FRACTURED SHALE GAS POTENTIAL IN NEW YORK

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ABSTRACT

In 1821, a shallow well drilled in the Devonian age shale ushered in a new era for the United States when natural gas was produced, transported and sold to local establishments in the town of Fredonia, New York. Following this discovery, hundreds of shallow shale wells were drilled along the Lake Erie shoreline and eventually several shale gas fields were established southeastward from the lake in the late 1800's. Since the mid 1900's, approximately 100 wells have been drilled in New York to test the fractured shale potential of the Devonian and Silurian age shales. With so few wells drilled over the past century, the true potential of fractured shale reservoirs has not been thoroughly assessed, and there may be a substantial resource.

While the resource for shale gas in New York is large, ranging from 163-313 trillion cubic feet (Tcf) and the history of production dates back over 180 years, it has not been a major contributor to natural gas production in New York. A review of the history and research conducted on the shales shows that the resource in New York is poorly understood and has not been adequately tested. Other shales such as the Silurian and Ordovician Utica Shale may also hold promise as new commercial shale gas reservoirs.

Experience developing shale gas plays in the past 20 years has demonstrated that every shale play is unique. A very large number of wells are required to economically and systematically develop a fractured gas shale play. Over 20,000 Devonian Shale wells are producing today in the Appalachian Basin. Over 7,000 Antrim Shale wells are producing in the Michigan Basin and over 1,200 Barnett Shale wells are producing in the Fort Worth Basin today. Each individual play has been defined, tested and expanded based on understanding the resource distribution, natural fracture patterns, and limitations of the reservoir, and each play has required solutions to problems and issues required for commercial production. Many of these problems and solutions are unique to the play. Continued investigation of the shale potential in New York is warranted. More data is needed that address the geologic and reservoir properties of the shale. Modern protocols should be used in drilling, testing, completing, stimulating and producing new wells.

1 INTRODUCTION

The Appalachian Basin in the northeastern United States is an important hydrocarbon province that has been producing oil and gas since the early 1800's. More than 40 trillion cubic feet (Tcf) of natural gas and millions of barrels of oil have been produced from reservoir rocks of all ages. Devonian-age shales are a significant resource in the basin. Their coal-like appearance, wide spread distribution, and stratigraphic nearness to the surface led to interest and use as an energy source dating back to the 1700's. The Devonian Shale of the basin has been estimated to contain up to 900 Tcf of natural gas, and an estimated 120,000 wells have produced roughly 3.0 trillion cubic feet (Tcf) of natural gas in the past 30 years. In addition to Devonian Shale, other stratigraphically older and deeper black shales are present in the basin, and the organic-rich Ordovician shales are believed to be a principle source rock for many of the productive reservoirs in the basin. These shales, though not frequently produced, are often noted in driller's logs to have significant gas shows when drilling through them, and may be potential reservoirs.

Curiosity about the black shales of New York from a geologic perspective and as a fuel source dates back to the late 1700's. The black coal-like appearance and slightly combustible nature of the shales were of interest to the coal industry, and gas seeps in creek beds motivated early explorationists to study the rocks and find use for them. The first know commercial shale gas well was drilled in 1821 in the town of Fredonia, Chatauqua County, New York near a gas seep along Canadaway Creek (de Witt, 1997). The well, drilled by William Aaron Hart, was completed as a gas producer in the shallow Dunkirk shale. The well was connected to pipeline and provided natural gas to Fredonia's main street businesses and street lamps in the 1820's. Following Hart's success, the development and use of shale gas proliferated along the south shore of Lake Erie, eventually spreading southward into Pennsylvania, Ohio, Indiana, and Kentucky. By the turn of the century hundreds if not thousands of wells had been drilled along the lake shore and in the basin, and were producing shale gas for domestic and small commercial use. However as exploration advanced, the development of shale gas wells diminished in favor of more productive conventional oil and gas horizons. It was observed early on that shale gas was tight, and while successful wells produced steadily over long periods of time, production volumes were extremely variable and unpredictable, but usually low (<100 mcfd). The mechanisms controlling production from these wells were not understood, and the technology to optimize production was in its infancy.

In the late 1960's, as natural gas reserves in the United States began to diminish, the U.S. Energy Research and Development Administration (ERDA, later the U.S. DOE) initiated a program to evaluate the Nation's gas resource. Recognizing that the Devonian and Mississippian black shales were a major gas resource that required advanced production methods for recovery, the ERDA launched the *Eastern Gas Shales Project* (EGSP) in 1976. The project was a joint research project between the DOE and numerous State, Federal, and private industrial organizations, which were brought together to participate in the research. NYSERDA entered the project in 1979 by initiating a 4 well R&D program.

2 GEOLOGY

New York forms the northern edge of the Appalachian Basin that exists from southern Ontario to Tennessee. With few exceptions, the state's bedrock primarily consists of Devonian-age and older formations. The younger rocks lie to the south and all sedimentary formations outcrop to the north, at the edge of the Adirondack uplift. The Ordovician and Cambrian become visible again in the St. Lawrence Lowlands.

The rocks in New York have been impacted by at least one of the three major Paleozoic tectonic events. This has left the subsurface folded, fractured, and compressed. Also, numerous sea level changes created significant unconformities including the Knox Unconformity. Studies indicate that the Devonian age and older rocks underwent deep burial before being uplifted to their current elevation. This tectonic history created the environment for hydrocarbon development and the trapping mechanisms to accumulate economic quantities of oil and natural gas. Figure 2.1 displays the orientation of the Paleozoic rocks in New York. Ordovician and younger rocks make up the central and western portions of the state which encompass the Ontario Lowlands and Allegany Plateau (Figure 2.2). Lake Ontario and the Adirondack Mountains form the northern boundary, the eastern margin is formed by the Hudson Lowlands and Taconic Mountains, and to the west terminates at the shore of Lake Erie. The structure of this region is fairly simple. Paleozoic rocks overlying the Precambrian crystalline basement outcrop along the northern extent of the Allegany Plateau, and dip gently to the southwest. In the southern portion of New York, a series of small-scale folds are present, extending from Chatauqua to Tioga counties. The folds are small anticlines, dipping less than 2^o, which are associated with the Appalachian Fold Belt, an arcuate belt of anticlines and synclines that extend southward into West Virginia (Frey, 1973).

In the last 1 million years, New York has endured significant continental glaciation, with ice thicknesses approaching one mile. According to Robert Milici, "glacial loading and post-glacial isostatic rebound in the gas-producing regions to the south of the Great Lakes appears to have created the fractured pathways for gas to have migrated from black shale source rocks into intercalated brittle silty and sandy reservoirs, as well as to have fractured and enhanced the storage capacity of these reservoirs (Milici, 1996). The ice at its maximum extent is estimated to have been over 1 mile thick, and the shear weight of the ice sheet caused the region to compress and sag (Isachsen, 2000). When the ice melted, ocean water temporarily flooded low-lying areas in the Champlain and St. Lawrence valleys that had been depressed forming the Champlain sea. Many marine deposits of this sea are now found at elevations exceeding 300 feet, indicating rebound of the region occurred. In the south where the glacial ice was thinner the rebound was less, however in the north where the ice was thicker, the rebound is over 400 feet. The uneven rebound is seen throughout northern New York. Glacial lake deposits that were once horizontal are now inclined to the north, and in the Lake Ontario region, the whole are has been tilted north to south. Post glacial rebound is now complete in New York, however the near-surface joint system has been enhanced and opened by the release of the glacial weight (Charpentier, 1982). The presence of horizontal fractures in the Devonian is mentioned in well records, and has been attributed to glacial unloading (Imbrogno, 2003).

Figure 2.1. Orientation of the Paleozoic Rocks, Central Appalachian Basin.

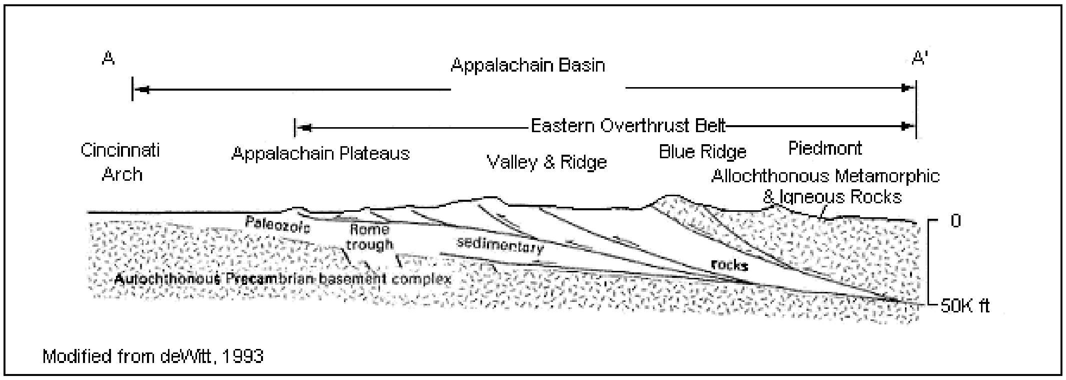
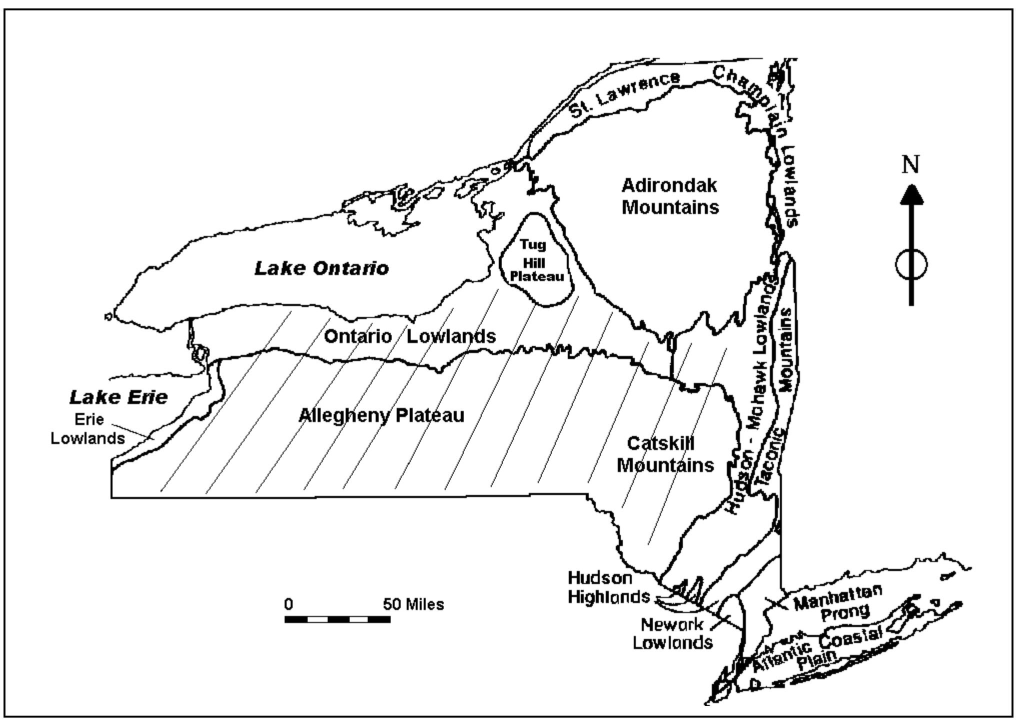


Figure 2.2. Physiographic Regions of New York.



Both gas and oil have been produced from rocks of many ages in New York, and the primary targets for operators in the past have been the gas-bearing sands in the Oriskany, Medina, Queenston, Chemung and

Fulmer Valley formations (Table 2.1). The organic rich black shales are the principal source rock for much of the oil and gas in the basin (Milici, 1992). In addition, gas shows have been noted frequently in drillers logs and petroleum related hydrocarbons have been observed in cuttings from the Ordovician-age Utica Shale (Robinson, 1989).

Table 2.1. Stratigraphic Column of New York; Oil and Gas Producing Horizons

PERIOD		GROUP	UNIT	LITHOLOGY	THICKNESS (feet)	PRODUCTION
PENNSYLVANIAN		Pottsville	Olean	Ss, cgl	75 – 100	
MISSISSIPPIAN		Pocono	Knapp	Ss, cgl	5 – 100	
DEVONIAN	UPPER	Conewango	Riceville	Sh, ss, cgl	70	
		Conneuat	Chadakoin	Sh, ss	700	
		Canadaway	Undiff	Sh, ss	1100 – 1400	Oil, Gas
			Perrysburg-Dunkirk	Sh, ss		Oil, Gas
				Sh		
		West Falls	Java	Sh, ss	365 – 125	
			Nunda	Sh, ss		Oil, Gas
			Rhinestreet	Sh		
		Sonyea	Middlesex	Sh	0 – 400	Gas
		Genesee	Geneseo	Sh	0 – 450	Gas
	?		Tully	Ls	0 – 50	Gas
	MIDDLE	Hamilton	Moscow	Sh	200 – 600	
			Ludlowville	Sh		
			Skaneateles	Sh		
			Marcellus	Sh		Gas
			Onondaga	Ls	30 – 235	Gas, Oil
	LOWER	Tristates	Oriskany	Ss	0 – 40	Gas
		Heldergerg	Manlius	Ls	0 – 10	
			Rondout	Dol		
SILURIAN	UPPER		Akron	Dol	0 – 15	Gas
		Salina	Camillus	Sh, gyp	450 – 1850	
			Syracuse	Dol, sh, slt		
			Vernon	Sh		
		Lockport	Lockport	Dol	150 – 250	Gas
		Clinton	Rochester	Sh	125	Gas
			Irondequoit	Ls		
	LOWER		Sodus	Sh	75	Gas
			Reynales	Ls		
			Thorold	Ss		
		Medina	Grimsby	Sh, ss	75 – 150	Gas
			Whirlpool	Ss	0 – 25	Gas
ORDOVICIAN	UPPER		Queenston	Sh	1100 – 1500	Gas
			Oswego	Ss		
			Lorraine	Sh		
			Utica	Sh	900 – 1000	
	MIDDLE	Trenton-Black River	Trenton	Ls	425 – 625	Gas
			Black River	Ls	225 – 550	
	LOWER	Beekmantown	Tribes Hill-Chuctanunda	Ls	0 – 550	
CAMB.	UPPER		Little Falls	Dol	0 – 350	
			Galway	Dol, ss	575 – 1350	Gas
			Potsdam	Ss, dol	75 – 500	Gas
PRECAMBRIAN				Gneiss, marble, quartzite		

(Modified from NYSERDA 1985).

2.1 STRATIGRAPHY

Organic-rich black shale beds are found in many different age rock formations in New York. Some are massive and very widespread correlating well to the shales in other regions of the Appalachian Basin, while others are thin and limited in area. The following section provides an overview of the stratigraphy of the primary black shale intervals in the Paleozoic section of New York. A large volume of literature exists that thoroughly discuss the many stratigraphic units and variances in New York. Several key references are presented in Table 2.2 and are just a few of the excellent resources which provide a more detailed account of the stratigraphy (for additional references see Bibliography in Appendix A).

2.1.1 Ordovician

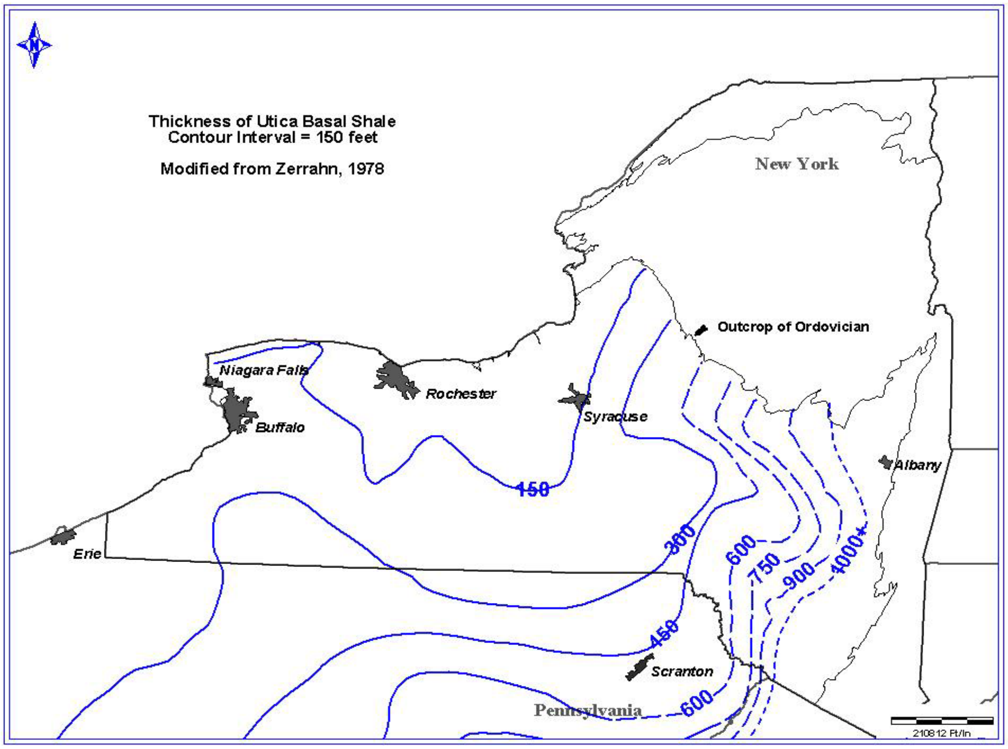
One of the oldest and most widespread black shales is the Ordovician-age Utica Shale. The Utica Shale lies conformably above the Trenton Limestone/Dolgeville Formation in New York (Table 2.1). It was deposited very broadly across the Appalachian Basin and into Ontario, and covers thousands of square miles. In New York the Utica is found in outcrop along the west and south-southeast sides of the Adirondack Mountains, and is well exposed in several locals along the northern margin of the Allegany Plateau (Figure 2.3). It is deeply buried over most of the state of New York, and from outcrop it dips to depths over 9,000 feet in the southern portion of the state (Wallace, 1988).

