SHALE GAS IN THE SOUTHERN CENTRAL AREA OF NEW YORK STATE:

Volume I

How to Find and Develop Shale Gas in New York State

Prepared for

NEW YORK STATE
ENERGY RESEARCH AND DEVELOPMENT AUTHORITY

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PREFACE

This report is presented in two volumes. The first volume is a general discussion of shale gas in New York State, and of the methods by which it may be obtained; this volume is intended to be a "how-to manual" for organizations considering drilling for shale gas. The second volume relates specific experience in locating and drilling four shale-gas wells in New York State.

EXECUTIVE SUMMARY - VOLUME I

Natural gas is formed in source rocks which originally contained the remains of plant or animal life, and which have since become deeply buried. Most commercial gas production is obtained from open-grained reservoir rocks, into which the gas has migrated from the source rocks. Conventional exploration for gas is the search for these reservoirs.

Shale gas is gas which is still trapped in the source rock; the grains of rock are too close together to allow the gas to move. Only if the rock is fractured can the gas flow to the well. Therefore shale-gas exploration (as distinct from conventional exploration) is a search for zones in the shale which are naturally fractured, or which are conducive to artificial fracturing.

The Appalachian Basin contains vast volumes of shale gas, and a significant portion of this is contained in three shales in south-central New York — the Rhinestreet, the Geneseo and the Marcellus.

The economics of shale-gas exploration in New York are not very attractive to the large oil and gas companies, which seek a rapid return on their investments. The situation may be quite different for organizations which are more concerned with security of supply and stability of cost; these may include manufacturing companies, colleges, hospitals, state institutions and industrial or agricultural cooperatives. For these, production of even a modest 50 Mcf/day/well, declining slowly over many years, would be appealing if it could be guaranteed.

To date three wells have been artifically fractured in the Marcellus shale of New York, and all three appear to be producers. This is only a small sample, and one of the wells is known to have encountered natural fractures. However, it does raise the possibility that (while nothing in exploration can be truly guaranteed) the chances of extracting at least some gas from the Marcellus — using modern fracturing techniques — are good.

The chances are improved if geological techniques can identify zones of a suitable degree of natural fracturing in the shale. These techniques are aided by detailed structure maps of the shale units; such a map has been prepared for the Geneseo shale, as part of this project.

The present conclusion is that the most likely source of shale gas in South-Central New York is the Marcellus formation.

Shale-gas wells should be drilled with air. The dry open hole should be logged with gamma-ray, density, temperature and noise logs. The shale should be artificially fractured using a nitrogen stimulation technique. Recommendations are given for each of these steps in the text.

1.1 INTRODUCTION

Natural gas is believed to be generated by the decay of organic material. Typically, this material is brought down the rivers and deposited on the sea bed with the river mud. Subsequent deposits bury both mud and organic material; the mud may become consolidated into shale, and the organic material — after the compressive and heating effects of prolonged burial — may yield gas.

The amount of organic material present in the shale depends primarily on the type and luxuriance of the vegetation on land. Where the amount is large the shale is said to be <u>organic-rich</u>; such shales are usually characterized by black or brown coloration, significant natural radioactivity, and low density. These shales become excellent source-rocks for gas. Other shales may be <u>organic-lean</u>; these may become useful source-rocks only if they are present in very large thicknesses.

Generally, much of the gas generated in a shale rises (or migrates) through the overlying sediments to the surface, and is lost. This loss may be accentuated if there are particularly permeable paths (open-grained rocks, or fault planes, or fracture zones) up to the surface. However, occasionally some of the migrating gas reaches an open-grained rock layer, and is trapped there by an impermeable rock above. This situation is the basis of conventional gas production; the gas is trapped in an open-grained <u>reservoir</u> rock and may be produced by drilling a borehole into that rock. The amount of gas recoverable depends on the volume of the gas-saturated reservoir and on the <u>porosity</u> of the rock; the rate at which this volume can be produced depends on the <u>permeability</u> of the rock.

Conventional exploration for gas is therefore the search for such reservoir bodies, in a position suggesting the likelihood of gas. Since these are few and far between, conventional exploration is aimed at very specific objectives — often no more than a few hundred acres in extent and no more than 10 or 15 ft in thickness.

Shale-gas exploration is quite different. First, it is directed at gas which has <u>not</u> migrated out of the source rock — for example, gas which is still contained within the tiny pores of an organic-rich shale. Second, the gas can be expected to be as widespread as the shale, and this can mean vast volumes; suitable shales extend, at thicknesses of hundreds or thousands of feet, over much of the Appalachian Basin. Third, although the porosity of the shale can be significant (so that vast volumes of rock imply enormous reserves of gas), the permeability may be very small; the gas is there only because it could not get out, and by the same token it cannot flow to a borehole.

Conventional exploration, therefore, is concerned to "hit the reservoir", and to find whether the reservoir contains gas. Shale-gas exploration has no difficulty at all in "hitting" the shale, and not much doubt whether the shale contains gas; the problem is to find shale in such a condition that it will allow gas to flow to the borehole.

Consequently, one can drill a well almost anywhere in the Appalachian Basin, and encounter shale gas; however, the flow may be miniscule, and quite uneconomic. The trick is to find — or artificially produce — local zones where the shale is permeable.

It has been known for many years that there are areas where the shale will produce. The Big Sandy field in Kentucky is a classic example; there is also significant shale-gas production in western New York, along the shores of Lake Erie. The distinctive feature which allows this production is now accepted to be the presence of <u>natural fractures</u> in the shale; after the consolidation of the rock, and the generation of gas in its pores, the shale has been fractured by natural processes, and the gas can now flow along the open fractures. The mechanism is that the gas <u>bleeds</u> into the fractures from the shale itself, and the fractures thus serve to collect the gas from a large volume of rock. Although the bleeding process from the matrix of the rock into a single fracture is very slow, significant production can be obtained if there is an extensive system of interconnecting fractures.

The other requirement for shale-gas production is that there must be some sort of impermeable seal above the fractured shale; if the system of fractures connects into a fracture or a permeable bed extending to the surface, all the gas will have been lost long ago.

The old shale-gas fields, therefore, represent zones in which a widespread shale has become locally fractured by natural processes. One approach to shale-gas exploration is to search for other such zones.

Another approach is based on the creation of a fractured zone within the shale by artificial means. This may be done by detonating explosives in the shale, or by pumping water or other fluid down a borehole (at very high pressure) until the rock cracks; such artificial fracturing processes are known generally as <u>stimulation</u>.

Obviously, the stimulation is more likely to succeed if the rock is already weakened by natural processes. Accordingly there are three approaches to shale-gas exploration:

- look for zones of natural fracture in the shale, and drill there,
- drill at <u>any</u> place where the shale is known to be present, and rely on stimulation processes to open up a fracture system,
- look for zones of natural fracture, and extend or infill the natural fractures by stimulation.

Of these, the second is the easiest, but the third is likely to yield more gas.

This, then, is the basic technical situation against which the economic considerations must be balanced. Historically, shale gas has offered no hope of the sort of bonanza occasionally obtained from exploration for conventional reservoirs; even from the best wells production was relatively modest, and the best that could be said for a shale-gas well was that the production tended to be maintained longer (to have a smaller <u>decline rate</u>) than that from a conventional well. Commercial exploration companies (and particularly the major ones) have therefore had little interest in shale gas; their natural concern is to drill wells which pay out early in their life. Even recent increases in the allowed and market price of gas have not provoked major exploration efforts for shale gas. The problem of finding zones of natural fracture in the shale is not one for which there are established solutions; the approach which relies entirely on artificial fraturing has clearly been shown to be unsuccessful in some areas, and the general attitude in the exploration industry is either negative or wait-and-see.

In a sense this is disappointing, for there can be no doubt that very large quantities of gas are at present locked up in the shale. Some years ago the feeling was that the exploration companies should be exhorted and goaded into shale-gas exploration for the national good. More recently, there has been an acceptance of the fact that such companies still have many opportunities available to them in conventional gas, and that shale gas (at present prices) may not be matched to their proper concerns and objectives. These considerations have provoked the realization that the exploitation of shale gas may properly and advantageously fall to manufacturing companies, hospitals, colleges and other organizations with major energy needs. If it were true, for example, that every such organization could drill a well, stimulate the shale, and obtain sufficient gas at a sufficient rate to satisfy its energy requirements for many years, then the economic considerations are quite different from those of an exploration company; the organization has no exploration overhead, and no pipeline costs, but it does have a compelling interest in security of gas supply and predictability of energy expenditure.

Accordingly it is the object of Part 1 of this report to set out, with a minimum of technical complications, the areas and circumstances in which industrial and institutional organizations can hope to find their own supplies of shale gas, to describe the techniques for drilling and producing gas, and to discuss the economics which can be expected.

It is only proper to point out that systematic exploration specifically for shale gas is relatively new; there is much yet to be learned, and presumably some disappointments yet to be suffered. However, the interest and the numbers of potential beneficiaries warrant this report at this stage.

1.2 THE SHALES OF SOUTH-CENTRAL NEW YORK

If a well is drilled to 4000 ft in Steuben County (as an example), the rocks penetrated are mostly shales. Some of these are organic-rich, and of great interest in the present context; others have negligible organic content, and hold no interest as source rocks. There are also two important limestones, and at least one important sandstone. All these formations have names, often derived from the place where the rocks outcrop at the surface. Figure 1.2-1b illustrates the rock sequence in such a well.

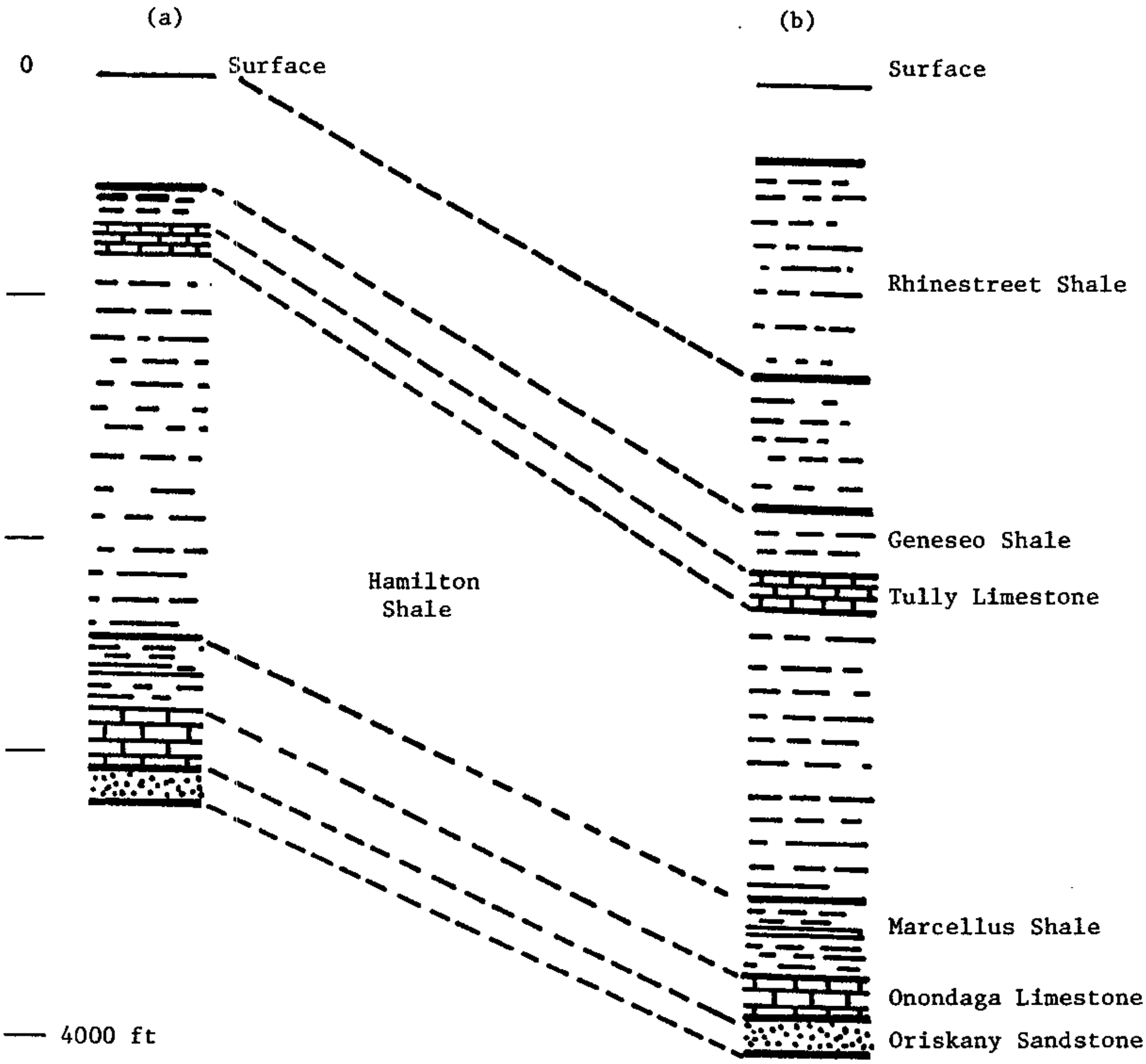

Figure 1.2-1 Typical geological columns in (a) Livingston County and (b) Steuben County.

The important markers in this sequence, easily recognizable to the driller, are the Tully limestone and the Onondaga limestone. Below the Onondaga limestone is the Oriskany sandstone, which is the traditional gas reservoir in Steuben County; this is irrelevant to the present discussion, except in that the drilling to this target has defined the thicknesses and distribution of the overlying shales, and often encountered shows of gas in them. Between the Tully and Onondaga is a very thick shale (the Hamilton shale) at the base of which is an organic-rich black shale called the Marcellus. Just above the Tully is another organic-rich black shale called the Geneseo. Higher in the sequence is a less rich but still prospective shale called the Rhinestreet. These three shales — in descending order the Rhinestreet, the Geneseo and the Marcellus — are the three primary concerns of shale-gas exploration in south-central New York.

A well drilled futher north, for example in Livingston County, would penetrate the same formations at less depth; this is illustrated in Figure 1.2-1a. Between the two locations, the rocks dip generally in a southerly direction, into the Appalachian Basin.

Thus to reach the Marcellus shale in Steuben County requires more drilling (and hence more expense) than in Livingston County. The depth of the shale is therefor an important factor in the economics. Figure 1.2-2 gives the approximate drilling depth through the Marcellus shale. Subsea depths to the base of the Geneseo shale are given in map series number 115 (see footnote [1]).

Also because of the dip into the Appalachian Basin, the shallower shale formations in the Steuben well may not be present in the Livingston well. Further, the thicknesses of the important shales change from place to place, as may their organic content. The next step in assessing the potential and the economics of shale gas at a proposed site is therefore the study of the maps in Figures 1.2-3 through 5, which show the presence and the total thicknesses of the organic-rich components of the important shales.[1] Economically, the first objective is to find a good thickness of organic-rich shale at shallow depth; there is also some advantage in having two or three shales present, to increase the options and chances of success.

1.3 LOCATION STRATEGIES

In shale-gas exploration, as in conventional gas exploration, an exploration company can range widely in search of the best locations to drill; it therefore uses all available techniques to identify the best prospects. A manufacturing company may have several plants, and need to know which location to

[1] These figures are based on maps prepared by A. Van Tyne (then of the New York State Geological Survey), and his colleagues, as part of the Eastern Gas Shales Project of the U.S. Department of Energy. The master maps, and other relevant studies, are available from the Morgantown Energy Technology Center, DOE, under the series numbers 100 through 131.

