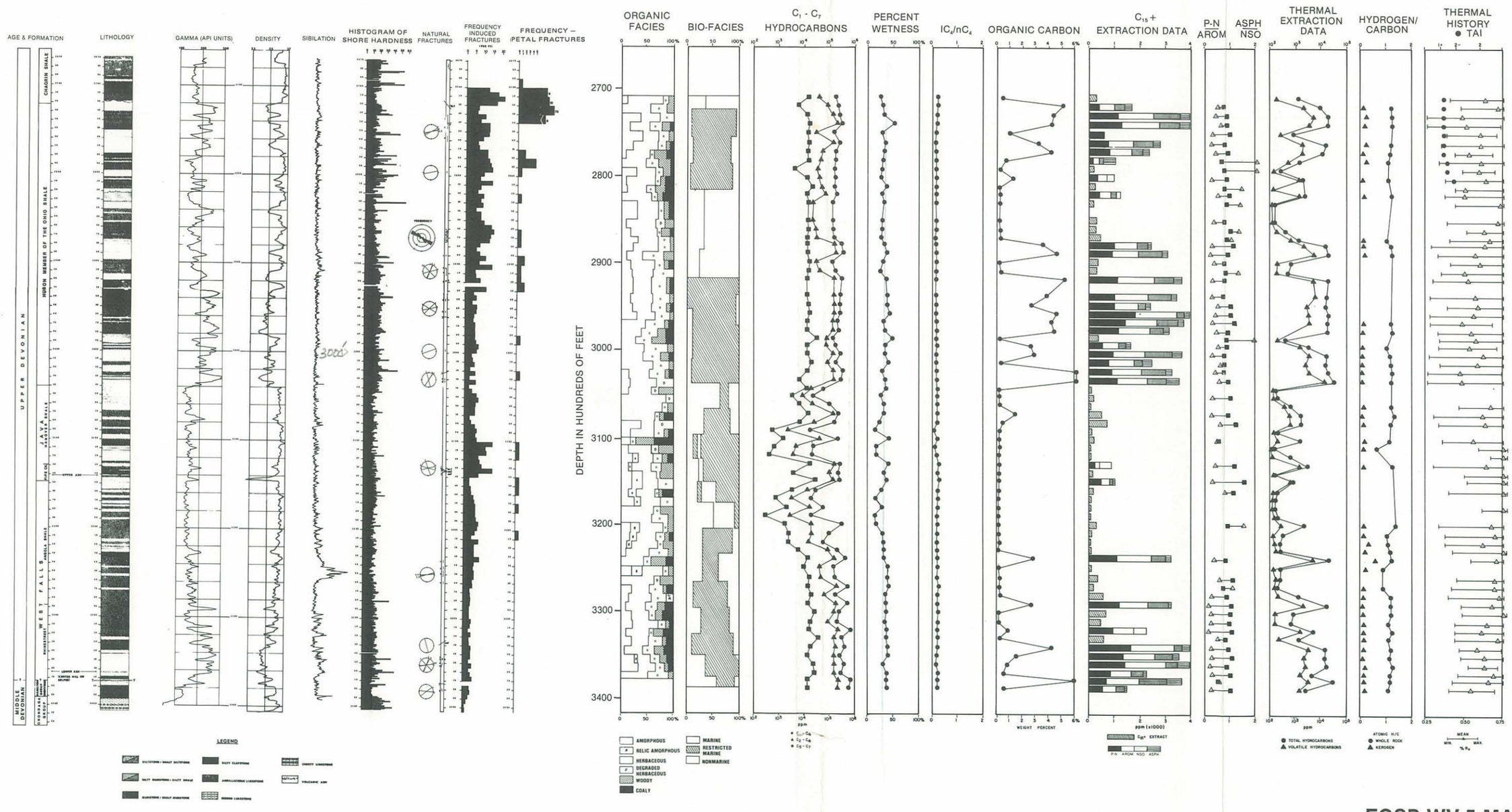


EGSP WV-5, MASON CO.