The Utica is a massive, fossiliferous, organic-rich, thermally-mature black to gray-black shale, and is considered to be the source rock for Lower Devonian through Cambrian production and shows. The Utica was deposited in a deep marine basin with a subsiding trough that generally trended north-south. It interfingers with the basal Dolgeville formation, which is composed of alternating beds of limestone and shale. Source rock for the organic-rich black shale was supplied from the eroding highlands to the east. Slowly the deep marine trough was filled in, and deposition of the upper Utica spread westward. The westward migration was periodic which is reflected in the presence of at least five facies intervals, which are bounded by unconformities or condensed beds (Lehmann, 1995). Each unit represents a pulse of subsidence and subsequent sedimentation in the basin, and all have several similarities. Each interval onlaps argillaceous limestone, and has shifted westward with respect to the underlying unit. The base of each unit is defined as a disconformity and/or stratigraphically condensed interval, and each appears to record a localized deepening event. The overlying black shale unit is thinner than the previous unit.

Figure 2.3. Utica Shale near Little Falls, New York

The thickest section of the Utica is found along the Mohawk Valley and was deposited in the subsiding trough where it is well over 2,000 feet thick. It thins to the north and west to less than 100 feet along the Lake Erie shoreline where it becomes somewhat silty. Over much of New York State, the Utica is less than 300 feet thick (Figure 2.4) (Zerrahn, 1978). The Utica is overlain by coarser clastics of the Lorraine Shale, which consists of shale, siltsone and fine-grained sandstones, which were deposited as the marine environment prograded westward and deltaic deposits pushed across New York from the east. Oil and gas shows have been reported in the black shale of the Utica and in its Dolgeville member, including a recent report of 1 MMscf/day (Trevail, 2003).

Figure 2.4. Isopach of the Utica Shale.



2.1.2 Silurian

The Silurian rocks of New York were deposited in the northern end of the Appalachian foreland basin during a relatively quiet tectonic time. They represent a short interval of geologic time, roughly 20 million years, however reflect a wide variety of depositional environments. Many of the Silurian rocks are extremely fossiliferous, indicating deposition in relatively shallow warm water. Silurian rocks in New York consist primarily of dolostone, limestone, evaporites, medium-gray and greenish-gray shales, and thin but persistent beds of phosphatic nodules and oolitic or fossil-rich hematite. No information regarding the organic content and thermal maturity of Silurian shale has been found. As they are primarily gray shales (there is one black shale member) they are not organically rich in general; however two shales in the Clinton Group are of interest because of their close proximity to the gas-charged productive horizons, and because two wells are reported to produce natural gas from Clinton Groups shales. However it may be that the gas in the producing rocks migrated there from other source rocks (Martin, 2003).

The Sodus Shale was deposited near shore in shallow warm water, and contains a readily identifiable "pearly shell" limestone layer, which formed as a result of a very dense population of small shellfish. The shale is greenish-gray to purplish and was probably deposited in shallow, stagnant, low energy water. One well is reported to produce from the Sodus Shale in Seneca County. Overlying the Sodus is the Williamson Shale, a black shale which was deposited in deep, almost lifeless, anoxic water which was created by the presence of a great deal of iron in the sediments. In a drastic change of environment, the Williamson is overlain by a fossil rich limestone bed, and the Rochester Shale. The Rochester Shale is brownish-gray, calcareous, and fossiliferous with interbedded argillaceous limestone layers, and is well exposed in numerous road cuts and creeks (Figure 2.5). One well is also reported to produce from the Rochester Shale in Seneca County.

Overlying the rocks of the Clinton Group is a continuing sequence of near-shore/marine rocks of the Lockport Group. The alternating layers of sand, shale, limestone are rich in fossils. The overlying Salina Group was deposited near-shore, and contains shales, dolostone, and numerous evaporite beds. The salt beds of the Salina had a great influence on the structural deformation of overlying rocks in the basin. The salt layer divides the rocks of the Allegheny Plateau horizontally, separating the youngest Silurian and Devonian rocks above from lower Paleozoic rocks below (Isachsen, 2000). The salts, which are extremely malleable, provided a zone of weakness that allowed the younger rocks above to slide to the northwest during regional compression without significant folding and faulting. The resulting horizontal fault, or *décollement* separates the fixed rocks below form the transported rocks above.

Figure 2.5. Rochester Shale Outcrop in New York.

(from http://www.earth.rochester.edu/ees201/ Rochester_FT/rochester.html).

2.1.3 Devonian

The Devonian section covers approximately 22,500 square miles in south-central New York (Figure 2.6), and represents some 50 million years of history. It crops out along the northern and eastern margin of the Allegheny Plateau and is roughly 3,000 feet thick near Lake Erie, where it is composed primarily of rocks with marine origins. To the southeast, it thickens to over 9,000 feet, and is composed primarily of rocks of continental origin (Isachsen, 2000). Depth to the base of the group increases from outcrop to over 4,000 feet in southern New York (Figure 2.7). The black shales in the Devonian section generally are thickest in the western and central portion of the Allegheny Plateau. To the east, they thin and pinch out, grading into coarser gray shales and siltstone. Interbedded are several thin, but widespread limestone units, which serve as marker beds used to differentiate between the numerous formations.

The gas-bearing shale portion of the Devonian in New York occurs in the Middle and Upper Devonian, and extends from the top of the Onondaga Limestone through the Perrysburg Formation (Figure 2.8)(Van Tyne, 1978). They are in ascending order: the Hamilton Group, Genesee Formation, Sonyea Group, West Falls Formation, and Canadaway Group. The rocks of the Hamilton Group are the oldest strata of the Devonian gas shale sequence. The group overlies the Onondaga Limestone, and consists of black and dark gray shales in the lower part, and limestone, light gray shale and mudstone in the upper part. The Hamilton

Group outcrops along the northern margin of the Allegheny Plateau, and thickens eastward from 250 feet near Lake Erie to over 2,500 feet in Ulster and Green counties. The Hamilton has been subdivided into four units: the Marcellus, Skaneateles, Ludlowville, and Moscow, which are separated by thin limestone beds. The basal unit of the Hamilton is the Marcellus Shale. The Marcellus formation is highly radioactive and regionally extensive, covering most of the Allegheny Plateau and extending southward through the Appalachian Basin. It is a “sooty” black/brown to dark gray fissile shale with interbedded layers of medium-gray shale and limestone nodules or beds of dark gray to black limestone. It ranges from 25 feet to over 100 feet in thickness.

The Stafford Limestone overlies the Marcellus and marks the base of the Skaneateles Formation, which is a dark to medium gray fossiliferous shale and mudrock, containing a thin, black shale, the Levanna Shale. The Skaneateles is more clastic in nature than the Marcellus and contains some sandy layers. It is overlain by the Centerfield Limestone, which marks the base of the Ludlowville Shale. The Ludlowville is a dark gray basal shale, overlain by a lighter shale.

The Geneseo Shale is the basal unit of the Genesee Formation, and is the primary black shale in the formation. It is a fissile, organic-rich shale which when broken emits a distinct petroleum odor (de Witt, 1993). The Geneseo attains a maximum thickness of 125 feet in central Steuben County. The Lodi Limestone overlies the Geneseo and consists of large discoidal limestone nodules in a bed of dark-gray fossiliferous siltstone. The overlying Penn Yan and West River shales are dark gray to medium gray organic-rich shale and mudstone, with some beds of black shale that extend into the Renwick. A thin limestone, the Genundewa, is found between the two shales in central New York, but pinches out southward and the shales grade into each other.

Figure 2.6. Devonian Outcrop in New York (modified from Isachsen et al 2000).

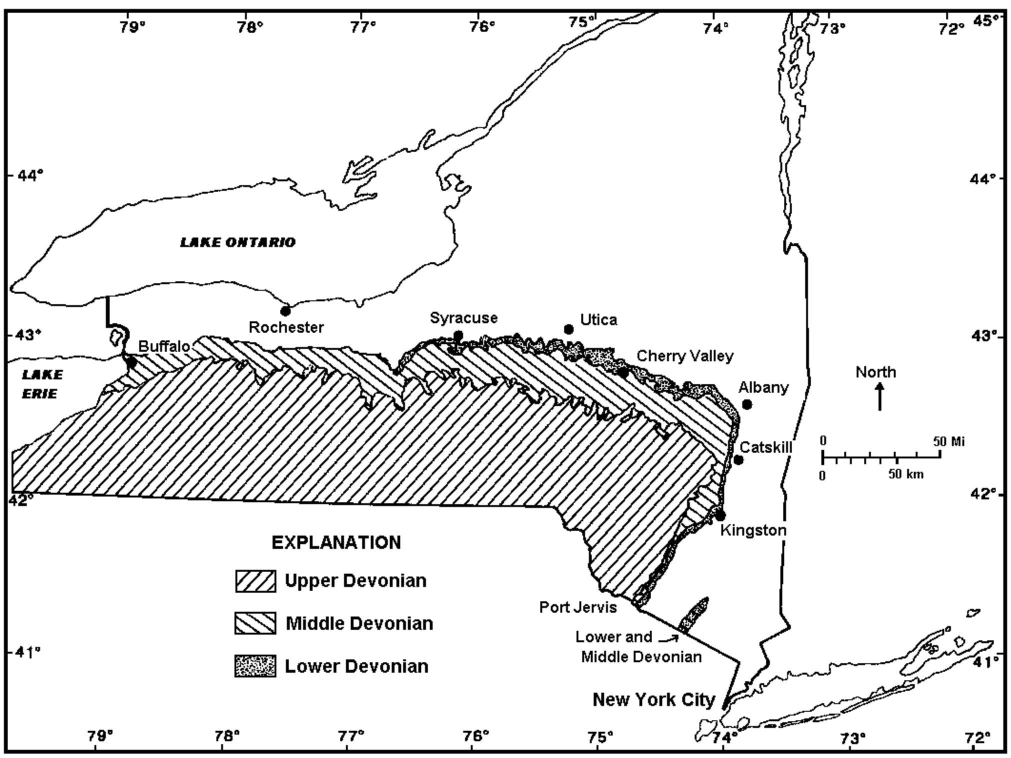
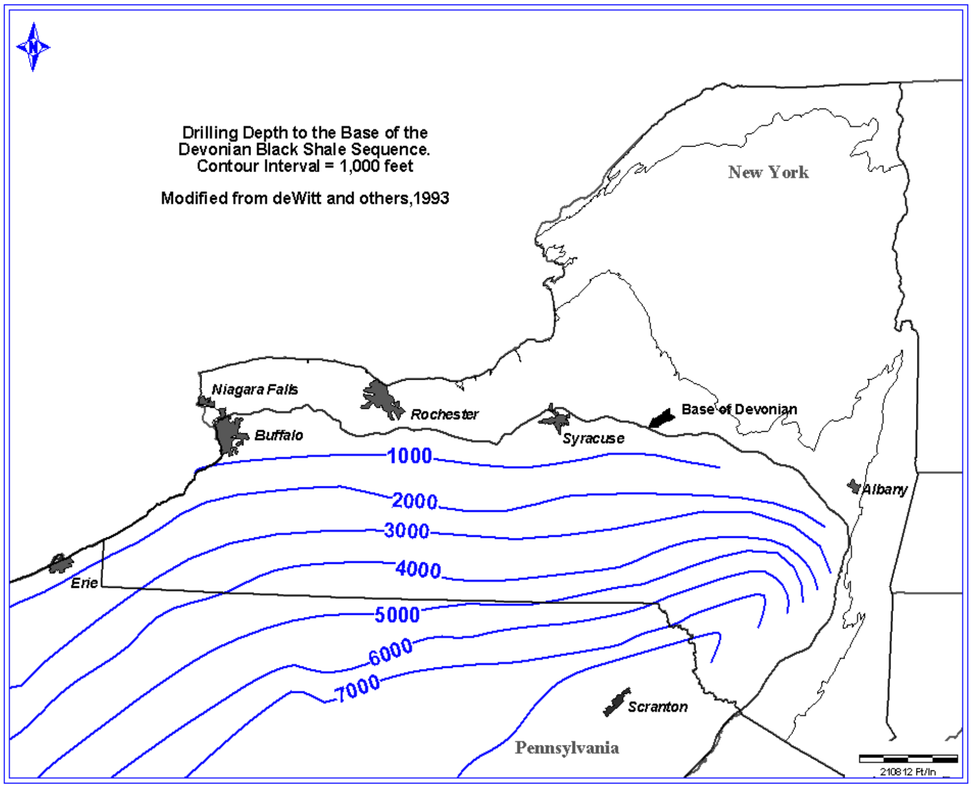


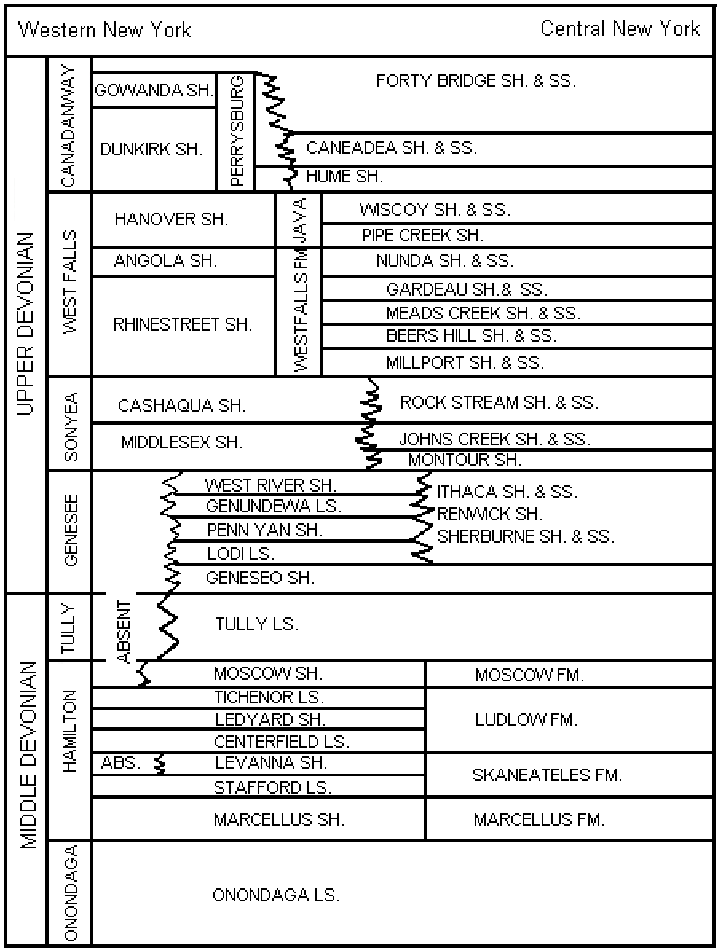
Figure 2.7. Drilling Depth to Base of the Devonian.



The Sonyea Group overlies the Genesee Formation and is subdivided into the Middlesex Shale and the Cashaqua Shale. Thickness of the Sonyea increases from approximately 10 feet at Lake Erie to over 800 feet in Tioga County. Like the Geneseo the Middlesex is a black organic-rich shale in western New York. Interbedded are layers of dark gray and brownish-black shales. It covers much of southern New York, and averages 65-75 feet thick in Yates and Steuben counties, and thins to the west to less than 10 feet. The Cashaqua is a gray shale with an abundance of flat ellipsoidal limestone nodules, and a few thin layers of black shale. The two shale members grade eastward into a thickening sequence of siltstone and silty shale, which is part of a common turbidite facies of the Catskill Delta.

The West Falls formation overlies the Sonyea Group, and consists of two shale-bearing formations, the West Falls Formation and the Java Formation. The Rhinestreet is the basal shale unit of the West Falls Formation. It is a thick, fissile, black shale outcropping in Chatauqua County where it is about 140 feet thick. To the east it thickens rapidly as it grades into and interfingers with the overlying gray Angola shale reaching a thickness of over 1,200 feet at the Allegany-Steuben County line, however the black shale component of the Rhinestreet thins eastward to less than 5 feet in Allegany County. The Overlying Java Formation ranges from 100 feet in thickness in western New York to over 600 feet in Steuben County. At the base of the Java is the thin, black Pipe Creek Shale. It is persistent, organic-rich black shale throughout its lateral extent. It is thin, not more than 25 feet at its maximum in south-central Cattaraugus County, and pinching out in northern Steuben County. The Hanover Shale is a gray shale, with some interbedded black shale beds. It thickens to the east grading into silty shale, siltstone, and sandstone.

Figure 2.8. Devonian Stratigraphic Column (Modified from Van Tyne, 1978).