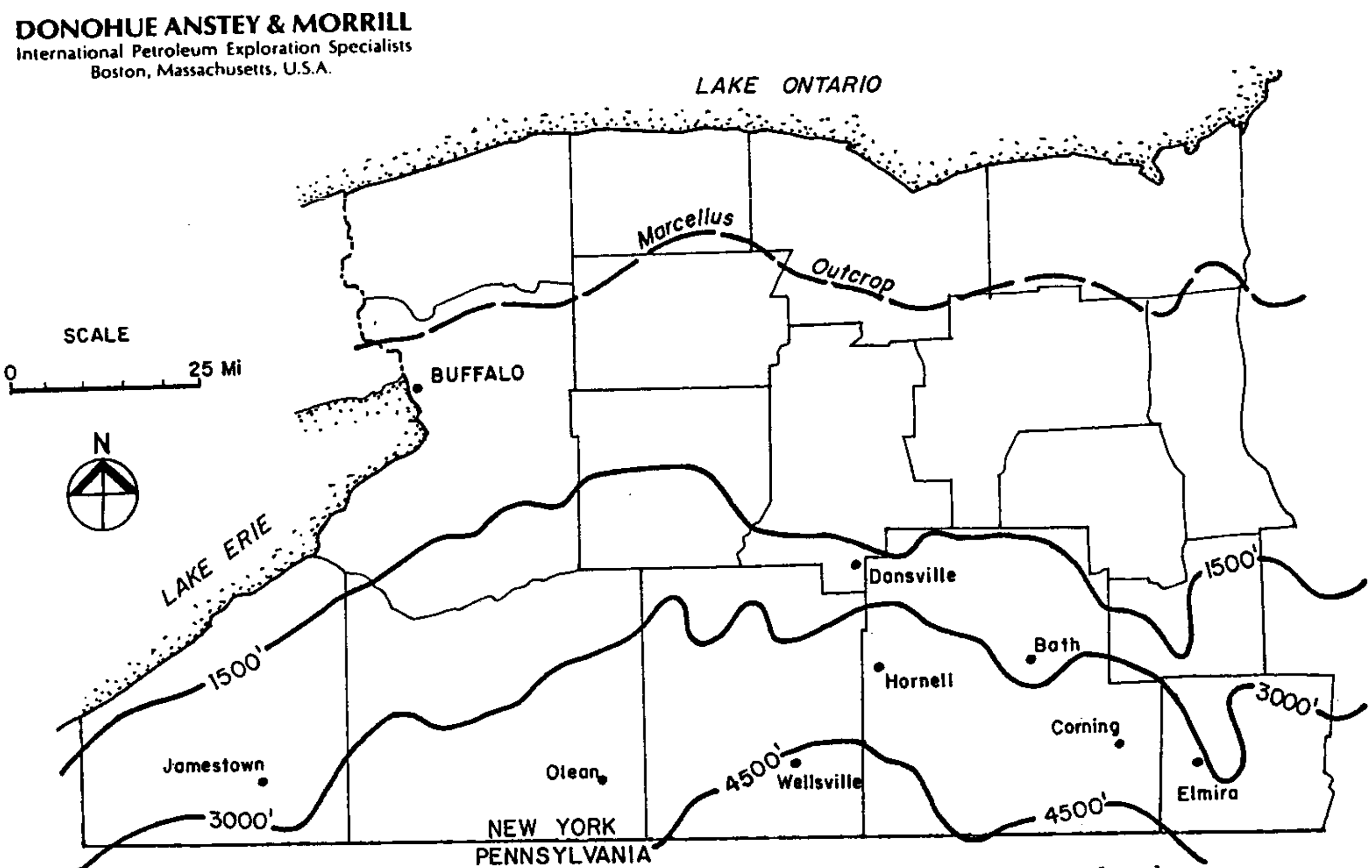

Figure 1.2-2 Map showing approximate contours of drilling depth (not sea level depth) required to penetrate the Marcellus shale.

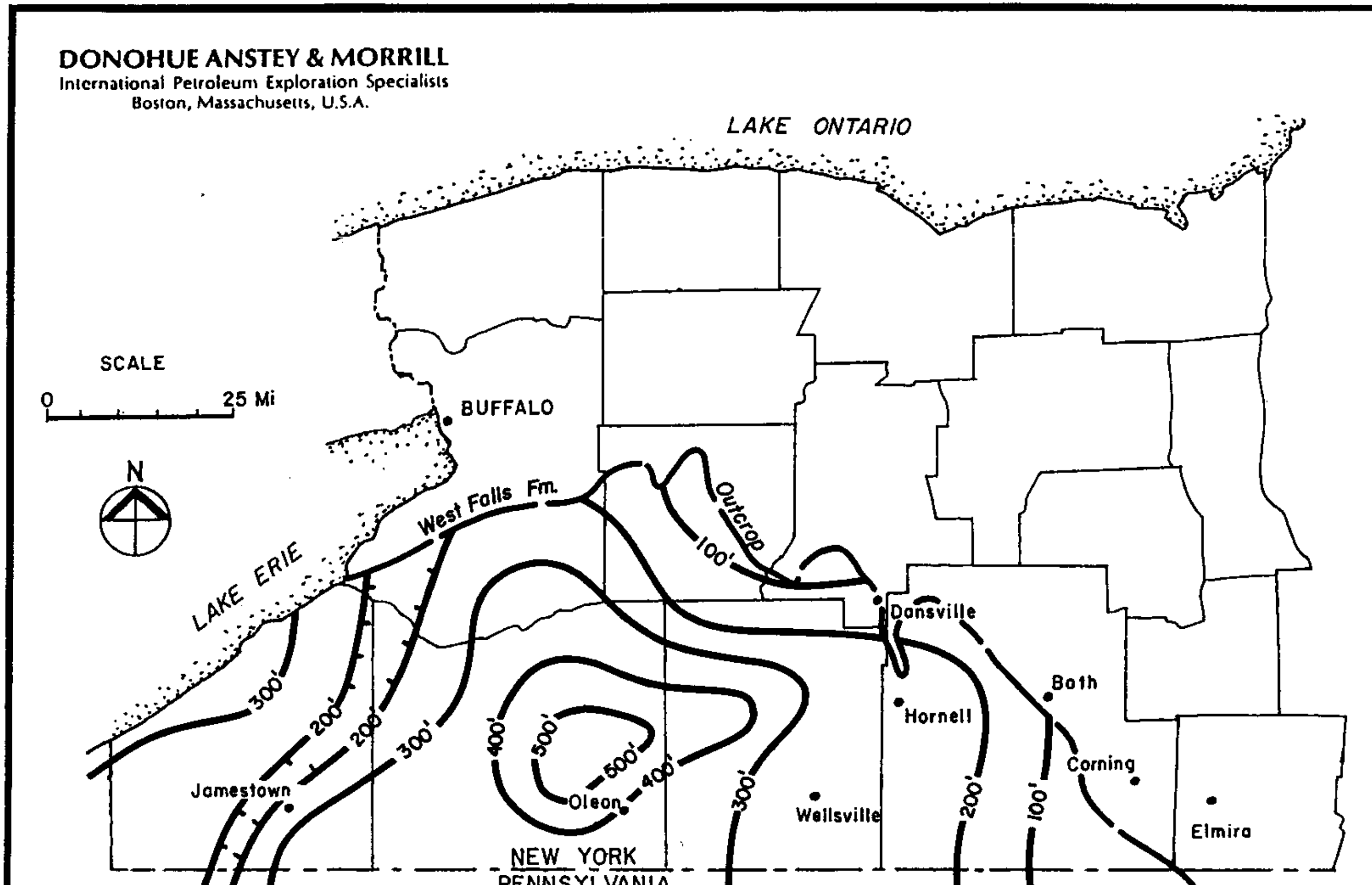

Figure 1.2-3 Thickness of black shale in the West Falls Formation (mostly Rhinestreet); data from sample studies. Thicknesses estimated from natural radioactivity, rather than color, are somewhat less, but show the same general trends.

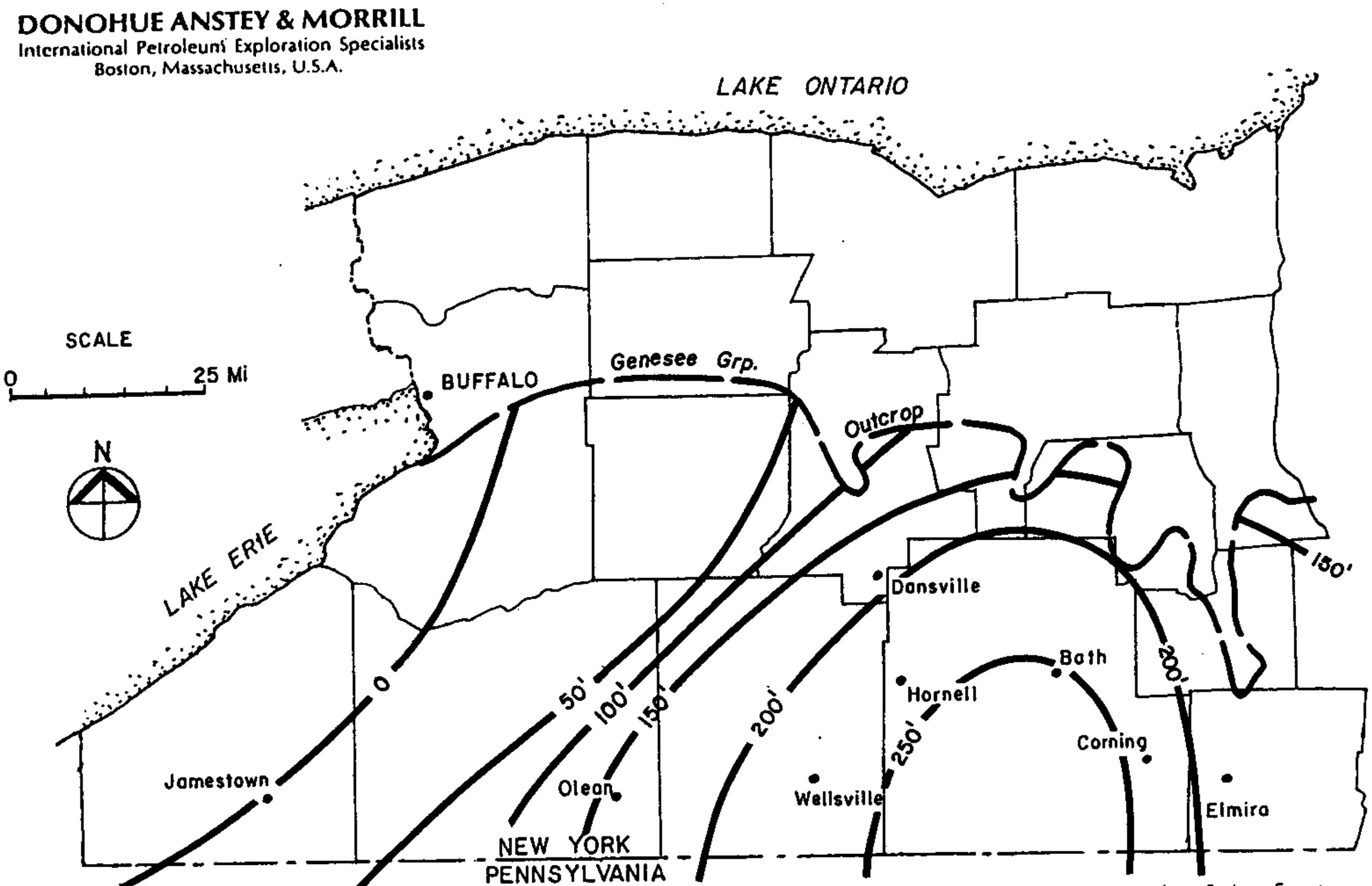

Figure 1.2-4 Thickness of the black shale in the Genesee Group (mostly Geneseo); data from sample studies. Thicknesses estimated from natural radioactivity, rather than color, are considerably less, but show the same general trends.

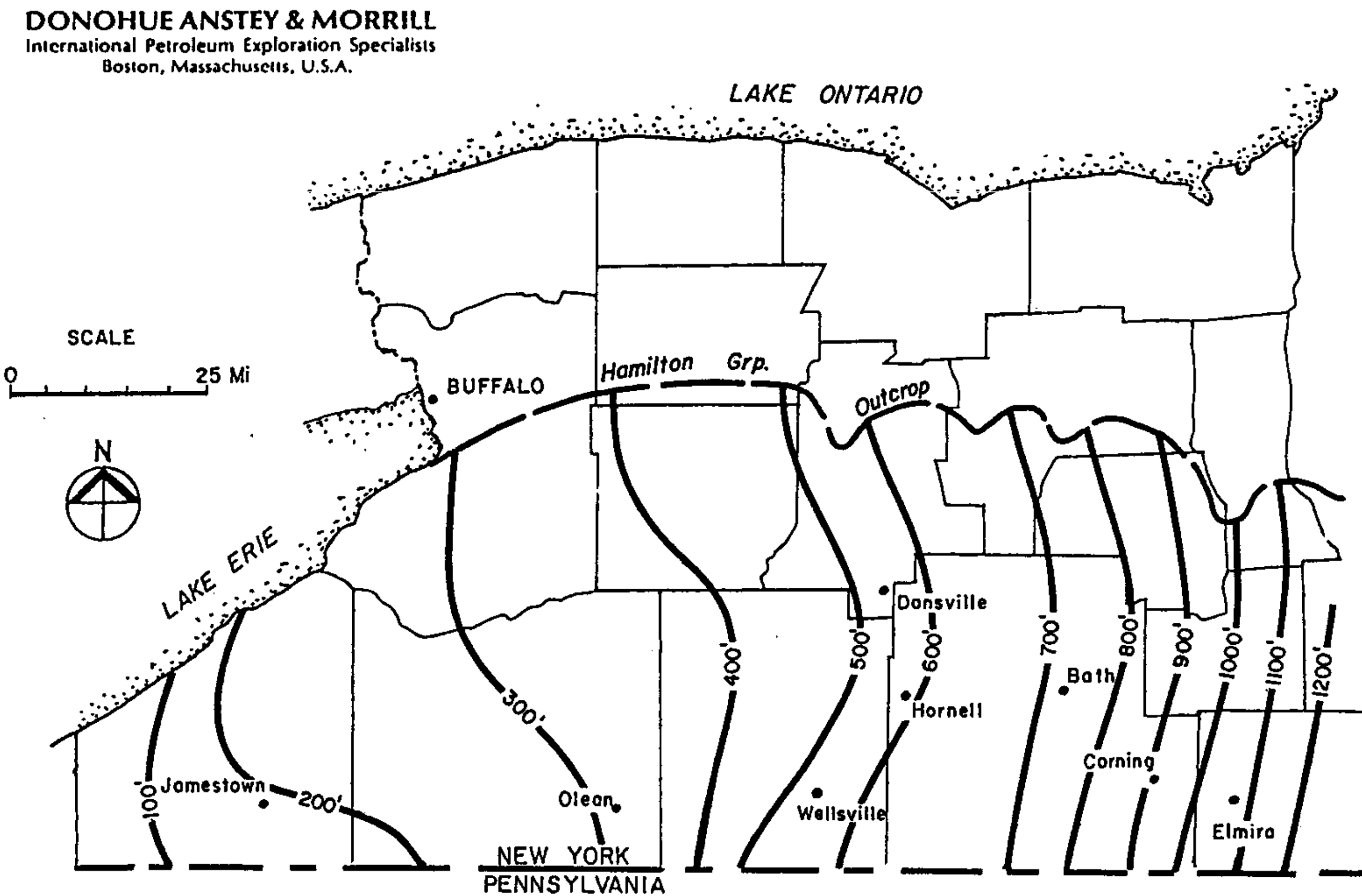

Figure 1.2-5 Thickness of the black shale in the Hamilton Group (mostly Marcellus); data from sample studies. Thicknesses estimated from natural radioactivity, rather than color, are very much less, but show the same general thickening to the east.

drill first. A college may have an extensive campus, and need to know how the chances of success vary over this spread. A cooperative may have a similar choice. An institution such as a hospital probably has little option in the location of its well; however, it is still worth assessing the suitability of this location, as an indicator of its potential. All interested parties are therefore concerned to know the techniques for successful location of shale-gas wells.

1.3.1 The Drill-Anywhere Approach

According to this approach, one checks only that a good thickness of organic-rich shale is available at reasonable depth, and proceeds to drill. In general, there is little chance of obtaining a significant natural flow of gas; success must depend on the stimulation.

Since the stimulation methods appropriate to shale gas are relatively new, and only recently established, there is little history on which to base the chances of success of this approach. In many wells in the southern part of the Appalachian Basin it is clear that there the chances are poor. In New York State only three wells have been stimulated in the Marcellus at the time of writing, and all three appear to be producers; there is therefore a possibility that the special characteristics of the Marcellus in New York will allow this approach. It is only a possibility; at least one of the wells is known to be unrepresentative of the Marcellus in general.

Of course, if this approach proved to work in New York, it would be a wonderful result; industries, institutions and cooperatives — wherever situated — could assure themselves of secure supplies of gas at known cost. But this cannot be promised at present.

1.3.2 The Old Shale-Gas Fields

Several shale-gas fields were discovered, produced and depleted in the 1920's, at a time when gas prices were very low. It is natural to ask if these fields could be revitalized at today's prices — either by modern stimulation, or by infill drilling, or by extension, or even by recharge after 50 years of abandonment.

