New York State Energy Research and Development Authority

Geologic, Engineering, and Economic Evaluation of the CO_2 Sequestration Capacity of New York's Gas Shales

Final Report

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Geologic, Engineering, and Economic Evaluation of the CO_2 Sequestration Capacity of New York's Gas Shales

Final Report

Prepared for the

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Albany, NY
nyserda.ny.gov

John Martin
Project Manager

Prepared by:

Advanced Resources International, Inc.
Arlington, VA

Michael Godec
Project Manager

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ABSTRACT

Carbon dioxide (CO_2) storage in carbonaceous, organic-rich gas shales is attracting increasing technical interest, especially in Appalachian Basin states with extensive shale deposits. Gas shale reservoirs are expected to react similarly to coal seams and desorb methane from organic matter and mineral surfaces while preferentially adsorbing CO_2. In addition, some portion of gas shale pore volume is expected to be available for CO_2 storage as non-adsorbed or "free" CO_2. Consequently, CO_2 injection into organic gas shales could provide dual benefits of secure CO_2 storage and enhanced recovery of adsorbed methane.

104 Marcellus wells and 81 Utica wells were selected from New York's ESOGIS (Empire State Oil and Gas Information System) digital log database and correlated to regional Marcellus and Utica stratigraphic cross-sections published by the New York State Museum. Total organic content (TOC), density porosity and water saturation were calculated from well logs to estimate effective, or gas-filled, porosity. Adsorbed methane and CO_2 content were extrapolated based on available CO_2 and methane adsorption isotherms. Total methane gas in-place as adsorbed gas and "free" gas (non-adsorbed gas in effective porosity) were calculated for each study well. A theoretical maximum CO_2 storage capacity, which assumes that all of the methane gas in-place is replaced by CO_2, was calculated for each study well. Individual well results were extrapolated to obtain estimates of total gas in-place and maximum CO_2 storage capacity for the New York and Marcellus and Utica exploration fairways identified by the New York State Museum.

For the Marcellus exploration fairway study area of approximately 3,387,000 acres (5,292 mi^2), the average methane gas in-place concentration is 75 Bcf/mi^2, of which 24 Bcf/mi^2 is estimated as adsorbed gas and 51 Bcf/mi^2 is estimated as free gas. Theoretical maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 56.4 Bcf/mi^2 on average, which is approximately equivalent to 3.3 MMt CO_2/mi^2, or 1.3 MMt/km^2. The Union Springs black shale member at the base of the Marcellus contributes 75 percent or more of total gas in-place (2.3 to 7.0 Bcf/40 acres; 36.8 to 112 Bcf/mi^2) and at least 71 percent of total CO_2 storage capacity.

For the Utica exploration fairway study area of 3,809,000 acres (or 5,951 mi^2), the estimated average methane gas in-place concentration is 129 Bcf/mi^2, of which 32 Bcf/mi^2 is adsorbed gas and 97 Bcf/mi^2 is free gas. Theoretical maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 86.7 Bcf/mi^2 on average, which is approximately equivalent to 5 MMt CO_2/mi^2, or 1.9 MMt/km^2. The Indian Castle Formation contributes most of total gas in-place and total CO_2 storage capacity, from 46 to 90 percent (5.0 to 7.2 Bcf/40 acres) depending on what other Utica formations are present.

Three 40-acre model areas for the Marcellus and four for the Utica were characterized for reservoir simulation using *COMET3*. For the Marcellus vertical well case, total cumulative gas production (0.14 – 0.55 Bcf/40 acres) represents recovery of 5 to 6 percent of total calculated gas in-place. Net CO_2 injected (1.0 – 6.0 Bcf/40 acres) represents 3 to 6 percent of total theoretical CO_2 storage capacity. Enhanced gas recovery from CO_2 injection represents 5 to 11 percent of cumulative gas production at year 30, and approximately 0.5 percent of calculated total

gas in-place. For the Utica vertical well case, total cumulative gas production (0.47 – 0.73 Bcf/40 acres) represents 5 to 7 percent of total calculated gas in-place recovered, and net CO_2 injected (0.37 – 0.6 Bcf/40 acres) represents 3 to 6 percent of total theoretical CO_2 storage capacity.

A horizontal well simulation case was investigated for one model area where most of the Utica potential resides in the organic-rich Indian Castle Formation. Compared to the vertical well case, a horizontal well (without hydraulic fracturing) provides a significant boost in gas recovery and net CO_2 injection and storage, increasing cumulative gas production by 32 percent over 30 years. Hydraulic fracturing of the horizontal well recovers an additional 6 to 20 percent of gas in-place depending on the length of the fractures assumed. The horizontal well case boosts total net CO_2 storage to 13 to 17 percent of theoretical maximum CO_2 storage capacity.

Key Words: adsorption isotherm, bulk density, carbon dioxide, CO_2, *COMET 3,* Dolgeville, effective porosity, enhanced gas recovery, exploration fairway, Flat Creek, gas in-place, gas shale, horizontal well, hydraulic fracturing, Indian Castle, injection, Marcellus Shale, methane, Oatka Creek, reservoir simulation, storage capacity, total organic carbon, Union Springs, Utica Shale, vertical well, water saturation.

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EXECUTIVE SUMMARY

Carbon dioxide (CO_2) storage in carbonaceous, organic-rich gas shales is attracting increasing technical interest, especially in Appalachian Basin states with extensive shale deposits. These shales are located in an area of the United States with a significant concentration of large CO_2 emission sources (coal-fired power plants), but where finding suitable geologic CO_2 storage sites is proving to be challenging. Therefore, if shales can be proven to be a cost-effective geologic option for CO_2 storage, opportunities for cost-effective and accessible storage will be greatly expanded. Gas shale reservoirs are expected to react similarly to coal seams and desorb methane from organic matter and mineral surfaces while preferentially adsorbing CO_2. In addition, some portion of gas shale pore volume is expected to be available for CO_2 storage as non-adsorbed or "free" CO_2, especially where previous hydraulic fracturing enhances injectivity. Consequently, CO_2 injection into organic gas shales could provide dual benefits of secure CO_2 storage and enhanced recovery of adsorbed methane.

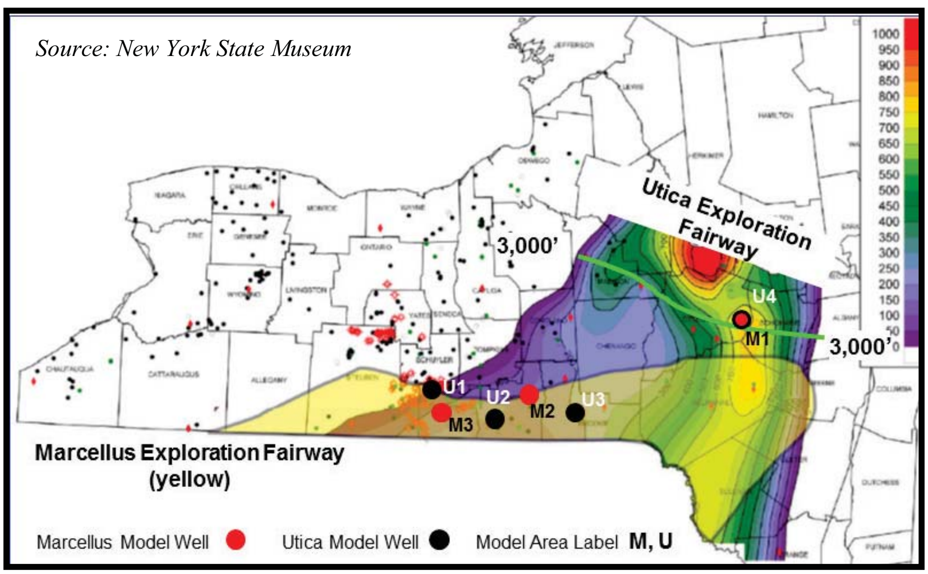
The potential CO_2 storage capacity of gas shales is just beginning to be rigorously assessed. Understanding the CO_2 storage capacity of such shales requires understanding the gas productive capacity of the shales. CO_2 storage capacity will be determined by the volume and rate of methane production from shale, which in turn determines the volume and rate of replacement by injected CO_2.

Extensive deposits of carbonaceous, organic shale in New York include Devonian, Silurian, and Ordovician age shale formations ranging in total thickness from 3,000 ft. to more than 5,500 ft. The possibility of CO_2 storage in New York's gas shales is among various options under consideration for geologic storage in the state. Gas shale could provide an opportunity for CO_2 storage in much of New York, at relatively shallow depths, while also potentially allowing for enhanced production of the state's natural gas resources. The focus of this report is the geological and reservoir characterization of CO_2 storage capacity in New York's gas shales, as well as identification of reservoir engineering and operational requirements for economical CO_2 storage.

In this study, wells with a complete log suite (gamma ray, resistivity, and density) were identified in New York's ESOGIS (Empire State Oil and Gas Information System) digital log database, which is maintained by the New York State Museum (NYSM). For the Marcellus shale, 104 study wells were selected; 81 wells were selected for the Utica shale. The study wells were correlated to regional Marcellus and Utica stratigraphic cross-sections published by the NYSM. Algorithms were developed to calculate organic content, porosity, and water saturation from well logs, and to estimate effective, or gas-filled, porosity. Adsorbed methane and CO_2 content were extrapolated based on available CO_2 and methane adsorption isotherms, estimated reservoir temperature and pressure, and calculated total organic content (TOC). The end result was a calculation of total methane gas in-place as adsorbed gas and as "free" gas (non-adsorbed gas in effective porosity) for each study well in units of billion cubic feet per acre (Bcf/acre). A theoretical maximum CO_2 storage capacity was calculated for each study well, which assumes that all of the methane gas in-place is replaced by CO_2. The individual well results were extrapolated to obtain estimates of total gas in-place and maximum CO_2 storage capacity for the Marcellus and Utica exploration fairways.

The log calculation algorithms for the Marcellus and Utica were based on public data from Marcellus cores from Chenango County and sidewall core samples acquired from a recently drilled well in Otsego County that penetrated both the Marcellus and Utica. Marcellus core data obtained from the NYSM include TOC, core porosity and permeability, x-ray diffraction mineralogy, gas content from canister desorption tests, methane adsorption isotherms, and mechanical properties. The Otsego County Marcellus and Utica core samples were used to obtain new methane and CO_2 adsorption isotherm data, as well as porosity, permeability, TOC, and mineralogy data. Based on the log correlations and log analyses of the study wells, model wells were selected for the Marcellus and Utica for reservoir simulation using *COMET3*. A "model area," assumed to be 40 acres, was characterized for each model well to facilitate comparison with reservoir simulation results. Three model areas were characterized for the Marcellus and four model areas for the Utica. The model areas are shown in **Figure ES-1**.

Figure ES-1: Location of Marcellus and Utica Model Areas within the Marcellus and Utica Exploration Fairways



Objectives of the reservoir simulation were to forecast cumulative methane gas recovery and cumulative net CO_2 storage after 30 years, as well as production and injection rates, and cumulative enhanced gas recovery under CO_2 injection. CO_2 injection was assumed to commence after 10 years of gas production. The injection and production wells were assumed to be vertical wells. For each model run, the cumulative total gas production and total net CO_2 injection were compared to the gas in-place and maximum CO_2 storage capacity calculated from well logs.

Methane gas in-place and theoretical maximum CO_2 storage capacity were calculated for the area contained within the Marcellus and Utica fairways identified by the New York State Museum. This analysis provides a first approximation, summarized in Table ES-1, of methane gas in-place and maximum CO_2 storage capacity for New York's Marcellus and Utica shales.

Table ES-1: Estimated Gas In-Place and Theoretical Maximum CO_2 Storage Capacity for Marcellus and Utica Shales in New York State

New York Marcellus and Utica Exploration Fairways	Marcellus	Utica
Total Acres (depth > 3,000 ft.)	3,387,165	3,808,702
Adsorbed Gas in-Place, Tcf	127	188
Non-Adsorbed ("Free") Gas in-Place, Tcf	272	578
Total Methane Gas in-Place, Tcf	**399**	**766**
Maximum CO_2 Storage, Adsorbed, Tcf	298	516
Maximum CO_2 Storage, Non-Adsorbed in effective porosity, Tcf	121	380
Total CO_2 Storage Capacity, Tcf	**419**	**896**

For the Marcellus study area in New York of approximately 3,387,000 acres (or 5,292 mi^2), the estimated average methane gas in-place concentration is 75 Bcf/mi^2, of which 24 Bcf/mi^2 is estimated as adsorbed gas and 51 Bcf/mi^2 is estimated as free gas. Maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 56.4 Bcf/mi^2, which is approximately equivalent to 3.3 MMt CO_2/mi^2, or 1.3 MMt/km^2. For the Utica study area in New York of 3,809,000 acres (or 5,951 mi^2), the estimated average methane gas in-place concentration is 129 Bcf/mi^2, of which 32 Bcf/mi^2 is adsorbed gas and 97 Bcf/mi^2 is free gas. Maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 86.7 Bcf/mi^2, which is approximately equivalent to 5 MMt CO_2/mi^2, or 1.9 MMt/km^2.

Reservoir simulation for this study assumes a vertical production well on 40-acre spacing; a sensitivity case assumes a horizontal well on 80-acre spacing. The calculated concentration of methane gas in-place for the Marcellus is expressed below in units of Bcf per 40-acre well spacing (in addition to Bcf per square mile) so that one can easily compare the estimated in-place volume with the model well recovery for a likely vertical well spacing. Similarly, the calculated theoretical maximum CO_2 storage, which assumes that all methane gas in-place is replaced by CO_2, is expressed in units of Bcf per 40-acre well spacing. Reservoir simulation of CO_2 injection after methane production assumes a single vertical injection well per 40 acre spacing. Units of Bcf per 40-acre injection well spacing are selected to compare easily with the model injection well results, and to estimate what percentage of theoretical maximum CO_2 storage is likely to be achieved.