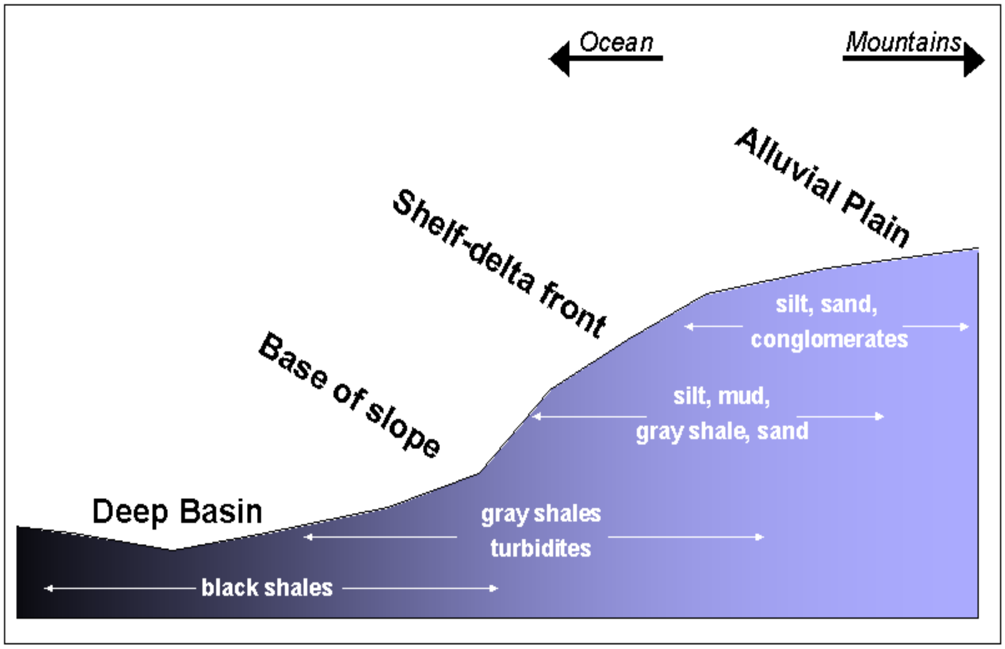


The uppermost unit of the black shale sequence is the Perrysburg Formation of the Canadaway Group. It is approximately 300 feet thick near Lake Erie and increases in thickness to over 700 feet in Cattaraugus County, thinning again toward Steuben County. The Perrysburg consists of a basal black shale, the Dunkirk Shale, overlain by the gray Gowanda Shale Member. The Dunkirk is another extensively deposited, organic-rich, black shale in the basin with equivalent shales (the Huron and Ohio) extending south into Alabama. In New York, the Dunkirk is a grayish-black to black shale containing some medium gray shales and siltstones in the upper part. It crops out and is well exposed in the vicinity of Dunkirk, Chatauqua County, ranging from 50 feet in thickness in the east to 110 feet in central Erie County. The black shale component of the Dunkirk varies from 50 feet in Chautauqua County to less than 25 feet in south Cattaraugus County (Van Tyne, 1978). The overlying Gowanda Shale is a gray shale with siltstone and very fine-grained sandstone, and an occasional black shale bed. In central and eastern New York the black shale content diminishes rapidly as the two formations grade into one another. From the Late Devonian into the Early Permian, the basin continued to fill with coarse clastics primarily of continental origin, which were deposited as the delta migrated to the west.

2.2 DEPOSITIONAL ENVIRONMENT AND THICKNESS OF BLACK SHALES

The environment of deposition for the marine shale sequences in the Appalachian Basin consisted of four broad regions; an alluvial plain, a shelf-delta front, the base of the slope, and the deep basin as depicted in Figure 2.9 (Kepferle, 1993). Deposition of the Paleozoic sediments occurred as mountains generally located to the east of the basin were eroded. Sediments were then transported westward via a massive delta complex and deposited on the alluvial plain and into the marine environment.

Figure 2.9. Deposition Model; Organic Rich Black Shales (modified from Kepferle, 1993).



The resulting clastic wedge that formed from the eroding highlands consists of very thick coarse conglomerates and sands in the east that grade westward (seaward) into finer-grained beach deposits, and open marine deposits (Figure 2.10) (de Witt, 1993B). The black shales coalesce in western New York where the deep marine basin existed quite constantly, and most extend south and west into Pennsylvania, Ohio, and West Virginia to varying extents. Changes in sea level and fluctuations in the rate of sediment supply caused the transgression and regression of the marine environment. During marine transgression, the deep marine basin environment would expand up the slope, onto the shelf and perhaps even across the shore zone, spreading east and south. This is reflected in the deposition of black shales over gray and green shales and sands of the near shore environment. When sediment supply increased, or sea level dropped, the marine environment regressed and the delta complex and associated clastic rocks pushed westward, depositing the interbedded gray shales, siltstones and sandstones. This type of cyclic deposition occurred repeatedly during Devonian time affecting the extent of deposition of each interval.

The thickness of the Devonian black shale has been evaluated by several authors, including VanTyne, De Witt, and Roen (Van Tyne, 1978 and 1997, de Witt et al., 1993, Roen, 1984). The thickness of each black shale bed is not depicted in this report but is well depicted by these authors in numerous reports, however thickness of each unit varies somewhat by author depending upon their methodology. Most black shales are easily recognizable on gamma-ray logs by their strong positive deflections (Figure 2.11). Thickness is determined by picking shale where the gamma-ray log exceeds 20 API units in positive value above the gray-shale base line. However, Van Tyne noted that “in certain cases, much of the black shale present does not exceed the 20 API limit and thus constitutes a thicker section than that measured in this way from the log,” which was particularly true in the Genesee and Hamilton groups, where differences in thickness in the sample studies exceeded the log response pick by a factor of 10 or greater (Van Tyne, 1978 and 1997).

De Witt noted in his evaluation that throughout much of the western and central Appalachian Basin the 20 API criteria are applicable in picking black shale thickness; however that it cannot be applied with assurance in the eastern part of the basin where the black shales lose the positive gamma-ray deflection (de Witt et al. , 1993).

Figure 2.10. Facies of the Middle and Upper Devonian.

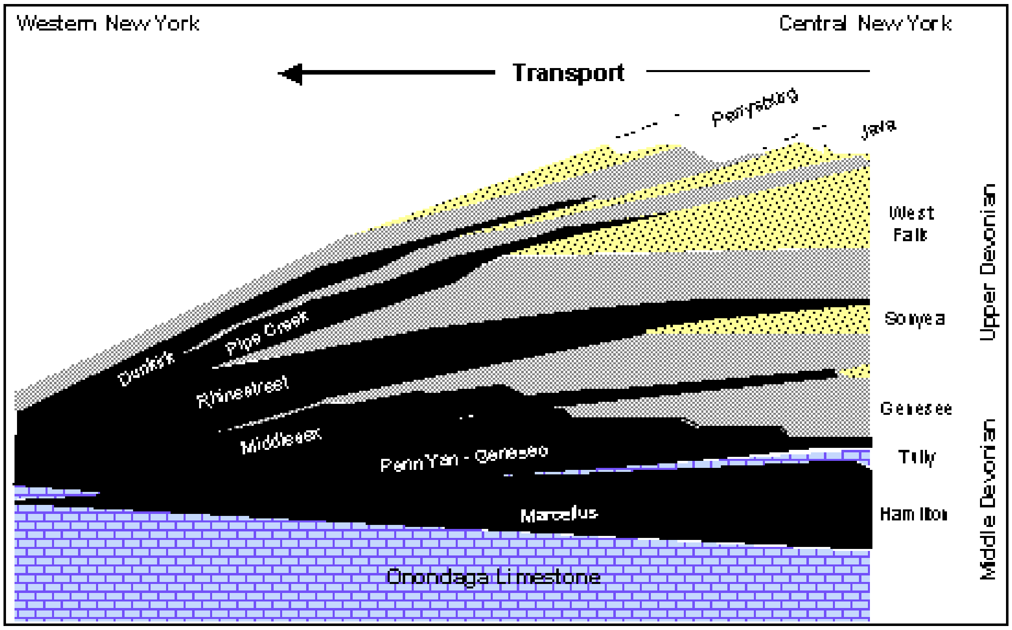
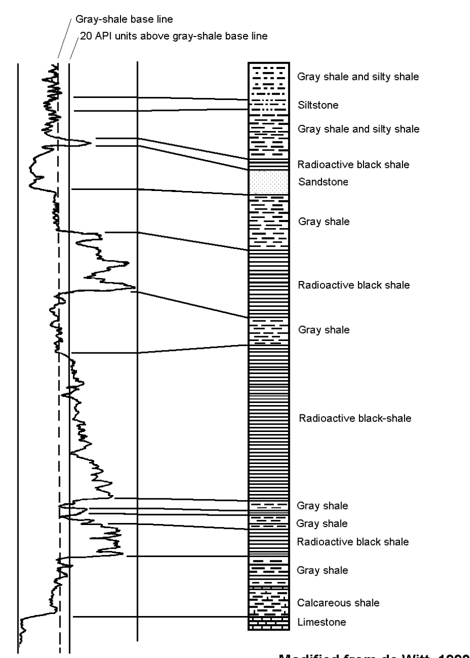


Figure 2.11. Gamma Ray Signature of Radioactive Black Shale.

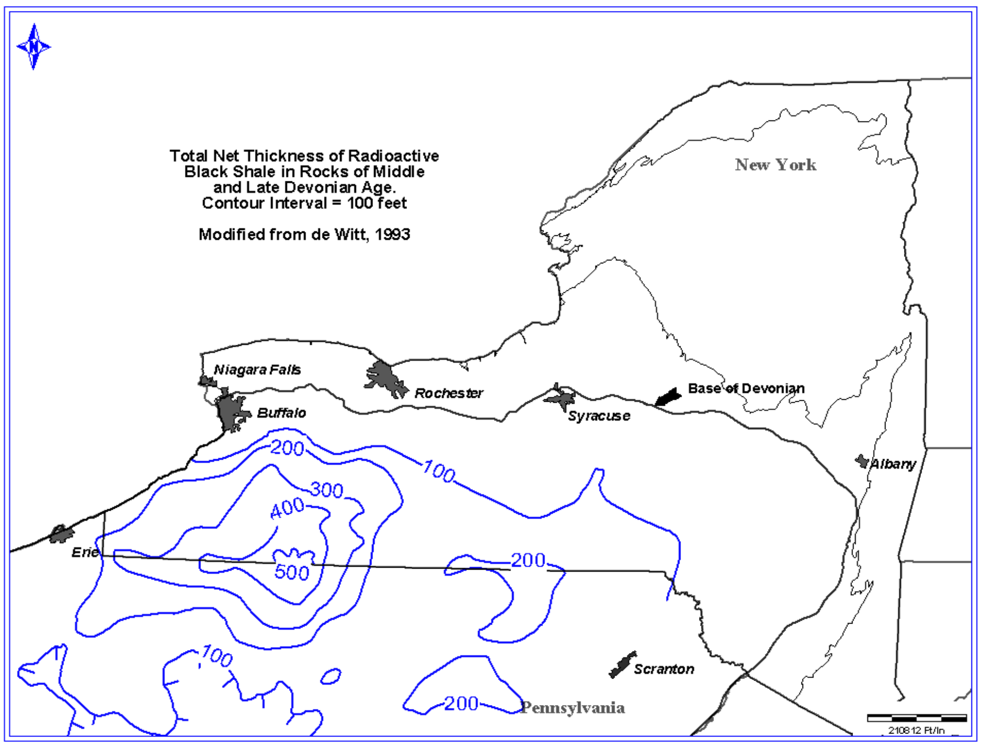


Modified from de Witt, 1993

As determined by de Wit using the 20 API gamma ray cut off, the net thickness of radioactive Devonian black shale ranges from less than 100 feet to over 500 feet (Figure 2.12) (de Witt et al., 1993). Generally the individual black shale units thicken from the western-central portion of the Allegheny Plateau toward the south/southeast. They are thickest in south-central New York, and thin to the east, grading into gray shales. The Hamilton Group black shales (primarily the Marcellus) range from less than 50 feet to about

100 feet over much of southern New York, but locally thicken to over 250 feet in northeast Tioga County. The Genesee Formation black shale is present in the western and central portion of the Allegheny Plateau, and ranges from less than 25 feet to over 125 feet in southern Steuben County. The Sonyea Formation (Middlesex black shale) is fairly thin, and not widespread, and ranges from less than 25 feet to just over 75 feet. The West Falls Formation, containing the massive and extensive Rhinestreet Shale, ranges from less than 150 feet to over 300 feet in southwestern New York. The Perrysburg Formation is present in southwestern New York, and thickens from less than 50 feet Chatauqua County to over 100 feet in central Erie County.

Figure 2.12. Radioactive Black Shale Thickness in New York.



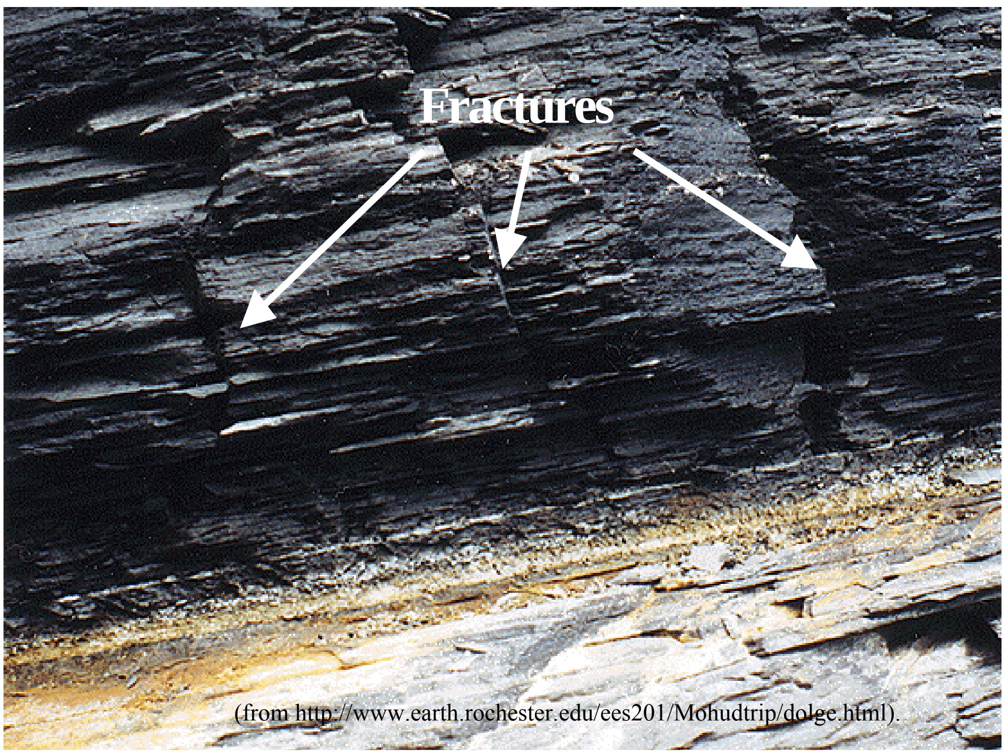
2.3 NATURAL FRACTURING

The rocks of the New York were strongly affected by the various stress regimes operating during the orogenic events mentioned above, and several episodes of natural fracturing occurred in the region. Natural fracturing is visible at many locations in New York. The regional fracturing patterns in the Devonian rocks of New York have been studied in depth by numerous authors including Parker (1942), Engelder (1980), Evans (1994), Gross (1991), and Loewy (1995).

Geologic studies of natural fracturing in New York indicate that various different vertical joint sets are present within the rocks of Middle and Upper Devonian age. Several different types of fractures (*joints*) are observed in the rocks, and each formed at different times and under varying circumstances (Wallace, 1988). *Alleghanian joints,* are planar cracks that formed during the Alleghanian Orogeny in response to the compression exerted upon the rocks. *Release joints* formed during the Mesozoic Era, and resulted from rock expansion as erosion removed many layers of overlying rock. *Unloading joints* formed later as the rock cooled and reflect the present stress field in the region (Wallace, 1988). The orientation of joints is related to the trajectory of the stress setting during the time of fracturing, and the orientation of maximum principal stress changed frequently during the regional geologic history. Generally, vertical joints propagate normal to the least principal stress, following the trajectories of the stress field at the time of propagation, thus the joint systems in the basin have varying orientations.

Organic content appears to have been a significant factor in joint development, and not all joint sets are present in all rocks. Black shales in particular have higher joint densities than adjacent gray shales, and joints often terminate at lithologic boundaries as seen in Figure 2.13 (University of Rochester, 2002). Some beds contain several different joint sets, while adjacent beds may contain only one set, thus the total joint density in a rock layer depends on the organic content and propagation mechanisms of the jointing episode. Five joints sets have been categorized by Loewy (1995), and were determined based on their "clustering of orientation and similarity of morphology" (Table 2.2). Timing of each jointing episode was determined by comparing abutting relationships between the different joints. Where a joint terminates against another joint, the terminating joint (abutting) is younger than the abutted joint.

Figure 2.13. Natural Fractures in Utica Black Shale



Joint spacing of the five joint systems varies from less than one meter to several meters. Density is greatest in black shales where it is usually less than one meter. In addition, joint densities are higher in thinner black shales than thicker black shales because of differences in total organic content (organic content is higher in thinner beds than thicker beds). Loewy also states that joint porosity decreases with increasing bed thickness, and that "overall joint porosities in the shales with the largest joint densities are less than 1%" [see Loewy (1995) "Observations and Experimental Data" pages 13-45, for a thorough discussion].

Little literature exists that discusses the natural fracturing in the Silurian and Ordovician. Natural fractures are present however, as seen in road cuts through the Utica Shale (Figure 2.13). In 1997 the Earth Satellite Corporation (1997) performed a remote sensing and lineament analysis of the Appalachian Basin in New York. The basis for their assessment was geologic interpretation of ten digitally-enhanced, Landsat Thematic Mapper ™ images within the outcrop of the Utica Shale in New York.

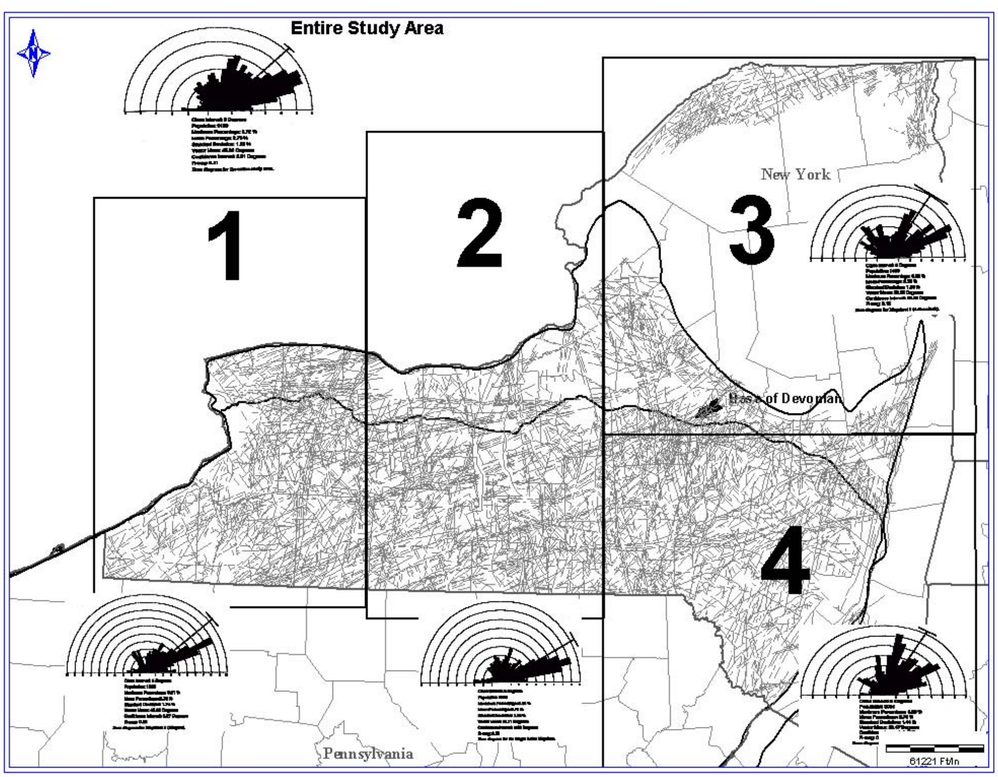
Table 2.2. Primary Joint Sets in New York.