The problem with this approach is the paucity of the records. Such records as exist are derived from the oral recollections of old-timers; they are incomplete, sometimes contradictory and often unlikely. However, as an exploration rationale it is better to start with something than with nothing, and the revitalization of old fields remains a valid approach. Attempts to do this in the old Rathbone and Dansville fields are described in Part 2 of this report; one or two other fields remain as possibilities.

1.3.3 Gas Shows

As noted above, a great number of wells targeted at the Oriskany sandstone have passed through the shales. Sometimes shows of gas are encountered in one or other of the shales, and some drillers (but unfortunately not all) record these shows and their depths on the drilling log.

When the recorded shows are plotted on a map, the appearance is of some clustering of the shows. It is natural to expect that a zone of such clustering would be a good place to drill a shale-gas well. However, there is a caution: the distribution of wells is very uneven, and the clustering of the shows must be distinguished from the clustering of the wells over the Oriskany gas-fields. In many areas, between the major Oriskany structures, there are few wells or no wells; the absence of shows does not necessarily degrade these areas.

A map displaying the reported shows is available from DOE (series number 101 in the reference on page 1-8).

1.3.4 The Search For Natural Fractures

The approaches listed above do not ask what is the mechanism of shale-gas production. The question is now: What additional approaches are indicated by the conclusion that gas production — both natural and stimulated — is likely to be larger if the shale is naturally fractured?

One approach attempts to observe or measure the effects of fracturing. Another attempts to identify geological happenings which are likely to have caused fracturing.

In the first category comes the study of satellite and aerial lineaments, and the measurement of seismic velocity.

Satellite lineaments are alignments of topographic features (river valleys, scarps, ridges, etc.) observed on images of the earth's surface obtained from orbiting satellites; these images may loosely be considered as photographs of the earth from very high altitude. Large-scale geological features become evident on these images — features which cannot be seen on conventional aerial photographs, or in the field. Thousands of images of New York State, at different seasons and with varying degrees of cloud cover, are available from the EROS Data Center, Department of the Interior. Aerial lineaments are alignments of topographic features seen on aerial photographs (which may be from high altitude or low altitude); aerial photographs of New York State are available from commercial survey companies.

Study of both satellite and aerial lineaments reveals a profusion of alignments cutting across the glacially-eroded topography of New York State. According to one theory of shale-well location, a drilling site should be selected in a zone of intense lineaments, or at the intersection of two or more lineaments. The hypothesis is that the lineaments are surface expressions of deep-seated geological movement, and that such movement is almost certain to have caused some fracturing of the deep rocks.

This approach to shale-well location has lost some favor recently. For one thing, lineament analysis is highly subjective, and no two analysts are likely to come to the same conclusion. For another, a surface expression of deep-seated geological movement is likely to mean that gas-transmitting fractures extend all the way to the surface, so that all or most of the gas is lost; this has led to the conclusion that one should not drill on a lineament, but at a distance from it such that the induced fracturing is not likely to connect to the surface vent. This distance cannot be predicted for a particular situation, and in any case the approach has to make the undemonstrated assumption that the fracture path is vertical. To the extent that lineament analysis is still practised, low-altitude aerial lineaments are regarded as of more value than high-altitude and satellite lineaments.

The detection of fractured zones in the shale by the measurement of seismic velocity is based on the fact that the speed of sound in rocks is reduced if the rocks are fractured (particularly if the fractures contain gas). The standard method of seismic exploration (which makes some sort of bang at the surface, and times the echoes) can be adapted to give a measurement of the speed of sound in the shale, provided that the shale is at least some hundreds of feet in thickness. This method is therefore a rather direct indication of the desired situation — extensive gas-filled fractures in the shale. The method has so far been tested by only one well, in Ohio[2]; present indications suggest success. However, the method is subject to major inaccuracies where the surface and the near-surface are geologically complicated. This militates against its use in New York, where the surface material can change abruptly from exposed bedrock to thick glacial fill. Consequently, no attempts to use the method have yet been made in New York; in any case, the method is very expensive, and, therefore, most suited to larger exploration companies.

The second category of methods of identifying natural fracture systems is that of recognizing geological happenings which are likely to have caused fracturing.

One geological prerequisite to fracturing is that the rocks be brittle. Young shales tend to be plastic, and only after prolonged burial do shales become brittle; this is why the old shales of New York (approximately 350 million years old) are candidates for shale-gas production, whereas young shales elsewhere are not.

Another relevant property of the rocks is obviously their strength; for the same applied force, weak rocks fracture and strong rocks do not. This strength, clearly, is a function of the constitution of the rock, of its porosity, and of the cement binding its grains. In part these depend on the conditions existing when the rock was originally laid down, and in part on what has happened since; although there must be local variation of the strength of the shale (and hence its susceptibility to fracture), it is scarcely possible to determine now, from

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[2] See Final Report on A Project to Test Shale Gas in Ohio, prepared by Donohue Anstey & Morrill for the U.S. Department of Energy and the Ohio Department of Energy.

the surface, where these variations are located. Perhaps the only clear conclusion from these thoughts is that the very organic-rich shales, by reason of their large content of organic material, are likely to be less dense, less strong and less brittle than organic-lean shales in comparable positions.

The other input to the fracturing mechanism, in addition to the strength and brittleness of the rocks, is the applied force. Fracturing forces may be occasioned by gravity, or by deep rock movement associated with adjustment of the earth's crust. Figures 1.3.4-1 and -2 illustrate two fracturing situations associated with gravity. Figures 1.3.4-3, -4 and -5 illustrate fracturing situations associated with folding and flexing of the deep rocks. Figure 1.3.4-6a illustrates a fault, where vertical movement has occurred at a fracture plane. Figure 1.3.4-6b illustrates a double fault or graben, as a limiting case of Figure 1.3-4-5b.

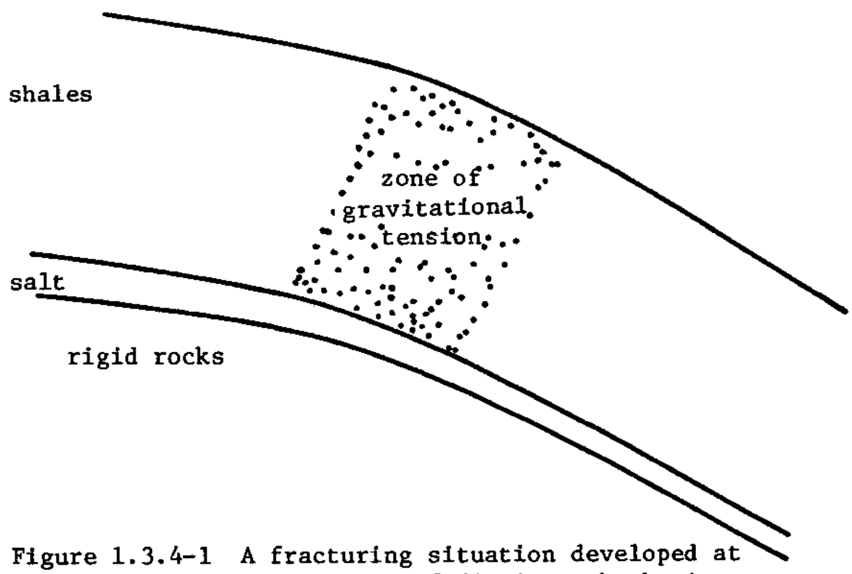


Figure 1.3.4-1 A fracturing situation developed at an increase of dip into the basin.

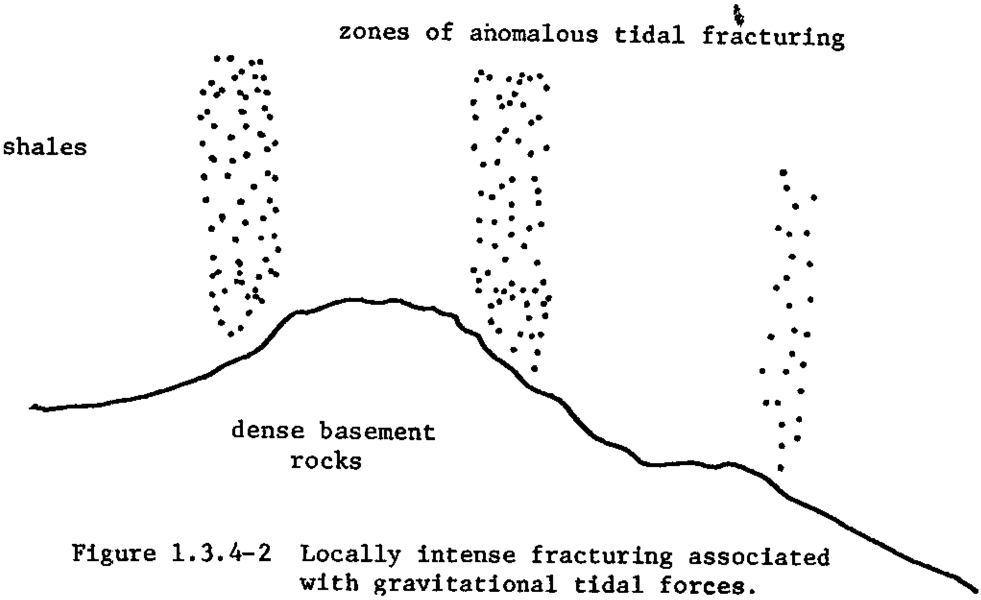


Figure 1.3.4-2 Locally intense fracturing associated with gravitational tidal forces.

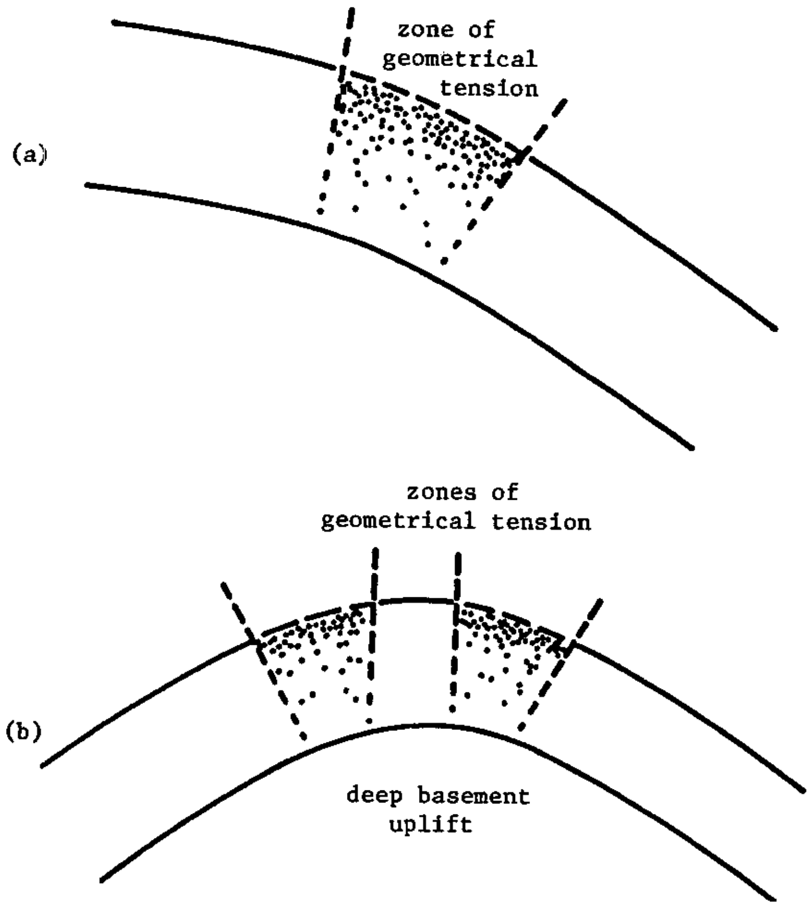


Figure 1.3.4-3 Fracturing situations associated with geometrical tension.

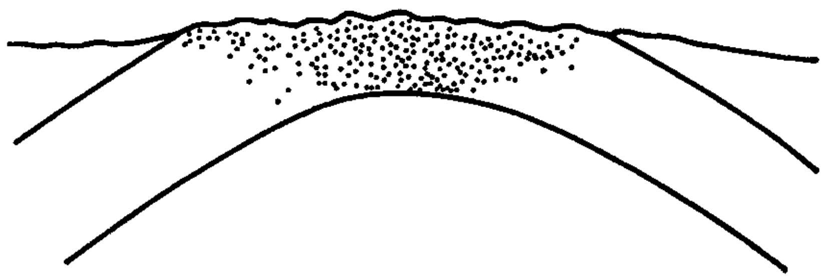


Figure 1.3.4-4 Supplementary fracturing associated with removal of compression due to overburden.

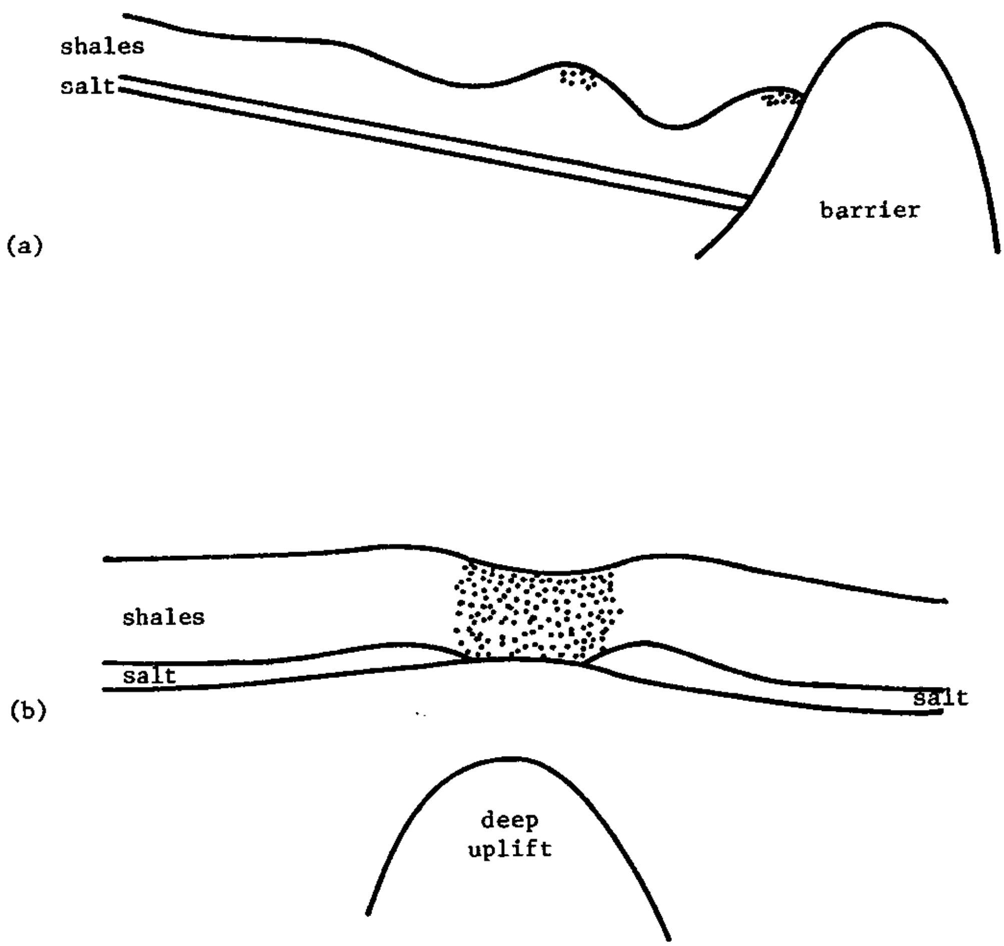
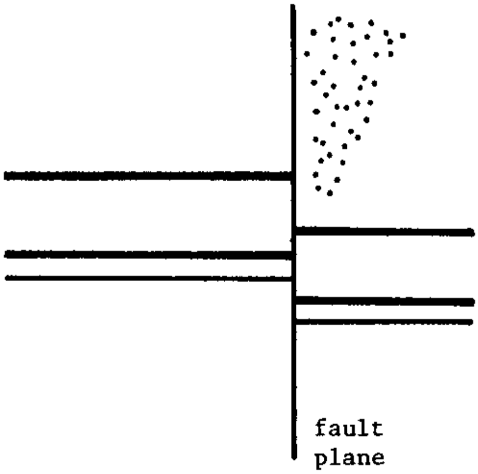


Figure 1.3.4-5 Two additional situations likely to yield fracturing.