Total calculated methane gas in-place (both adsorbed and 'free' gas in-place) for the Marcellus in New York study area ranges from 2.7 Bcf/40 acres (43.2 Bcf/mi^2) to almost 8.9 Bcf/40 acres (142.4 Bcf/mi^2). Total theoretical maximum CO_2 storage capacity ranges are slightly higher, from 3.1 Bcf/40 acres (49.6 Bcf/mi^2) to 9.3 Bcf/40 acres (148.8 Bcf/mi^2). The difference between a total calculated methane gas in-place volume and total theoretical maximum CO_2 storage volume is mainly due to preferential adsorption of CO_2 by organic rich shale. Methane and carbon dioxide adsorption isotherms indicate that the organic-rich Marcellus and Utica shales preferentially adsorb more than three times the amount of CO_2 as methane. For the case where "free" or non-adsorbed methane gas in-place is assumed to be replaced by injected CO_2, reservoir temperature and pressures for the New York Marcellus and Utica study areas and the formation volume factors for methane and carbon dioxide appear to favor methane storage over carbon dioxide. For the most organic-rich shale, preferential adsorption of CO_2 appears to exert greater influence than preferential methane storage as "free gas", under reservoir conditions; hence, theoretical maximum CO_2 storage volumes are generally greater than calculated total methane gas in-place. For example, approximately 20 percent of the calculated methane gas in-place in the Marcellus black shales is adsorbed, but adsorbed CO_2 accounts for 55 to 63 percent of total maximum CO_2 storage capacity (1.8 to 5.8 Bcf/40 acres, or 28.8 to 92.8 Bcf /mi^2). For the Marcellus model areas, the Union Springs black shale member at the base of the Marcellus contributes 75 percent or more of total gas in-place (2.3 to 7.0 Bcf/40 acres; 36.8 to 112 Bcf/mi^2) and at least 71 percent of total CO_2 storage capacity.

For the Utica in New York, total gas in-place ranges from 9.1 Bcf/40 acres to 10.9 Bcf/40 acres (145.6 to 174.4 Bcf/mi^2). Theoretical maximum CO_2 storage capacity ranges from 8.2 to 10.3 Bcf/40 acres (131.3 to 164.8 Bcf/mi^2). For the Utica model areas, the Indian Castle Formation contributes most of total gas in-place and total CO_2 storage capacity, from 46 to 90 percent (5.0 to 7.2 Bcf/40 acres; 80 to 115.5 Bcf/mi^2) depending on what other Utica formations are present. If the Flat Creek Formation is present with sufficient thickness, it may provide nearly as much CO_2 storage capacity as the Indian Castle. Adsorbed gas contributes 16 percent to 25 percent of total calculated methane gas in-place for the Utica overall. Similar to the Marcellus, 51 to 65 percent of calculated maximum CO_2 storage capacity in the Utica is as adsorbed CO_2 (4.6 to 6.7 Bcf/ 40 acres; 73.6 to 107.2 Bcf/mi^2).

Three permeability cases were evaluated using reservoir simulation. A "low" permeability case appears to best represent the Marcellus and Utica gas shale reservoirs based on comparison to a limited set of annual production data for New York shale wells. More work is needed to refine the representation of reservoir permeability in the model and the interaction between the matrix and fracture system porosity and permeability. For the Marcellus low-permeability, vertical well case, total cumulative gas production (0.14 – 0.55 Bcf/40 acres; 2.2 – 8.8 Bcf/mi^2) represents recovery of 5 to 6 percent of total calculated gas in-place. Net CO_2 injected (0.1 – 0.6 Bcf/40 acres; 0.6 – 3.6 Bcf/mi^2) represents 3 to 6 percent of total theoretical CO_2 storage capacity. Enhanced gas recovery from CO_2 injection ranges from 7 MMcf/40 acres to 61 MMcf/40 acres. The enhanced gas recovery component represents 5 to 11 percent of cumulative gas production at year 30 and approximately 0.5 percent of calculated total gas in-place. For the Utica low-permeability, vertical well case, total cumulative gas production (0.47 – 0.73 Bcf/40 acres) represents 5 to 7 percent of total calculated gas in-place recovered, and net CO_2 injected (0.37 – 0.6 Bcf/40 acres) represents 3 to 6 percent of total theoretical CO_2 storage capacity.

A horizontal well simulation case was investigated for one of the Utica model areas where most of the Utica potential resides in the organic-rich Indian Castle Formation. Compared to the vertical well case, a horizontal well (with no hydraulic fracturing) provides a significant boost in gas recovery and net CO_2 injection and storage, increasing cumulative gas production by 32 percent over 30 years from 1.22 Bcf/80 ac to 1.61Bcf/80 ac and more than doubling net CO_2 storage from 1.20 Bcf/ 80 acres to 2.5 Bcf/ 80 acres. Hydraulic fracturing of the horizontal well recovers additional of gas in-place, 0.07 Bcf/80 acres for a "small' frac case and 0.24 Bcf/80 acres for a "large' frac case.[1] The small frac case boosts gas recovery by 38 percent compared to the vertical well and the large frac case boosts gas recovery by 52 percent compared to a vertical well.

Hydraulic fracturing of the horizontal well increases net CO_2 storage by an additional 0.22 Bcf/80 acres for the small frac case and by 0.61 Bcf/80 acres for a large frac case. A horizontal well with no frac stores approximately 13 percent of theoretical maximum CO_2 storage capacity. For the "small" frac case, net CO_2 stored is 14 percent of maximum CO_2 storage capacity. For the large frac case, net CO_2 stored increases to 17 percent of maximum CO_2 storage capacity.

Recommendations

This project presents a first approximation of total methane gas in-place and theoretical maximum storage CO_2 storage capacity within the Marcellus and Utica shale exploration fairways identified by the New York State Museum for the state of New York. Both the Marcellus and Utica shales appear to have significant gas in-place and potential storage capacity for CO_2. Recovery factors for adsorbed and "free" gas in-place are unknown but expected to be different. Consequently, the accessibility and economics of potential adsorbed and non-adsorbed phase CO_2 storage capacity may be significantly different.

Sources of uncertainty that impact the gas in-place and CO_2 storage capacity calculations and the reservoir simulation results include: 1) limited CO_2 and methane isotherm data for the Marcellus and Utica; 2) lack of reservoir test data and sustained production data for calibration of the reservoir simulation results; 3) accurate representation of variable reservoir matrix-fracture characteristics in *COMET3*. Recommendations for further work to refine and expand this analysis are focused on reducing or eliminating these uncertainties by acquiring additional reservoir and engineering data to improve the reservoir characterization, as well as industry insight into hypothetical development scenarios.

Specific recommendations include the following:

- Obtain additional isotherm data for the Marcellus and Utica, particularly CO_2 isotherms
- Improve the representation of Marcellus and Utica regional and fracture systems and local fracture density in the reservoir simulation of fracture permeability and porosity. This would incorporate the latest understanding of areal variation in Marcellus and Utica fracture trends, fracture spacing and orientation, and in situ fracture widths
- Obtain industry input for more accurate representation of reservoir pressure. Investigate potential extent into southern New York of the Pennsylvania Marcellus "overpressure fairway"

[1] "Small" frac case assumes 200 ft. total fracture length. "Large" frac case assumes 550 ft. total fracture length. Both cases assume equal number of fractures and equal fracture spacing.

- Obtain sustained Marcellus production data and reservoir test data to calibrate *COMET3* results and improve model representation of reservoir permeability

- With industry and New York State input, identify hypothetical development scenarios. Focus on one or two "most likely" Marcellus and Utica development approaches and investigate engineering options to optimize gas recovery with CO_2 storage

- Further investigate potential limitations of reservoir depth on CO_2 storage in New York. The current analysis computes CO_2 storage capacity assuming storage reservoir depths greater than 3,000 ft. Potential depth limits to economic CO_2 storage (either shallow or deep limits) were not explicitly addressed in this analysis.

INTRODUCTION

BACKGROUND

Carbonaceous (organic-rich) gas shales have been recognized as sharing some of the same methane storage characteristics as coal seams. In gas shales, natural gas is adsorbed on kerogen and clay surfaces similar to methane storage within coal seams. Gas is also stored as “free” (non-adsorbed) gas in fracture porosity and inter- and intra-particle microporosity. The relative amounts of adsorbed and free gas recovered during the producing life of a shale gas well are unknown.

Although still in the conceptual stage, CO_2 storage in carbonaceous gas shales is attracting increasing technical interest, especially in Appalachian Basin and Mid-Western states with extensive shale deposits. In coal seams, it has been demonstrated that CO_2 is preferentially adsorbed at a ratio of two or more CO_2 molecules for every methane molecule displaced. Carbonaceous gas shale reservoirs are expected to react similarly and desorb methane while preferentially adsorbing CO_2. In addition, some component of gas shale pore volume is expected to be available for CO_2 storage as non-adsorbed CO_2, especially where previous hydraulic fracturing has enhanced injectivity. In theory, CO_2 injection into carbonaceous gas shales could provide dual benefits: an economic benefit from incremental recovery of the desorbed methane and the environmental benefit of secure CO_2 storage.

New York State is remarkably endowed with numerous thick and extensive carbonaceous shale formations (black and gray shales). These include Devonian, Silurian, and Ordovician age shale formations ranging in total thickness from 3,000 ft. to more than 5,500 ft. In August 2006, the New York State Energy Research and Development Authority (NYSERDA) and the New York State Museum (NYSM) published a preliminary review of the CO_2 sequestration potential in New York.[2] This review summarized the state of technology for CO_2 capture, transport, and sequestration, and provided a preliminary characterization of the opportunities for geologic sequestration in the state. Among the various options for geological sequestration in New York, the report discussed the possibility of CO_2 storage in the state’s gas shales. Gas shale could provide an opportunity for CO_2 storage in much of New York, at relatively shallow depths, while also potentially allowing for the enhanced production of the state’s natural gas resources.

The potential CO_2 storage capacity of gas shales is just beginning to be rigorously assessed. The critical factors determining the storage capacity and injectivity of CO_2 in gas shales are the volume and rate that methane can be desorbed and then produced from the shales. Consequently, understanding of the CO_2 storage capacity of such shales requires understanding of the gas productive capacity of the shales. Moreover, achieving the benefits associated with storing CO_2 in gas shales is expected to result in incremental gas production. The NYSM is currently engaged in a statewide geologic assessment of the potential of Devonian age Marcellus and Ordovician age Utica shales for both enhanced gas recovery (EGR) and resultant CO_2 storage.

[2] New York Research and Development Authority, Overview of CO_2 Sequestration Opportunities in New York State, August 2006

The dual focus of the project reported here are the geological and reservoir characterization of CO_2 storage capacity in gas shales in New York, as well as preliminary identification of reservoir engineering and operational requirements for economical CO_2 storage, answering not just "How much CO_2 can be stored in gas shales?" but also "What are the critical factors that can influence optimum CO_2 storage volumes, injection rates, and enhanced gas production?" This report expands upon previous and ongoing work of NYSERDA and the NYSM, and involved collaboration with an operating company engaged in development of gas shale resources in the state.

PROJECT OVERVIEW

Project Objectives

This report examines the challenges associated with CO_2 storage in New York's Marcellus Shale (Middle Devonian age, Hamilton Group) and the Utica Shale (Ordovician age). As such, the primary goal of this work was to complement and expand upon (but not duplicate) recent work by the NYSM.

The low permeability and porosity typical of gas shales in general and New York shales in particular makes CO_2 storage in shales challenging, especially relative to other storage targets such as depleted conventional oil and gas reservoirs and deep saline aquifers. Low porosity constrains the potential storage capacity of the shales, while low permeability constrains the injectivity of gas shales. Such constraints are counter-balanced by the strong adsorptive capacity of gas shales for CO_2 and the potential to store CO_2 securely.

Project objectives included the following:

- Use existing geologic data to develop a basin-level geologic characterization of the Marcellus and Utica shales, focusing on attributes affecting CO_2 storage capacity and CO_2 injectivity

- Collect additional new data for CO_2 storage and gas production-related parameters from new shale wells in New York. From these new data, combined with the review of existing data, partition the New York Marcellus and Utica formations for the purposes of modeling. Identify shale formation zones and/or geographic areas of apparent varying CO_2 storage capacity

- Using Advanced Resources' proprietary *COMET3* triple-porosity/dual-permeability reservoir simulator for gas shale reservoirs and coalbed methane, perform reservoir modeling for both natural gas production and CO_2 injection in New York's gas shales

- Describe the potential constraints to economic CO_2 sequestration in New York gas shale. Identify alternative approaches to overcome constraints and perform sensitivity analysis to identify critical performance factors.

GEOLOGIC CHARACTERIZATION OF NEW YORK GAS SHALE

Several organic-rich black shale formations occur in New York, ranging in age from the late Ordovician through the middle to late Devonian. A comprehensive overview of New York's gas shale formations is provided by Hill, Lombardi, and Martin, 2002. While some of the New York black shale formations are limited in areal extent and thin, others are massive and extend throughout the state of New York and the Appalachian Basin region, providing an extensive natural gas resource and CO_2 storage potential. The middle Devonian Marcellus shale (the lowermost black shale of the Hamilton Group) and the upper Ordovician Utica shale are the most widespread of New York gas shale formations, thus providing the best potential for CO_2 injection for enhanced gas recovery and permanent CO_2 sequestration.

The Reservoir Characterization Group of the NYSM is engaged in comprehensive characterization of the Marcellus and Utica Shale gas potential in New York. This ongoing work has produced:

- Significant revision of the tectonic and depositional model for New York black shales in general, and the Marcellus and Utica shales in particular (Smith, 2010; Smith and Leone, 2010b)
- Analysis of Marcellus and Utica reservoir characteristics (Leone and Smith, 2010)
- Integration of reservoir data and the revised depositional framework to identify potential "exploration fairways," the most favorable areas for gas shale development in the Marcellus and Utica (Smith and Leone, 2010a; Martin and others, 2008).