Well: D/K Farm #3

A.P.I. No. 47-053-20146

Drilling Completed: January 6, 1978



EGSP WV-5 MASON CO

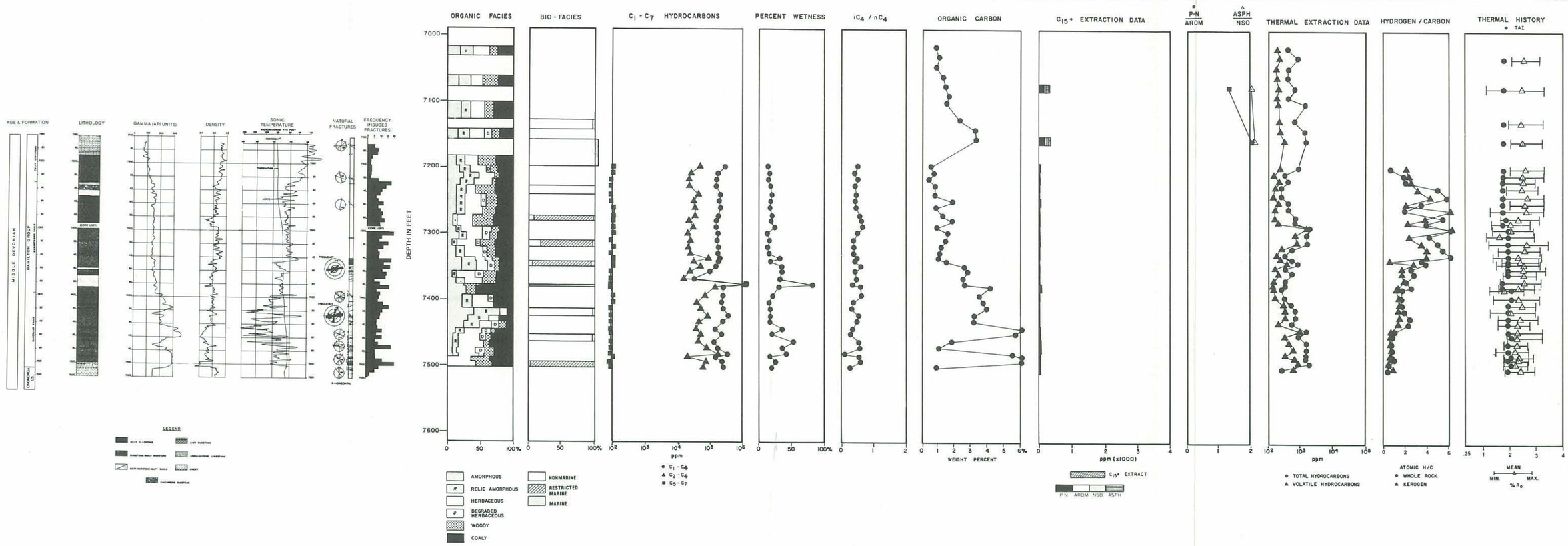
EGSP WV-6, MONONGALIA CO.