(a)



(b)

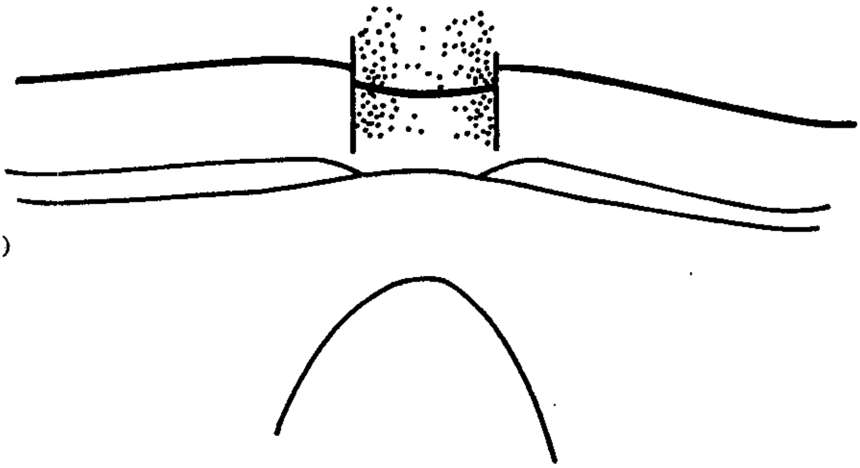


Figure 1.3.4-6 The development of faults.

For a period after the formation of a fault, until the fault plane becomes mineralized and cemented, it offers an excellent conduit for gas. It can be expected, therefore, that if the fault extends to the surface (or to upper permeable layers), the gas released from a shale into the fracture system near the fault has been lost. Thus, although major faults extending to the surface can be detected on satellite images and aerial photographs, there is little inducement to drill on the fault — and great uncertainty whether it is worth drilling a few hundred feet from the fault. If the fault does not come to the surface, however (or to wherever the surface was at the time of faulting), then the zone of faulting through the shale may be a good target.

The difficulty of locating fracture zones in the shale is now clear. If the fracture system has an expression at the surface, the gas has probably gone. If it does not, how is it to be found? The only surface measurement which is likely to detect the fracture system directly is that of seismic velocity, which (as discussed earlier) may not be feasible in the glaciated topography of New York. Therefore the search has to be by inference from the known geology; wherever features of the types illustrated in the preceding figures are known to exist, fracture zones can be postulated in the dotted areas[3].

The first method of establishing the whereabouts of such features is by compilation of the driller's logs from all the wells drilled in south-central New York. As noted earlier, the drillers usually record the tops of the two formations which show as clear markers — the Tully and the Onondaga. They are not able to detect with assurance the tops of the important shales, and so it is necessary to work by inference from the Tully or the Onondaga. The depths to the Tully, for example, can be corrected to a datum (usually sea-level), posted on a map, and contoured to give a representation of the top-Tully surface over the State. This contour map has been constructed as part of the present project; it may be consulted in the office of DA&M in Boston.[4] Although the organic-rich

[3]Of course the illustrated features do not constitute a complete list; many other features and combinations of features may be surmised. One important possibility is the "depositional structure" discussed by Hennington in another Final Report to the U.S. DOE.

[4]This map is more detailed than the base-Geneseo map referred to on page 1-8.

Geneseo shale lies unconformably on the Tully below it, the structural features evident in the top-Tully contours may be taken as a first measure of those in the Geneseo. This is also reasonably safe, as an approximation, for the Rhinestreet.

For the Marcellus, overlying the Onondaga, it is necessary to prepare a separate map, for the top-Onondaga. This is because, in several areas, there are marked differences between the top-Onondaga and the top-Tully surface; in general the flexing and folding in the Onondaga is more marked than that in the Tully, and many faults and grabens in the Onondaga do not exist at Tully level. These faults and grabens may be very important for shale gas in the Marcellus (and possibly in the rest of the Hamilton) since they satisfy the requirement that the faults do not extend to the surface. It is expected that the Onondaga map will be made in a later stage of the present project.

The manner of use of these maps is as follows. Suppose that a college is considering drilling a well to test for shale gas. For economic reasons, of course, it would prefer to drill only through the Rhinestreet, or perhaps through the Geneseo. What are its chances of encountering natural fractures in these shales? These chances are increased if the top-Tully map, at the college location, shows a hinge line, where the spacing of the contour lines suddenly decreases (Figure 1.3.4-7a). The chances are increased on the upper flanks of anticlines, where the contour signature resembles Figure 1.3.4-7b. The chances are increased on the downthrown side of faults (Figure 1.3.4-6a); the faults are shown as heavy dashed lines on the maps, with the downthrown side indicated by D. The chances are increased within and above grabens if the sides are vertical or sloping outwards; the contour signature of grabens is typically two near-parallel faults, both marked D in the space between them. Such a situation might have a contour signature like Figure 1.3.4-7c.

If none of these features is present at the college location, the interest switches to the Marcellus, and to the search for similar contour signatures in the Onondaga map.

In the reading of contour maps, it must be remembered that in some places the contours are well defined, whereas in others there is virtually no control.

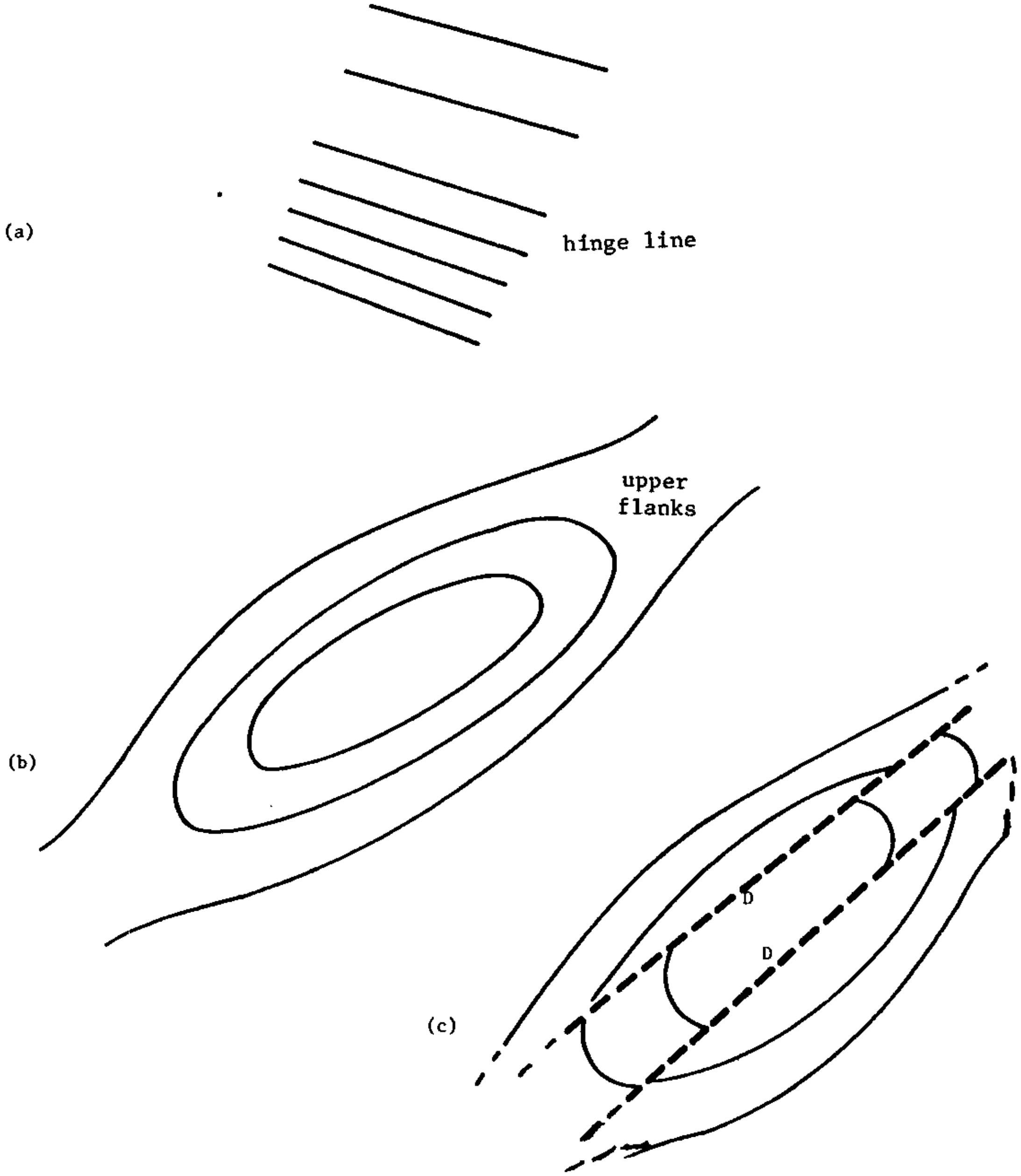


Figure 1.3.4-7 Contour signatures of a hinge line, an anticline, and an anticline cut by a graben.

Thus the contours are generally established beyond major doubt where many wells have been drilled; this means over the anticlines containing the known Oriskany fields. Between these anticlines there may be few wells or no wells; in this case the contours are drawn to suggest the simplest allowable situation, and there is the possibility that interesting features exist unknown. So the absence of any encouragement to expect fracturing, in an area of sparse well control, should not be taken as precluding success.

Where there is doubt of the presence or degree of a feature suggesting fracturing, the seismic method may be used to resolve it. This is not the seismic method in the sense used previously — for the measurement of the speed of sound in the shale — but in the traditional sense of an echo-sounding technique. Thus used, it can determine the ups and downs and faults and grabens in the subsurface formations (particularly, in this context, the Tully and the Onondaga).

For a specified investigation, a seismic crew can be hired (usually during the summer) for about $4000 a mile. The technique is to lay out a line along a convenient road passing the proposed well location, preferably at right angles to contours. For technical reasons, the line can scarcely be less than 3 or 4 miles long. Then the hope is that the final results of the seismic work show a geologic feature, at Tully or Onondaga depth, which encourages the expectation of fractures in the shale. The fear is that the seismic results are not conclusive, and require another line, and another...

Some exploration companies, seeking gas in the Oriskany or deeper formations, have conducted extensive seismic surveys in New York State. Then, becoming disillusioned by failure, they have left the area, and offered their seismic results for sale through brokers. The cost is typically $400-600 a mile. Thus it would be folly to commission a new seismic survey without checking what is already available; Figure 1.3.4-8, as an example, shows seismic lines available from one source.

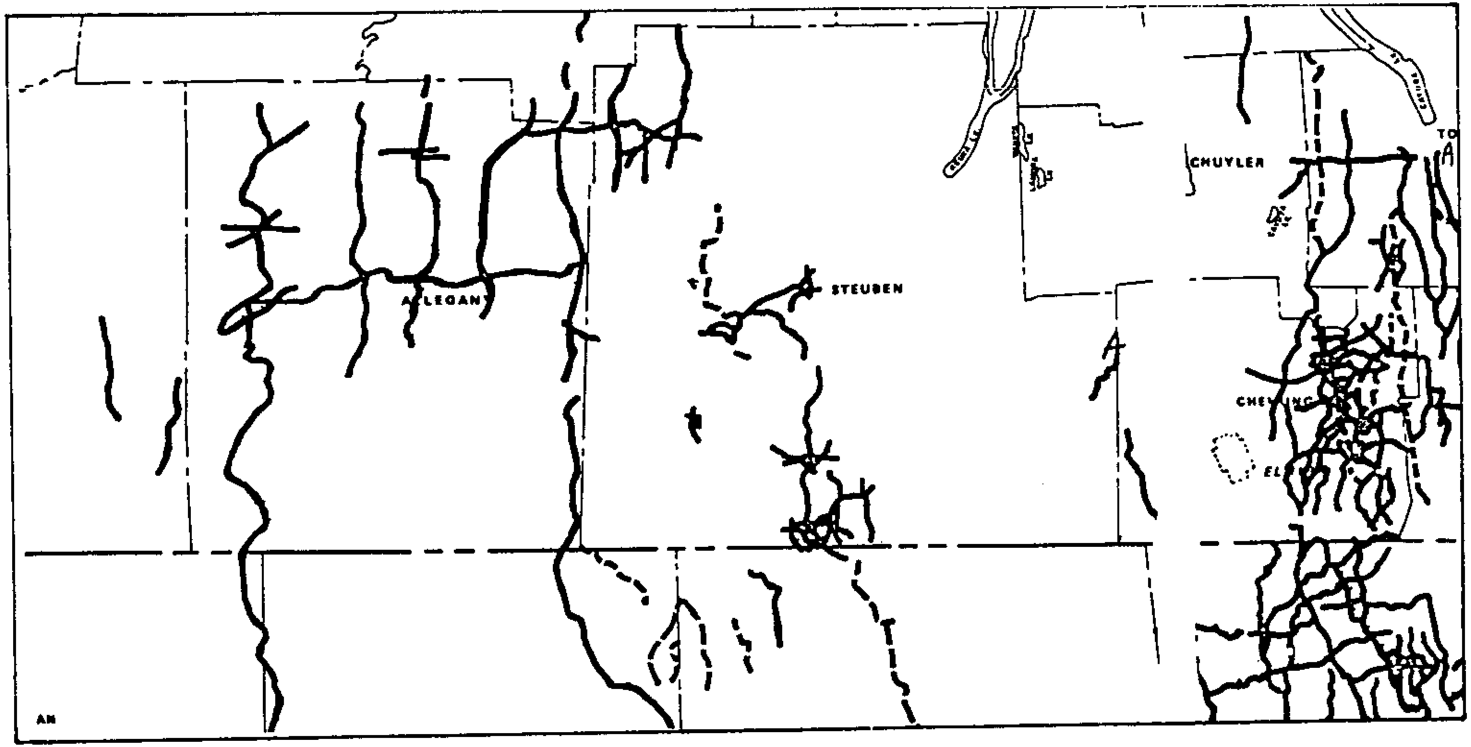


Figure 1.3.4-8 Seismic lines available from one brokerage source.

Some fracture situations, as discussed earlier, owe their existence to deep-seated movements in the basement. These are often detectable (though with less resolution than that given by seismics) by the study of magnetic maps. Local maps made from ground measurements are available in some areas; full aeromagnetic coverage is available in the extreme southern part of the State, extending down into Pennsylvania.

This long section may be summarized as follows:

- The chances of useful shale-gas production are increased if the shale is naturally fractured, provided that the fractures do not extend to the surface.

- The density of satellite and aerial lineaments may suggest areas of natural fracture, though with the risk that at least some of the fractures extend to the surface.

- The only method which approaches a direct indication of the existence of fractures at depth is that of measuring the speed of sound in the shale, using seismic velocity analysis. This is an expensive and rather technical method; further, it may not work in the glacial conditions of New York.

- Otherwise, the probable existence of natural fractures can be inferred from the presence of geologic features likely to generate them. Prime candidates are hinge lines, flexes, uplifts, faults and grabens. In areas of dense drilling, the existence and location of these features can be established by contouring the depths to marker formations broadly conformable with the shale.

- The seismic method can be used to confirm the existence and location of such features.

1.3.5 The Search For Conduits

Figure 1.3.5-1 illustrates what would be a very attractive situation. In very diagrammatic form, it suggests that three separate fracture systems in the shale intersect a "conduit" (which may or may not be horizontal). Then a well in the

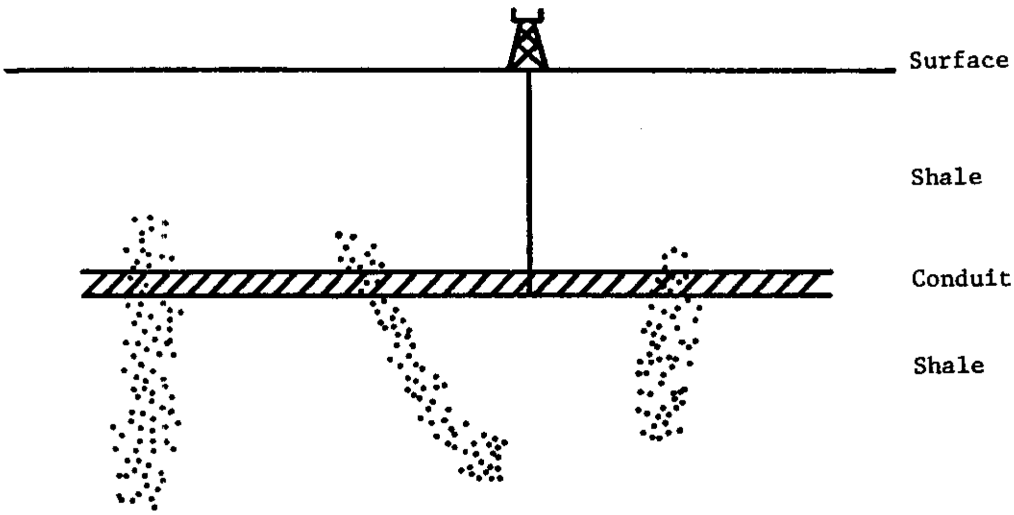


Figure 1.3.5-1 An idealized conduit system.

position shown can obtain gas from a considerable volume of the shale, provided the gas can flow from the three fracture systems along the conduit to the borehole. And the well location is not critical — the well itself need not penetrate a fracture system.