The Marcellus and Utica exploration fairways identified by the NYSM are also potential fairways for CO_2 storage and enhanced gas recovery via CO_2 injection. This storage concept is based on the hypotheses that:

- Large-scale methane production from gas shale formations creates adsorption sites and void space to be occupied by injected CO_2
- Horizontal well configurations and reservoir stimulation required for economic methane recovery from shale also enhance CO_2 injectivity by enhancing reservoir permeability and the connectivity of natural fractures, as well as vastly expanding the surface area contacted by injected CO_2
- Preferential adsorption of CO_2 by organic-rich shale further displaces methane, thus enhancing methane production.

The geological characterization of the Marcellus and Utica shales for this report builds upon the previous work by the NYSM and focuses on the Marcellus and Utica exploration fairways identified by NYSM and NYSERDA. Methane gas in-place is estimated for the Marcellus and Utica shale exploration fairways from petrophysical analyses of well logs. Using available CO_2 isotherms for the Marcellus and Utica, theoretical maximum CO_2 storage capacity for the Marcellus and Utica are estimated. Model areas are identified for the Marcellus and Utica within the approximate exploration fairway boundaries for simulation using *COMET3*. Reservoir simulation examines potential cumulative gas production, CO_2 storage, and enhanced gas recovery under various reservoir quality scenarios.

MARCELLUS

Marcellus Stratigraphy and Type Log

The Marcellus Formation is the lowermost formation of the Middle Devonian age Hamilton Group. **Figure 1a** shows a simplified stratigraphic column for New York, identifying both the Marcellus Formation and the Utica Group. **Figure 1b** provides a more detailed look at the Middle Devonian stratigraphy showing the location of the Marcellus black shale above an unconformity at the top of the Onondaga limestone (Smith, 2010). Other Middle Devonian black shales similarly onlap and pinch out against limestones and subaerial unconformities to the west (Smith, 2010). The names “Marcellus Formation” and “Marcellus Shale” are often used interchangeably, although commonly the name ”Marcellus Shale” refers to the most organic-rich zones, the black shale, of the lowermost Marcellus Formation. The Marcellus Formation extends over 18,700 square miles in New York. Depth to the Marcellus ranges from surface outcrops in the north and east, down to depths exceeding 5,000 ft. in southern New York. Total thickness ranges from less than 25 feet in Cattaraugus County to more than 1,800 feet along the New York – Pennsylvania border in the vicinity of Tioga, Broome, and Delaware Counties.

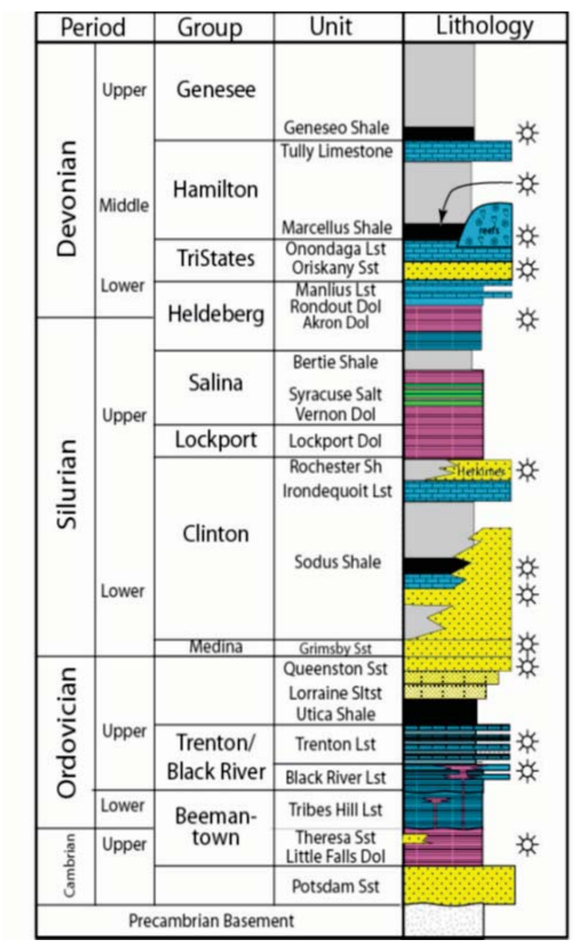
The depositional environment for the Marcellus Shale and other organic-rich Devonian black shales shown in **Figure 1b** has been reinterpreted recently by the New York State Museum. The Marcellus black shale appears to have been deposited in a fairly shallow water marine environment (water depths less than 100 ft.) in an actively subsiding foreland basin. The marine basin onlapped subaerially exposed land to the west while undergoing active subsidence and deepening to east. This is illustrated in **Figure 2**, which is a schematic regional cross-section of the Marcellus showing the on-lapping relationships of the Marcellus against a tectonic high to the west.

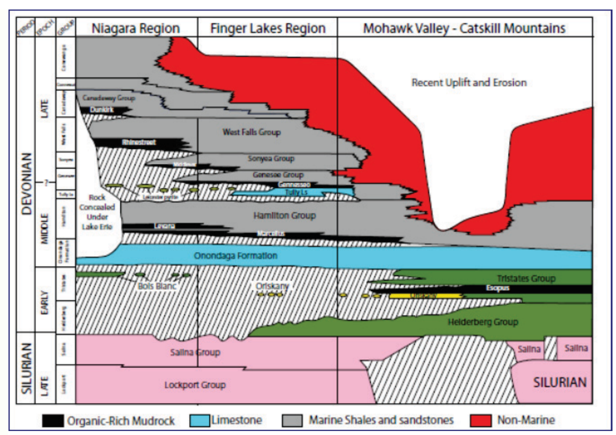
The landward, shallow part of the marine basin accumulated the greatest amount of organic material, which became progressively diluted in deeper water due to the influx of siliciclastics and organic-lean mudstones from uplifted areas to the east. Restricted marine circulation and oxygen-depleted conditions apparently prevailed for long durations in the landward areas of the marine basin, allowing for the preservation of organic material in relatively shallow water (Smith, 2010; Smith and Leone, 2010).

Figure 3 shows a type log of the organic-rich lower Marcellus Formation from the Beaver Meadows #1 well in Chenango County. The Marcellus Formation consists of black and gray shale, siltstone, and interbedded limestone (Leone and Smith, 2010). **Figure 3** shows three divisions of the Marcellus Formation identified by the NYSM. These include the Union Springs (lowermost member), Cherry Valley Limestone (middle), and the Oatka Creek (upper member), which is divided into the lower Oatka Creek black shale and the upper Oatka Creek gray shale. The Union Springs and Oatka Creek black shales are the target reservoirs for Marcellus gas production. In New York's southern tier, the Cherry Valley Limestone is interbedded with thin shales, which appear on well logs to be organic-rich, comparable in density and gamma ray response to the Oatka Creek and Union Springs black shales. In some areas, to the south and east, the Cherry Valley may provide a minor contribution to gas in-place and CO_2 storage capacity. The Marcellus stratigraphy shown in **Figure 3** is used in this analysis as the basis for the geologic model and reservoir layering for gas in-place analysis and reservoir simulation.

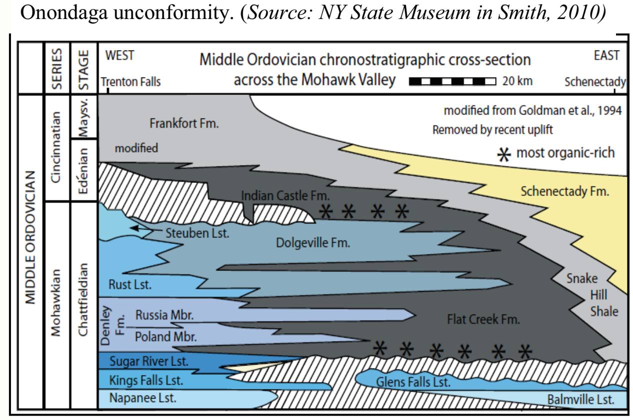
Figure 3 shows the typical density and gamma ray log response of the Marcellus black shales, as well as carbonate content and total organic carbon content (TOC) from core data. The Union Springs is composed of thinly interbedded limestone and black, organic-rich mudstone. TOC values range from less than 1 percent (weight percent) in the predominately limestone beds to as much as 10 to 12 percent in the Union Springs shale. Low bulk density and high gamma ray correspond to high TOC and low carbonate content (Leone and Smith, 2010). For example, bulk density of less than 2.65 gm/cc from the Beaver Meadows #1 density log corresponds to laboratory measured TOC of greater than 1 percent.

Figure 1: New York Stratigraphic Column



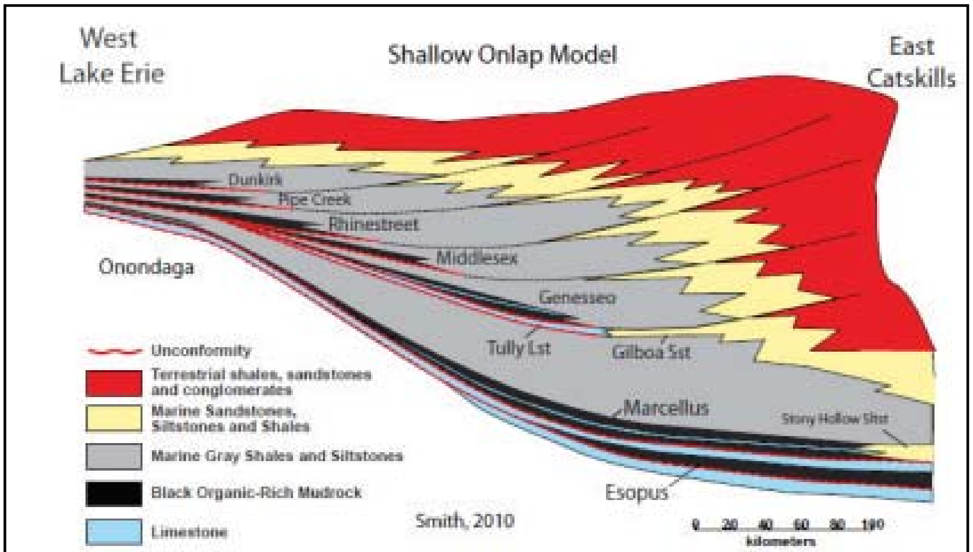


(1b) Middle Devonian stratigraphy showing Marcellus above the Onondaga unconformity. (*Source: NY State Museum in Smith, 2010)*



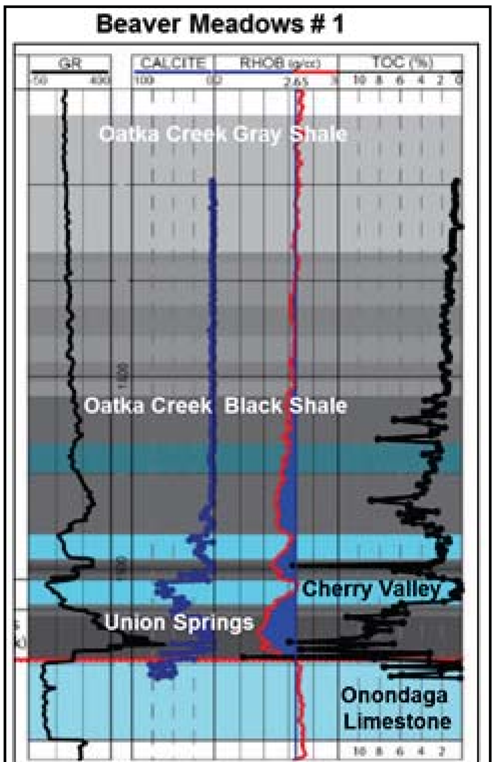
(1c) Utica Formations and unconformities at base of Lower Indian Creek and Flat Creek Fms. (*Source: NY State Museum in Smith, 2010)*

Figure 2: Schematic Cross-Section Showing Shallow Onlap Depositional Model for the Marcellus Shale



Source: New York State Museum

Figure 3: Marcellus Shale 'Type Log' – Beaver Meadows #1, Chenango County



Source: New York State Museum

UTICA

Utica Stratigraphy and Type Log

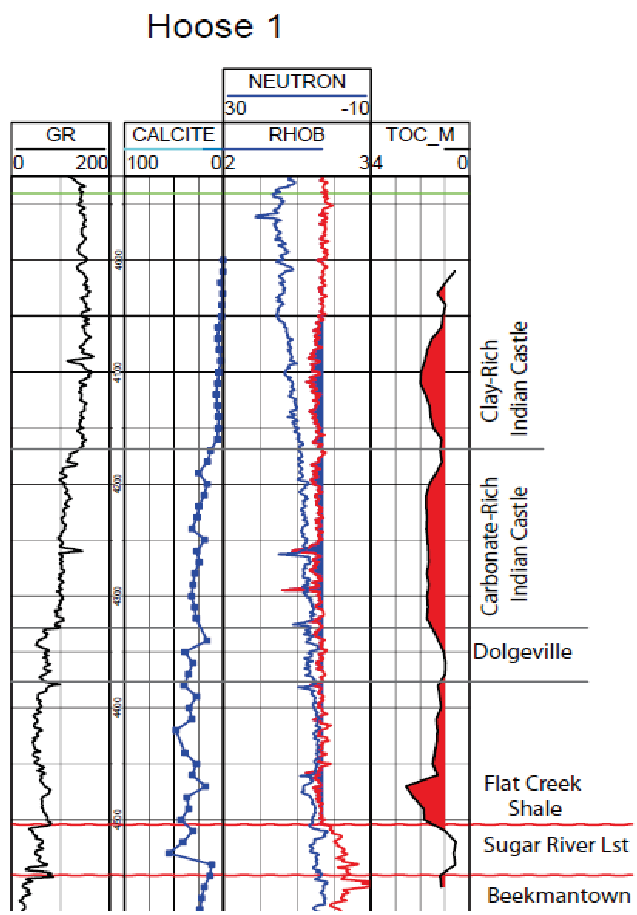
The Ordovician Utica Group contains predominately black shale and black shaley carbonate. The Utica and equivalent formations extend from Quebec and Ontario, Canada, across New York and south to Tennessee. In New York, the Utica extends for approximately 28,500 square miles from outcrops along the southern and western Adirondack Mountains to the southern tier, where the Utica occurs at depths greater than 9,000 ft. **Figure 1**, showing the generalized stratigraphic column for New York, identifies the relative stratigraphic position of the Utica Group. **Figure 1c** provides more detail, showing the three formations that comprise the Utica in New York (Flat Creek, Dolgeville, and Indian Castle) and general stratigraphic relationships to the Trenton Limestone (Smith, 2010).