Order	Type	Orientation	Rock Type	Timing / Stress
1	Cross-fold (CF)* ***Set I*****	N-NW (320 º to 010 º)	Gray shale, siltstones, and Black Shale	Natural hydraulic fracturing during N-NNW compression during the Alleghanian Orogeny, formed at depth.
2	070º ***Set III*****	070º	Black/Gray Shale ***below*** Rhinestreet fm.	Release joints, propagating during basin uplift and regional rifting, formed at depth.
3	E-W	085 º	Rhinestreet & Ithaca Formation Black shales only	Relaxing of formation tension resulting in release joints, formed at depth.
4	Fold Parallel (FP) ***Set II*****	E-NE to E-W 070 º east to -045 º west	Gray/Black shale Most dense in and above the West Falls Group	Unloading, Release joints propagated during uplift.
5	E-NE	E-NE	Gray shale, siltstones, and Black Shale	Unloading-type, Parallel present stress field (Neotectonic), shallow depth.

* Consists of several joint sets that are not differentiated
** Regional set nomenclature by Parker (1942)

The orientation of natural fractures was evaluated for four map sheets within the entire study area as depicted in Figure 2.14, and the rose diagrams generated by Earth Satellite Corporation (1997) show that the dominant fracture orientation varies from west to east. On sheets 1 and 2, where the upper Devonian sequence is very near the surface, northeast to eastern fractures dominate. On sheet 3, the wide variation in fracture orientation observed is “indicative of the fact that this sheet contains both the northeastern-most portion (mostly Ordovician section of the Appalachian Basin) and the St. Lawrence Lowlands portion of the study.” Sheet 4 shows that “the effect of basement reactivation of trends associated with the Taconic orogeny (N5º-20ºE and N5º-20ºW trends) and the trends associated with the eastern-most portion of the Appalachian Basin (N45º-55ºW, N25º-40ºE and N45º-60ºE) are evident.”

Figure 2.14. Rose Diagrams of Four Study Areas



Joints in Ordovician-age rocks are more profoundly influenced by preexisting basement structure, the Taconic Orogeny and related structural grain, and by the Salina Salts, which would have transferred "almost all the stress from subsequent tectonism to the overlying sequences and resulted in a muted effect in the underlying Ordovician Rocks" (Earth Satellite Corporation, 1997).

The potential for development of fractured shale reservoirs depends upon the presence of extensive natural fractures, and "current ambient stress in New York suggests that subsurface fracture orientations in an east-northeast direction will likely be most favorable as the major feeders for hydrocarbons into fractured reservoirs in either the source rocks or conduits to other reservoirs" (The Cadmus Group, 1997).

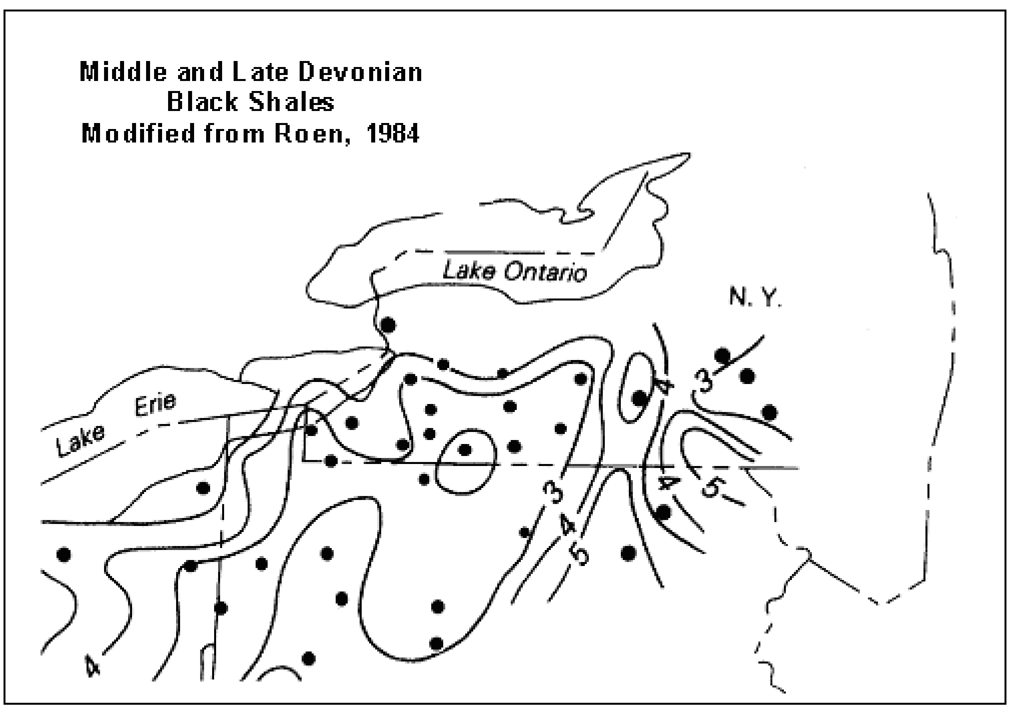
3 Geochemistry

The amount of gas present in organic rich shales (at a given locality) is dependent on three factors: 1) the amount of organic matter originally deposited with the rock, 2) the relative origins of the different types of organic matter and the original capacity of each for gas generation, and 3) the degree of conversion of the organic matter to hydrocarbon natural gas. The first two factors are largely dependent on conditions present at the site of deposition, and the third is determined by intensity and duration of post-depositional heating, or load metamorphisim due to maximum depth of burial. The second factor is relatively constant for Devonian shale samples studied. This also assumes that the natural gas has remained, to some extent, trapped in the source to become a "reservoir."

3.1 TOTAL ORGANIC CARBON

The amount of organic carbon present in the rock is not only important as a source rock, but it also contributes to the natural gas storage by adsorption and or solution within the reservoir system. In the Appalachian Basin, darker zones within the Devonian Shale (higher organic content) are usually more productive that the organic-poor gray zones (Schmoker, 1980).

Figure 3.1. Average Organic Content (%) of the Devonian Shale in New York.



Total organic carbon (TOC) measurements have been made on both core and drill cuttings in the Devonian Shale in New York. Table 3.1 summarizes the measurements from core samples by formation (Streib, 1981, Zielinski, 1980). Both tables are averages of multiple data points from individual wells and from multiple wells by Devonian Shale member. TOC values range from low values less than 0.5% in the upper Devonian shales to over 6% in the middle Devonian shales. The data also show a general trend of increasing TOC going from central New York to western New York as well as a general trend of increasing TOC with depth or age of Devonian Shale (Figure 3.1). However, Weary, et. al. describe a Middle Devonian Marcellus cuttings sample taken from Livingston County with a measured TOC of 11.05% (Weary, 2001).

No TOC data is available for Silurian shales. Measurements of total organic carbon in the Utica Shale have been reported in literature (Hay, 1989, Hannigan, 1994, Ryder, 1998, Wallace, 1988). Table 3.3 is a summary of the data. The range is from approximately 0.16% to 4.0% with an average of 1.68%.

Table 3.1. TOC from New York Devonian Shale Drill Cuttings.

Group	Member	Van Tyne 9 Well Data Set Average All Wells / All Depths Total Organic Carbon (%)	USGS 20 Well Data Set Average All Wells / All Depths Total Organic Carbon (%)
	Dunkirk Shale		1.14
Canadaway			
	Hanover Shale		0.80
Java			
	Pipe Creek		
	Angola Shale		0.89
West Falls			
	Rhinestreet Shale	1.95	1.47
Sonyea	Cashaqua Shale		0.65
	Middlesex	2.83	1.50
	West River		1.34
Genesee	Pen Yan Shale	2.40	1.58
	Geneseo Shale	4.00	0.92
	Hamilton Shale		0.80
Hamilton			
	Marcellus Shale	6.05	3.87

Table 3.2. Published Organic Carbon Data for the Utica Shale in New York.

Source	Range of Weight Percent Organic Carbon
Hay and Cisne, 1989 / Outcrop in Central New York	1% – 3.5%, average 1.75%
Hannigan and Mitchell, 1994 / Outcrop, east-central New York	1% – 4%, average 2.22%
Wallace and Roen, 1989 / Subsurface and Outcrop	0.16% - 3.19%, average 1.09%

3.2 KEROGEN TYPE

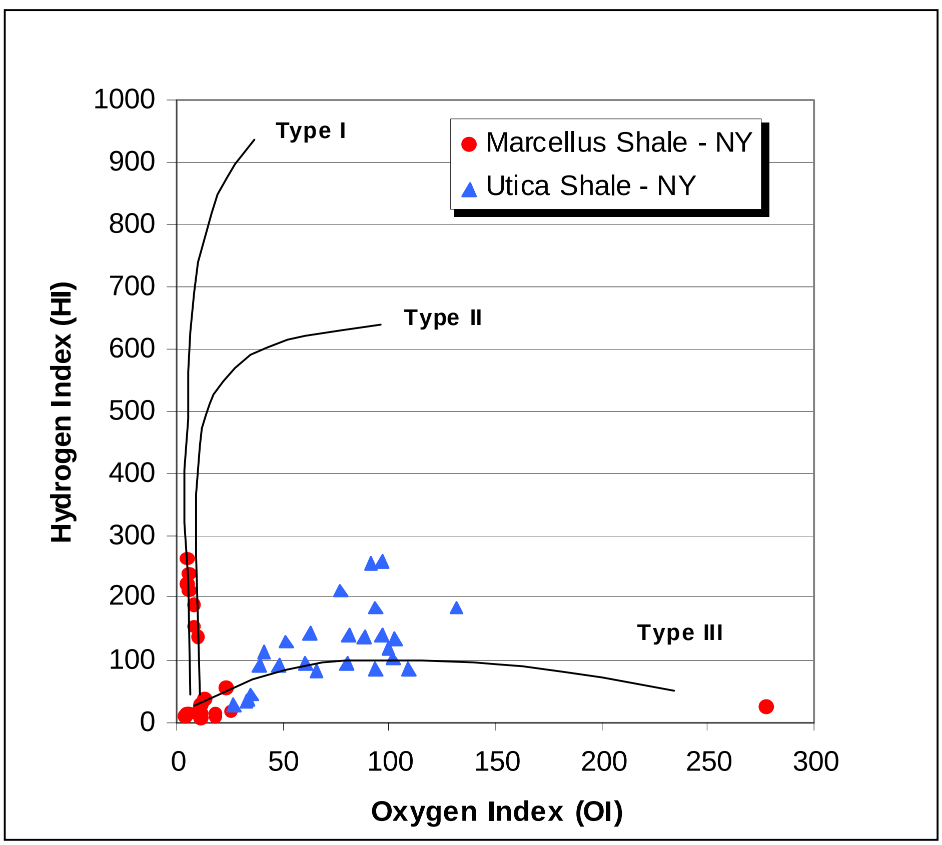
Knowing the type of kerogen that is present in the rock provides information on hydrocarbon source potential and depositional environment. Kerogen type can also influence the amount of natural gases stored by adsorption as well as diffusion rate. The classification scheme for kerogen evolved initially from the optical maceral analysis of coal. Elemental analysis was later applied to kerogen analysis. The elemental analysis is based on the quantification of the hydrogen/carbon (H/C) and oxygen/carbon (O/C) ratios from Van Krevelen (1961). A plot of the ratios, called the Van Krevelen diagram, was developed to diagrammatically determine kerogen types and thermal maturation. The ratios on the Van Krevelen diagram were replaced with the indices (HI and OI) from Rock-Eval data resulting in a modified Van Krevelen diagram (Espitaliè, 1977). This modified diagram is used to determine kerogen types. Figure 3.2 is a further breakdown and description of the four common types of kerogen.

Figure 3.2. Kerogen Types (Waples, 1985).

Kerogen Type	Depositional Environment	Organic Precursors	Hydrogen Product
I	Lacustrine	Algae	Liquids
II	Marine, Reducing Conditions	Marine Algae, Pollen, Spores, Leaf Waxes, Fossil Resins	Liquids
III	Marine, Oxidizing Conditions	Terrestrial-Derived Woody Materials	Gas
IV	Marine, Oxidizing Conditions	Reworked Organic Debris, Highly Oxidized Material	None

Published Rock-Eval data for the Marcellus shale and the Utica Shale in New York State was plotted on a modified Van Krevelen diagram (Figure 3.3) (Weary, 2000). The data show that the Marcellus is primarily Type II kerogen with a mixture of Type III and the Utica is primarily Type III kerogen with a mixture of Type II. Both shales with these kerogen assemblages are capable of generating liquids and gases. No Rock-Eval data is available for the Silurian Shales in New York.

Figure 3.3. Published Rock-Eval Data for Marcellus and Utica Shales in New York Plotted on a Modified Van Krevelen Diagram.



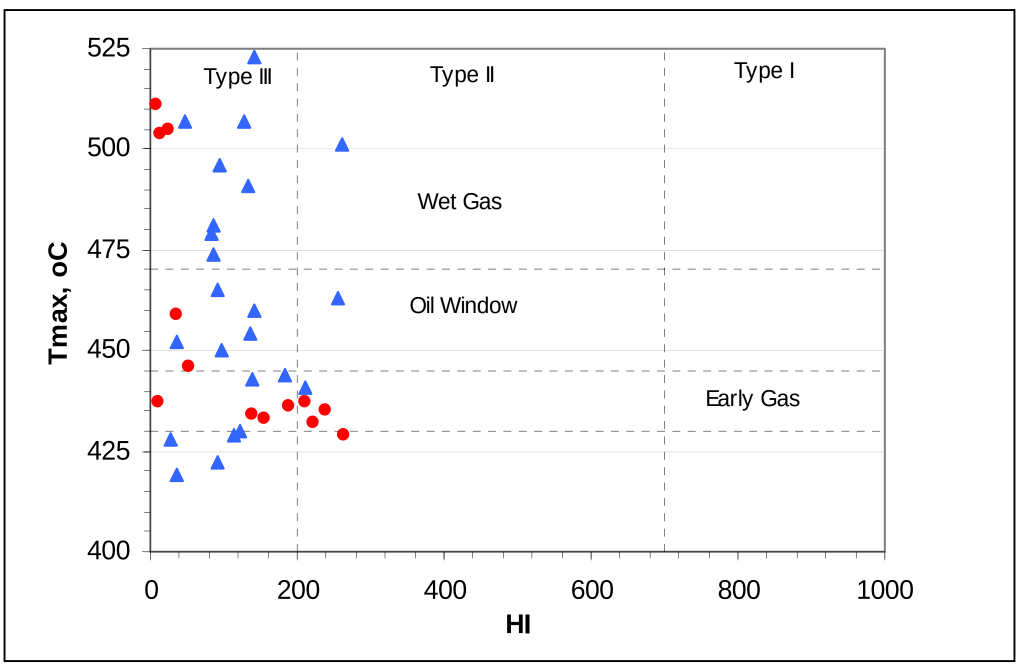
3.3 THERMAL MATURITY

The maturation level of the kerogen is used as a predictor of the hydrocarbon potential of the source rock. It also is used to high-grade areas for fractured gas shale reservoir potential and as an indicator for investigation biogenic gas within a shale reservoir system. Thermal maturation of the kerogen has been found to also influence the amount of natural gas that can be adsorbed onto the organic matter in shale. Thermal maturation can be determined by several techniques, including Rock-Eval, vitrinite reflectance, thermal altercation index and conodont alteration index. Multiple techniques should be employed to help determine thermal maturity of a shale.

3.3.1 Rock-Eval

Rock-Eval can be used to assist in determining the thermal maturation level of kerogen. Peters (1986) defined the thermal parameters in which T_{max} (maximum temperature) can be used to define the dimensions of the oil window (Peters, 1986). The top of the oil window is generally assumed to occur between T_{max} values of 435ºC and 445ºC and the bottom of the oil window occurs at 470ºC. Plotting T_{max} and hydrogen index can show the thermal maturation and kerogen type of the samples. Published Rock-Eval data for the Marcellus Shale and the Utica Shale in New York State was plotted using the technique after Peters (Figure 3.4) (Weary, 2000). This Figure shows the spread of maturity of the samples measured. The samples were from different depths and ranged from central New York to western New York. No Rock-Eval data is available for the Silurian shales in New York.

Figure 3.4. Published Rock-Eval Data for Marcellus and Utica Shale. Plotted After Peters (1986).



3.3.2 Vitrinite Reflectance

Reflectance of coal macerals in reflected light has long been used to evaluate coal ranks. Reflectance measurements have been extended to particles of disseminated organic matter occurring in shales and other rocks (kerogen) and have been the most widely used technique for determining maturity of source rock. Typical analysis normally shows a distribution of reflectance corresponding to the various constituents or macerals of the kerogen. Because humic or vitrinite particles are generally used for reference to the coalification scale, the mean random reflectance of vitrinite (Ro) is preferred to other particles. In some cases, there may be several groups of vitrinite particles with different reflectance present. In these situations, it is recommended that only the group with the lowest reflectance should be used. Other groups with higher reflectance are considered "reworked." Table 3.3 is a breakdown of the different stages of maturation with vitrinite reflectance.