The first candidate for such a conduit would be a permeable bed such as an open-grained sandstone. In this case the situation may appear to be totally conventional; the discoverers may naturally conclude that they have a conventional sandstone reservoir full of gas, and produce it accordingly. Only as additional information becomes available may it be evident that the amount of gas being produced is larger than could be expected from the known thickness of the sandstone, and that the well is actually a shale-gas well. It is likely that many of the old shallow gas-fields of New York and Pennsylvania are of this type, and that their nature as shale-gas fields has never been fully recognized.

The second candidate for such a conduit might itself be a fractured zone. For example, it is possible that a layer within the shale, deposited very rapidly or at a time of rapid subsidence, became overpressured on burial; although in an old rock it is likely that the overpressure has been relieved, yet after relief the shale particles are not likely to have settled into the same degree of compaction as the shale above and below. Such a layer, then, may still have anomalous permeability.

A conduit of this type is believed to have been demonstrated in the Corning area of Steuben County. Two wells have been drilled to test it; one was a clear failure, and the other produced a gas flow which declined very quickly. The present assessment of this conduit is therefore negative, but the concept of a conduit remains very attractive if one can be found elsewhere. The exploration strategy is to search the records of neighboring wells for shows of gas (at substantially the same level) which do not come from bodies of conventional reservoir type.

1.3.6 Shallow Gas And Geochemistry

It is often observed, in drilling for oil and gas, that shallow gas pockets are encountered above significant accumulations of petroleum. These are of no commercial importance, in general; indeed they are a nuisance. They occur because the seals (or cap-rocks) on the deep accumulations are not perfect, so that tiny amounts of gas continually seep upwards; if these encounter a silty or sandy reservoir body on the way up, with a trap above, then a small gas pocket is formed. Of course, small gas pockets of indigenous gas occur in many rock sequences; the present concern is with additional gas pockets derived from petroleum at greater depth.

Where fractures exist in the sequence, but these fractures do not extend to the surface, there is even more reason to expect gas pockets in any sandy or silty layer above or near the top of the shale. These gas pockets may have large — even dramatic — flows of gas when they are penetrated by the drill, but the gas flow is short-lived and uneconomic for commercial exploitation.

The reason for mentioning these shallow gas pockets is that they could conceivably form the basis of an exploration technique. Small gas pockets may exist everywhere, but an area where they exist in profusion is likely to be a target for important deeper gas.

The first assessment technique would be the drillers' records of gas shows at shallow depth (for example, up to several hundred or a thousand feet). Unfortunately the drillers, knowing that these shows have no intrinsic commercial interest, do not usually record them.

A second technique would be to use the fact that these gas pockets (or at least the larger ones) are likely to show as locally strong reflections — bright spots — on seismic results. Although this approach is very effective in seismic work at sea, the surface conditions and the usual recording geometry in New York (coupled with the cost) probably exclude it in the present context.

A third technique would be geochemical — the testing of soil and/or water samples for chemicals or bacteria indicative of a supply of hydrocarbons. This is not detecting shallow gas pockets so much as gas which has actually escaped to the surface; consequently there is a risk that it is merely indicating gas which has long since been lost from the deep accumulation. The method is subject to "noise" from woodlands, marshes and the drips of crank-case oil from Joe Blow's tractor. However, it does remain a possibility; at the time of writing it is to be tested under another DOE contract.

Finally, the significance of surface seeps cannot be dismissed entirely. This is said with some hesitation, because nearly every landowner loves to talk about the smell of gas in his well water, or the rainbow rings on his pond. Much of this is of little consequence. However, it does appear to be well authenticated that, during the life of the old Dansville shale-gas field, it was possible to set light to small seeps of gas through the mud in a creek bottom. So listen... but be cautious.

1.3.7 Combinations

In practice, of course, no one would adopt one of the above location strategies in isolation from the others. However sophisticated the technique for finding natural fracture systems, it still makes good sense to prefer the areas of old shale-gas production, to search the records for shows, and to listen to the stories of old timers.

1.4 DRILLING THE WELL

Two matters must receive attention before a well is drilled — the lease, and the permit.

It is essential to have the mineral rights before drilling. An exploration company obtains these by taking a lease from the landowner; typically, such a lease in New York might have the following characteristics:

- The lease grants an exclusive right to develop the land for petroeum purposes.
- The lease may be for all petroleum production, or it may be restricted to particular depths or formations.
- During the primary term of the lease (1-10 years) the lessee may elect to commence drilling operations, or to defer such operations; in the latter case he must pay "delay rentals," typically $1/acre/year in New York.
- If the land is not developed for petroleum within the primary term, the lease terminates.
- If petroleum is discovered within the primary term, the lease is automatically extended as long as production continues (the secondary term).
- The landowner receives 1/8 of the value of the petroleum produced. In addition, there is usually an entitlement to free gas, up to some reasonable domestic consumption.

An organization planning to drill a well on its own land obviously does not need a lease; however, it should check that the mineral rights to its land have not been leased to others. If they have, and the lease is not about to terminate, it may be able to negotiate a recovery of the rights; this may be eased if the recovered rights are restricted to drilling the shale.

The permit to drill a well is issued by the New York State Bureau of Mineral Resources, Department of Environmental Conservation (in Albany). The Bureau publishes a booklet, "Rules and Regulations for Mineral Resources", which summarizes the law. Among the requirements likely to be imposed by the permit are:

- The well cannot be less than 660 ft from a lease boundary, 1320 ft from a well producing from the target formation, 100 ft from an inhabited dwelling, 150 ft from a public building, 75 ft from a road and 50 ft from a public river, stream or other body of water.

- Surface casing must be set to ensure that the well does not contaminate potable water.
- If the well is an interesting one, geologically, samples of the drilling cuttings must be taken — typically every 10 ft — and submitted to the State.
- If and when the well is abandoned, stipulations are made as to how this should be done.
- If a field is discovered and developed, restrictions are imposed on the spacing of the wells; in New York these are typically 40 acres.

A permit application must include a properly surveyed plat of the proposed well location.

The next step, after issuance of the permit, is to make an access road and to clear the site. The road must be capable of taking the drilling rig, and the site must be large enough for the several-or-many trucks needed for the stimulation; both of these depend on the depth of the target.

A drilling rig appropriate to a target of 3000 ft or less is likely to be truck-mounted, and to represent 4-5 tractor-trailer loads. Beyond this depth the rig is likely to be trailer-mounted and to represent perhaps 13 loads. It may be necessary to go out-of-state to find a drilling contractor who can offer the appropriate rig. Mobilization costs can be minimized by waiting until the rig is in the area.

The drilling is invariably commissioned from a drilling contractor. It normally takes one day to move in and rig up. Then the well is "spudded". The first stage is to drill the hole for the surface casing; this must extend below the deepest potable-water level, and it is usual to drill to 500 ft with an 11-inch bit. Because of the likelihood of water, this part of the drilling may be done using mud as a circulating medium; alternatively, the drilling may be started with air and then changed to mud when and if water is encountered. The steel casing (normally 8 5/8-inch) is then lowered, and set in the hole by pumping cement down the inside and up the annulus. This may take one day, after which the cement must be left (for perhaps 8 hours) to cure.

The cement inside the surface casing is drilled out with a 7 7/8-inch bit, and drilling then continues to total depth (TD). For a 1500-ft hole this may take 1 1/2 days; for a 3000-ft hole 3 1/2 days; and for a 4500-ft hole 5 1/2 or 6 days. The drilling is relatively easy in the shale, and drilling difficulties are unusual or absent.

As soon as the drill is in the shale, it is desirable (perhaps even mandatory) that the drilling should be done with <u>air</u> as the circulating medium. This is because of the risk that the shales contain smectite, a clay mineral which swells on contact with untreated water; such swelling can permanently reduce or eliminate gas-permeable paths through the shale. If no formation water is encountered during the drilling, therefore, it is best to drill with air alone. If small quantities of water are encountered, a specially-formulated soap is added to foam the water, so that the flow of air can carry the foam back up the hole. If the quantities of water encountered are too great for this, the drilling medium is changed from air to mud, and potassium chloride (typically at 2% concentration) is added to inhibit the swelling of the shale. In particularly difficult cases, it may be necessary to "case off" the formation producing the water, in a manner analogous to that used for the surface casing; this adds significantly to the expense, but has not (so far) been found necessary in New York.

As the drilling proceeds, the Tully limestone is evident as a marked decrease of drilling rate. The Geneseo may be evident, just before the Tully, by the blackness of the cuttings. Similarly the black Marcellus may be evident just before the hard Onondaga.

In the southern tier of counties the Marcellus is divided into two by a thin limestone called the Cherry Valley. Sometimes drillers mistake the Cherry Valley for the Onondaga; in the context of shale gas from the Marcellus, it is very important to be sure that the well passes through the Cherry Valley and through the lower Marcellus to the Onondaga.

But it may be important not to penetrate through the Onondaga (which in some parts of the area, southwest of Bath, is only 10-12 ft thick) into the Oriskany. Of course, one may be lucky, and hit an Oriskany gas field. More likely, the Oriskany will produce only water, and this water may imperil the shales above.

It may be practical to terminate the drilling in the Onondaga, and to test the shale, while keeping open the option of deepening the well to the Oriskany (as a gamble) if the shales prove unproductive. If this is desired it should be planned, since it affects bit sizes and casing diameters.

As discussed earlier, the well may encounter significant natural flows of gas from shallow gas pockets. Up to some reasonable flow (in the driller's judgment, perhaps 1000 Mcf/day) the gas can be flared while the drilling continues. For greater flows it may be necessary to shut down the rig while the gas blows down. In some cases it may be necessary to change from air to mud (treated with potassium chloride, of course) in order to contain the gas.

At this stage the drilling is complete, but the drilling rig is still required to run the casing. Before that, geophysical logs must be run in the open hole to measure appropriate properties of the rocks. The operation consists of lowering one or more measuring tools down the hole, on a wire line, and recording the measurements, as a function of depth, on a strip-chart log.

Although a large range of logging tools is available, only a few of these have been found useful in shale-gas exploration in New York. Specifically, it is wise to run:

- caliper, measuring variations in the diameter of the hole,
- gamma-ray, measuring the natural radioactivity of the rocks,
- compensated density, measuring the electron density of the rocks using a gamma-ray source,
- neutron porosity, measuring the hydrogen content of the rocks using a neutron source,
- temperature, in which the normal increase of temperature with depth may be interrupted by cooling consequent on the escape and expansion of gas into the hole,

o noise, in which a microphone detects the hissing of gas escaping into the hole.

Of these, the first four can be run on a single trip into the hole, using multiple tools. Since the gamma-ray response is the most clearly diagnostic of the shale, the gamma-ray tool should be the lowermost; if, for example, a well is drilled only a few feet into the Tully, or into the Onondaga, this ensures that at least the gamma-ray log is obtained right through the shale above.

For the same reason, the temperature and noise logs are usually run separately if the well is to test the Marcellus in an area where the Onondaga is thin.

The results of the logging are available immediately, and it is wise to have an expert on site to make a first analysis. He can, for example, give an immediate confirmation that the target formations have been reached, he can assess their degree of organic content, and he can identify the points at which gas may be entering the hole.

Figure 1.4-1 illustrates typical relationships between the rocks and their gamma-ray response. Figure 1.4-2 shows typical gamma-ray and density responses of the lowermost Geneseo shale (and the Tully below it). The high radioactivity and low density characteristic of an organic-rich shale are clearly seen in the Geneseo. Figure 1.4-3 gives the corresponding responses for the Marcellus shale (and the Onondaga below it). The interruption of the Marcellus shale by the Cherry Valley limestone is also evident.

All the logs discussed above can be run, without liquid filling, in the uncased hole. Other logs (including particularly the sonic, long sonic and fracture identification logs) can be of some benefit for research purposes, but they require filling the hole with water; in the present context the risk of swelling in the shales does not warrant this.

The logging process is done by a logging contractor; it typically takes 4-8 hours. The laws of Murphy prevail, and this is usually in the middle of the night.

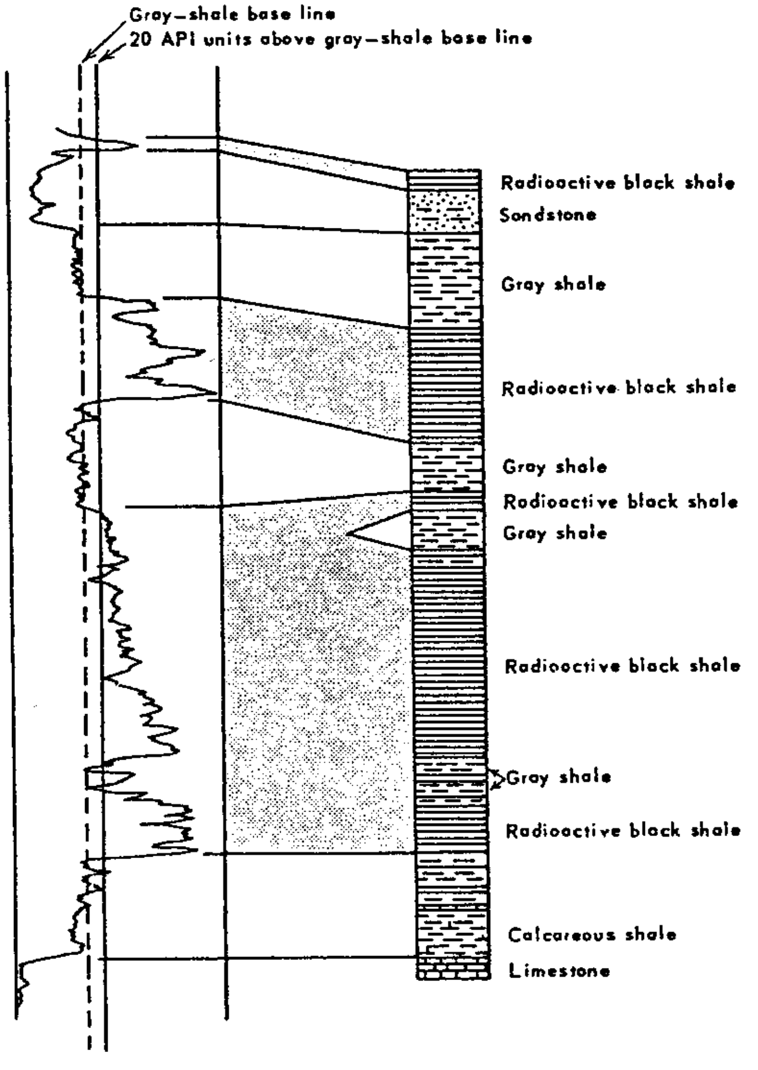


Figure 1.4-1 Typical relationships between rocks and their gamma-ray response (courtesy API).