Subsurface stratigraphic correlation of the Utica can be challenging because of multiple formation names and conflicting depths for formation tops in various public data sources. The stratigraphic framework provided by the NYSM's regional Utica cross-sections (Smith, 2010; Smith and Leone, 2010a; Smith and Leone, 2010b) was used as the basis for identifying Utica formation tops on well logs, correlating relevant Utica reservoir layers, and developing an initial geologic model for reservoir simulation and analysis of gas in-place. As with the Marcellus Formation, the terms "Utica Shale," "Utica Group," and simply "Utica" are commonly used interchangeably to refer to massive, organic-rich, black and gray calcareous shale and shaley limestone formations that occur in facies relationship to the Trenton Limestone and the siliciclastic Lorraine Formation and equivalents.

Figure 4 shows the Hoose #1 well in Otsego County as a type log for the Utica. The Flat Creek Formation is the lowermost member of the Utica Group and is composed of an organic-rich, calcareous shale that is time-equivalent to the Trenton Limestone. The upper Flat Creek grades laterally into the Dolgeville Formation (middle member of the Utica), which consists of thin interbedded limestone and organic black shale. The Dolgeville is time-equivalent to the shallow marine facies of the Trenton Limestone. An erosional unconformity is present at the top of the Trenton and Dolgeville Formations, which are overlain by the Lower Indian Castle, the uppermost formation of the Utica. The Lower Indian Castle contains an upper clay-rich member ("clay-rich Indian Castle") and a lower carbonate-rich member ("carbonate-rich Indian Castle"). The Flat Creek and Lower Indian Castle have the highest organic carbon content, ranging from 1.5 percent to 3.5 percent TOC. Overall, the Utica in New York has significantly lower TOC than the Marcellus, and is thermally super-mature throughout its extent (Smith, 2010; Smith and Leone, 2010a; Leone and Smith, 2010).

As with the Marcellus, the Utica is interpreted as having been deposited on the shallow, craton-ward margin of an actively subsiding foreland basin. Like the Marcellus, the Utica wells with the highest organic carbon are bounded at the base by subaerial unconformities. During Utica deposition, the marine basin appears to have experienced extensive normal faulting, which may contribute to uneven accumulation and preservation of organic material in the Utica compared to the Marcellus, and a greater amount of natural fracturing in the Utica (Smith and Leone, 2010a).

Figure 4: Utica Shale 'Type Log' – Hoose #1, Otsego County



Source: New York State Museum; Smith and Leone, 2010b

STUDY AREA

Utica and Marcellus Exploration Fairways

Previous geological work by the NYSM characterized the trends in thickness, total organic carbon content (TOC), and thermal maturity for the Marcellus and Utica. **Figure 5** from Smith and Leone, 2010 shows depth to the top of the Marcellus black shale and net thickness of organic-rich Marcellus black shale (defined as calculated TOC greater than 1.5 percent). From the outcrop, subsurface depth of the top of the organic-rich lower Marcellus increases to the south and southwest to more than 6000 ft. The net thickness of organic rich Marcellus ranges from less than 25 ft. in western New York to more than 300 ft. Thermal maturity of the Marcellus shale, as indicated by calculated vitrinite reflectance, Ro, increases to the east and southeast with increasing depth and net thickness. The red line on **Figure 5** indicates calculated vitrinite reflectance, Ro, of 1.1 percent, the apparent 'gas window' boundary for the Marcellus. West of the 1.1% Ro line, the Marcellus shale is not in the gas window; east of this boundary, Marcellus thermal maturity increases with depth to as much as 4.0% Ro (Smith and Leone, 2010).

Figure 6 shows that the subsurface depth of the top of the lower Utica ranges from 1000 ft. to more than 10,000 ft. Total organic content of the Utica increases generally to the south and east in southern New York. **Figure 6** shows total thickness of organic-rich Utica (defined as calculated TOC of 1 to 2 weight percent; thickness increases to the east and southeast to more than 1000 ft. Throughout New York the apparent thermal maturity of the Utica exceeds the dry gas window (calculated vitrinite reflectance greater than 2.2 %Ro), making the Utica "super mature." This means that hydrocarbon generation is complete and remaining gas has been adsorbed into the shale matrix.

NYSERDA and the NYSM previously identified exploration fairways for Marcellus and Utica shale gas based on the maps of net organic thickness, depth, and thermal maturity illustrated in **Figures 5** and **6**. The Marcellus and Utica exploration fairways are shown in **Figure 7** and are defined by the following criteria:

- At least 50 ft. net thickness of organic-rich shale (defined as TOC greater than approximately 1.5 percent – 2.0 percent for Marcellus/ Utica). Thermal maturity of the Marcellus in the gas generation window as indicated by calculated vitrinite reflectance of least 1.1 percent Ro
- Subsurface depth of 3,000 ft. or greater.

The exploration fairways are estimated to represent the minimum criteria needed for economic Marcellus or Utica production. Correlation of measured TOC from cores and cuttings to corresponding bulk density values from density logs, indicate that organic-rich Marcellus and Utica shale with TOC of at least 1.5 to 2.0 percent can be identified on well logs by the lowest bulk density values. A minimum net organic thickness cut-off for economic production is unknown; however, the Marcellus 50-ft net thickness contour corresponds to the Marcellus gas window boundary, so 50 ft. of net organic thickness was selected as a reasonable first approximation for economic production from the Marcellus (Smith and Leone, 2010). A depth cut-off of 3,000 ft. was selected to approximate a sufficient depth to protect drinking water aquifers, as well as adequate reservoir pressure for economic gas production rates. This depth also represents an approximate miscibility cut-off for CO_2, where reservoir pressure is adequate for injection of CO_2 as a dense phase, thereby increasing the efficiency of enhanced gas recovery and CO_2 storage.

Figure 7 shows substantial overlap of the Marcellus and Utica exploration fairways, indicating shale gas production potential from the Marcellus and Utica, as well as dual CO_2 storage potential. The area contained within the Marcellus and Utica exploration fairways identified in **Figure 7** was selected as the study area for this report, for the purposes of calculating a regional estimate of total gas in-place and maximum CO_2 storage capacity; for identifying model areas, and for forecasting potential gas production, enhanced gas recovery, and CO_2 injection and storage. The selection of study area presumes that the most prospective areas for shale gas production will also be the most technically attractive and cost-effective areas for CO_2 injection, enhanced gas recovery, and CO_2 storage.

Figure 5: Depth and Thickness of Organic-Rich Marcellus Shale

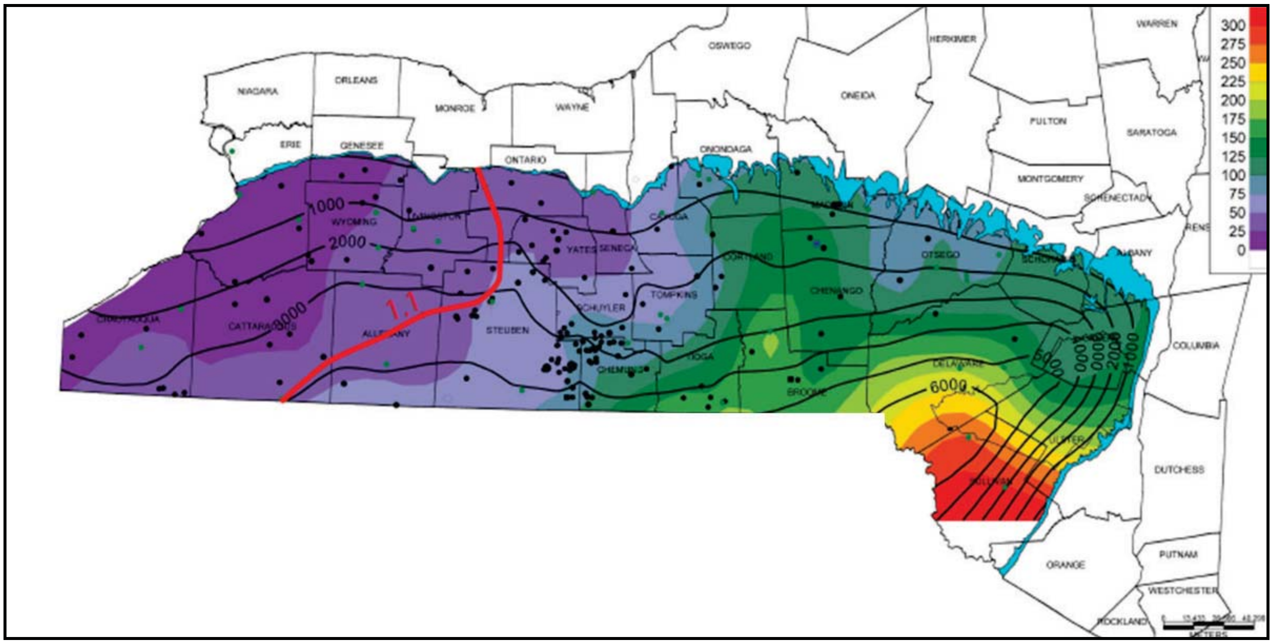


Figure 6: Depth and Thickness of Organic-Rich Utica Shale

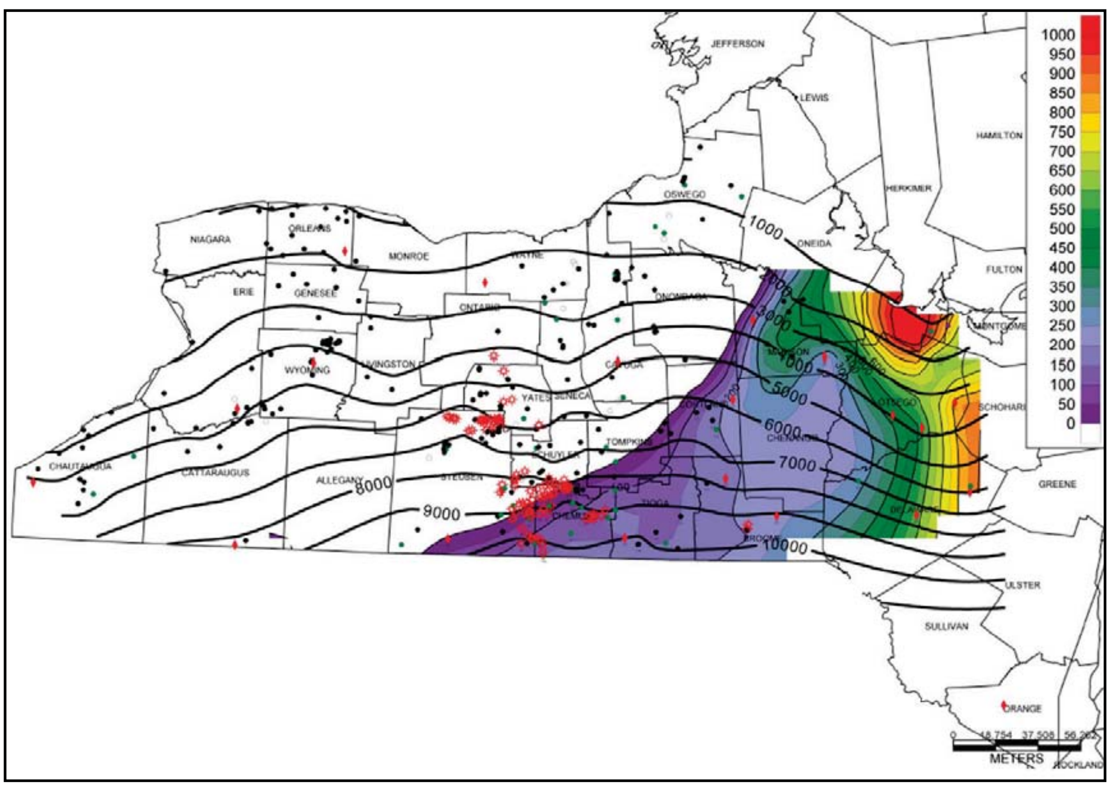
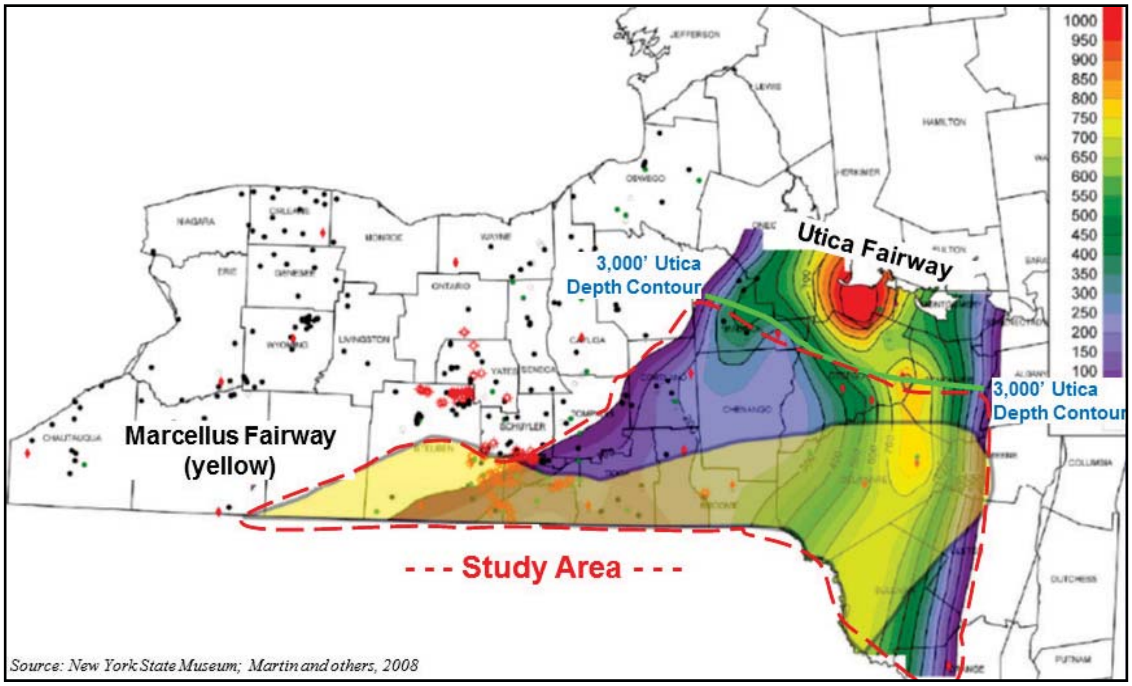


Figure 7: Marcellus and Utica Exploration Fairways and Prospective CO_2 Storage



Model Wells

Digital well logs were selected from the study area and vicinity for calculation of gas in-place and CO_2 storage capacity for the Marcellus and Utica. Well logs were correlated to current regional cross-sections of the Marcellus and Utica developed by the NYSM. The organic-rich members of the lower Marcellus and Utica identified by the NYSM were designated as the model layers for reservoir simulation. For the Marcellus, the model layers include:

- Oatka Creek Black Shale
- Cherry Valley Limestone
- Union Springs Member

The model layers for the Utica include:

- Indian Castle Fm., clay-rich
- Indian Castle Fm., carbonate rich
- Dolgeville Fm.
- Flat Creek Fm.