Table 3.3. Vitrinite Reflectance Categories for Thermal Maturity.

Vitrinite Reflectance	Comments
R_o <0.5 to 0.7%	Diagenesis stage, source rock is immature
0.5 to 0.7% >R_o<1.3 %	Catagenesis stage, main zone of oil generation
R_o >2.0%	Metagenesis stage, methane remains as the only hydrocarbon (dry gas zone)
R_o is the mean reflectance in oil.	

Table 3.4 summarizes vitrinite reflectance data from nine wells in the Marcellus Shale (Van Tyne, 1993). There is a general trend of increasing thermal maturity going from western New York toward central New York. This general trend in the Marcellus Shale is further supported by the vitrinite reflectance data reported from drill cuttings in the USGS report by Weary (2000) (Figure 3.5). No vitrinite reflectance data has been reported for the Silurian or Ordovician shales.

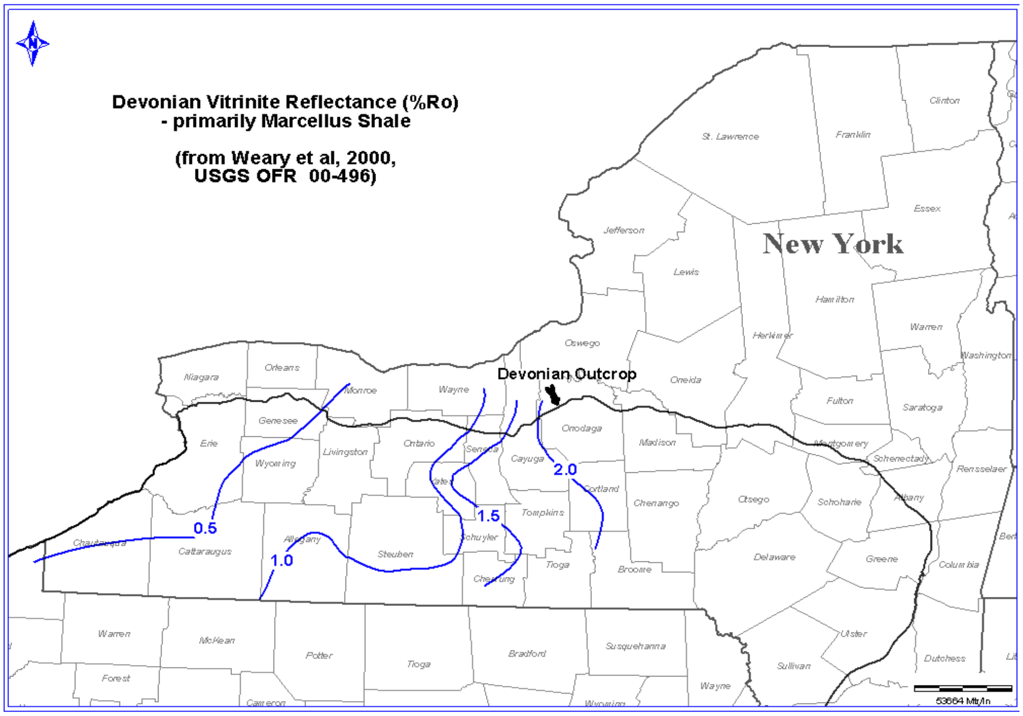
Table 3.4. Summary of Thermal Maturity Data; Marcellus , New York.

Well / County	Depth (ft)	Ro (%)
St. Bonaventure , Cattaraugus County	3,600-3,640	1.23
Portville Central School, Cattaraugus County	4,140-4,180	1.2
Houghton College #1 Allegany County	2,270-2,290	na
Houghton College #2, Allegany County	2,380-2,410	1.18
BOCES Fee #1, Allegany County	3,240-3,290	1.27
Meter #1, Livingston County	1,570-1,600	1.31
Alfred University #1, Allegany County	3,950-3,960	1.65
Hammel #1, Allegany County	4,662-4,690	1.65
Valley Vista View #1, Steuben County	3,882-3,895	1.65
Average All Wells / All Depths		**1.39**

3.3.3 Thermal Alteration Index

The uses of progressive changes of color and/or structure of pores, pollen or plant-cuticle fragments is also used as an indicator of thermal maturation of the kerogen. Kerogen coloration is reported on a scale of 1 to 5, and is referred to as Thermal Alteration Index (TAI) (Staplin, 1969). Different types of spore or pollen grains can show different sorption values at low levels of maturation. TAI averaged 3.20 for the Rhinestreet Shale interval from NY#3 well in Steuben County New York that was cored from 1,203 to 1,263 feet (Streib, 1981). Similar TAI values were measured from the NY#4 well in Steuben County, 3.2 for the Geneseo (2,970 – 3,080 feet) and 3.4 for the Marcellus (3,780 – 3,842 feet) (Streib, 1981). All samples indication maturation levels above 150°C. No TAI values were available for the Silurian or Ordovician shales.

Figure 3.5. Devonian Vitrinite Reflectance (%Ro)



3.3.4 Conodont Alteration Index

The thermal maturity of shales can also be inferred from published conodont alteration indices (CAI), a scale of color alteration in conodonts (a marine fossil) (Epstein, 1977). In general, the CAI of a conodont increases with depth and temperature as a result of metamorphisim. Table 3.5 summarizes the indices. A recent study of thermal maturity in Ordovician and Devonian rocks has been completed by the USGS and New York Geological Survey (Weary, 2000). In the Upper Devonian shales, CAI values range from less than 1.5 in to 2.5 west to east. In Middle Devonian shales, CAI increases from about 1.5 in western New York to 2.5-3 in the central area (Figure 3.6) (Tetra Tech, 1980). Silurian CAI values are similar to the Middle Devonian. Upper Ordovician rocks in western New York have CAI values of 2-3, which put them within the more advanced stage of wet gas generation. In southern New York, where CAI values are 3-5, the Ordovician rocks are prospective for dry gas (Figure 3.7) (Weary, 2000).

Table 3.5. Conodont Alteration Indices (Streib, 1981).

CAI	Equivalent Ro (%)	Hydrocarbon Occurrence
1	< 0.8	Early-Mature Oil
1.5	0.7 –70.85	Early-Mature Oil
2	0.85 – 1.3	Late-Mature Oil
3	1.4 – 1.95	Wet Gas
4	1.95 – 3.6	Post-mature Dry Gas
5	> 3.6	Post-mature Dry Gas

Figure 3.6. Devonian Conodont Alteration Index (CAI) Isograds.

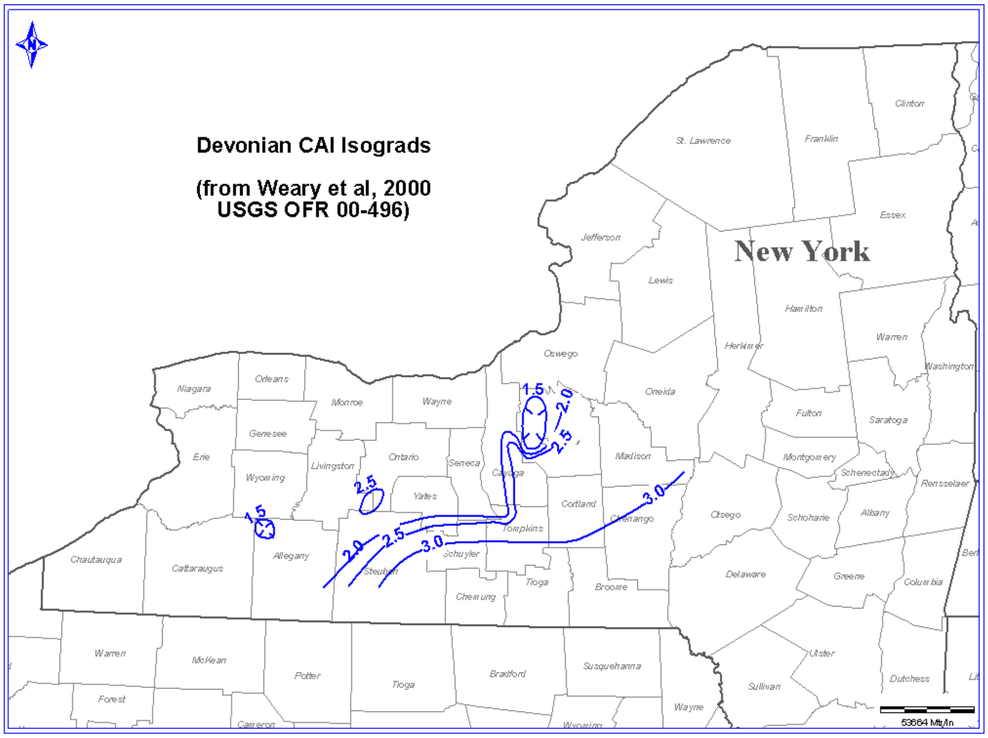
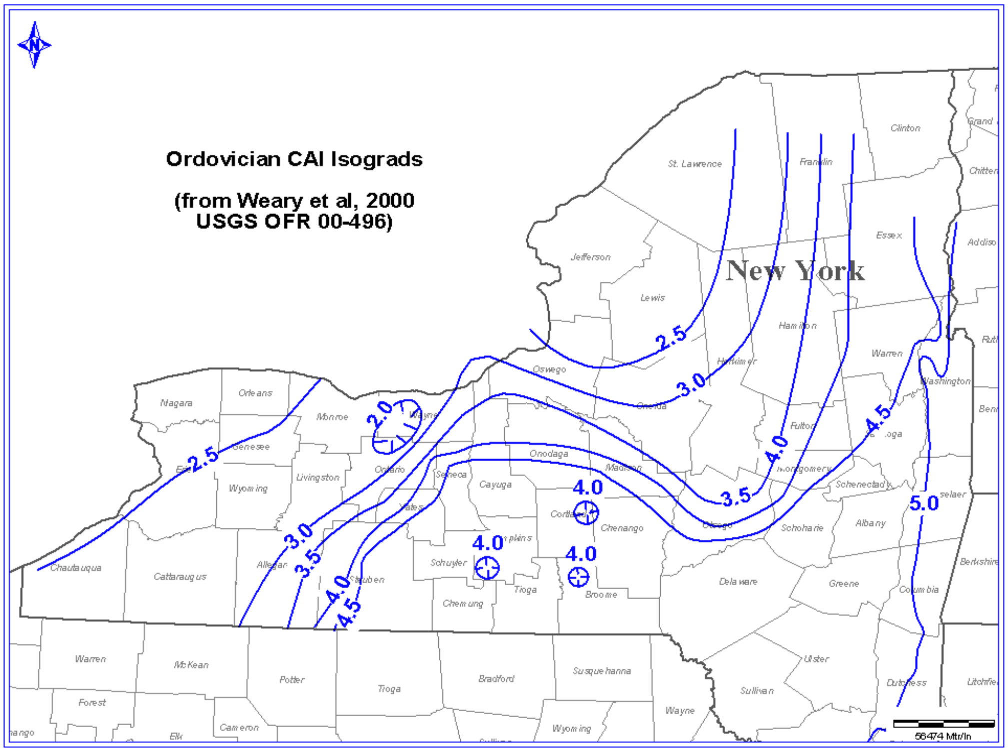


Figure 3.7. Middle and Upper Ordovician Conodont Alteration Index (CAI) Isograds.



4 Natural Gas Resource and Production

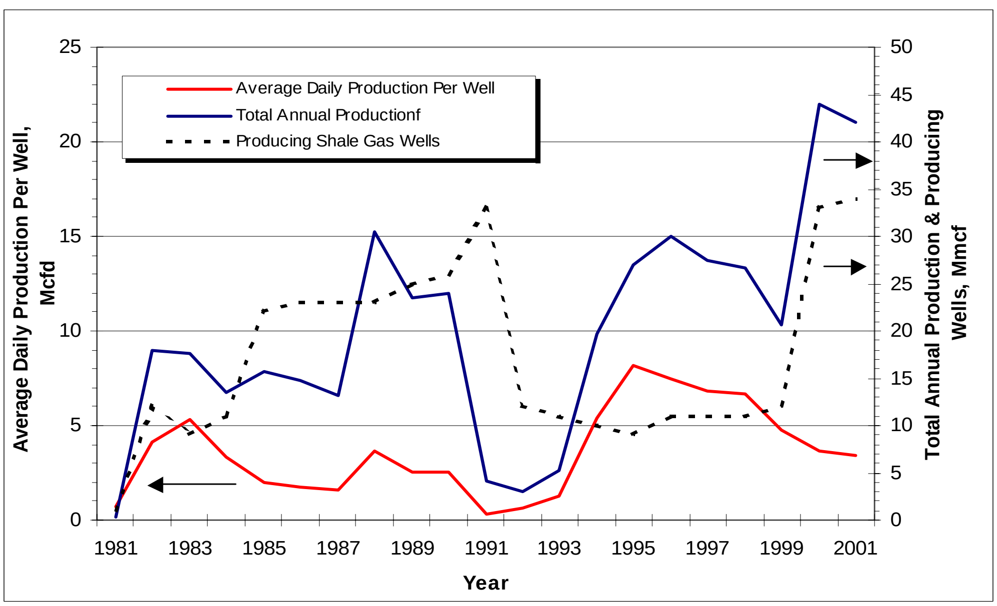
The information and data available regarding the amount of natural gas resource contained in the organic-rich shales in New York is dated and only available for the Devonian-age shale. No information or studies have been done for the Silurian shales or Ordovician shales in New York or the Appalachian Basin. No estimates have been published for the technically recoverable reserves in the Devonian Shale in New York.

Natural gas production data was not reported to the state of New York prior to 1983. Data prior to this period is sketchy and is considered unreliable. Even though production data is now reported to the State, many of the shale wells producing today are for home or local use and may not be producing at fullest potential or from a reservoir management perspective. Some of these wells are not metered and estimates for annual production are provided. As of 2001, there are 8 wells producing from the Devonian-age shale in New York. Two wells are producing from Silurian-age shales and no wells are producing from the Utica Shale (Ordovician-age). Production data is shown in Figure 4.1, and highlights the annual natural gas production from shale wells in New York as well as the average daily production per well and the number of producing wells per year. This data is derived from the Annual New York State Oil, Gas, and Mineral Resources report published by the Division of Mineral Resources of New York State (NYSDEC, 2002).

4.1 NATURAL GAS RESOURCE

The natural gas resource estimates for Devonian-age shales in the Appalachian Basin vary widely. Estimates range from a low of 225 Tcf to a high of 2,579 Tcf (National Petroleum Council, 1980, Zielinski, 1982). The estimates vary based on type of shale included in the analysis (black and or gray), reservoir thickness and gas content per cubic foot of reservoir. Estimates for the Devonian Shale resource in New York were calculated in the 1980 National Petroleum Council Study, Table 4.1.

Figure 4.1. New York Shale Gas Production Data from 1981-2001.



Two estimates were made in the NPC study using either log-based data or sample-based data. The gas content for both approaches were the same: 0.6 scf/cf for black shale (>230 API units) and 0.1 scf/cf for gray shale (<230 API units). The net reservoir thickness varied for each approach as indicted in the table. For the log-based approach, black shale thickness was determined as shale with >230 API units from a gamma ray log. For the sample based approach, black and gray shales were identified by color. The area for assessment was 19,069 mi^2 (National Petroleum Council, 1980).

New York ranks third in resource, behind Pennsylvania and West Virginia, accounting for 14.5% of the Devonian Shale natural gas resource in the Appalachian Basin. Unfortunately, no state-by-state estimates were made for technically recoverable natural gas in the 1980 NPC study.

Table 4.1. New York Devonian Shale Resource Assessment, 1980 NPC Study.

Study	Shale Thickness (Feet)	Resource Base (Tcf)	Resource Base (Bcf/Mi^2)
LOG DATA:			
Black Shale	59	19	0.99
Gray Shale	2,731	145	7.60
Total	2,790	164	8.60
SAMPLE DATA:			
Black Shale	619	198	10.38
Gray Shale	2,171	115	6.03
Total	2,790	313	16.41

In 1992, the U.S. Geologic Survey (USGS) published a resource assessment of the Devonian Shale in the Appalachian (Charpentier, 1993). The assessment, described as qualitative, broke up the Appalachian Basin into 19 sub-areas. The approach used by the USGS for each of the 19 play areas was geologic based, and were based on structural and stratigraphic criteria. Parameters used to help define boundaries include: thickness of black shale, total organic carbon, thermal maturity of organic matter, and structural complexity (development of natural fractures). Table 4.2 summarizes the gas-in-place estimates from the study.

The shale gas potential was rated using a **low**, **moderate** and **good** system. In areas where all of the parameters fall within ranges suitable for generation and accumulation of natural gas, a designation of **good** is used. In areas where *a* majority of the parameters fall within favorable ranges and the remaining are close to acceptable standards, a designation of **moderate** is used. In areas where a majority of the parameters do not fall within acceptable ranges, a designation of **low** is used. For detailed evaluation parameters within each individual play area and the basis for the potential designation, the reader is referred to the original USGS open file report.

As with the 1980 NPC study, no estimates were made for recoverable natural gas for each play area. Six of the play areas are in part within the New York State boundaries. Of these six plays, two are rated as good (Play 3 and 15), two are rated as moderate (Play 6 and 17) and two are rated as low (Play 16 and 19) (Charpentier, 1993).

Table 4.2. Estimates of In-Place Natural Gas Resources in the Devonian Shale, by Play Area.