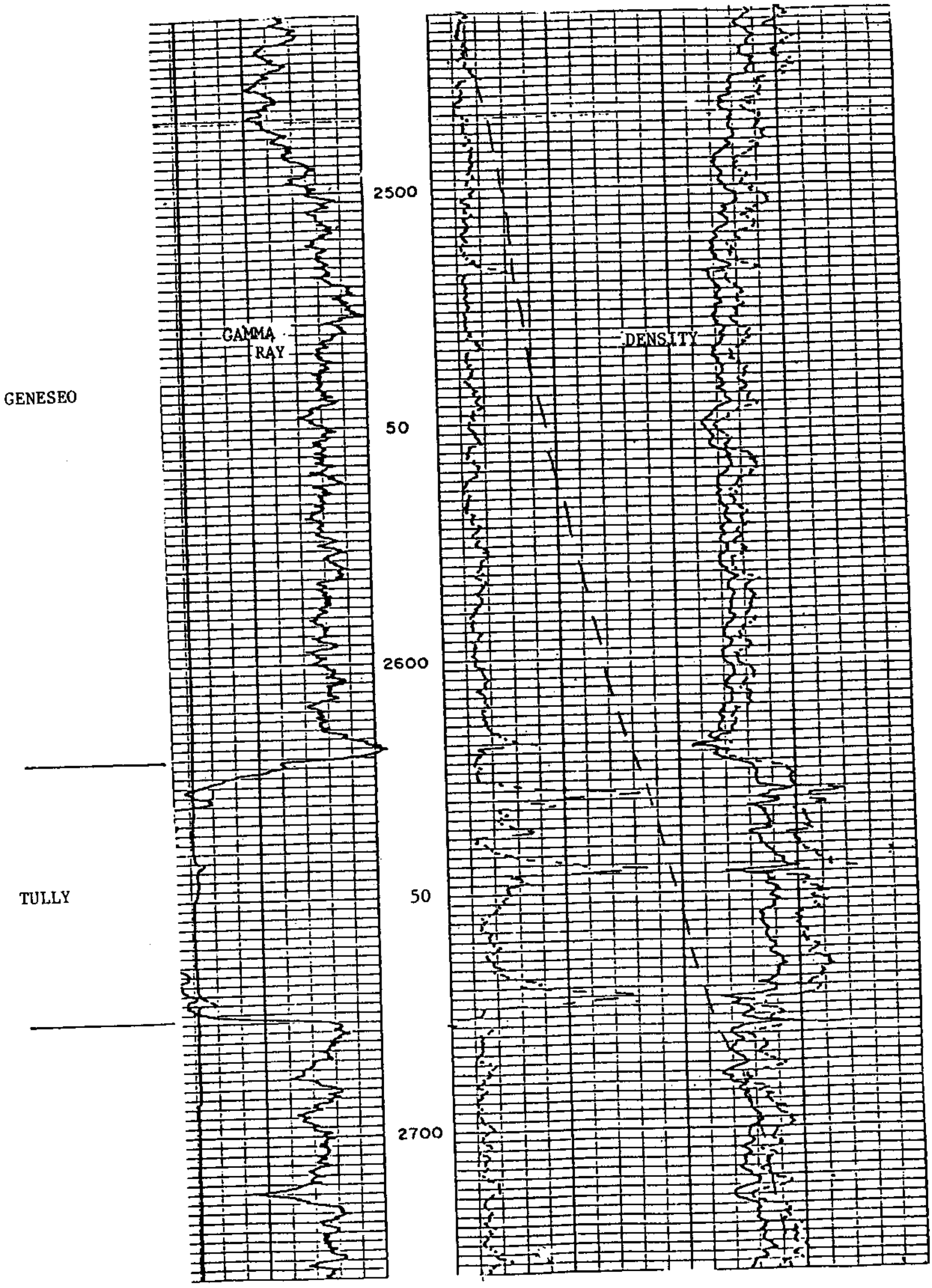


Figure 1.4-2 Typical gamma-ray and density responses of the Geneseo shale and the Tully limestone.

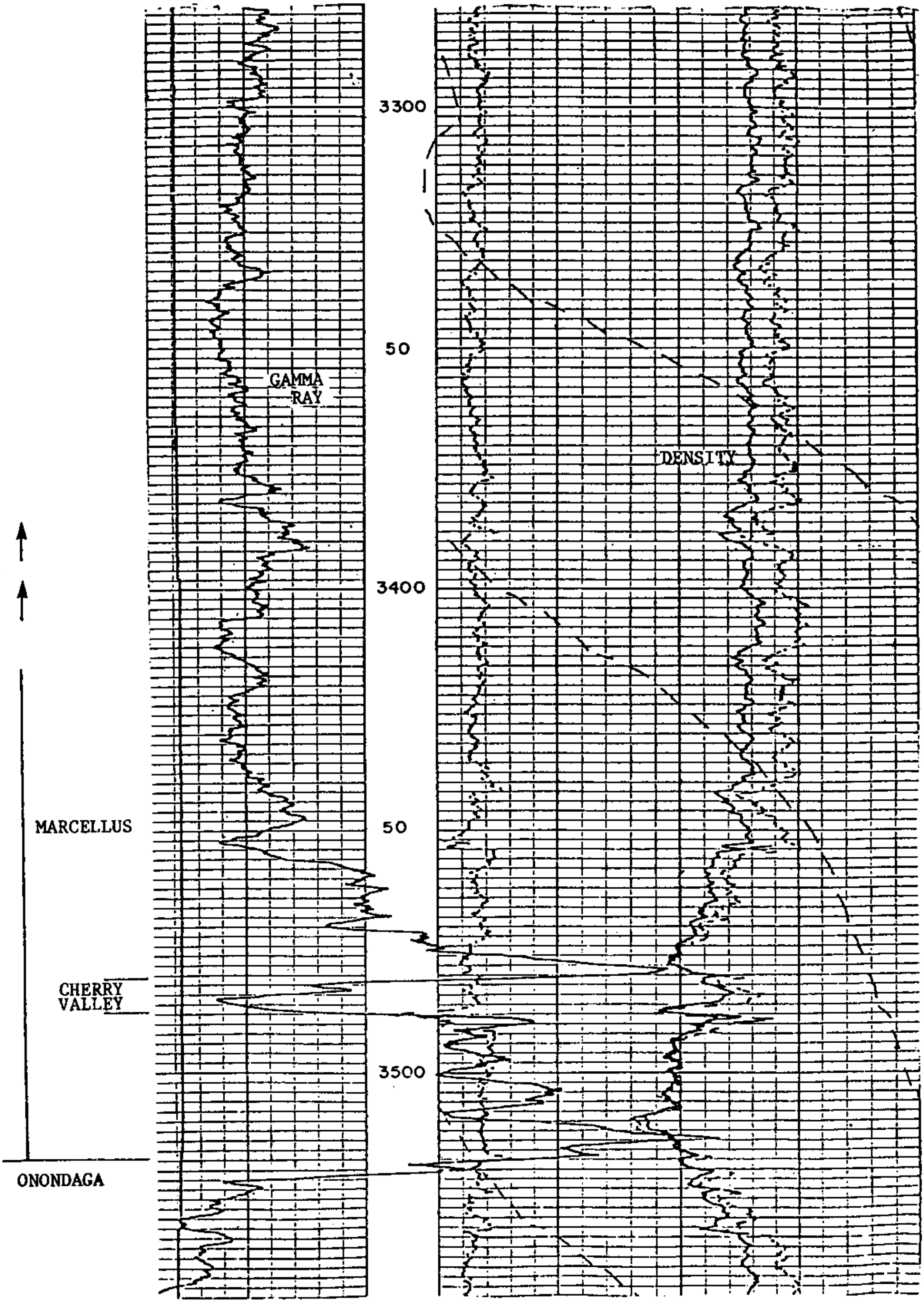


Figure 1.4-3 Typical gamma-ray and density responses of the Marcellus shale and the Onondaga limestone.

If the message of the logs is favorable (or at least not unfavorable) the decision is usually made to case the entire hole — to run pipe. A string of steel casing, typically 4 1/2 inches in diameter, is lowered almost to the bottom of the hole. Cement (made with potassium-chloride solution, of course) is pumped down the casing and up the annulus until it extends safely above the zone of interest. The operation of running and setting pipe may take 12-16 hours, after which the drilling rig is released and moved off hole.

The cement typically takes at least 3 days to cure. Toward the end of this period a service rig (which is smaller and cheaper than a drilling rig) is brought in and made ready.

The next operation is to perforate the casing in the zone where, on the basis of the logs, gas is expected. The points where perforations are desired are decided on the basis of the suite of logs run before the casing, usually on the criterion of including levels of extreme radioactivity, anomalously low density, and known gas entry. The first step is to run a casing-collar-locator log, to establish where the casing collars are and to guard against differences in the depth measurement between the original logs and the perforating gun. The desired perforation depths are transferred to this new log, hydrochloric acid (15%) is dumped into the hole to cover all of them, and the perforating gun is lowered to the first of these depths. By remote control, a perforating bullet is fired through the casing and the cement, penetrating a few inches into the shale. Each perforation is typically 3/8 or 1/2 inch in diameter.

Figure 1.4-4 gives a schematic representation of the well at this stage; the diagram assumes that the target is the Marcellus, and foreshortens the vertical scale for clarity.

It is usually wise to break down the perforations. Typically this is done by pumping clean treated water into the hole (using a pump truck provided by the well-service contractor) at a pressure in the range 1500-3000 psi. When a flow is established, perf balls are dropped; the number of perf balls is typically 1 1/2 times the number of perforations. The balls are configured to block the perforations progressively, with the perforations taking the greatest flow

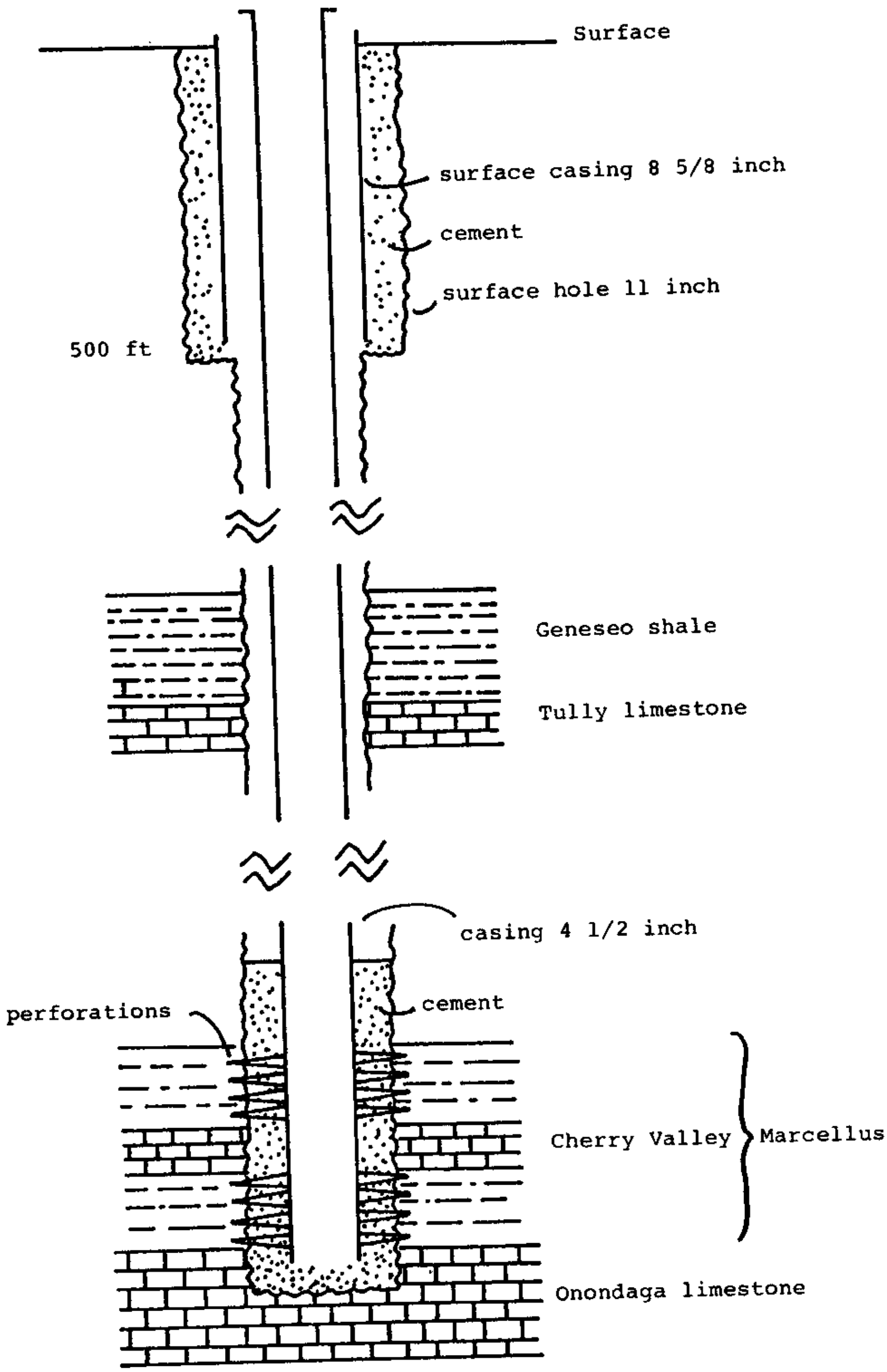


Figure 1.4-4 Diagrammatic view of casing string and perforations for a well designed to test the Marcellus.

being blocked first. The sign of a good balling-off is a rapid increase of pressure (and decrease of flow) after the dropping of the perf balls.

The entire perforating operation is likely to take 1 day. Thereafter the well is allowed to flow-back the breakdown fluid and perf balls into the mud-pit. (Visitors beware — the perf balls may come out like bullets.) The liquid remaining in the hole must then be swabbed out. The flow-back and swabbing may take a further 1-2 days.

The well is now in condition to produce gas naturally, and it may be tested for production at this stage. Experience in New York suggests that the natural flow to be expected from the Geneseo and Marcellus is small or negligible, and that if it is not so initially it is likely to become so fairly quickly. Natural production from the Rhinestreet is even less likely to be significant, unless the well happens to intersect a major fracture. The next stage, then, is the stimulation.

1.5 STIMULATING THE WELL

Two methods of inducing artificial fractures in the producing formation are common in the industry — explosive fracturing and hydraulic fracturing. The U.S. Department of Energy has determined that explosive fracturing, while cheaper, yields less total gas; accordingly hydraulic fracturing is preferred. However, in order to minimize the risk of shale-swelling, the conventional process using water is modified to use a large proportion of the inert gas nitrogen in the hydraulic fluid. This report therefore adopts the nitrogen frac as the recommended stimulation technique.

Although the stimulation takes only an hour or two, it is a massive operation which must be planned carefully. For example, several days may be necessary to procure and transport the enormous quantities of liquid nitrogen.

A typical stimulation recommended for a deep Marcellus well (for example in the southern half of Steuben County) would be described as a 50,000 gallon treatment with 80,000 lb of sand. The operation is as follows.

The nitrogen is continuously heated, vaporized and compressed as it is used. First the nitrogen is injected into the well to form a nitrogen pad as the spearhead of the frac. Then the nitrogen flow is combined, at the wellhead, with a blend of sand, foaming agent and treated water; the proportions are such as to give a 75-quality foam. The combination fluid is at a pressure capable of fracturing the shale formation; this, of course, is a function of depth and of the constitution and condition of the rock — for a deep Marcellus well it might be 4000-5000 psi. The sand (typically a proportioned combination of 20/40 mesh and 80/100 mesh) is swept into the fractures created; on relaxation of the fracturing pressure much of it remains as a proppant, holding the fractures open. The stimulation contractor continuously monitors and adjusts the fluid pressures and the flow rates for optimum indications. After the intended volume of sand has been "put away", the process is stopped abruptly and the instantaneous shut-in pressure is measured; this is a useful diagnostic. Thereafter the shut-in pressure is measured at 5, 10, 15, 20...minutes; this also is useful in understanding what has been the effect of the stimulation on the rock.

At this stage the stimulation contractor moves off the site, and the well is opened to flow back the frac fluid. This process (clean-up) may take several or many days, even weeks. The flow is constrained through a small hole (a choke), and the choke size is increased in small changes as the downhole pressure decreases. It is important to be patient, and not to use a choke size so large that the flow can blow the sand back out of the formation. Some indication of the quality of the well is obtained at this stage, in that the better wells clean up quickly. As the frac fluids begin to be spent, gas is likely to appear.

Finally, the frac fluid remaining in the hole must be swabbed out (possibly several times) before gas can flow freely, and before the well can be tested. Then comes the moment of truth — or rather the first of several moments of truth.

An initial measure of the performance of the well is an open-flow test. First the well is shut-in until the pressure stabilizes; it is then fully opened (for example, from the 4-inch casing, or through a 2-inch reducer). A Pitot tube is then inserted into the center of the gas stream, and the manometer reading taken; this is convertible into Mcf/day, from standard tables.

At first, of course, the well produces the gas in the borehole, which can flow very freely. Then it produces the gas in the artificial propped-open fractures, which also flows freely. This immediate flow is of little significance; the important flow, as discussed in previous sections, is that which bleeds from the shale itself into the fracture system. Thus there must always be a major decline in flow after the well is turned on; there should be no popping of champagne corks at the moment of opening the valve.

The open-flow test gives little indication of what the well will produce in practice, because in practice it always operates against a back-pressure (a pipeline pressure, or some sort of appliance). Further, the test wastes gas. Therefore it is usual to conduct a further test — normally an <u>isochronal test</u>. In this test, in its <u>modified isochronal</u> form, the well is first shut-in for a stabilization period, and then opened for an hour and closed for an hour, four times, though progressively increasing chokes. The four chokes (which may be, for example, 1/16, 3/32, 1/8 and 1/4 inch) allow a measurement of the flow rate as a function of time. The data may be manipulated to yield a production figure against any specified back pressure. Also calculable is an absolute open flow, which is a theoretical figure of flow against zero pressure; as a course rule of thumb, the actual production is likely to be no more than a quarter of this, but the figure is useful for comparative purposes.