Recent and on-going work by the NYSM provides a tectonic and depositional framework for understanding the stratigraphy of the Utica Group.[3] Stratigraphic relationships in the Utica are complex; the upper Flat Creek and Dolgeville are time-equivalent to the Trenton. In addition the Flat Creek grades laterally into the Dolgeville. A subaerial unconformity tops the Dolgeville and its Trenton equivalent, which is then overlain by the Lower Indian Castle. In addition the Utica Shale was deposited during active normal faulting, which control the thickness and areal extent of the most organic-rich horizons (Smith and Leone, 2010b). These stratigraphic relationships can be difficult to discern from well logs alone. Consequently, for some study wells, subsurface correlation of the Utica to the NYSM regional cross-sections was challenging, and may require future adjustment. Overall, the subsurface Utica correlations appear to fit reasonably well with the stratigraphic framework provided by the regional cross-sections. Maps of calculated values such as average TOC, average porosity, adsorbed methane and CO_2, etc., appear to be reasonable compared to the NYSM's regional geologic characterizations of the Utica and Marcellus.

From the individual well calculations, three model wells were selected for the Marcellus and four model wells were selected for the Utica for reservoir simulation using *COMET3* to forecast gas production, CO_2 injection, CO_2 storage, and potential enhanced gas recovery under CO_2 injection. The model well locations designated as "model areas" are shown in **Figure 8,** which also shows available Marcellus and Utica core data and adsorption isotherms. Marcellus whole core, methane adsorption isotherms, core porosity and permeability, TOC, and x-ray diffraction mineralogy were available for the EOG Resources Beaver Meadows #1 and Oxford #1 wells in Chenango County. The Gastem Ross #1 well in Otsego County provided porosity and permeability, TOC, and x-ray diffraction mineralogy data from sidewall core plugs for the Marcellus and Utica. Composite sidewall core samples from this well were also used to obtain CO_2 and CH_4 adsorption isotherms for the Marcellus and Utica.

[3] For example, see Smith, L. B. and Leone, J. 2010b, Tectonic and Depositional Setting of Ordovician Utica and Devonian Marcellus Black Shales, New York State, poster presentation, American Association of Petroleum Geologists Annual Convention and Exhibition, New Orleans, LA, April 11-14, 2010.

Figure 8: Marcellus Union Springs Net Pay Thickness Map Showing Marcellus and Utica Model Areas and Data Wells

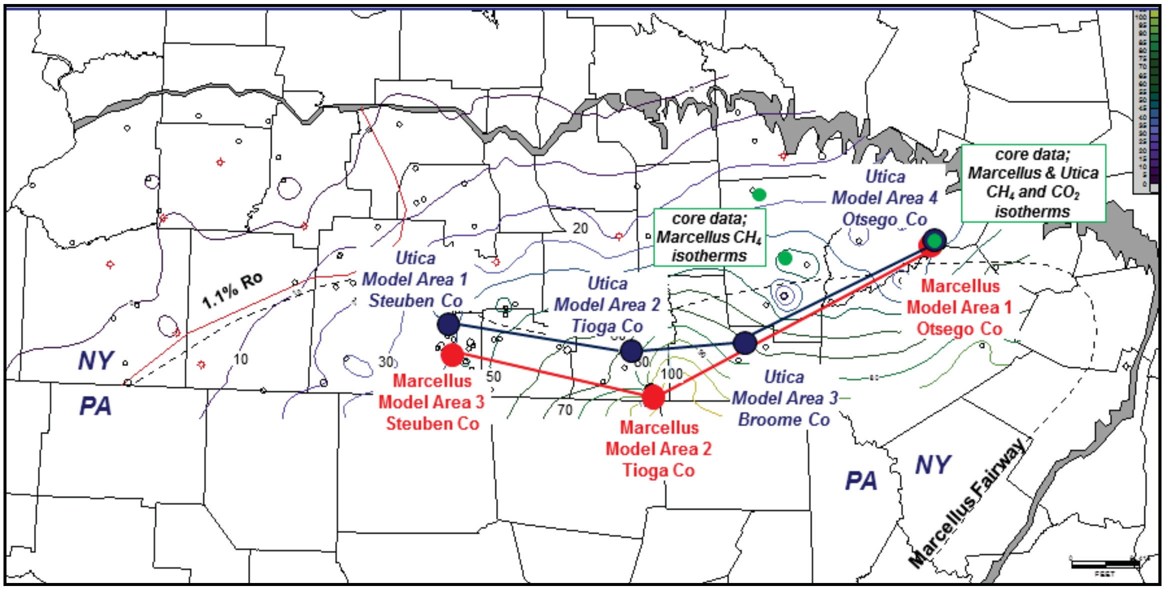


Figure 9 is a southwest to northeast stratigraphic cross-section between the Marcellus model areas. **Figure 10** shows a comparable southwest to northeast stratigraphic cross-section between the Utica model areas. The cross-sections show the formation top picks for the model wells based on correlation to the NYSM regional cross-sections. The logs shown on both cross-sections include gamma ray, resistivity, bulk density, neutron porosity, and photoelectric log (PE). Gamma ray is normalized across all wells; very high gamma ray readings of 200 api units or greater are highlighted with pink shading.

X-ray diffraction mineralogy data for the Marcellus and Utica were used to extrapolate a characteristic grain density for non-organic reservoir matrix. Using the available data, plus cross-plots of bulk density and TOC from the cored wells, bulk density cut-off values were estimated to identify zones with high organic carbon content. The organic-rich zones are highlighted by blue shading on the cross-sections in **Figures 9** and **10**.

High TOC zones in the Marcellus are identified by bulk density of less than 2.63 g/cc and a normalized gamma ray log response greater than 200 api units. The TOC of the Utica is less than the organic content of the Marcellus by a factor of two to three. Consequently, the Utica zones with high TOC do not exhibit the same combination of high gamma ray response and low bulk density as the Marcellus, although **Figure 10** also indicates higher gamma ray log readings in the Utica across the apparent organic-rich zones. A bulk density cut-off of 2.68 g/cc was selected to identify the high organic content zones in the Utica.

Figure 9: Marcellus Stratigraphic Cross-Section through Model Areas

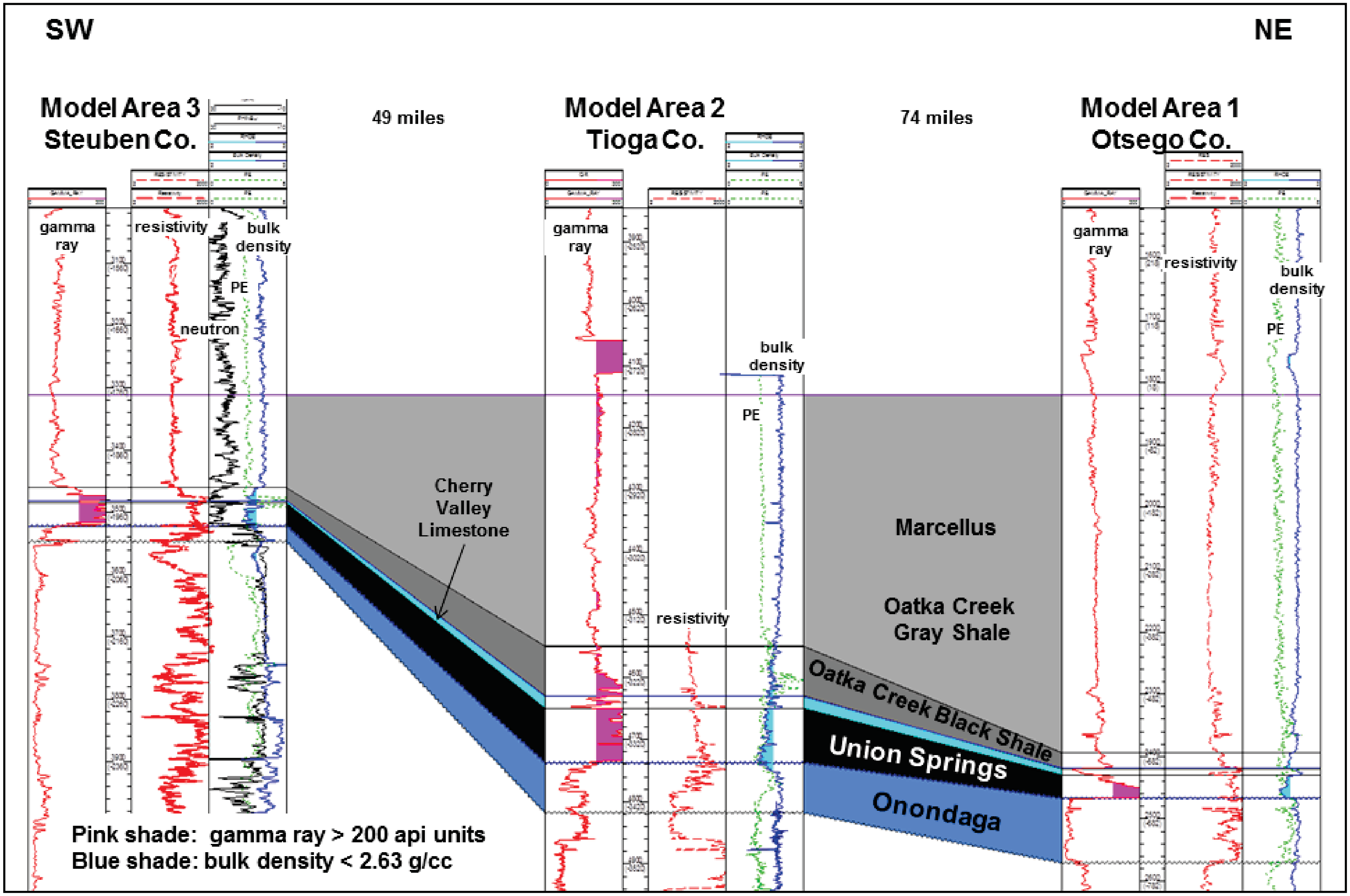
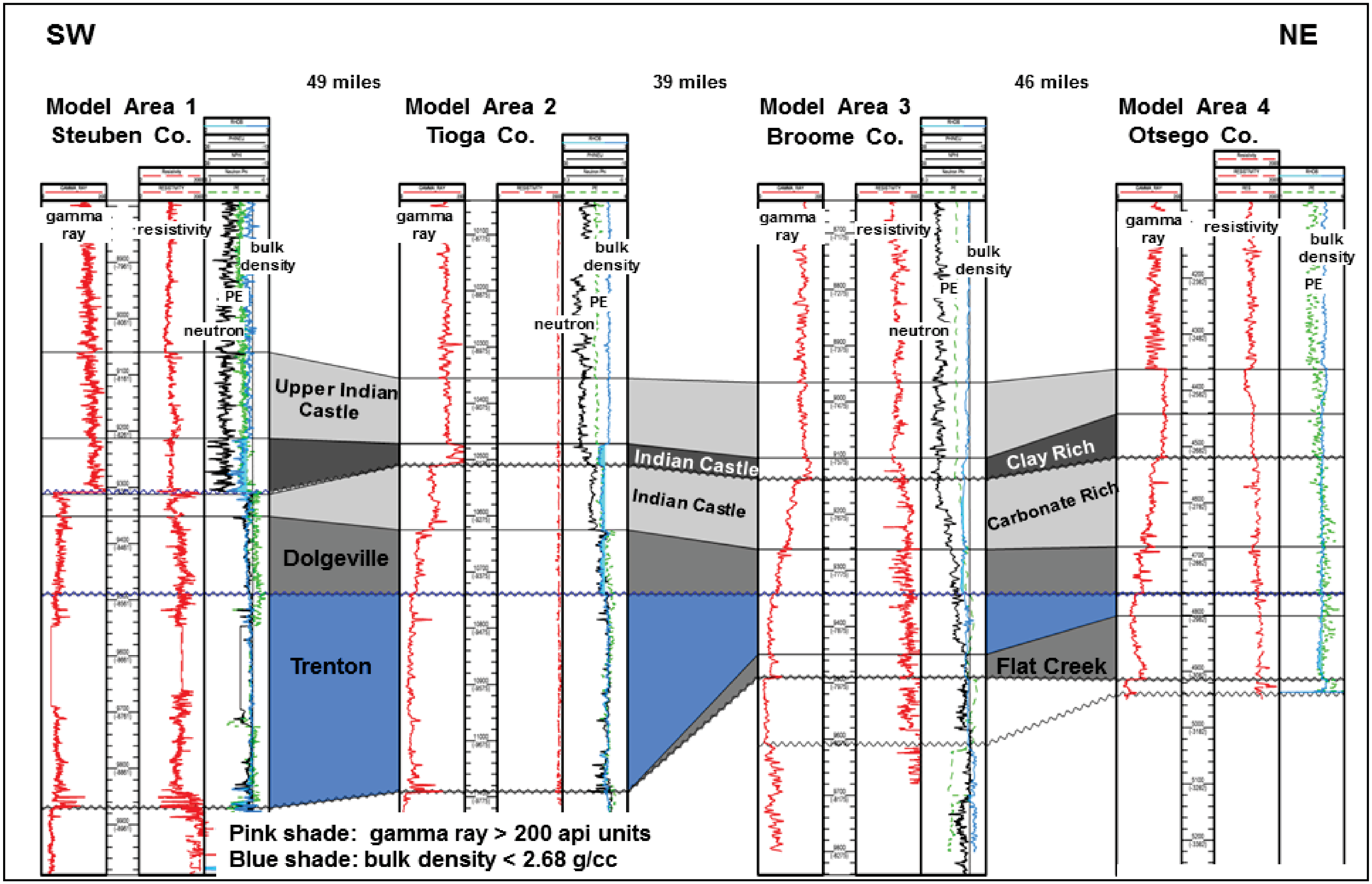


Figure 10: Utica Cross-Section through Model Areas



DATA

This section summarizes various data that were directly used in the evaluation of gas in-place and CO_2 storage capacity.