Play		Natural Gas Resource (Tcf)			
Number*	Name	Low F_{95}	High F_5	Mean	Shale Gas Potential
1	North-Central	17.9	34.2	25.9	Moderate
2	Western Lake Erie	21.7	31.3	26.5	Good
3	Eastern Lake Erie	2.1	3.3	2.7	Good
4	Plateau Ohio	44.4	76.2	59.9	Low
5	Eastern Ohio	35.2	55.1	44.7	Moderate
6	Western Penn-York	20.4	28.2	24.3	Moderate
7	Southern Ohio Valley	19.7	36.2	27.7	Moderate
8	Western Rome Trough	38.0	74.0	56.0	Good
9	Tug Fork	13.7	25.9	19.7	Good
10	Pine Mountain	10.7	18.7	14.6	Moderate
11	Plateau Virginia	3.9	10.2	7.1	Good
12	Pittsburgh Basin	76.8	129.9	102.1	Low
13	Eastern Rome Trough	70.7	132.5	100.3	Good
14	New River	38.5	91.7	63.1	Low
15	Portage Escarpment	8.5	21.3	14.6	Good
16	Cattaraugus Valley	10.4	23.2	16.6	Low
17	Penn-York Plateau	98.1	195.2	146.0	Moderate
18	Western Susquehanna	24.1	67.7	44.9	Low
19	Catskill	22.1	75.8	47.6	Low
	Basin Total	577.1	1130.8	844.2	

* *Basin,* Gray shading indicates play area, in part, resides within the state of New York

Modified from Charpentier, 1993.

4.2 DEVONIAN SHALE GAS PRODUCTION IN NEW YORK

Natural gas production in black shales of the Dunkirk, Rhinestreet and Marcellus was established in numerous wells, and several small fields in New York during the 19th century. Few details are available for these early wells. A review of well records show approximately 100 wells that were drilled with designated API numbers for Devonian-age shale production (Figure 4.4). Most of these wells were drilled after 1970. At the end of 1999, 10 wells produced 6.3 Mmcf of natural gas from Devonian Shale. The average daily flow rate per well (assuming a full 12 months of production) was 1.73 Mcfd. Table 4.3 is a summary of the fields with Devonian Shale gas production.

Table 4.3. Devonian Gas Shale Fields in New York in Order of Year of Discovery.

Gas Field	Year	Producing Zone	Avg. Depth (feet)	IP (mcfd)	Wellhead Pressure (psia)	No. of Prod. Wells	Status As of 1999	Cum. Prod. Thru 2001* (mmcf)
Lakeshore Belt	1821	Dunkirk	200	10-100?	?	300 (?)	?	52.89
Naples	1880	Marcellus	1,300	1.5-20	150 (?)	12	Abnd.	32.18
Dansville	1881	Lower Hamilton	1,000	10-100	50 (?)	7	Prod.	5.57
Rushville	1902	Lower Hamilton	650	60	35	10 (?)	Abnd.	Na
Bristol	1914	Marcellus	650	3-850	50	10	Abnd.	Na
Southern Erie County	1920's	Rhinestreet-Hamilton	800	40-150	225	?	na	Na
Rathbone	1931	Nunda, Rhinestreet	1,000	100-2,000	225	28 (?)		2.20
Genegantslet	1964	Upper Hamilton	1,200	2,166	565	3		Na
Pikes Corners	1978	Devonian Shale				1	Prod.	18.53
Alfred	1981	Marcellus	3,950	40	1720	1	Abnd.	1.28
Four Mile	1981	Marcellus	3,600	14	1520	1	Abnd.	
Elmira	1982	Marcellus	2950	86		1	Prod.	9.29
Cafferty Hill	1982	Marcellus		17		1	Prod.	3.1
Avoca	1982	Marcellus				2	Prod.	46.89
Karr Valley	1982	Marcellus	3,480	330	1,720	1	Prod.	15.69

Modified from Van Tyne, 1983. Discovery year is determined as date of first shale gas production for fields with gas production from other horizons.*Cumulative production data are obtained from New York State Oil and Gas Drilling and Production and Mineral Resources Annual reports and others sources as available and begins as of 1981.

4.2.1 The Discovery Well and Early Production

Sometime during 1821, Edward Howard, an owner of a woolen mill in the town of Fredonia, New York, was dissatisfied with his water well (shallow and ran dry seasonally) and decided to drill a new well in the shale just below his mill. He began simply by "drilling" with an iron bar a few feet long. After drilling a few feet into the shale, he observed water and bubbles of gas escaping from the shale. A friend by the name of William Aron Hart, a gunsmith of the village, visited the mill from time to time and became interested in his friends experiment and its outcome (Orton, 1899).

William Hart continued working on the hole that Edward had started under the mill until the "drill" broke, leaving a portion of the bar "steadfast in the shale" and shutting off the gas flow in the well. Mr. Hart abandoned the well and set about drilling another well nearby for gas. He went down successfully about 40 feet, but found no volume of gas. Still not discourage, he set about looking for the gas veins (fractures) that were well known in the area, which had been seeping gas at the surface for centuries. He located his third attempt near one of the largest natural gas seeps on the banks of Canadaway creek. He drilled down at least 26 feet and possibly 70 feet and found what he had been looking for – good gas flow (Orton, 1899).

William Hart quickly realized the potential of the natural gas, built a crude gasometer to collect the gas and laid a gas line using light weight lead pipe, ¾ inch in diameter, to the Abell House (a hotel) and several stores on the opposite side of the street of the hotel and began to transport and sell the gas. Around 1830, the flow rate from the well was gauged at 880 cubic feet in 12 hours (1.76 Mcfd). The well continued to produce and supply the town through 1858 (37 years). A second well was drilled nearby by a newly formed gas company called Fredonia Gas Light Company. The well produced about 2 Mcf per day and continued to supply the town with natural gas for illumination. Drilling continued into the 20th century. Records indicate reports were made of salt water in the wells as early as 1887 and the need to pump the wells up to 4 times a year and to "never shut them in." A typical 300-foot shale well cost approximately $300 and the gas was sold for $1 per thousand cubic feet around the turn of the century (Orton, 1899).

During the 1800's hundreds of shallow gas shale wells were drilled in the area and along the shores of Lake Erie, giving rise to the establishment of Lakeshore Field. During these early years, drilling for natural gas expanded geographically as well as geologically in New York and elsewhere across the nation. The oldest established gas shale field in New York is Naples, located in southern Ontario County. The field was discovered in 1880 and 19 wells ranging in depth from 1,220 feet to 1,400 feet were drilled. Twelve were completed in the Marcellus, of which 11 were reported to be producing 1-2 Mcfd as of the early 1980's for a local utility (Van Tyne, 1983). Other fields discovered in the 19th century include the Lakeshore Field and the Dansville field. The Lakeshore field includes many of the early wells drilled along the shores of Lake Erie following the discovery made by William A. Hart in 1821.

4.2.2 20th Century Production

During the first half of the 20th century several shale fields were discovered including Rushville and Bristol, Southern Erie County, and the Rathbone, Steuben County. The Rathbone field was discovered in 1931 and thirty-one wells were drilled in the field. Twenty-four wells were producers, four were dry holes, two were plugged and abandoned due to poor performance, and one well produced oil. The wells were typically 900-1,500 feet in depth and targeted the Nunda and Rhinestreet shales of the West Falls Formation. Reservoir pressure was reported as 225 psig and flow rates (IP's) ranged from 100-2,000 Mcfd (Newland, 1936).

Gas shows in many wells were reported during drilling and testing elsewhere in southern New York in subsequent years, yet only a handful of wells were drilled and completed as shale producers. Little information is available for these wells but IP's reported ranged from small to over 1 Mmcfd. Most of the wells were completed in the Lower Hamilton Group, including the Marcellus Shale. The wells were usually fracture stimulated which sometimes improved production, but other times killed the well. It is estimated that 27 wells were completed as Marcellus producers since the 1960's. Cumulative production from these is unknown.

Prior to the NYSERDA/DOE program, the last shale gas field formally designated was Genegantslet, in Chenango County. In 1964 the Decker #2 well was drilled in the southern part of the town of Smithfield and encountered gas in the upper Hamilton. The well tested at 2,166 Mcfd, and was completed in the Marcellus Shale. Nine other wells were drilled, but only 3 wells produced gas (Table 4.4) (Van Tyne, 1983).

Table 4.4. Genegantslet Field (Chenango County) Marcellus Shale Well Data.

Well Name	Date	TD	Formation	IP, MCFD/Pressure
Decker #1	1963	3,265	Sand (Silt?)	Dry Hole
Decker #2	1964	2,050	Marcellus Sh	I0F 1650 Mcf/day down to 1000 Mcf blow after 54 hrs. IRP - 600# down to 540# after 2 wks; 1 yr later 1/7/65, NYSNGC gauged 2166 Mcf A/5 hrs. blow: RP - 565#
Decker #3	1964	3,685	Helderburg Lm	No show in Marcellus, Dry Hole
Decker #4	1964	2,002	Marcellus Sh	IOF 250 Mcf and FOF 332 Mcf, IRP at 565#
Flannigan #1	1965	2,462	Unknown	"scum" show @ 1110-1130 & gas show 25-50 mcfd @ 1502-1515 in Hamilton – Dry Hole
J. Bottle #1	1965	2,015	Marcellus Sh	25 Mcfd @ 1958' & 2-3 Mmcfd @1975' / 575# in 5 hours
J. Bottle #2	1965	2,100	Unknown	Dry Hole
Collyer 1	1966	2,201	Unknown	IOF-6.8 Mcfd in Hamilton, estimated RP-200 # -Dry Hole
Decker #5	1967	6,292	Hamilton	

Table 4.5. NYSERDA Wells Drilled to Test Viability of Older Fields.

Well Name / API #	County/ Field	Field Discovery Date	Date	Tested/ Completed Formation	IP (Mcfd)	Cum. Prod. (Mmcf) Through 2001 / Status
Valley Vista View #1 31-101-15268	Steuben Rathbone	1931	July 1980	Rhinestreet Marcellus	Dry 200	3.453 P&A
Meter Farm #1 31-051-15480	Livingston Dansville	1881	Sept. 1980	Hamilton (Marcellus)	411	5.526 Active
Elliot #1 31-123-17347	Yates Rushville	1902	Aug. 1982	Marcellus	Dry (water)	Dry Hole
Widmer #1 31-069-17366	Ontario Naples	1880	Sept. 1983	Hamilton (Marcellus)	40	1.027 P&A
Data from Donohue, 1981, 1984B, and Charpentier, 1993, and New York Production Database. (NYSDEC, 2002)						

Several of the wells drilled as part of the NYSERDA research program had a primary objective to test the viability of drilling and completing wells in old fields and using modern technology. These four wells and fields are summarized in Table 4.5.

Following the NYSERDA funded exploration and testing program, several fields were established. Although many of the fields were established with only one well, several continued to produce through 2001. Many of the fields are designated for home use or private use. Production data is often not measured and produced volumes vary based on the needs of the user. Cumulative production from those Devonian shale wells reporting totaled 288.3 Mmcf. This data is taken from the Annual New York State Oil, Gas, and Mineral Resources report published by the Division of Mineral Resources of New York State.

4.3 SILURIAN SHALE GAS PRODUCTION IN NEW YORK

Two gas fields have been discovered in Silurian shales (Table 4.6). Meridian Exploration discovered the Reeder field in Seneca County. The Ritter #1019-1 well was drilled in June 1989 and was completed open hole in the Rochester Shale. Casing was set (4 ½ inch diameter) at 1,549 feet and the well reached a total depth of 1,782 feet (driller). The well was completed as an open-hole natural flow with a reported IP of 2,258 Mcfd. The well has produced 48.32 Mmcf through 2001.

Table 4.6. Silurian Gas Shale Fields in New York in Order of Year of Discovery.

Gas Field	Disc. Year	Producing Zone	Avg. Depth (feet)	IP (mcfd)	Wellhead Pressure (psia)	No. of Prod. Wells	Status As of 1983	Status As of 2001
Reeder Creek	1989	Rochester Shale	1,782	2,258	568	1	Abnd.	Prod.
Neilson Road Pool	1990	Sodus Shale	1,865	6,038		1	Prod.	Prod.
Source: NYSDEC, 2002 Production Database								

Meridian Exploration discovered the Neilson Road Pool in Seneca County. The Neilson #1146-1 well was drilled in January 1990 and was completed open hole in the Sodus Shale. Casing was set (7" diameter) at 1,161 feet and the well reached a total depth of 1,865 feet. The well was completed as an open-hole natural flow with a reported IP of 6,038 Mcfd. The well has produced 83.94 Mmcf through 2001. An additional test was drilled by Belden and Blake Corporation. They unsuccessfully tested the Marcellus and Rochester shales in their Wonderview Farms 1-A well drilled in Schuyler County in early 2002 and the well was plugged and abandoned.

From 1981 to 2001, cumulative production from the two Silurian gas shale wells was 132.3 Mmcf. This data is taken from the Annual New York State Oil, Gas, and Mineral Resources report published by the Division of Mineral Resources of New York State (NYSDEC, 2002).

5 RESEARCH AND DEVELOPMENT DEVONIAN SHALE WELLS

The most complete data packages available in the public domain for shale gas wells in New York come from the research & development (R&D) wells drilled by U.S. Department of Energy (DOE). NYSERDA sponsored three formal Devonian Shale exploration programs from 1980 to 1983 (Donohue, 1984B). DOE drilled two wells in the late 1970's prior to the NYSERDA programs to characterize the shale as part of their Eastern Gas Shale Project (EGSP) (Struble, 1982). In total there were 15 research wells drilled with different objectives and testing protocols used. Additional support for many of the NYSERDA wells came from the U.S. DOE. Several of the wells were cored and thoroughly analyzed, completed, treated and production tested. Tables 5.1 and 5.2 summarize the research wells. Figure 5.1 shows the location of the R&D wells relative to the shale gas fields in New York. Several of the wells produced gas for commercial use and four wells are still producing as of 2001.

Figure 5.1 Location of R&D Wells in New York and Associated Fields.

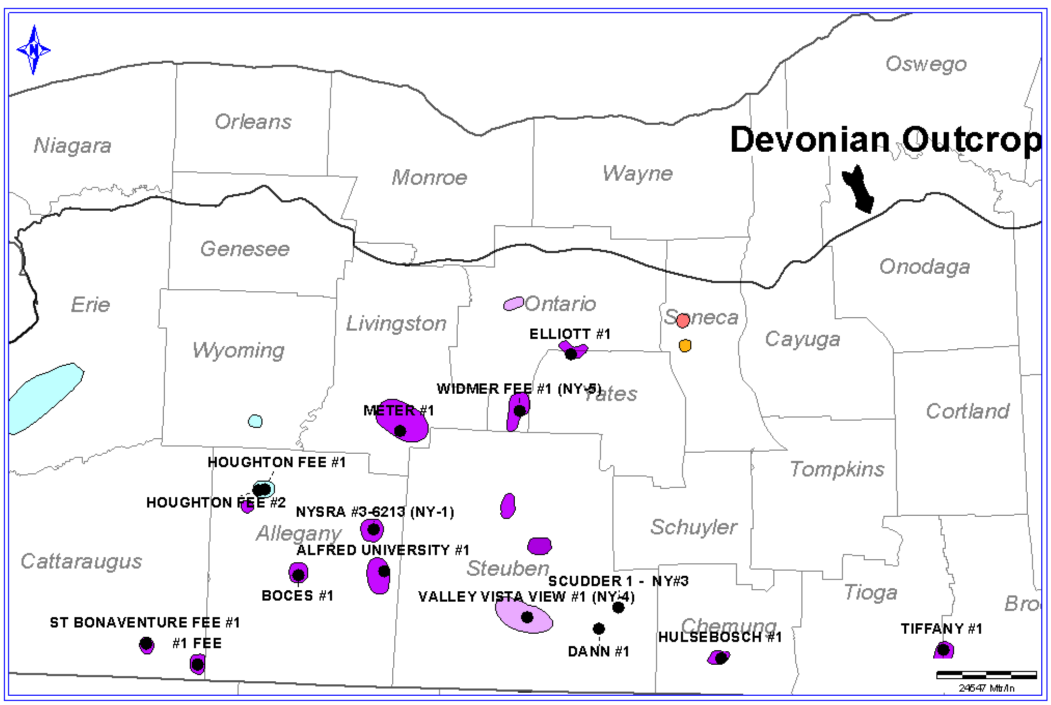


Table 5.1. Research and Development Devonian Shale Test Wells Drilled in New York.