After these tests, there remains the problem of knowing whether the figures truly represent gas bleeding from the shale into the fractures, or whether the gas is still coming from the fractures themselves. In the latter case a rapid decline of production is to be expected in the future, followed by a stabilization to the true shale production — but at an unknown time. And if the gas is already bleeding from the shale, there still remains the unknown of the decline rate. The only answer to these questions is to produce the well.

If it is convenient to connect the well to a pipeline, or to use the gas directly, then this is clearly the best course — use the gas, or sell the gas, and see what happens. However, if the well is far from a pipeline, or from a point of use, one may hesitate before committing to the expense of this connection. A defensible course may be to open the well to free flow for a period (being careful to observe the regulations of the Bureau of Mineral Resources of the New York State Department of Environmental Conservation), and to see if the production is sustained. This is wasteful of gas; it also gives no definite assurance that the well would not decline the day after the test is ended. However, every day of sustained production increases the hope that the production is indeed bleeding from the shale.

When the clean-up process is complete (but not before), a sample of the gas is taken for analysis. The important results are the constitution of the gas and its heat content. Shale gas from New York State is (like most natural gas) predominatly methane; however, it has an unusually high proportion of ethane, and this serves to increase its heat content. Typical values range from 1050 to 1200 BTU/cf.

If all indications are favorable, the well is connected to its permanent use by a gas line. This may require the negotiation of a right-of-way, if the best route passes across another's property. The line must accord with state regulations. For a single well producing 100 Mcf/day, a 2-inch pipe is suitable. The connection of the line to the well is through a well-head incorporating appropriate valves and test ports; a flow meter is also required at a suitable location. If the well produces some formation water with the gas, it becomes necessary to install a string of <u>tubing</u> (which may be used to siphon the water) and a simple <u>separator</u>, and to dispose of the water.

Thus, although the drilling and stimulation of a well involve a great deal of action, upheaval and noise — for a period of a month or so — the final successful result is inconspicuous , undemanding of attention, and silent.

"Free" energy. Clean, obedient and independent. Very enticing.

1.6 THE ECONOMICS OF SHALE GAS

In section 1.3.1 the possibility was raised, very tentatively, that in New York it may be possible to <u>guarantee</u> useful shale-gas production by drilling and stimulating the Marcellus. If this were true there would be substantially no risk, and it becomes easy to compute the economics. This situation is considered first, as a base.

The assumptions made here are as follows:

- No risk; every well produces after stimulation.

- The capital costs of the well are 80% "intangible," which means that this proportion can be written off for tax purposes in the year in which the costs are incurred.

- The capital costs of the completed well (which are largely drilling costs and stimulation costs, both dependent on depth) are $130,000 for a well to 1500 ft, $175,000 for a well to 3,000 ft and $210,000 for a well to 4500 ft. These costs are representative for 1980. The depth appropriate to any particular location can be read from the map of drilling depth to the base Marcellus (Figure 1.2-2).

- The gas price is taken at $5.00/Mcf on 1 January 1982, and escalated at 10%/year thereafter.

- The decline rate of the well is taken as 10%/year.

- The net revenue interest in the well is 75%, which is appropriate to commercial exploration. For an organization drilling a well on its own property, this figure is likely to be 100%.

- The working interest is 100%.

- The operating cost of the well is $500/month, escalated at 10%/year.

- Federal income tax is 46%.

Except for the hypothetical elimination of risk, most of these assumptions are fairly safe; the two which merit discussion are the gas price and the decline rate.

At the time of writing, the price of shale gas is deregulated; one gets what one can. In areas where gas from other sources is plentiful, this may be only $2.50/Mcf. In others it is already $4.73/Mcf. The price of Canadian gas, at the NY border, is $4.60/Mcf. On balance, and without projecting recent price-rises unreasonably, $5.00/Mcf seems a fair figure for January, 1982.

The decline rate for Marcellus gas in New York is quite unknown. Many or most conventional reservoirs decline at more than 10%/year; the use of 10% is based solely on the observation that production from shale-gas fields (in other areas, and from different formations) has in many cases been maintained for 20 or 30 years (or even more). However, as noted earlier, it is not known whether modern stimulation techniques merely accelerate the same total production, or whether they genuinely increase the total production. Further, the Marcellus is not a thick unit, and it seems clear that a very extensive system of artificial fractures would be necessary to yield sustained production for decades. The 10% assumption for decline rate may therefore be optimistic; nobody knows.

With the above assumptions, the commercial payout period for a well can be calculated for a range of depths and initial productions. These calculations are graphed in Figure 1.6-1, and corresponding calculations for the rate of return after tax are graphed in Figure 1.6-2. From the first graph, for example, it is evident that a 4500 ft well with initial production of 100 Mcf/day (all used, against whatever back-pressure is applicable) would pay out in less than 2 years. From 1500 ft, production of only 50 Mcf/day would pay out in 2 1/2 years. The payout for production of less than 25 Mcf/day is very long.

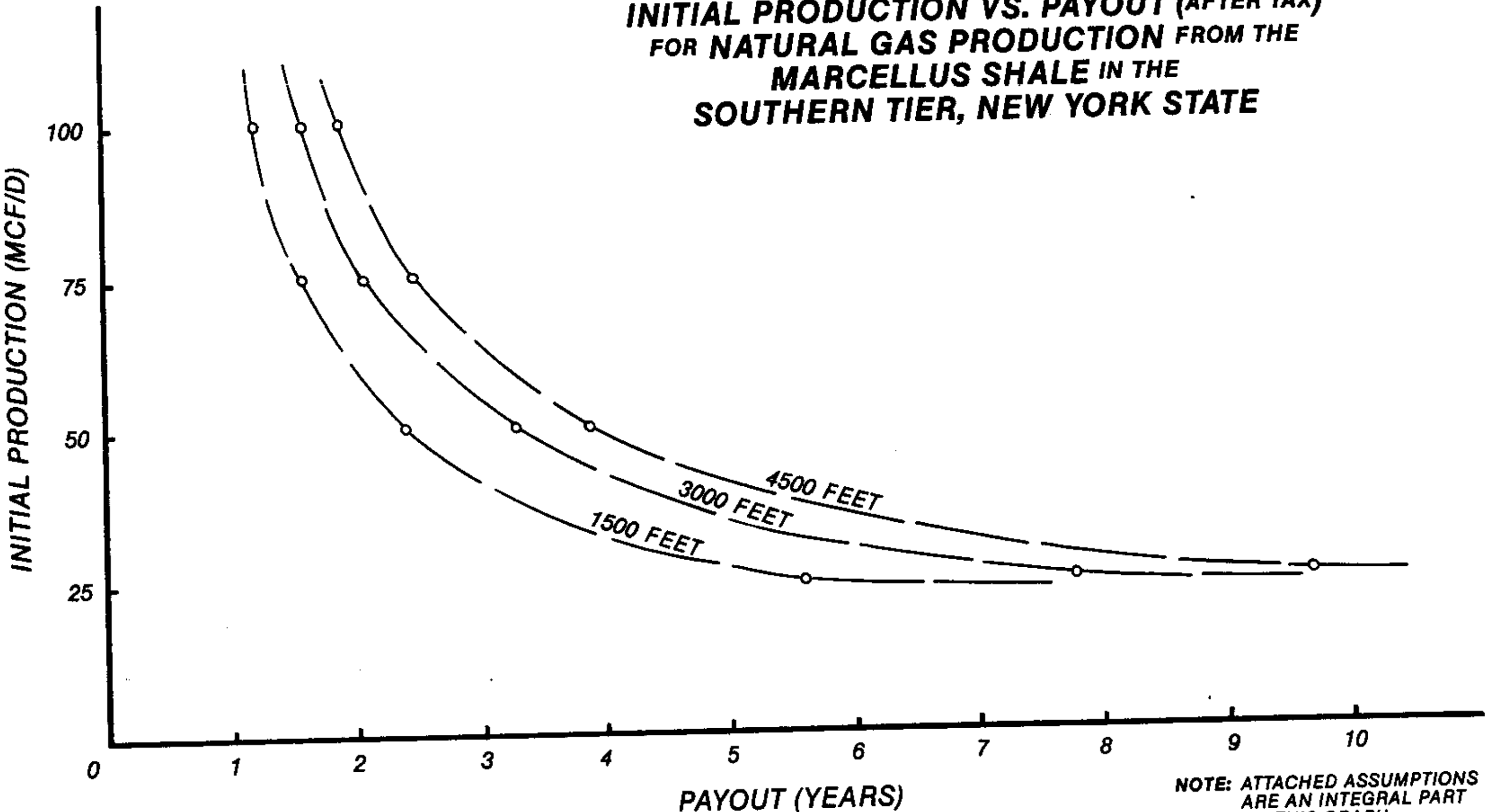
These figures, and the corresponding rates of return, are not very attractive to a commercial exploration company with a high exploration overhead — particularly when coupled with the fact that risk cannot be discounted in practice. This explains why these companies are not dominating the scene in the search for gas, and why the opportunity exists for other organizations with different criteria of viability. Thus a hospital or a college may be more concerned with stability of price than with rapid payout after tax; a manufacturing company may be more concerned with security of supply and immunity from curtailment. These concerns do not have to be very strong to make the curves of Figure 1.6-1 palatable — even attractive.

There remains the matter of the risk. As noted earlier, the present score for stimulated Marcellus wells in south-central New York appears to be 3 out of 3. However, this sample is very small, and in any case it may not be entirely representative.

An exploration company, drilling many wells, spreads its risk. Thus, from Figure 1.4-1, it knows that a 100 Mcf/day well to 3000 ft will pay out in 1.6

Figure 1.6-1

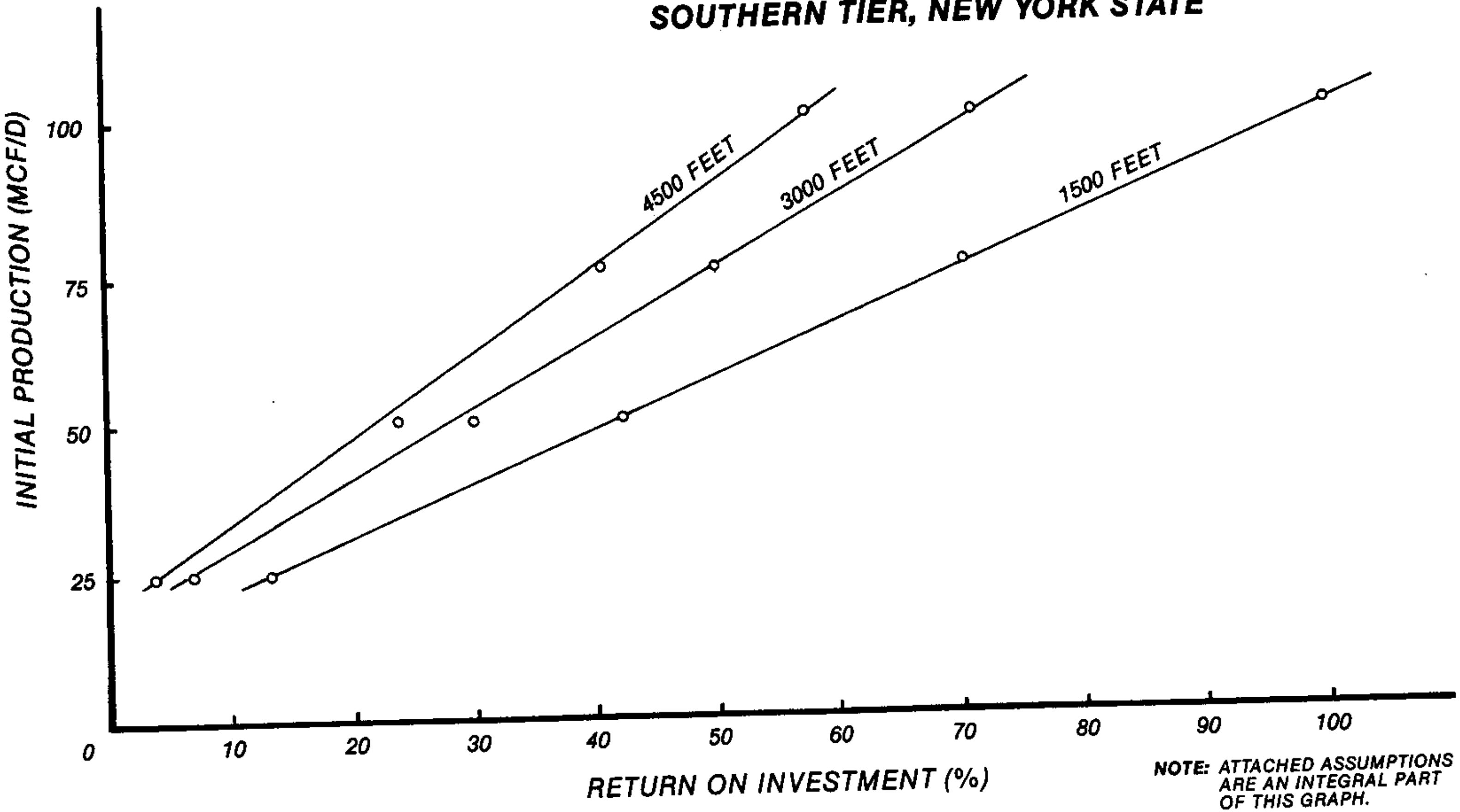
INITIAL PRODUCTION VS. PAYOUT (AFTER TAX) FOR NATURAL GAS PRODUCTION FROM THE MARCELLUS SHALE IN THE SOUTHERN TIER, NEW YORK STATE



NOTE: ATTACHED ASSUMPTIONS ARE AN INTEGRAL PART OF THIS GRAPH.

Figure 1.6-2

INITIAL PRODUCTION VS. RETURN ON INVESTMENT FOR NATURAL GAS PRODUCTION FROM THE MARCELLUS SHALE IN THE SOUTHERN TIER, NEW YORK STATE



NOTE: ATTACHED ASSUMPTIONS ARE AN INTEGRAL PART OF THIS GRAPH.

years. If it has to drill two wells to get this same production, because one is dry, the payout is 3.3 years. If it has to drill four wells, because three are dry, the payout is 7.8 years. It therefore balances the payout of success against the chance of success. A college, however, would probably have neither the land nor the funds to drill three dry holes in hopes that the fourth would be a producer. It is therefore important that the minimum likely production from any Marcellus well (which would be a dry hole to an exploration company) should represent acceptable economics to the college. At the time of writing this is a reasonable hope, but no promise.

(A computer tabulation of the details of the economic calculations, together with additional measures of commercial appeal, is given in Appendix I to Part 1 of this report. A breakdown of the cost of a 3000-ft Marcellus well is given in Figure 1.6-3.)

Survey		$ 350
Permit		20
Site Preparation		10,000
Drill		40,000
Log		5,000
Casing		20,000
Cement		7,000
Perforate		2,000
Breakdown		3,500
Stimulation		25,000
Service Rig		7,000
Tubing		7,130
Wellhead		3,000
Flow Line		1,200
Surface Equipment		10,000
Gas Sales Line		3,800
Master Meter & Connection		3,250
Field Supervision		9,000
Administrative Overhead		9,750
Contingency (5%)		8,000
	TOTAL	$175,000

Figure 1.6-3 Example of capital costs of a 3000 ft Marcellus Shale well; lease consideration and title search are not included.