Adsorption Isotherms

Methane and CO_2 adsorption isotherms were available from three wells (**Figure 8**). The Marcellus isotherm data are shown in **Figure 11** and the Utica isotherms are shown in **Figure 12**. Methane isotherm data for the Beaver Meadows #1 and Oxford #1 wells in Chenango County are available from the NYSM. Methane isotherms for the Marcellus and Utica from the Ross #1 well in Otsego County were made available to the project courtesy of Gastem USA, Inc. The Marcellus and Utica CO_2 isotherms were acquired by NYSERDA for this analysis, and these data are included in **Appendix A**.

Total Organic Carbon

Total organic carbon measurements were available from the NYSM for the Marcellus cores from the Beaver Meadows #1 and Oxford #1wells in Chenango County. **Figure 13** is a cross-plot of TOC and bulk density, which shows that TOC of 3 percent corresponds to bulk density of approximately 2.63 g/cc. **Figure 14** is a cross-plot of TOC measured from Utica sidewall cores and log bulk density. The samples are from the Indian Castle, Dolgeville, and Flat Creek. Measured TOC ranges from 2.2 percent to 1.4 percent, and corresponding bulk density ranges from 2.63 to 2.68 g/cc. Based on this data set, 2.68 g/cc was selected as the bulk density cut-off value to discriminate the most organic-rich Utica Shale on well logs.

X-Ray Diffraction Mineralogy

X-ray diffraction mineralogy data are available from the NYSM for 21 Marcellus samples from the Beaver Meadows #1 and Oxford #1 wells in Chenango County. The samples include the Union Springs and the Oatka Creek black shale, the Cherry Valley, and undifferentiated Marcellus gray shale above the Oatka Creek. The mineralogy data for the Union Springs and Oatka Creek black shale samples were averaged to determine a characteristic mineralogy for Marcellus black shale, and to extrapolate grain density values that more accurately reflect the complex mineralogy. X-ray diffraction mineralogy data were made available for this study courtesy of Gastem USA, Inc. for four Utica samples from the Indian Castle and Flat Creek formations in Otsego County. **Table 1** compares the x-ray diffraction mineralogy and extrapolated matrix grain density for the Marcellus and the Utica.

Figure 11: Marcellus CH_4 and CO_2 Adsorption Isotherms

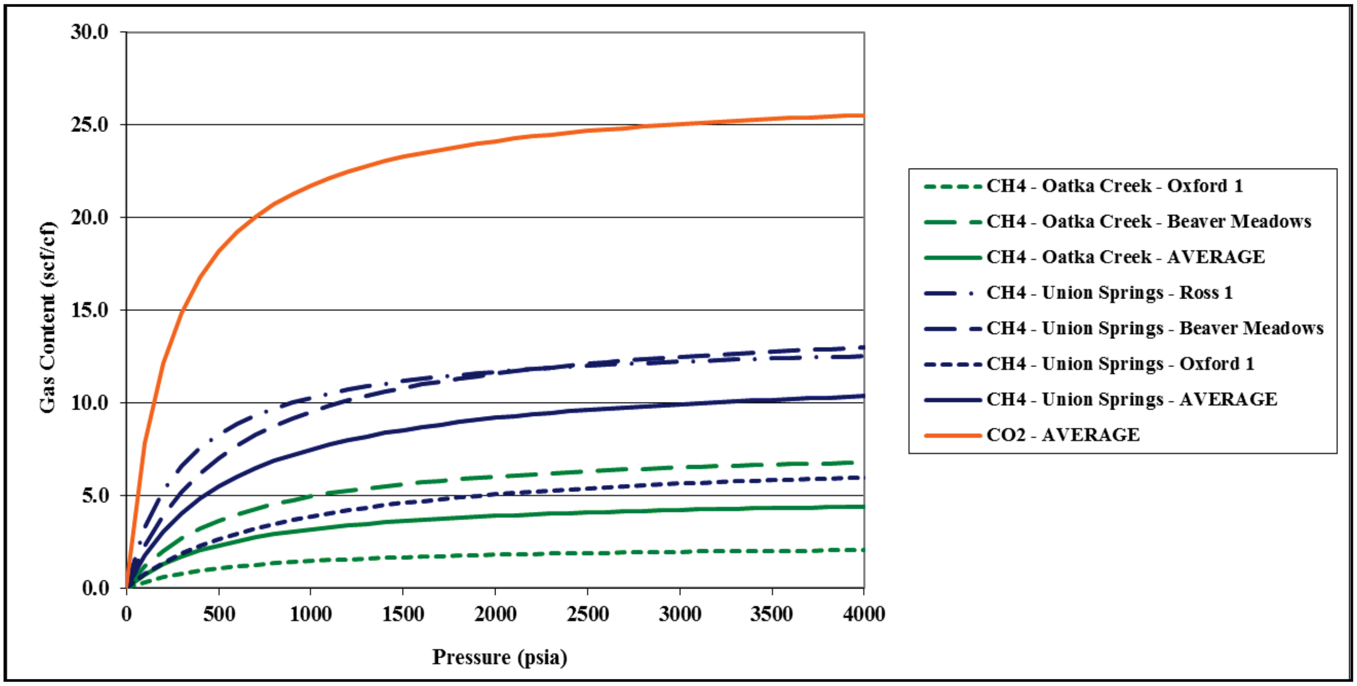


Figure 12: Utica CH_4 and CO_2 Adsorption Isotherms

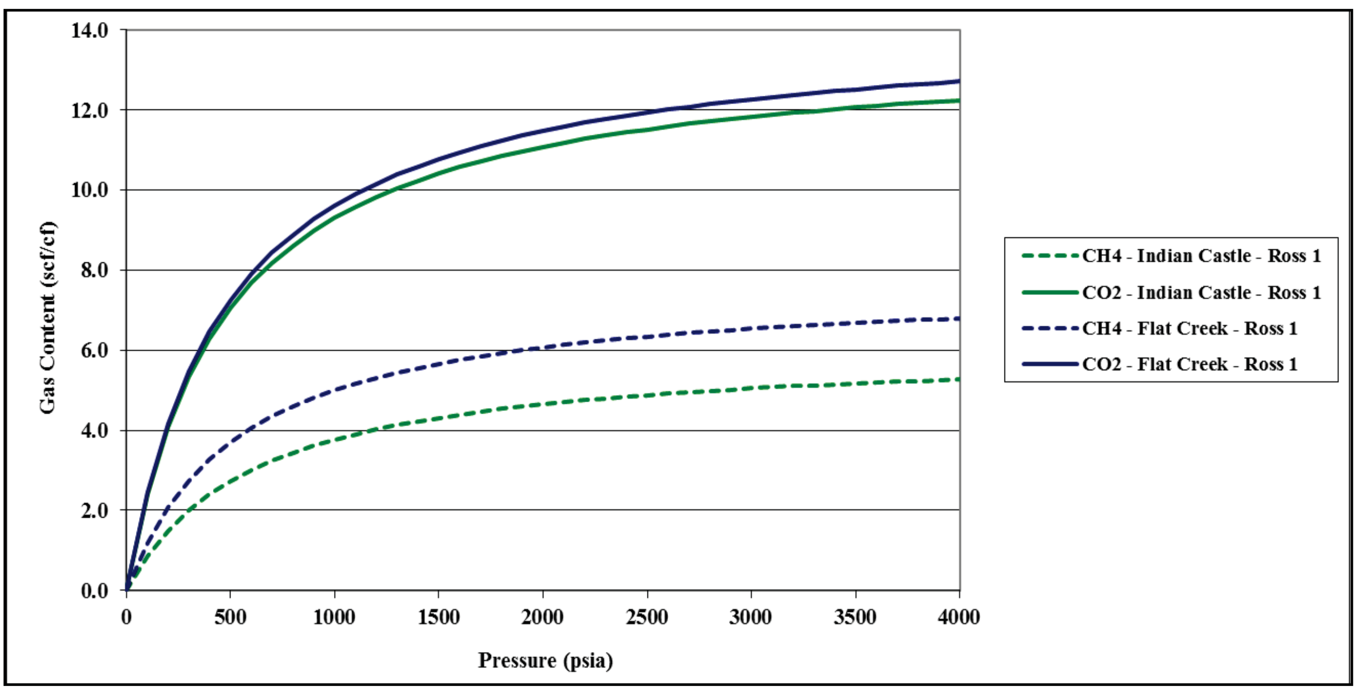


Figure 13: TOC vs Bulk Density for Marcellus Shale

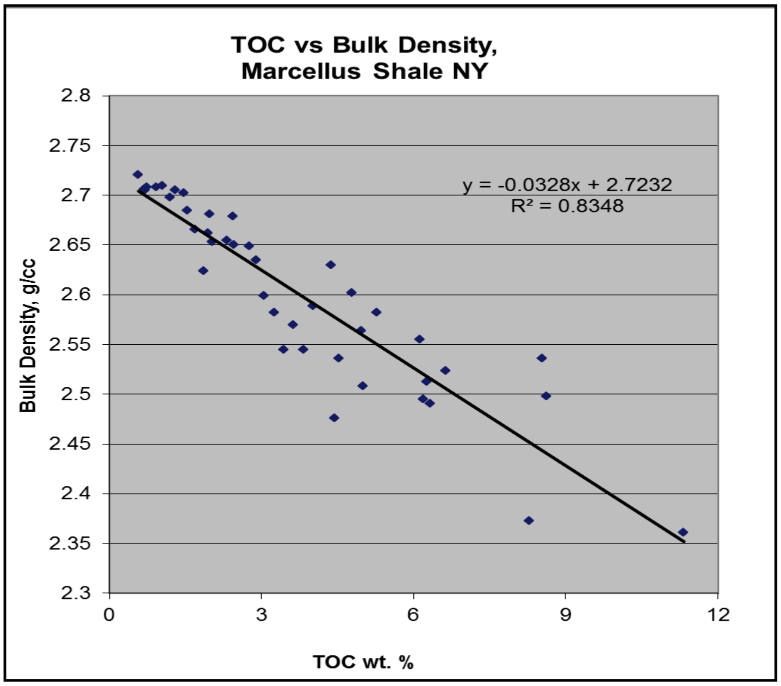
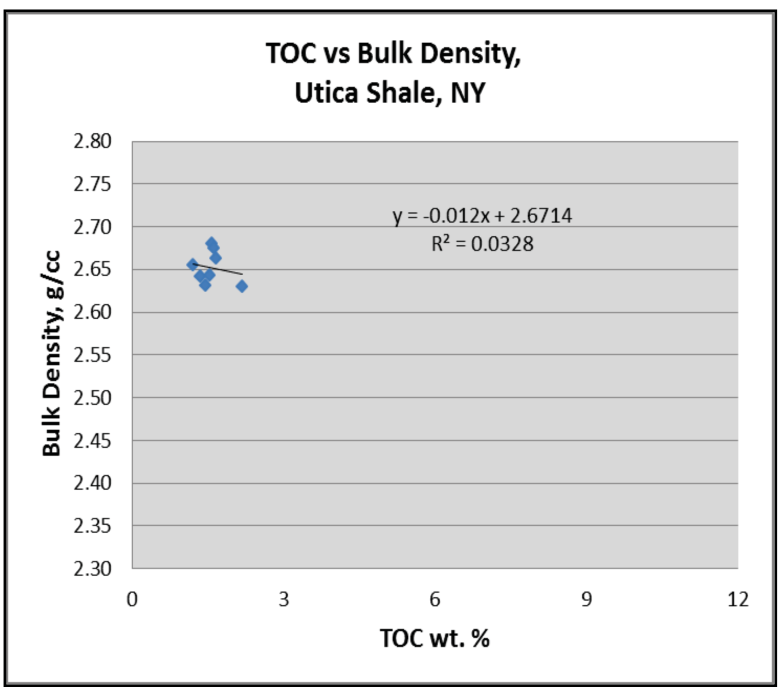


Figure 14: TOC vs Bulk Density for Utica Shale



The mineralogy of the Indian Castle and Flat Creek Formations appear to be distinct, and different from the Marcellus black shale. The Marcellus black shale has a significant component of pyrite compared to the Utica, which contributes to the high matrix grain density for the Marcellus. The Utica formations contain a significant portion of dolomite compared to the Marcellus. The clastic mineral component of the Marcellus and Indian Castle are similar except that the clastic component of Marcellus is dominantly quartz, while the clastic mineral component of the Indian Castle contains a significant amount of plagioclase feldspar. The Flat Creek is especially interesting because of the very high carbonate (calcite and dolomite) and correspondingly low quartz content. The Flat Creek is the least clay-rich of the Utica Group formations and might be classified as a micrite in part. **Table 1** also includes average mineralogy data for the Lower Utica Shale in Quebec (from Theriault, 2008), which shows that the Quebec data resemble the New York Flat Creek samples.