Well Name API #	County	Date	TD (feet)	TD Fm.	Protocol
Alfred Univ. #1 31-003-16203	Allegany	1981	3987	Onondaga	Drill cuttings - chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
NYSERA #3-6213 (EGSP NY-#1) 31-003-13549	Allegany	1978	5325	Queenston	Core
BOCES #1 31-003-16227	Allegany	1981	3350	Onondaga	Drill cuttings - chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
Dann #1 31-101-15404	Steuben	1980	1400	Rhinestreet?	NA
Elliot #1 31-123-17347	Yates	1982	900	Onondaga	NA
Houghton College #1 Fee 31-003-14253	Allegany	1979	2333	NA	Drill cuttings - chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
Houghton College #2 Fee 31-003-16202	Allegany	1981	2471	Onondaga	Chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
Hulsebosch #1 31-015-17318	Chemung	1982	3030	Onondaga	NA
Meter #1 31-051-15480	Livingston	1980	1642	NA	Drill cuttings - chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
Portville Central School #1 Fee 31-009-16232	Cattaraugus	1981	4227	Onondaga	Drill cuttings - chemical analysis, mineralology, organic content, x-ray diffraction, pressure transient testing.
Scudder #1 (EGSP NY-#3) 31-101-15382	Steuben	1980	1300	Rhinestreet	Core
St. Bonaventure Univ. #1 Fee 31-009-16214	Cattaraugus	1981	3996	Onondaga	Drill cuttings - chemical analysis, mineralology, Organic content, x-ray diffraction, pressure transient testing.
Tiffany #1 31-107-17788	Tioga	1982	4457	Onondaga	NA
Valley Vista View #1 (EGSP NY-#4) 31-101-15268	Steuben	1980	3850	Onondaga	pressure transient testing and Core.
Widmer #1 31-069-17366	Ontario	1983	1220	Onondaga	NA

NA; Not Available/Not Reported

Table 5.2. Research & Development Devonian Shale Wells Completion Summary

Well Name API #	County/ Field	Phase	Date	Tested/ Completed Formation	IP (Mcfd)	Calculated Open Flow (Mcfd)	Cum. Prod. (Mmcf) Through 2001 / Status
Alfred Univ. #1 31-003-16203	Allegany Alfred	1	June 1981	Marcellus	40	35	1.284 P&A
BOCES #1 31-003-16227	Allegany Belmont	2	June 1981	Marcellus	73	105	4.135 P&A
Dann Farm #1 31-101-15404	Steuben Rathbone	1	Aug. 1980	Rhinestreet	270	10	0.074 P&A
Elliot #1 31-123-17347	Yates Rushville	3	Aug. 1982	Marcellus	Dry (water)	0	Dry Hole
Houghton College #1 Fee 31-003-14253	Allegany Houghton	0	Nov. 1978	Marcellus	1,300	130	24.750 P&A
Houghton College #2 Fee 31-003-16202	Allegany Houghton	2	July 1981	Marcellus	77	23	0.788 P&A
Hulsebosch #1 31-015-17318	Chemung Elmira	3	Aug. 1982	Marcellus	86 (89)	545 (23)	7.086 Active
Meter Farm #1 31-051-15480	Livingston Dansville	1	Sept. 1980	Hamilton (Marcellus)	411	95	5.526 Active
NYSERA #3-6213 31-003-13549	Allegany Karr Valley	0	Jan. 1981	Marcellus	333		15.69 Active
Portville Central School #1 Fee 31-009-16232	Cattaraugus Portville	2	June 1981	Marcellus	22	18	1,130 P&A
Scudder Farm #1 31-101-15382	Steuben Rathbone	1	Aug. 1980	Rhinestreet	dry	0	0 Unknown
St. Bonaventure Univ. #1 Fee 31-009-16214	Allegany Four Mile	2	June 1981	Marcellus	14	19	2.592 P&A
Tiffany #1 31-107-17788	Tioga Cafferty Hill	3	Aug. 1982	Marcellus	17	9 (23)	1.658 Active
Valley Vista View #1 31-101-15268	Steuben Rathbone	1	July 1980	Rhinestreet Marcellus	dry 200	0 110, 142	3.453 P&A
Widmer #1 31-069-17366	Ontario Naples	1	Sept. 1983	Hamilton (Marcellus)	40	12	1.027 P&A

Data from Donohue, 1984B, Charpentier, 1993, and NYSDEC, 2002 New York Production Database.

6 RESERVOIR CHARACTERIZATION

Reservoir characterization in gas shale reservoir systems focuses primarily on natural fractures because most known productive gas shale reservoirs are gas saturated with extremely low permeability and required multiple sets of open natural fractures for commercial production of natural gas. There are other properties that are also important in characterizing the reservoir potential of shale. These properties are covered below and information is provided for the shales in New York where available. Unfortunately, there is very little published data on the reservoir properties of the shales in New York. The majority of the data comes from the three wells cored and studied as part of the US DOE Eastern Gas Shale Project. Additional data has been published on drill cuttings.

6.1 NATURAL GAS COMPOSITION

The composition of produced natural gas can have an impact on the overall economics of a gas shale play as well as provide information related to its source. In several fractured shale gas plays, the composition of the produced natural gas impacts economics and provides evidence of microbiologic and thermogenic processes (Walter 1997 and 2001). Unfortunately, very little gas chemistry and gas and water geochemistry is available from shales in New York. Thus it is difficult to attempt to draw comparisons to other gas shale plays, such as the shallow biogenic Antrim shale play in northern Michigan Basin.

The best source of natural gas composition from gas shales in New York was from the USBM project that looked at produced natural gas composition across the United States (Moore, 1987). In this report, six wells with natural gas production from Devonian Shale were analyzed along with one water well and one natural seep. The data shows methane concentrations of 80-95% and concentrations of ethane and propane from 3% to 15%. The heating value of the gas measured (BTU) ranges from 901 to nearly 1300 BTU's. The majority of the data points were sampled in 1979. No detailed geochemistry is available to investigate the biogenic or thermogenic processes. No gas composition data is available for either the Silurian or Ordovician shales of New York.

6.2 NATURAL FRACTURES

Open, orthogonal or multiple sets of natural fractures increase the productivity of gas shale reservoirs due to the extremely low matrix permeability of shales (Hill, 2000). Natural fracture formation was addressed in Section 2.6. Finding these natural fracture systems are critical to commercial production of natural gas and is considered one of the primary exploration strategies. Identification and characterization of natural fractures is typically done either at the surface through outcrop studies or in-situ through the use of geophysical logs or core. In addition, indications of natural fractures are often associated with natural gas shows while drilling a well, especially on air or under-balanced.

In New York, only a minimum amount of oriented core has been taken in the shale reservoir systems for natural fracture characterization and no formation imaging logs or down-hole cameras results have been published for natural fracture characterization. Three wells were cored in New York during the DOE Eastern Gas Shale Program and natural fracture characterization was published for them (Cliff Minerals, Inc., 1980B, 1980C, and 1981).

Table 6.1 summarizes the natural fractures identified in the oriented core from the Devonian Shale for the three research wells. No significant shows were associated with the cored intervals. The NY #1 (NYSERDA #3-6213) well was completed in the Marcellus Shale (which was not cored) and was producing intermittently at the end of 2001.

Table 6.1. Devonian Shale Natural Fracture Orientation from Oriented Core.

Group	Unit	NY #1 Depth (ft)	Fracture Orientation	NY #3 Depth (ft)	Fracture Orientation	NY #4 Depth (ft)	Fracture Orientation[1]
Canadaway	Dunkirk Shale	370-515	N85°W (1) N85°E (2)				
Java	Hanover Shale	515-546					
		963-984					
	Pipe Creek	984-1018	N85°E(2)				
West Falls	Angola Shale	1018-1021					
		1328-1355					
	Rhinestreet Shale	1335-2345	N35-45°W (4) N70-90°W (7) N70-90°E (14)	1203-1263	N2°E (2) N48°E (1)		
Sonyea	Cashaqua Shale	2345-2359	0				
		2486-2495					
	Middlesex	2495-2629	N45-65°E (4) N25°W (1)				
Genessee	West River	2629-2664	N40-70°E (1) (4)				
		2723-2730					
	Genundewa	2730-2737	N20°W (1)				
	Pen Yan Shale	2737-2866	N70-80°W (3) N35°E (1)				
	Lodi Limestone	2866-2876	0				
	Geneseo Shale	2876-2924	N35°E (1) N80°W (1)			3010-3080	N50°W (1)
Hamilton	Tully Limestone	2924-2929	0			3080-3084	N50°E - N60°E (major)
	Marcellus Shale					3790-3842	N50°W - N60°W (minor)

[1] Six feet of the Onondaga formation was cored and included 2 joints, 3 microcracks and 10 faults - major trend is N20°W-N30°W. (Cliff Minerals, Inc., 1980B, 1980C, and 1981)

Based on available information, cumulative production from the Devonian Shales is 15.89 Mmcf. The greatest number of fractures from the core analysis was in the Rhinestreet shale, which was not completed in this well. The NY #3 (Scudder #1) well was not completed and was plugged and abandoned. The NY #4 (Valley Vista View #1) well tested the Rhinestreet which proved to be poor and was eventually completed in the Marcellus Shale and produced for a short period of time before it was plugged and abandoned. Unfortunately, due to completion circumstances and poor well performance, no observations can be made for improved well performance related to the presence of orthogonal natural fractures.

No core or subsurface natural fracture descriptions are available for the Silurian or Ordovician shales.

6.3 NATURAL GAS STORAGE CAPACITY

In shale reservoirs, natural gas is stored three ways: as adsorbed gas on organic material, as free gas within the rock pores, and as free gas within the system of natural fractures. These different storage mechanisms affect the amount of gas stored as well as the speed and efficiency of gas production.

6.3.1 Adsorption

Natural gas can be adsorbed onto the surface area of organic material in shale and to some degree onto the surface area of clays (if dry). The process of adsorption is controlled by properties such as the amount of organic carbon present, the thermal maturity of the kerogen, reservoir temperature, pressure, in-situ moisture of the shale and gas composition (Hill, 2002).

In many fractured gas shale reservoir plays, TOC has been correlated to total gas content. Figure 6.2 shows two correlations of gas content with TOC from the Antrim Shale in the Michigan Basin and the New Albany Shale from the Illinois Basin (Hill, 2002). It should be noted that these correlations are specific to a given play and should be calibrated with measured data for different depths and reservoir pressure gradients. TOC can be derived from geophysical logs such as density (Schmoker, 1980). Correlations have been developed in several gas shale plays using the density log to calculate the gas in place in shale with calibrated data (Decker, 1993 and Zuber, 2002).

Based on the linear relationship of gas content to TOC, one would expect a similar relationship for adsorption isotherms. This was first established in the Antrim Shale by the Gas Research Institute, and has been further developed in other fractured shale plays (Zuber, 2002 and S.A. Holditch, 1995). A large number of methane adsorption isotherms were run and the relationship of increasing storage capacity to TOC was apparent.

Figure 6.3 shows an example of multiple isotherms from an Antrim Shale well in the Michigan Basin. As the TOC value increases, the methane storage capacity is also increasing. As with the relationship to gas content, this relationship is play-specific and should be calibrated with measured data as the organic material changes with origin and maturity.

However, no gas content data or sorption isotherms have been measured in the Devonian Shales of New York or for the Silurian and Ordovician shales. These are the type of data that should be collected to fully understand the storage and transport properties of natural gas in shale.

Figure 6.2. Comparison of Gas Content vs.Total Organic Carbon in Two Gas Shale Plays

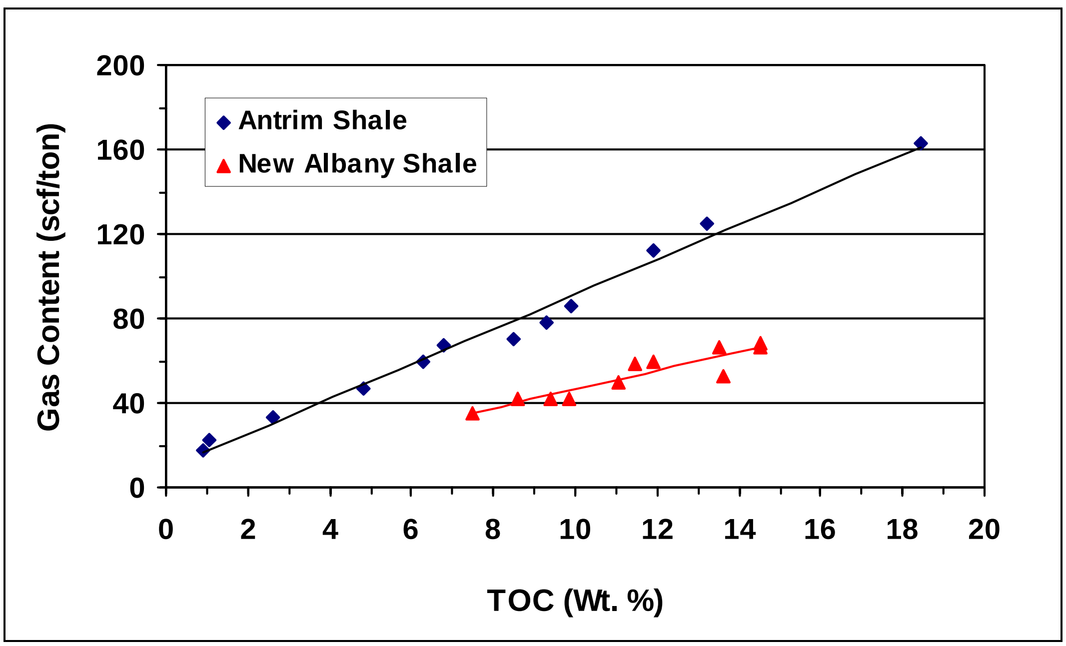
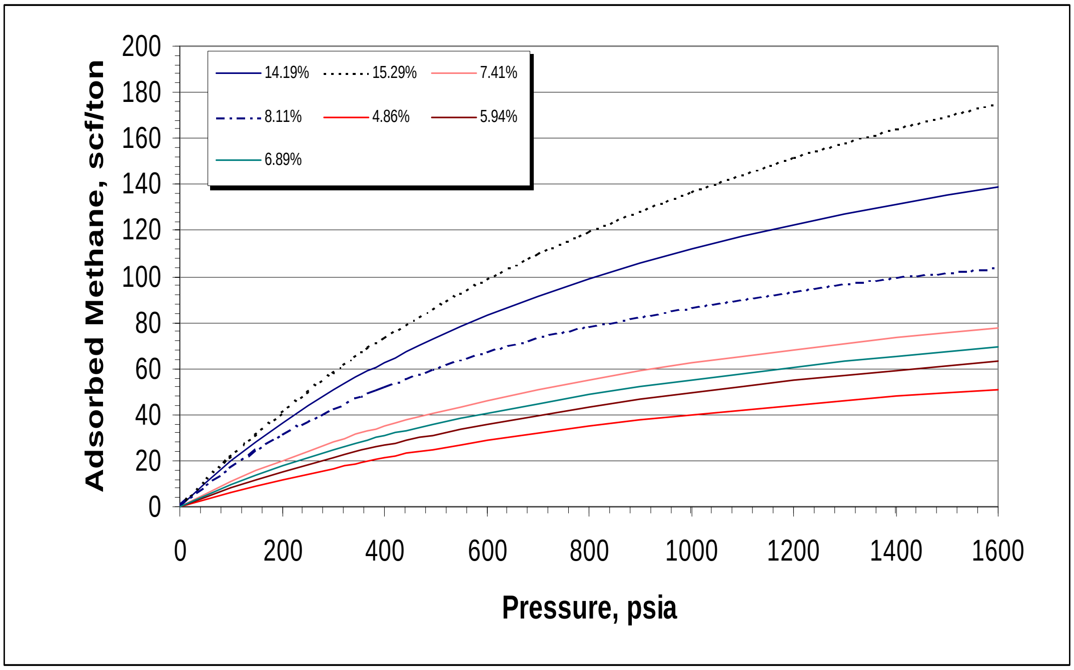


Figure 6.3. Multiple Methane Adsorption Isotherms, Antrim Shale Well, Michigan Basin.



6.4 POROSITY

In conventional reservoirs, porosity and fluid saturations are among the most important reservoir properties to determine. This is also true for gas shale reservoirs. Shale can have significant amounts of porosity and significant amounts of oil and free gas in that porosity. Even in older shales such as the Ohio Shale in the Appalachian Basin or the Antrim Shale in the Michigan Basin, porosity can range up to 15 percent, and free gas can occupy up 50% of the porosity. It is important to be able to assess this potential, primarily from well logs, which should first be validated and calibrated from core analyses.

6.4.1 Historical Data

Although core data was collected and porosity was measured in three wells in New York, little effort was made to understand fluid saturations and develop well log interpretations during the US DOE EGSP. The most comprehensive porosity data was measured on NY #1 well in Allegany County, New York. Porosities were measured using the mercury intrusion method as well as determined from density data (Kalyoncu, 1979). A wide range of porosity was reported from the core, from a low of 0% to a high of 18.3% on a 10-foot basis. No data was reported on fluid saturations.

6.4.2 New Methodology

The key data needed from core analyses to calibrate the log analyses are porosity and the saturations of gas, oil, and water. Prior to 1987, shale core analysis data in the Appalachian Basin was sparse and believed not to be very reliable. As a result of the several Gas Research Institute funded programs from 1987 to 1993, new core analysis methods were developed for measuring porosity and fluid contents (Gas Research Institute, 1989, 1993 and 1996). These new methods, which rely primarily on crushing of the core, show much higher porosity and free gas contents than previously reported.

Procedures for these new methods, and some of the results, are summarized in the following (Gas Research Institute, 1993).

1. The cores (conventional full diameter, or rotary sidewall) should be kept preserved (sealed) until the time of analyses to avoid fluid alteration or kerogen oxidation.
2. Bulk density of each shale sample is first measured by weighing and by mercury immersion.
3. Each shale sample is crushed.
4. Oil and water is extracted from each weighed sample using boiling toluene (Dean-Stark method) for one/two weeks. The water is condensed into a sidearm collector. Sample size should be > 50 grams. The shale sample is then dried in an oven at roughly 230ºF for one/two weeks, and weighed. Extracted oil volume is calculated from the weight loss, less water collected. In some shales (such as Antrim) the kerogen can oxidize during the extraction and drying process that may cause a weight gain and interfere with the material balance. For these shales, this is prevented by using a nitrogen blanket during extraction and by using a vacuum oven for drying.
5. Grain volume of the dried shale sample is then measured with helium in a standard Boyle's Law device.
6. Pore volume and porosity (Ø) are derived from the bulk volume and the grain volume. Water and oil volumes are subtracted from the pore volume to find the gas volume, and fractional saturation of each fluid (S_G, S_O, and S_W).

Table 6.2 shows typical shale properties using this new core analysis for three basins. Note all the measurements are at ambient conditions, assuming no stress loading. Detailed analysis has shown a reduction of 0.5 p.u. to adjust the measurements to reservoir stress for comparison to geophysical log results (Gas Research Institute, 1996).

Table 6.2. Typical Shale Properties from Core Analysis, Three Basins.

Basin, Shale	Ø, %	Sg, %	So, %	Sw, %	Number of Wells, Core Samples Analyzed
Appalachian, Ohio	4-9	15-50	0-20	35-70	4/519
Michigan, Antrim	8-12	10-50	10-45	20-70	2/249
Ft. Worth, Barnett	5	N/A	N/A	N/A	1/9

6.5 PERMEABILITY

Permeability is a primary reservoir property required for economical natural gas production from gas shale plays. Matrix permeability of shales is extremely low. However, wells produce natural gas at rates that require permeability to be much greater than measured in core. This "bulk" permeability of the reservoir incorporates the natural fracture system and is normally determined through well testing and production data analysis.