APPENDIX I

Assumptions:

0) No Risk

1) Capital Costs: 1500 foot well \$130,000
   (80% Intangible) 3000 foot well \$175,000
   4500 foot well \$210,000

2) Gas Price: \$5.00 (as of 1/1/82) escalated at 10%/year

3) Decline: 10%/year

4) Net Revenue Interest: 75%

5) Working Interest: 100%

6) Operating Cost: \$500/well/month escalated at 10%/year

7) After-Tax Calculations: Federal Tax Rate .46

DATA

	PAYOUT (YEARS)	ROR[1] (%)	RESERVES (MMcf)
1500 feet			
25 Mcf/d	5.6	13.3	53.57
50 Mcf/d	2.4	42.3	118.51
75 Mcf/d	1.6	70.3	183.47
100 Mcf/d	1.2	100.5	248.81
3000 feet			
25 Mcf/d	7.8	7.2	53.57
50 Mcf/d	3.3	30.1	118.51
75 Mcf/d	2.1	50.2	183.47
100 Mcf/d	1.6	71.1	248.81
4500 feet			
25 Mcf/d	9.7	4.1	53.57
50 Mcf/d	3.9	24.3	118.51
75 Mcf/d	2.5	40.9	183.47
100 Mcf/d	1.9	57.8	248.81

[1] Rate of Return

DATA FILE

```
SHALEF       20:26MST    03/04/81

10 MARCELLUS AT 3000 FEET WITH 75 MCFD INITIAL PRODUCTION (Format Convention)
20 $DATA ............(Format Convention)
40 IEVMO=1...........
50 IEVYR=1982.......(Evaluation Reference Date, 1/1/82)
60 MXLIFE=30........(Maximum Project Life 30 years)
70 NWELLS=30*1......(Number of wells - 1 well for 30 years)
80 PRDTIM=DAY.......(Production Time Unit - gas production per day)
90 DECG=EXP.[1]
100 QGASI=.075......(Initial gas production rate in 1,000,000's of cubic feet)
110 DECPCG=.1.......(Annual production decline - 10%/yr.)
120 QGASF=0.........(Final gas production rate in the year 2012)
130 PRESC=PCT.......(Gas price escalation to be a percentage increase per year)
140 PRRES=5.0.......(Inital gas price is $5 per 1000 cubic feet)
150 PRRESS=.1.......(Gas price escalation is, 10%/yr.)
160 ROY=30*.125.....(Landowners royalty is 1/8 of the gross value of production)
170 ORRMG=30*.125...(Overriding royalties equal 1/8 of the gross value of production
180 OPESC=PCT.......(Operating costs escalation to be a percentage increase per year
190 OEDWM=500.......(Initial  operating cost is $500 per well per month)
200 OEDWMS=.1.......(Operating cost escalation is 10%/yr.)
210 INTAN=1*140,29*0(Capital costs: Intangible cost $140,000 incurred in 1982)
220 TANGA=1*35,29*0.(Tangible costs $35,000 incurred in 1982)
230 DPRA=UOP........(Depreciation is based on unit of production method)
240 IVCPCA=.1[2]
250 $END............(Format Convention)
```

[1]Decline calculated using exponential method.

[2]Investment tax credit is 10% in 1982.

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 1500 FEET WITH 25 MCFD INITIAL PRODUCTION

********** BRIEF SUMMARY **********

NET LEASE DATA *

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	53.57
INVESTMENT (M$) ($1,000's)	=	130.00

NET PROFIT INDICATORS *	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	137.1	76.6
PV C FLOW AT 15.000 PCT (M$)[3]	2.4	-5.3
PAYOUT (YRS) (Years)	5.4	5.6
RATE OF RETURN (PCT) (%)	15.5	13.3

[1] Gas reserves in 1,000,000 cubic feet

[2] Cash flow in $1,000

[3] Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 1500 FEET WITH 50 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	118.51
INVESTMENT (M$)($1,000's)	=	130.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	733.4	398.6
PV C FLOW AT 15.000 PCT (M$)[3]	209.1	105.7
PAYOUT (YRS)(Years)	2.2	2.4
RATE OF RETURN (PCT)(%)	53.8	42.3

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 1500 FEET WITH 75 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	183.47
INVESTMENT (M$) ($1,000's)	=	130.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	1459.0	790.4
PV C FLOW AT 15.000 PCT (M$)[3]	421.7	220.4
PAYOUT (YRS) (Years)	1.4	1.6
RATE OF RETURN (PCT) (%)	96.9	70.3

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 1500 FEET WITH 100 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	248.81
INVESTMENT (M$) ($1,000's)	=	130.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	2264.6	1225.5
PV C FLOW AT 15.000 PCT (M$)[3]	636.2	336.1
PAYOUT (YRS) (Years)	1.0	1.2
RATE OF RETURN (PCT) (%)	148.8	100.5

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 3000 WITH 25 MCFD INITIAL PRODUCTION

BRIEF SUMMARY

NET LEASE DATA

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	53.57
INVESTMENT (M$) ($1,000's)	=	175.00

NET PROFIT INDICATORS	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	92.1	53.2
PV C FLOW AT 15.000 PCT (M$)[3]	-42.6	-32.0
PAYOUT (YRS) (Years)	7.6	7.8
RATE OF RETURN (PCT) (%)	8.1	7.2

[1] Gas reserves in 1,000,000 cubic feet

[2] Cash flow in $1,000

[3] Present value of the cash flow at 15% discount rate in $1,000

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+ OIL AND GAS LEASE +
+ ECONOMIC EVALUATION +
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MARCELLUS AT 3000 FEET WITH 50 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	118.51
INVESTMENT (M$) ($1,000's)	=	175.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	688.4	375.2
PV C FLOW AT 15.000 PCT (M$)[3]	164.1	79.0
PAYOUT (YRS) (Years)	3.0	3.3
RATE OF RETURN (PCT) (%)	36.8	30.1

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 3000 FEET WITH 75 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	183.47
INVESTMENT (M$)($1,000's)	=	175.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	1414.0	767.0
PV C FLOW AT 15.000 PCT (M$)[3]	376.7	193.5
PAYOUT (YRS)(Years)	1.9	2.1
RATE OF RETURN (PCT)(%)	65.3	50.2

[1] Gas reserves in 1,000,000 cubic feet

[2] Cash flow in $1,000

[3] Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 3000 MCFD WITH 100 MCFD INITIAL PRODUCTION

********** BRIEF SUMMARY **********

NET LEASE DATA *

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	248.81
INVESTMENT (M$)($1,000's)	=	175.00

NET PROFIT INDICATORS *	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	2219.6	1202.1
PV C FLOW AT 15.000 PCT (M$)[3]	591.2	309.3
PAYOUT (YRS)(Years)	1.4	1.6
RATE OF RETURN (PCT)(%)	98.0	71.1

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

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+   OIL AND GAS LEASE   +
+  ECONOMIC EVALUATION  +
+                       +
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MARCELLUS AT 4500 FEET WITH 25 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	53.57
INVESTMENT (M$) ($1,000's)	=	210.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	57.1	35.0
PV C FLOW AT 15.000 PCT (M$)[3]	-77.6	-52.6
PAYOUT (YRS) (Years)	9.7	9.7
RATE OF RETURN (PCT) (%)	4.3	4.1

[1]Gas reserves in 1,000,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

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+ OIL AND GAS LEASE +
+ ECONOMIC EVALUATION +
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MARCELLUS AT 4500 FEET WITH 50 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT) (%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	118.51
INVESTMENT (M$) ($1,000's)	=	210.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	653.4	357.0
PV C FLOW AT 15.000 PCT (M$)[3]	129.1	58.1
PAYOUT (YRS) (Years)	3.7	3.9
RATE OF RETURN (PCT) (%)	29.1	24.3

[1] Gas reserves in 1,000,000 cubic feet

[2] Cash flow in $1,000

[3] Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 4500 FEET WITH 75 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	183.47
INVESTMENT (M$)($1,000's)	=	210.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	1379.0	748.8
PV C FLOW AT 15.000 PCT (M$)[3]	341.7	172.7
PAYOUT (YRS)(Years)	2.3	2.5
RATE OF RETURN (PCT)(%)	51.7	40.9

[1] Gas reserves in 1,000,000 cubic feet

[2] Cash flow in $1,000

[3] Present value of the cash flow at 15% discount rate in $1,000

OIL AND GAS LEASE
ECONOMIC EVALUATION

MARCELLUS AT 4500 WITH 100 MCFD INITIAL PRODUCTION

++++++++++ BRIEF SUMMARY ++++++++++

NET LEASE DATA +

INITIAL WORKING INTEREST (PCT)(%)	=	100.00
OIL + COND. RESERVES (MSTB)	=	0.00
RESIDUE + SOLN GAS RESERVES (MMCF)[1]	=	248.81
INVESTMENT (M$)($1,000's)	=	210.00

NET PROFIT INDICATORS +	BEFORE INC TAX (Income)	AFTER INC TAX (Income)
C FLOW (M$)[2]	2184.6	1183.9
PV C FLOW AT 15.000 PCT (M$)[3]	556.2	288.4
PAYOUT (YRS)(Years)	1.7	1.9
RATE OF RETURN (PCT)(%)	76.8	57.8

[1]Gas reserves in 1,000 cubic feet

[2]Cash flow in $1,000

[3]Present value of the cash flow at 15% discount rate in $1,000

++++++++++ SUMMARY ++++++++++

INTERESTS +

INTL WORKING INT (PCT) = 100.000 INTL ROYALTY INT (PCT) = 25.000
INTL CAPITAL INT (PCT) = 100.000 AVG. ROYALTY INT (PCT) = 25.000
(INTL = Initial; PCT = Percent; AVG. = Average)

RESERVES + PROJECT LIFE +

LIFE (YRS) = 26.95

RESERVES

Gas Reserves (in 1,000,000 cubic feet)

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS (Tot.Res.)	0.0	0.0	244.6	0.0	0.0	0.0	0.0
WORK INT[1]	0.0	0.0	244.6	0.0	0.0	0.0	0.0
NET[2]	0.0	0.0	183.5	0.0	0.0	0.0	0.0

[1]Working Interest Share of Gross Reserves [2]Working Interest Share of Reserves After Royalties

NET PRESENT VALUE +

Dis. (Discount) RATE (%)	+++ BEFORE INCOME TAX +++ OP. INC (M$) (Operating Income $1,000's)	INV. (M$) (Investment $1,000's)	C FLOW (M$) (Cash Flow $1,000)	+++ AFTER INCOME TAX +++ OP. INC (M$)	INV. (M$)	C FLOW (M$)
0.00	1589.0	175.0	1414.0	942.0	175.0	767.0
5.00	1015.4	175.0	840.4	626.1	175.0	451.1
10.00	720.5	175.0	545.5	462.7	175.0	287.7
15.00	551.7	175.0	376.7	368.5	175.0	193.5
20.00	446.0	175.0	271.0	309.1	175.0	134.1
30.00	324.3	175.0	149.3	239.5	175.0	64.5
15.00	551.7	175.0	376.7	368.5	175.0	193.5

(Same as previous columns)

NET PROFIT INDICATORS +	+ BEFORE INCOME TAX +	+ AFTER INCOME TAX +
PAYOUT (YRS) (Years)	1.93	2.12
RATE OF RETURN (PCT) (%)	65.30	50.17
UNDIS C FLOW/UNDIS INV[1]	8.08	4.38
DIS C FLOW/DIS INV[2]	2.15	1.11
DIS C FLOW/UNDIS INV[3]	2.15	1.11

[1]Undiscounted cash flow divided by undiscounted investment

[2]Discounted cash flow divided by discounted investment

[3]Discounted cash flow divided by undiscounted investment

OIL AND GAS LEASE
ECONOMIC EVALUATION

Parameters
of case
being analyzed

MARCELLUS AT 3000 FEET WITH 75 MCFD INITIAL PRODUCTION, Before and After Income Tax

YEAR	GROSS OIL + COND. STB	GROSS[1] RES. + SL GAS MMCF	NET REV.[2] AFTER ROYLTY M$	NET OP EXP[3] LCL TX + CAP M$	NET[4] C FLOW B. TAX M$	CUM. NET[5] C FLOW B. TAX M$	NET[6] C FLOW A. TAX M$	CUM. NET[7] C FLOW A. TAX M$
1982	0.0	26.0	97.4	181.0	-83.6	-83.6	-56.0	-56.0
1983	0.0	23.4	96.5	6.6	89.9	6.3	50.1	-6.0
1984	0.0	21.0	95.5	7.3	88.2	94.5	49.0	43.1
1985	0.0	18.9	94.5	8.0	86.6	181.1	48.0	91.1
1986	0.0	17.0	93.6	8.8	84.8	265.9	46.9	138.0
1987	0.0	15.3	92.7	9.7	83.0	348.9	45.8	183.8
1988	0.0	13.8	91.7	10.6	81.1	430.0	44.7	228.5
1989	0.0	12.4	90.8	11.7	79.1	509.1	43.5	272.1
1990	0.0	11.2	89.9	12.9	77.0	586.2	42.3	314.4
1991	0.0	10.1	89.0	14.1	74.9	661.0	41.1	355.5
1992	0.0	9.1	88.1	15.6	72.6	733.6	39.8	395.3
1993	0.0	8.2	87.2	17.1	70.1	803.7	38.4	433.7
1994	0.0	7.3	86.4	18.8	67.5	871.2	37.0	470.6
1995	0.0	6.6	85.5	20.7	64.8	936.0	35.4	506.0
1996	0.0	5.9	84.6	22.8	61.9	997.9	33.8	539.8
1997	0.0	5.3	83.8	25.1	58.7	1056.6	32.1	571.9
1998	0.0	4.8	83.0	27.6	55.4	1112.0	30.2	602.1
1999	0.0	4.3	82.1	30.3	51.8	1163.8	28.3	630.4
2000	0.0	3.9	81.3	33.4	47.9	1211.7	26.1	656.5
2001	0.0	3.5	80.5	36.7	43.8	1255.5	23.9	680.4
2002	0.0	3.2	79.7	40.4	39.3	1294.9	21.4	701.9
2003	0.0	2.8	78.9	44.4	34.5	1329.4	18.8	720.7
2004	0.0	2.6	78.1	48.8	29.3	1358.6	16.0	736.6
2005	0.0	2.3	77.3	53.7	23.6	1382.2	12.9	749.5
2006	0.0	2.1	76.6	59.1	17.5	1399.7	9.6	759.1
2007	0.0	1.9	75.8	65.0	10.8	1410.5	5.9	765.0
2008	0.0	1.6	70.9	67.4	3.5	1414.0	2.0	767.0
TOT.	0.0	244.6	2311.5	897.5	1414.0	1414.0	767.0	767.0

[1] Gas Prod. in 1,000,000 cubic feet
[2] Net Revenue after Royalties in $1,000's
[3] Net Operating Expense Local Taxes and Capital Costs in $1,000's
[4] Net Cash Flow Before Taxes in $1,000's
[5] Cumulative of Preceding Column in $1,000
[6] Net Cash Flow After Taxes $1,000
[7] Cumulative of Preceding Column in $1,000

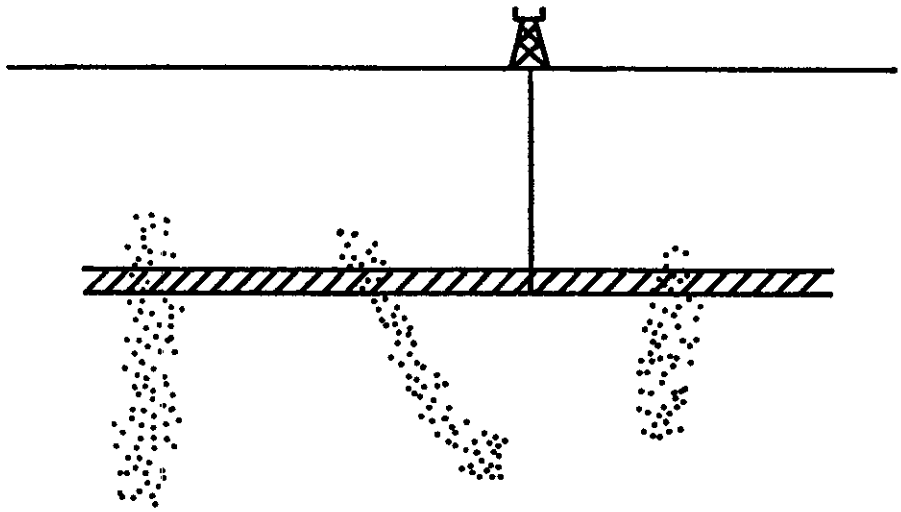

Figure 1.3.5-1 An idealized conduit system.

position shown can obtain gas from a considerable volume of the shale, provided the gas can flow from the three fracture systems along the conduit to the borehole. And the well location is not critical — the well itself need not penetrate a fracture system.

The first candidate for such a conduit would be a permeable bed such as an open-grained sandstone. In this case the situation may appear to be totally conventional; the discoverers may naturally conclude that they have a conventional sandstone reservoir full of gas, and produce it accordingly. Only as additional information becomes available may it be evident that the amount of gas being produced is larger than could be expected from the known thickness of the sandstone, and that the well is actually a shale-gas well. It is likely that many of the old shallow gas-fields of New York and Pennsylvania are of this type, and that their nature as shale-gas fields has never been fully recognized.

The second candidate for such a conduit might itself be a fractured zone. For example, it is possible that a layer within the shale, deposited very rapidly or at a time of rapid subsidence, became overpressured on burial; although in an old rock it is likely that the overpressure has been relieved, yet after relief the shale particles are not likely to have settled into the same degree of compaction as the shale above and below. Such a layer, then, may still have anomalous permeability.