**Table 1: X-ray Diffraction Bulk Mineralogy (weight percent)
for Marcellus and Utica Black Shale (Non-Organic Mineral Fraction)**

Formation	Quartz	K-Feldspar	Plagioclase	Calcite	Fe-Dolomite	Dolomite	Siderite	Pyrite	Total Clay	Grain Density
Marcellus	**39.0**	**0.6**	**3.67**	**22.4**	**0.6**	**1.4**	**0.3**	**8.1**	**23.9**	**2.77**
Utica – Indian Castle	**25.7**	**0.2**	**11.8**	**23.0**	**0**	**7.1**	**0**	**1.2**	**30.3**	**2.74**
Utica – Flat Creek	**9.8**	**0.7**	**1.6**	**59.0**	**0**	**8.1**	**0**	**0.1**	**20.0**	**2.76**
Lower Utica-Quebec	**10.0**	**0.5**	**4.5**	**50.0**	**0**	**5.0**	**0**	**0**	**25.0**	**2.73**

ESTIMATED GAS IN-PLACE AND THEORETICAL MAXIMUM CO_2 STORAGE CAPACITY

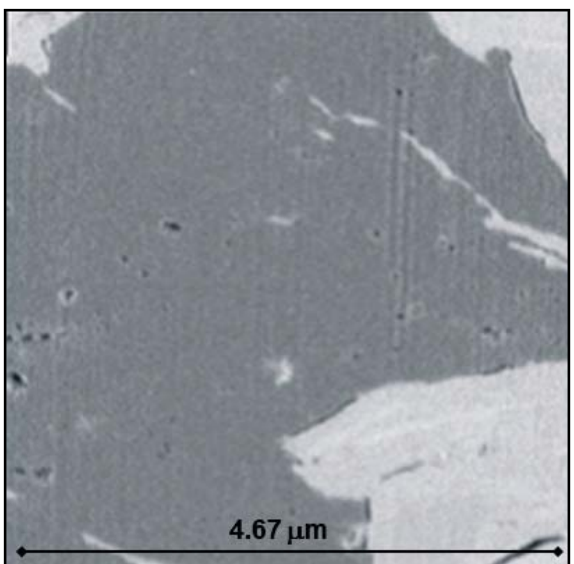
METHODOLOGY

Overview of Calculated Gas In-Place and CO_2 Storage Capacity

Calculated methane gas in-place for the Marcellus and Utica is assumed to have two components: 1) methane adsorbed on organic matter contained in the shale and 2) non-adsorbed methane, or free gas, contained within remaining void space in the shale after all adsorption sites are occupied. Such voids could include:

- Fracture porosity in macro and microfractures
- Intergranular porosity between silt-size carbonate particles and detrital clastic grains
- Microporosity along dissolution seams
- Micro- and nano-scale porosity within the framework of component minerals (e.g., between clay mineral "sheets" and "booklets," and within pyrite framboids)
- "Tubular" micro- and nano-scale porosity within organic matter. (An example of commonly observed porosity within organic material in shale is shown in **Figure 15**.)

Figure 15: Example of Porosity within Kerogen in Shale



Source: Heath et al., 2011

Estimation of methane gas in-place thus requires two separate steps to calculate the quantity of adsorbed gas and the quantity of free gas. Similarly, CO_2 storage capacity is assumed to have two components: storage of an adsorbed CO_2 phase displacing methane and storage of non-adsorbed CO_2 in effective porosity. The theoretical maximum CO_2 storage capacity assumes that all methane gas in-place adsorbed and free, is replaced by CO_2.

Digital well logs used to estimate methane gas in-place and CO_2 storage capacity were provided to the project by the NYSM's Empire State Oil and Gas Information System (ESOGIS). Wells selected for gas in-place calculation have a density, gamma-ray, and resistivity log suite across the entire zone of interest, either the lower Marcellus or the lower Utica. One hundred four wells were selected from the ESOGIS digital log database for the Marcellus, and 81 wells were selected for the Utica. The organic-rich zones of the Marcellus and Utica included in the gas in-place and CO_2 storage capacity determination follow the stratigraphic characterization of Smith and Leone (2010a, b). The reservoir layers, or zones, included in the log calculations are the Union Springs and the Oatka Creek black shale members of the Marcellus, and the Lower Indian Castle (both clay-rich and carbonate-rich members), Dolgeville, and Flat Creek Formations of the Utica Group. The log calculations were made using IHS Petra software. Gas in-place and theoretical CO_2 storage capacity were calculated for the adsorbed component using available CH_4 and CO_2 adsorption isotherms. A volumetric approach was used to estimate non-adsorbed gas in-place within effective (gas-filled) porosity. The log calculation approach is described in the next section of this report.

The end result of the log calculations are estimates of total methane gas-in place in billion cubic feet per acre (Bcf/ac) for the Marcellus and Utica in the exploration fairways, and theoretical maximum CO_2 storage capacity including an adsorbed component and non-adsorbed component. Units of Bcf/ac were selected for ease of scaling the calculated results to estimate gas resource in-place or CO_2 storage capacity for any well spacing of interest, such as 40 or 80 acres, and for ease of converting to units of Bcf/sq. mile. For example, **Figure 16** shows a contour map of the calculated theoretical maximum CO_2 storage as adsorbed CO_2 for the Marcellus Union Springs member, and **Figure 17** shows the calculated theoretical maximum CO_2 storage capacity as non-adsorbed CO_2 replacing methane in effective porosity. Additional maps showing calculated adsorbed and free gas in-place and calculated CO_2 storage capacity for the Marcellus Oatka Creek black shale and organic-rich formations of the lower Utica Group are provided in **Appendix B.**

Figure 16: Marcellus Union Springs - Calculated Maximum CO_2 Storage Capacity as Adsorbed CO_2, Bcf/ac

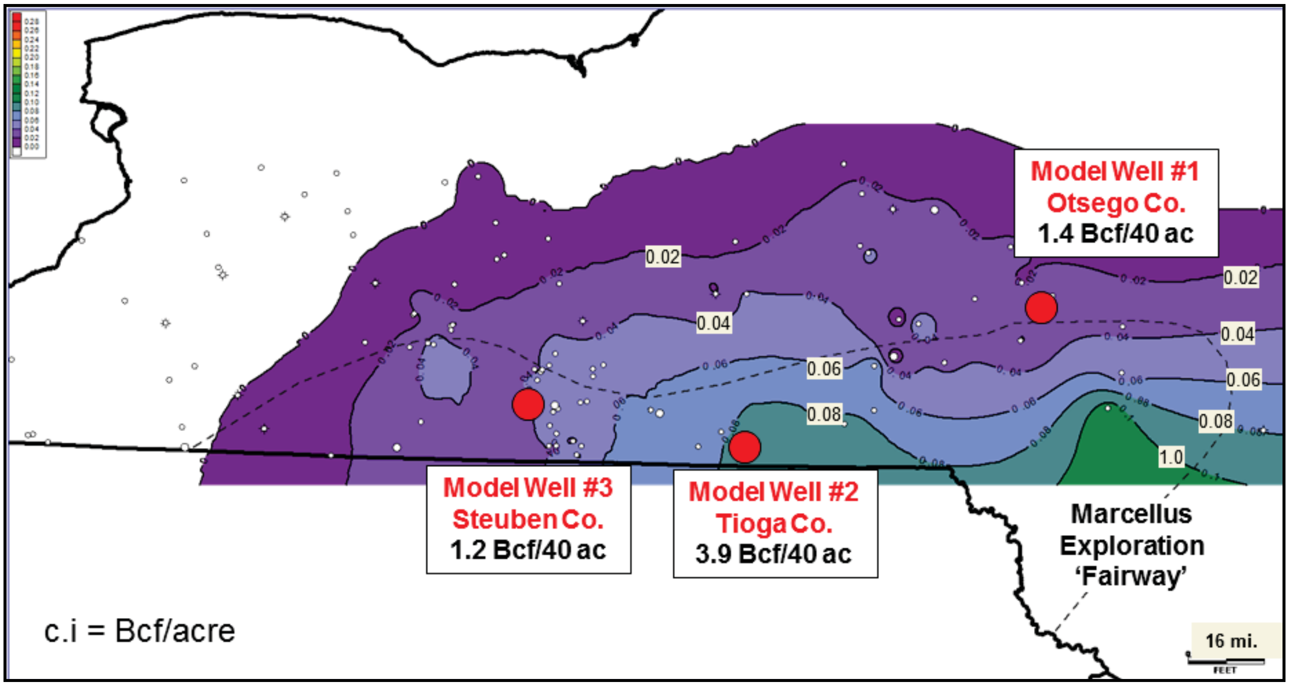
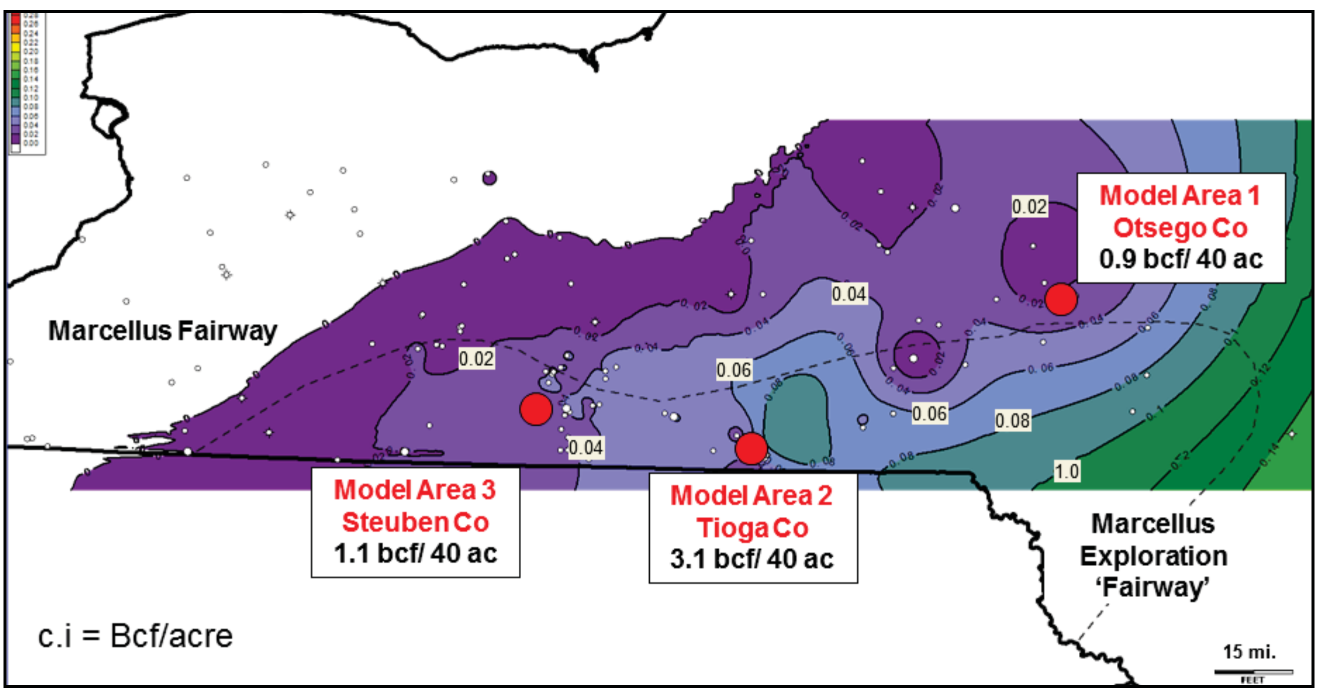


Figure 17: Marcellus Union Springs – Calculated Maximum CO2 Storage Capacity Replacing Non-Adsorbed Methane in Effective Porosity, Bcf/ac



The Marcellus and Utica wells used in the analysis are listed in **Appendix C** with the methane gas in-place and CO_2 storage capacity calculated for each. Total gas in-place and CO_2 storage capacity were extrapolated from the individual well log calculations for the New York counties shown within the boundaries of the Marcellus and Utica shale exploration fairways previously identified by the NYSM and illustrated in **Figure 7**. Calculated gas in-place and storage capacity values in Bcf/ ac for each county were multiplied by the approximate acres contained within the exploration fairways, where depth to the organic-rich lower Marcellus or lower Utica zones is greater than 3,000 ft. The county values were summed to obtain a total estimate for the entire fairway area, which is summarized in **Table 2**. The county-level estimates are provided in **Appendix D**.

Table 2: Estimated Gas In-Place and Maximum CO_2 Storage Capacity for Marcellus and Utica Shales in New York State

New York Marcellus and Utica Exploration Fairways	Marcellus	Utica
Total Acres (depth > 3,000 ft.)	3,387,165	3,808,702
Adsorbed Gas in-Place, Tcf	127	188
Non-Adsorbed (Free) Gas in-Place, Tcf	272	578
Total Methane Gas in-Place Tcf	**399**	**766**
Maximum CO_2 Storage, Adsorbed, Tcf	298	516
Maximum CO_2 Storage, Non-Adsorbed in effective porosity, Tcf	121	380
Total CO_2 Storage Capacity, Tcf	**419**	**896**

The gas in-place and capacity calculations in **Table 2** should be regarded as a first approximation of basin-scale gas in-place and CO_2 storage capacity. These estimates must be calibrated and refined as future shale gas production data, well test data, reservoir data, and further reservoir simulation results become available. An additional caveat is the very limited data available to estimate significant input parameters to the calculations. For example, core data are rare for the Marcellus and Utica, especially in New York, and few CO_2 adsorption isotherms have been obtained for New York shale. To estimate adsorbed CO_2 storage capacity, a limited isotherm data set must be extrapolated across a comparatively large geographical area encompassing significant variation in reservoir depth, temperature, and pressure.

Well Log Analysis Methodology for New York Gas Shale

Following is a description of the well log analysis methodology and assumptions used to calculate the gas in-place and theoretical maximum CO_2 storage capacity for the Marcellus and Utica provided in **Table 2**.

Porosity from Density Log.

- The density, resistivity, and gamma ray logs were quality checked for each well. Log curves were depth corrected and the gamma ray and bulk density logs were normalized.