Well: M.E.R.C. #1

Drilling Completed: April, 1978

A.P.I. No. 47-061-20370

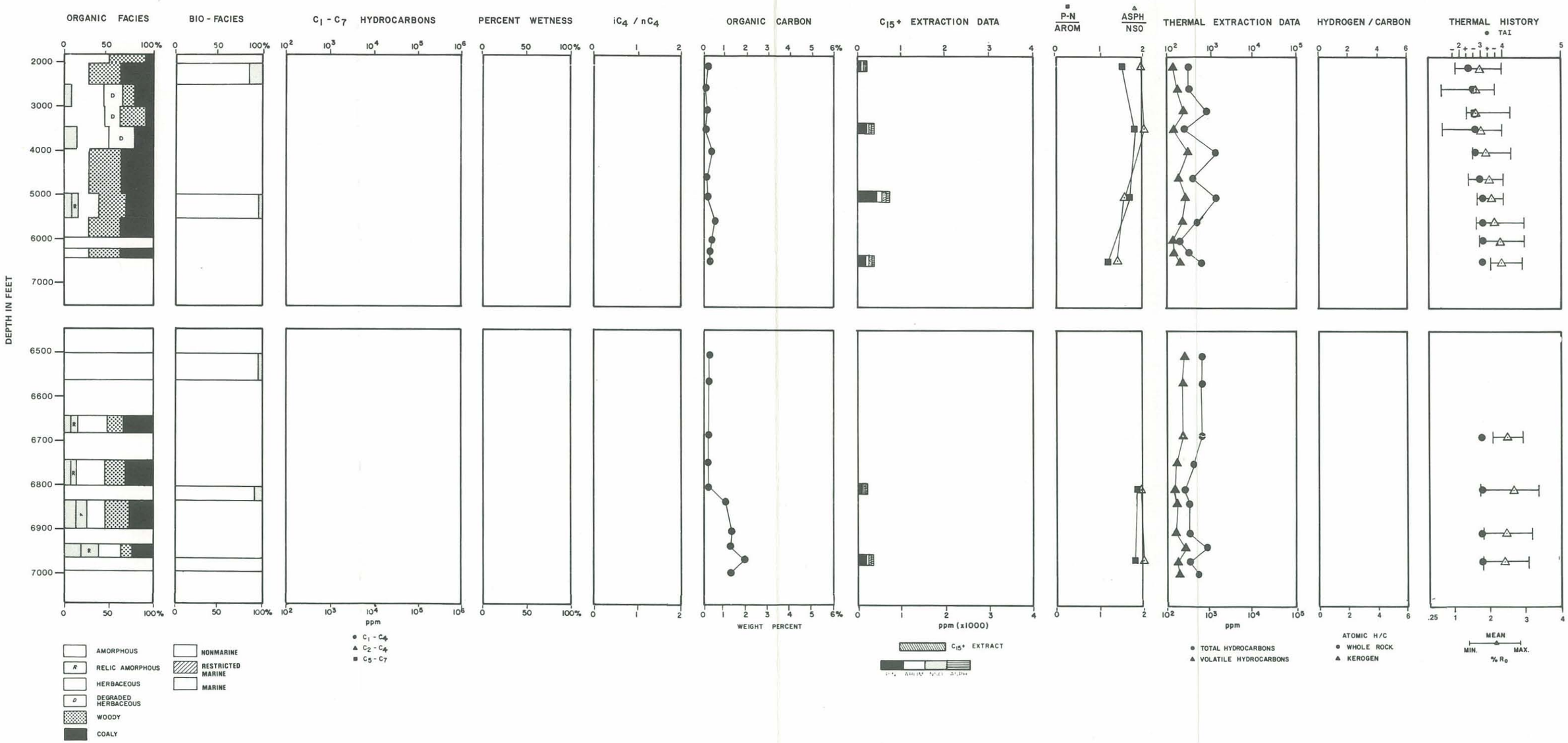
Sheet 1 of 2



EGSP WV-6
MONONGALIA CO

Sheet 1 of 2 B-29

EGSP WV-6, MONONGALIA CO. Sheet 2 of 2



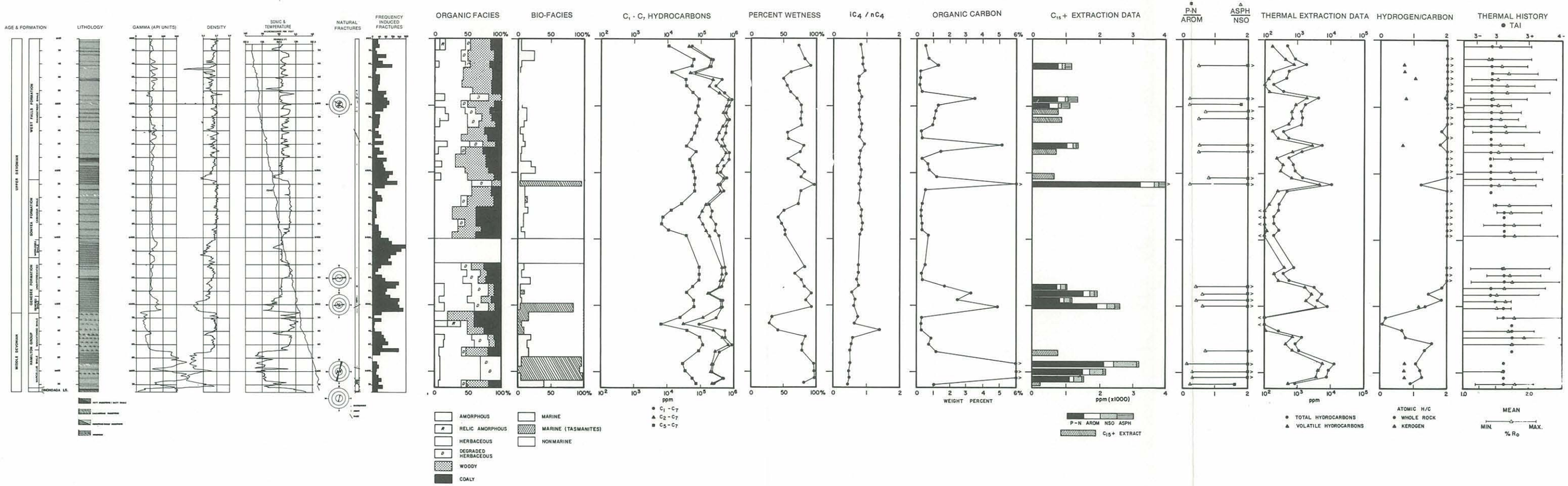
EGSP WV-6
MONONGALIA CO

Sheet 2 of 2

EGSP-WEST VIRGINIA NO. 7, WETZEL CO.