Older Devonian Shale literature reports matrix permeabilities in shale from less than 0.01 md to 1 md (Soeder, 1988). Absolute permeability measurements on NY #3 and NY #4 showed permeability in the < 10 to 191 microdarcy range (Swartz, 1982). These values were believed to be high due to the presence of microfractures due to stress release, core handling, and/or coring induced. More recent measurements using a novel testing protocol found matrix permeabilities in unfractured shale to be 0.2 $x10^{-8}$ md to 5.5 $x10^{-8}$ md. The importance of matrix permeability was further defined through simulation. For matrix permeability (K_m) values within the range of 10^{-9} md $K_m < x10^{-6}$ md, K_m is one of the important controls on permeability. For matrix permeabilities less than 10^{-9} md, recovery is too low to be of economic interest. For matrix permeabilities > 10^{-6} md, recovery is essentially independent of K_m and is productivity is more controlled by natural fracture properties and spacing (Soeder, 1988).

As stated above, pressure-transient testing is typically done to characterize bulk permeability. In 1983, NYSERDA commissioned additional testing of eight research wells completed in the Marcellus Shale in New York. The primary objective was to estimate recoverable reserves and deliverability of the wells and to evaluate stimulation procedures used on the wells (Lynch Consulting Co., 1983).

The testing rationale for the wells incorporated modified isochronal testing. The general procedure consisted of flowing the wells at two increasing rates by use of a critical flow prover. The flow periods were designed to test ensure that the formation was tested. Where possible, the two rates would be used to examine skin factors. The test was followed by an extended shut-in period (Lynch Consulting Co., 1983).

The testing program was only partially successful. There were difficulties with obtaining reliable data which was attributed to fracture fluid buildup in the wellbore and that gas production at low pressures is likely from desorption and the associated analysis problems. No bottom hole pressure gauges were used, which would of assisted data analysis. Table 6.3 is a summary of the well performance characteristics from three of the eight wells (Lynch Consulting Co., 1983). The permeability-thickness product is generally similar to other pressure testing analysis from Devonian Shale wells (0.1 – 10 md-ft) (Lynch Consulting Co., 1983).

Table 6.3. Well Performance Characteristics from Three Marcellus Shale Completions in New York.

Well	Slope ((M)psia^2/cpx10^6)	Perm-Thickness (md-ft)	Thickness (ft)	Permeability (μd)	Skin
Valley Vista View #1	8.5	3.25	15	216	-2.0
Houghton College #1	1.6	7.28	26	203	-2.3
Houghton College #2	16.1	0.14	34	4.1	-2.6

No matrix or bulk permeability measurements were available for the Silurian or Ordovician shales in New York.

6.6 Reservoir Pressure

Knowledge of reservoir pressure is critical in determining the amount of resource in place and reserves, and is an important input parameter for reservoir simulation. Reservoir pressure can be determined from pressure transient testing.

Pressure surveys were conducted on all eight research wells described in the previous section. The surveys were run following stimulation, subsequent to clean-up and shut-in operations. The pressure data shows a reservoir pressure gradient between 0.46 to 0.51 psia/ft. (Lynch Consulting Co., 1983). This is higher that the reservoir pressure gradient found in other producing Devonian Shale gas fields in West Virginia and Kentucky (0.4 to 0.12 psia/ft).

6.7 Rock Mechanics

Because of the nature of the permeability and distribution in the reservoir system, most gas shale wells are either completed as a natural producer or stimulated in order to achieve commercial production. During the U.S. DOE EGSP and GRI Gas Shale programs, studies were conducted on measuring the mechanical properties of Devonian Shale to assist in the evaluation, optimization and understanding of hydraulic fracturing. Historically, the early Devonian Shale wells in New York were either completed openhole as natural producers or "shot" with nitroglycerin. In the 1980's, the wells were typically hydraulically fractured using a nitrogen foam and proppant to stimulate the well through casing perforations. This section will focus on the work conducted in New York.

Extensive mechanical properties testing were done on oriented core samples from 30 wells taken during the U.S. DOE EGSP. This testing included directional ultrasonic velocity, point load, directional tensile strength and characterization of pre-testing fractures (Gregg, 1986). The overall analysis concluded that tests conducted under zero confining pressure are not useful for determining the orientation of maximum horizontal stress (σ_{Hmax}). This work was conducted on NY #1, NY #3 and NY #4 wells. Overall fracture orientation from NY #1 well was N60^{o}E$\pm$15^o. A secondary fracture orientation was reported N90^{o}E$\pm$15^o. Overall fracture orientation from NY #3 well in the Rhinestreet Shale interval was N90^{o}E$\pm$15^o. A secondary fracture orientation was reported N60^{o}W$\pm$15^o. For the NY #4 well, overall fracture orientation in the Geneseo Shale was N60^{o}W$\pm$15^o. The Marcellus Shale interval has a preferred fracture orientation N30^{o}W$\pm$15^o for this well. The present day stress direction (maximum horizontal stress) in the New York region is reported as N60^{o}E (Gross, 1991).

Fracture toughness was measured on five wells from the EGSP (Swartz, 1982). Two of the five wells were NY #3 and NY #4. The average fracture toughness value (K_{Ic}) for all five wells was 860 psi √in. The highest fracture toughness was measured on NY #3, 1202 psi √in. The average fracture toughness values for NY #3 was 1085 psi √in and for NY #4 was 848 psi √in. (Swartz, 1982).

The most extensive study on in-situ stress in the Devonian section was conducted in three boreholes drilled in Steuben County, New York near the town of South Canisteo (Evans, 1989A). The wells were located approximately 12 miles southeast of NY #1 well. During this study, 75 openhole stress measurements were made in the three wells from the Dunkirk Shale through the Tully Limestone. Readers are referred to the paper for more detail and information on the testing and analysis. The results of the study are summarized as follows (Evans, 1989A):

1. Horizontal stresses in the shales undergo a major transition in magnitude at a stratigraphic level that is coincident with a group of sand beds near the base of the Rhinestreet shale.
2. The principal *drop* in stress corresponds to an offset in S_h and S_H of 508 psi (3.5Mpa) and 1,305 psi (9 Mpa) respectively.
3. Above the group of sands, a "trust" regime conditions prevail, and the least horizontal stress in the shales is at least as great as the vertical stress.
4. Below the sands the regime is strike slip with both horizontal stresses showing lateral uniformity.
5. Stresses in the quartz-rich and limestone beds are substantially higher that the surrounding mudstones.
6. The orientation of maximum principal stress as determined by induced fracture direction is ENE throughout the section.
7. Significantly different orientations of fractures were obtained for adjacent tests in which almost identical ISIPS were observed, suggesting that the fractures quickly reorient themselves to propagate normal to the least principal stress direction.
8. Vertical traces were observed in those tests where ISIPs apparently reflect S_v, suggesting that rotation to a horizontal fracture was also rapid.

Further analysis by the authors found that the major systematic drop in stress level that occurs near the base of the Rhinestreet Shale (on the basis of local and regional strain data) corresponds to the top of the section that held abnormal high pore pressures (Evans, 1989B). The implications of this study suggest that hydraulic fracturing of the Rhinestreet Shale and intervals above could result in abnormally high treating pressures with the potential for the creation of horizontal fractures, at least in the region studied by the authors.

7 EXPLORATION AND DEVELOPMENT STRATEGIES

The following two sections outline strategies for exploration and development associated with fractured gas shale reservoirs in New York. The strategies are not intended to be all-inclusive, but rather provide operators and interested parties with methodologies, approaches and ideas to assist them in evaluating and developing the large natural gas resource that resides in fractured gas shale reservoir systems.

7.1 EXPLORATION STRATEGIES

Exploration strategies for gas shale plays should focus on locating areas with significant natural gas resources present that also have sufficient permeability (both matrix and bulk) for economic production.

7.1.1 Geologic Mapping

The evaluation of a shale gas play should consider the geological circumstances that may have created a favorable environment for the deposition and accumulation of shales and the generation of hydrocarbons. Geologic mapping pertaining to formation thickness, depth and structure are basic requirements, as well as cross-section generation to view lateral changes in lithology and in well log response in the gamma-ray curve, and to identify zones that may indicate the presence of gas.

7.1.2 Formation Evaluation

Significant progress has been made in the area of formation evaluation for Devonian Shales using geophysical logs. GRI research has developed a log model based on core and log analysis from a large data set in the Appalachian Basin. This model has been extended to other shale plays such as the Antrim Shale and Barnett Shale (Gas Research Institute, 1996). When combined with other diagnostic tools such as the mud log, borehole television and temperature log, geophysical log analysis can be used to evaluate completion intervals in gas shales.

Like most of the Appalachian Basin, wells in New York are typically drilled on air. This limits the type of geophysical logs that can be run in an air-filled borehole. A typical logging suite in the Appalachian Basin for the GRI log analysis includes dual induction, temperature, litho-density with photoelectric adsorption index (Pe), sidewall neutron, special gamma ray and borehole television (Gas Research Institute, 1996).

Log analysis in shales involves both standard techniques and special techniques. Depth shifting, environmental corrections and standardization are part of the pre-processing steps (Gas Research Institute, 1996).

Because of the complex mineralogy of shales, log responses to various minerals present is taken into account before porosity and fluid saturations are determined. The GRI log model groups the minerals into five categories (Gas Research Institute, 1996):

1. Quartz (includes quartz, calcite, dolomite, k-feldspar and plagioclase)
2. Clay (illite, kaolinite and chlorite)
3. Pyrite (pyrite, ankerite and siderite)
4. Kerogen, and
5. Porosity

Once porosity is determined as part of the analysis, water saturation and bulk volume hydrocarbon are calculated. If a wellbore can be filled with fluid as part of the logging process, natural fracture identification logs can be incorporated into the geophysical logging program.

Because the GRI log model was developed in the Appalachian Basin, it should be directly applicable for the Devonian shales in New York and also applicable to other shales with modifications as required by the various minerals present in the shale. Generally speaking, the most favorable completion intervals are those with the highest porosity (> 4.0%), most fractures and best sustained mud log shows. Kerogen-rich shales will typically have the best gas-in-place (free and adsorbed), the highest natural fracture density, and lowest stress (Gas Research Institute, 1996). However, it should be noted that in some parts of the Appalachian Basin, gray shales (organic-lean) are commercially productive.

7.1.3 Natural Fracture Identification

Operators have historically used multiple techniques to locate areas of increased natural fracture density. While seismic technology continues to advance, locating fracture systems in organic-rich shales remains elusive. Thus operators have attempted to correlate other techniques such as surface lineament analysis, outcrop studies, magnetics, and various geologic mapping approaches to look for areas where fracturing may be present due to basement structure, regional and local structure, or other tectonic influences.

With most naturally fractured gas shale reservoirs, finding indicators of productivity can be helpful with regard to evaluating a completion and identifying pay. This is often done during the drilling and logging phase of a well.

When drilling a well, natural gas shows are considered indicators of potential in many reservoir systems. This is especially true when drilling with air or underbalanced. In tight, naturally fractured reservoirs such as shales, strong shows of natural gas can also be considered indicators of potential. Good shows are characterized by high natural flow rates that do not degrade (blow down) quickly, but are carried to total depth of the well. In New York, many of the wells drilled on air often have shows of natural gas associated with shale sections in the well. In some circumstances the shows are so strong that the drilling is terminated at the show and the well is completed naturally open-hole.

However, if a well does not have a show of natural gas while drilling on air it does not mean that the well has poor reservoir potential. Gas shows are normally associated with natural fractures penetrated by the drill bit. In the Appalachian Basin, the majority of the natural fractures present at depth are vertical or nearly vertical. Unless the fracture spacing is very close, the likelihood of hitting a vertical natural fracture with a vertical wellbore is extremely small.

As mentioned earlier, geophysical logs can be used to help identify and characterize intervals with natural fractures present. A temperature log and noise log can identify intervals that are producing natural gas. In shale reservoirs, these indicators are often directly associated with natural fractures in the borehole. For natural fracture characterization, other logs are required.

Three log types are most often used for fracture characterization. They include microresistivity, acoustic reflectance, and borehole television logs. The first two devices required a liquid-filled borehole for utilization. The borehole television device is ideal for an air-drilled hole. Each of the tools can determine natural fracture strike. The microresistivity and acoustic reflectance tools can determine dip magnitude and the borehole camera can only infer magnitude (Gas Research Institute, 1996). Research has shown that it is not the number of natural fractures encountered that make a good well, rather the presence of intersecting natural fractures. Table 7.1 summarizes the advantages and disadvantages of the tools (Gas Research Institute, 1996).

Table 7.1. Comparison of Fracture Identification Devices Used in Appalachian Basin.

Tool	Advantages	Disadvantages
Microresistivity	High resolution Good strike/dip quantification of both natural and induced fractures Data routinely corrected for borehole deviation and magnetic declination Low operational sensitivity	Expensive Requires liquid in the borehole Limited coverage with a single pass (pad device) Joint identification dependent largely upon degree of spalling Large spalls difficult to quantify
Acoustic Reflectance	Essentially full borehole coverage usually results in superior fracture identification Good strike/dip quantification of natural; fair for induced fractures	Expensive Requires liquid in the borehole Joint identification dependent largely upon degree of spalling Large spalls difficult to quantify Tools not routinely corrected for borehole deviation and magnetic declination
Borehole Television	Quick and inexpensive Can be run in air filled borehole High resolution visual image easily reviewed and interpreted with TV and VCR Full borehole coverage Gas/fluid entry detection Can properly identify/quantify many large spalls as joints Good strike quantification, qualification of dips	Light intensity varies around borehole, slight view obstructions by arms No or poor dip quantification Poor identification of induced fractures Joint identification dependent largely upon spalling Limited identification of bedding

7.2 DEVELOPMENT STRATEGIES

Development strategies can be either focused on drilling and completing new wells or adding shale intervals in existing wells prior to abandonment often called pay additions. Historically, most shale wells in New York have been associated with the drilling of a new well. Because of the extremely low permeability of shale, development strategies will typically include stimulating the reservoir to maximize productivity.

7.2.1 Stimulation

Historically, shale wells in the Appalachian Basin were completed open-hole either naturally (no-stimulation) or shot with some form of propellant such as nitroglycerin. This is true for Devonian Shale wells in New York as well. As new forms of reservoir stimulation technology were developed, they were applied to the shale plays in the Appalachian Basin.

With the advent of hydraulic fracturing around the middle of the 20th century, shale wells have experienced a wide range of fracturing techniques in an attempt to provide the optimal stimulation with respect to fracture length and productivity. Today, nitrogen-based foam fracturing is the primary technique used in vertical shale wells in the Appalachian Basin. Foam-based systems are preferred because of the low fluid loss, lower amount of liquid pumped into the reservoir, and energy assist in flowing the wells back. Other techniques are also used today, but they are area-specific.

In New York, most of the early wells were completed naturally open-hole or shot with explosives such as nitroglycerin or judamite. During the early 1980's all of the research wells were stimulated with nitrogen foam system. All of these treatments were single-stage jobs pumped down casing and used from 25,000 to 80,000 pounds of proppant. Table 7.2 is a summary of eight foam fracture treatments (Lynch Consulting Co., 1983). Five of the wells have fluid volumes recovered during initial clean-up operations. The average fluid recovery is approximately 50%. This leaves 50% of the treatment fluid in the reservoir, which caused fluid loading problems short-term during testing and long-term during production operations. None of the wells used tubing and downhole pumps to assist in unloading the wells early in their life.

Table 7.2. Fracture Treatment Summary of New York Devonian Shale Wells.

Well	Treatment Date	Total Sand (lbs)	Total Fluid Pumped (bbls)	Total Fluid Recovered (bbls)*	Fluid Remaining (bbls)
Valley Vista View #1	12/81	80,000	312	na	
Houghton #1	10/79	50,000	333	na	
Meter #1	11/80	76,000	289	na	
Houghton #2	9/81	60,000	333	168	165
St. Bonaventure	8/81	60,000	333	164	169
Portville	7/81	60,000	333	164	169
Alfred	7/81	60,000	333	146	187
BOCES	7/81	60,000	333	159	174
* Recovered during initial clean up of wells					

New fluid additives have been developed over the past decade as well as new design considerations, such as flowback and quality control, that have improved hydraulic fracture performance (Ely, 1988). These new advances should improve well performance in New York as well. Other stimulation techniques such as straight nitrogen gas fracturing and liquid CO_2 and sand should be experimented with in the different shale reservoir systems in New York Abel, 1981, Yost, 1993). Coiled tubing fracturing technology has recently been applied to the Devonian Shale in the Appalachian Basin with good results (Stidham, 2001). This technology is effective in both new wells and in old wells for restimulation or recompletion operations.

7.2.2 Horizontal / High Angle Wells

Since the early 1980's high-angle and horizontal wells have been contemplated, studied and drilled in the Devonian shales of the Appalachian Basin. Much of the work in this area has been sponsored by the U.S. DOE. Horizontal well drilling technology continues to advance and numerous improvements have been made in drilling systems, wellbore orientation and drilling motors. The majority of the high-angle and horizontal wells drilled in the Devonian Shale have been technical successes, but marginal to poor economical successes. Most of the wells required some form of stimulation, which increased well costs dramatically.

With improved technology and reduced drilling costs, operators are beginning to reconsider horizontal and high-angle wells in tight naturally fractured reservoirs. This technology might be applicable in New York shales. Fracture spacing in New York may be larger that other shale plays where vertical wells and hydraulic fracturing is applicable. For certain formations, areas and depths in New York, hydraulic fracturing may create horizontal fractures (or very complex fractures) which might reduce the effectiveness of this fracturing. High-angle well bores may also provide a mechanism to contact more shale and increase the chances of intersecting multiple natural fracture sets. This may also be a viable technology to drill in or near older gas shale fields. These are a few of the reasons to investigate this technology as a development strategy in New York.

7.2.3 Recompletions

With several thousand existing well bores in New York, the potential to add additional pay zones that are behind pipe at low incremental costs can be very attractive, especially when the estimated reserves cannot support the drilling and completion of a new well. This is how the Lewis shale in the San Juan Basin is being developed today (Frantz, 1999). In New York, there are multiple pay zones that can be tested and added to a well. From the Ordovician Utica Shale to the Upper Devonian Rhinestreet Shale, the potential for economical pay additions is increased due to large number of reservoirs to evaluate.

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