Well: Emch & Pyles No. 1 A.P.I. No. 47-103-20645

Drilling Completed; October 17, 1978



APPENDIX C

INDIGENOUS GAS ALGORITHMS

Algorithms for Indigenous Gas Values include:

Map Unit 1 - Early Marcellus Time:

$$IG\ (MCF/A \cdot F) = -126.58 + 43.66\ (OC) + 37.24\ (TAI),\ R^2 = 0.99$$

Map Unit 2 - Late Marcellus Time:

$$IG\ (MCF/A \cdot F) = -174.23 + 39.14\ (OC) + 54.38\ (TAI),\ R^2 = 0.95$$

Map Unit 3 - Hamilton Group/Post Marcellus Time:

$$IG\ (MCF/A \cdot F) = -40.15 + 41.95\ (OC) + 12.27\ (TAI),\ R^2 = 0.99$$

Map Unit 4 - Genesee/Geneseo Time:

$$IG\ (MCF/A \cdot F) = -41.10 + 39.41\ (OC) + 15.13\ (TAI),\ R^2 = 1.00$$

Map Unit 5 - Sonyea/Middlesex Time:

$$IG\ (MCF/A \cdot F) = -43.72 + 43.83\ (OC) + 12.80\ (TAI),\ R^2 = 1.00$$

Map Unit 6 - Early Lower Olentangy/Early Rhinestreet Time:

$$IG\ (MCF/A \cdot F) = -111.86 + 33.07\ (OC) + 42.72\ (TAI),\ R^2 = 0.98$$

Map Unit 7 - Late Lower Olentangy/Late Rhinestreet Time:

$$IG\ (MCF/A \cdot F) = -43.21 + 29.84\ (OC) + 18.41\ (TAI),\ R^2 = 0.98$$

Map Unit 8 - Middle Olentangy/Angola Shale Time:

$$IG\ (MCF/A \cdot F) = -17.59 + 32.14\ (OC) + 6.85\ (TAI),\ R^2 = 0.97$$

Map Unit 9 - Upper Olentangy/Java FM. Hanover Shale Time:

$$IG\ (MCF/A \cdot F) = -16.54 + 27.25\ (OC) + 7.64\ (TAI),\ R^2 = 1.00$$

Map Unit 10 - Early Lower Huron/Early Dunkirk Time:

$IG\ (MCF/A \cdot F) = -109.93 + 24.99\ (OC) + 56.79\ (TAI),\ R^2 = 0.98$

Map Unit 11 - Late Lower Huron/Late Dunkirk Time:

$IG\ (MCF/A \cdot F) = -59.68 + 28.70\ (OC) + 25.45\ (TAI),\ R^2 = 0.97$

Map Unit 12 - Early Middle Huron Time:

$IG\ (MCF/A \cdot F) = -29.40 + 27.63\ (OC) + 12.81\ (TAI),\ R^2 = 0.99$

Map Unit 13 - Late Middle Huron Time:

$IG\ (MCF/A \cdot F) = -16.53 + 27.16\ (OC) + 6.43\ (TAI),\ R^2 = 0.99$

Map Unit 14 - Early Upper Huron Time:

$IG\ (MCF/A \cdot F) = -60.39 + 22.79\ (OC) + 34.87\ (TAI),\ R^2 = 0.99$

Map Unit 15 - Late Upper Huron Time:

$IG\ (MCF/A \cdot F) = -83.78 + 24.84\ (OC) + 43.77\ (TAI),\ R^2 = 0.99$

Map Unit 16 - Chagrin Time:

$IG\ (MCF/A \cdot F) = -5.92 + 20.66\ (OC) + 4.46\ (TAI),\ R^2 = 0.98$

Map Unit 17 - Cleveland Time:

$IG\ (MCF/A \cdot F) = -118.97 + 27.15\ (OC) + 56.93\ (TAI),\ R^2 = 1.00$

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