- Shale volume (V_{shale}) was computed from the gamma ray log. A linear shale index approach produced the most consistent results compared to other published methods for estimating shale volume from the gamma ray log.

$$V_{shale} = (GR_{\text{log reading}} - GR_{\text{clean sand}}) / (GR_{shale} - Gr_{\text{clean sand}})$$

- TOC was calculated from the bulk density log using the method developed by Schmoker (1993) for Devonian shale of the western Appalachian Basin:

$$TOC_{calculated} = 55.822((\rho_{Shale}/\rho_{log})\text{-}1)$$

  Where, ρ_{Shale} = maximum bulk density of gray shale (low organic content) and ρ_{log} = bulk density reading from the log.

- Density porosity ($\phi_{density}$) corrected for TOC was calculated from the density log:

$$\rho_{log} = \rho_{matrix} (1 - \phi_{density} - TOC_{calculated}) + \rho_{fluid} (\phi_{density}) + \rho_{TOC} (TOC_{calculated})$$

  Where, ρ_{matrix} = matrix grain density determined from x-ray diffraction mineralogy or whole core analysis; ρ_{fluid} = density of formation water; ρ_{TOC} = density of organic matter; and ρ_{log} = bulk density reading from the log.

Adsorbed Gas In-Place and Maximum Adsorbed CO_2 Storage Capacity. Adsorbed methane and CO_2 in units of standard cubic foot per ton (scf/ton) were calculated using Langmuir coefficients based on the available isotherm data for the Marcellus and Utica in New York and reservoir temperature and pressure extrapolated based on depth:

$$V_{adsorbed} = (V_L x\ P_{res})/(P_L + P_{res})$$

Where, $V_{adsorbed}$ = volume of adsorbed gas at a reservoir pressure, P_{res}; V_L = Langmuir volume from adsorption isotherm; P_L = Langmuir pressure from adsorption isotherm.

For the Marcellus wells, the Langmuir coefficients selected for calculating adsorbed gas were determined based on calculated TOC, since enough data were available to broadly correlate TOC and apparent adsorption isotherm behavior. For the Utica, adsorption isotherms for both methane and CO_2 were available from a single well. These data were applied to all the Utica wells in the study area, an assumption that would be greatly improved if more Utica isotherm data could be obtained.

Reservoir temperature and pressure curves were created for each study well by applying a temperature and pressure gradient to the log depth. Marcellus and Utica reservoirs are assumed to be normally pressured throughout the study area. The Marcellus in northeast Pennsylvania is known to be over-pressured with reservoir pressure gradients of 0.6 to more than 0.7 psi/ft. The Marcellus in Bradford County and western Susquehanna County, Pennsylvania is sometimes called the Marcellus over-pressured “fairway”. (Wrightstone, 2009; Zagorski and others, 2011) This area of reservoir overpressure may extend into southern New York in Chemung, Tioga and Broome Counties, in which case a normal reservoir pressure gradient of 0.435 psi/ft. may not be the best assumption for the Marcellus in these counties. Lacking specific Marcellus reservoir pressure data for southern NY counties, a normal pressure gradient was assumed. By replacing the assumed normal reservoir pressure gradient with a greater pressure gradient, the resulting higher reservoir pressure is expected to increase the calculated volume of adsorbed methane gas in-place.

Adsorbed methane in-place or CO_2 in-place (scf/acre) was computed by multiplying the adsorbed gas “concentration” (scf/ton) obtained from the previous step by an estimated quantity of shale (tons/acre):

Tons shale = (thickness *x* area *x* shale density *x* conversion factor (g/cc to tons/acre-ft.))

For each study well, tons of shale was computed for each acre-foot of reservoir thickness and multiplied by the computed curve of adsorbed gas content in scf/ton. The result was computed log curves for each study well of adsorbed methane in-place (scf/acre-ft.) and maximum adsorbed CO_2 (assuming all adsorbed methane is replaced by injected CO_2). The final step summed the calculated curves for each study well and converted the units to Bcf/ac, yielding total adsorbed methane gas in-place, or maximum CO_2 storage capacity for each well.

<u>Non-Adsorbed ‘Free’ Methane Gas In-Place.</u> Free (non-adsorbed) methane gas in-place was estimated by first computing an effective (gas-filled) porosity:

$$\phi_{effective} = \phi_{density}\, x\, (1 - S_w)$$

Where, S_w = calculated water saturation (fraction).

All water in the pore system is assumed to be immobile, either immobilized by capillary forces in the smallest pores, bound by hydrostatic forces to pore walls and mineral surfaces, or incorporated into the structure of clay minerals. Effective porosity is assumed to be the fraction of total porosity not occupied by water. This is the pore volume available to be occupied by methane, so effective porosity is also called ‘gas-filled’ porosity in this report.

Water saturation was calculated using the Simandoux modification of the Archie equation for shaley sandstones (Simandoux, 1963 in Asquith and Krygowski, 2004):

$$S_w = ((0.4 \; x \; R_w)/\phi^m) \; x \; \{[(V_{shale} / R_{shale})^2 + ((5 \; x \; \phi^m)/(R_t \; x \; R_w))]^{1/2} - (V_{shale}/ R_{shale})\}$$

Where, S_w = water saturation; R_w = water resistivity at formation temperature; ϕ = porosity; m = Archie cementation exponent (common default = '2'); V_{shale} = shale content; R_{shale} = resistivity of the shale; R_t = deep resistivity log reading.

For this analysis, a three-part linear solution to the Simandoux equation published by Crain (1986) was implemented in PETRA to calculate water saturation foot by foot for each study well. The Crain version of the Simandoux algorithm is provided in **Appendix E**.

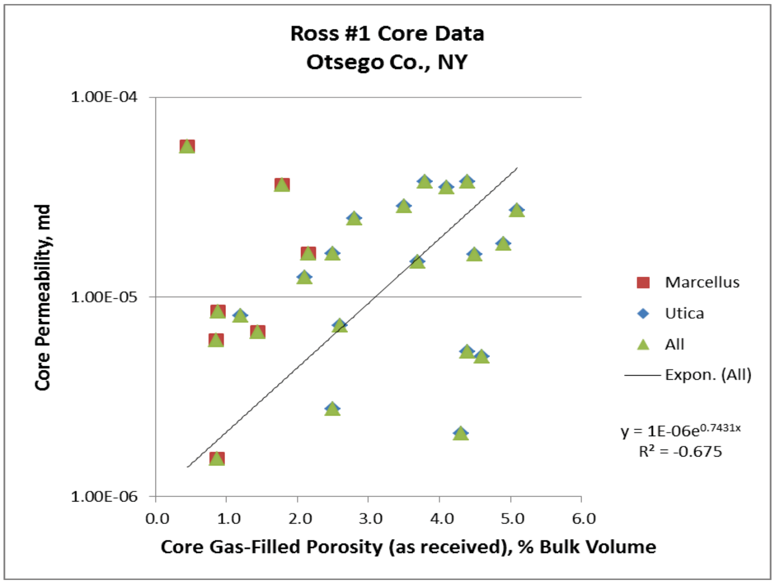
The total porosity calculated from the bulk density log was multiplied by the calculated pore volume fraction not occupied by water (1 – Sw). For example, typical calculated total porosity for the Union Springs is 6 percent to 10 percent. Average calculated water saturation for the Union Springs ranges from 10 percent or less, to more than 30 percent. Assuming no mobile water, the effective (gas-filled) pore volume would range from 0.9 to 0.7 of total pore volume, and the calculated effective or gas-filled porosity would range from 4.2 percent to 9 percent.

Effective (gas-filled) porosity was calculated foot-by-foot for the Marcellus and Utica in each study well. Cross-plots of core porosity and permeability data from the Gastem Ross #1 well in Otsego Co were used to estimate a 'pay' cut-off of 3 percent effective porosity. This porosity cut-off establishes the net reservoir thickness for calculating both methane gas in-place and maximum CO_2 storage capacity. For both the Marcellus and Utica shales in New York, gas saturation is calculated for the total reservoir thickness. Limited core data (discussed below) suggests that the lowest porosity zones correlate to the lowest matrix permeability, and would be the least favorable zones for releasing gas into a fracture system (either natural or induced) or for injecting CO_2. The porosity cut-off is intended to remove zones from the analysis that may contribute to a high total free gas in-place, but may contribute little or nothing to methane gas recovery or future storage volumes for CO_2.

Figure 18 shows the combined Utica and Marcellus core data for the Ross #1. Both total core porosity and effective or 'gas-filled' porosity were measured for each sample; Figure 18 correlates measured gas-filled core porosity to core permeability, which ranges from 10^{-4} millidarcies (md) to 10^{-6} md. Measured gas-filled core porosity of approximately 3 percent or greater corresponds to core permeability of at least 10^{-5} md.[4] For core porosity less than 3 percent, the corresponding permeability is an order of magnitude lower, in the range of 10^{-6} md. By using these data to set a net reservoir thickness cut-off at 3 percent effective porosity, zones with the lowest permeability (and presumably, the poorest methane deliverability and CO2) are excluded from the calculation of gas in-place and theoretical maximum CO_2 storage capacity.

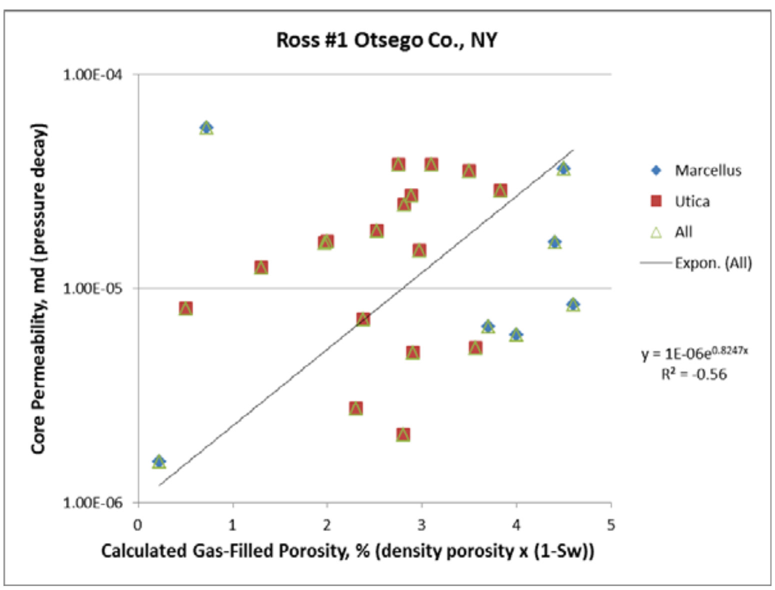
[4] In Figure X, gas-filled core porosity of 3.1 percent corresponds to permeability of 1.0E-05 md. Gas-filled core porosity of 2 percent corresponds to permeability of 4.4E-06 md.

Figure 18: Ross #1; Cross-Plot of Core Permeability and 'Gas-Filled' Core Porosity



The **Figure 19** shows a cross-plot of core permeability and the corresponding effective porosity calculated from the density log for the cored intervals in the Ross #1. **Figure 19** shows that log-calculated effective porosity of 3 percent or greater also corresponds to core permeability of 10^{-5} md.[5]

Figure 19: Ross #1; Cross-Plot of Core Permeability and Calculated 'Gas-Filled' Porosity from Density Log



[5] In Figure Xx, gas-filled core porosity of 3.0 percent corresponds to permeability of 1.2E-05 md. Gas-filled core porosity of 2 percent corresponds to permeability of 5.2E-06 md.

Using PETRA, Marcellus and Utica 'pay' zones were identified where the computed effective (gas-filled) porosity is 3 percent or greater. The total thickness of these porous zones constitutes the net reservoir thickness (the 'effective' reservoir thickness) for calculating free methane gas in-place.[6] The volume of free gas in-place for each acre-foot of net reservoir thickness was computed:

$$\text{Free methane gas-in-place} = (43560 \, x \, \phi_{effective}) / Bg_{CH4}$$

Where, Bg_{CH4} (rcf/scf) = the appropriate formation volume factor for methane computed for each study well based on depth and extrapolated reservoir temperature and pressure.

The result was a computed curve yielding for each study well free (non-adsorbed) methane gas in-place in units of Bcf per acre-ft. A final step summed the calculated curves for each study well and converted the units to Bcf/ac, yielding total non-adsorbed methane gas in-place for each well.

Theoretical Maximum CO_2 Storage as 'Free' CO_2 (Non-Adsorbed). The maximum capacity for CO_2 storage as 'free' gas (non-adsorbed CO_2) was calculated by assuming that all calculated free methane gas in-place is replaced by CO_2. Methane gas must be removed from the reservoir by production to make reservoir volume available for injected CO_2. The methane recovery factors for the Marcellus and Utica are unknown but are certain to be significantly less than 100 percent, hence computed CO_2 storage capacity as 'free', non-adsorbed CO_2 is a theoretical maximum.

Maximum CO_2 storage capacity as non-adsorbed CO_2 was computed for each acre-foot of net reservoir thickness by substituting the appropriate formation volume factor for CO_2 (Bg_{CO2}) at the extrapolated reservoir pressure and temperature for the depth. Similar to free methane gas in-place, the result was a computed log curve for each study well yielding non-adsorbed CO_2 replacing free methane gas in-place in units of Bcf per acre-ft. A final step summed the calculated curves for each study well and converted the units to Bcf/ac, yielding the theoretical maximum CO_2 storage capacity as free CO_2 for each well. Total maximum CO_2 storage capacity includes the theoretical maximum CO_2 storage capacity as 'free' CO_2, as well as the maximum CO_2 storage capacity as adsorbed CO_2.[7]

Variables and Assumptions for Marcellus and Utica Gas In-Place Calculations. **Table 3** summarizes assumed values for log analysis parameters and variables that were used for the log calculations. The individual well log analyses yielded various calculated reservoir values for the Marcellus and Utica, which were mapped to identify apparent variation in reservoir characteristics across the study area, and to select "model" wells for reservoir simulation. The calculated values include:

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[6] The net reservoir thickness used for calculating gas in-place may be referred to as net 'pay' or the 'pay' zones. The term 'pay' derives from the concept that within the total thickness of a gas reservoir, only certain intervals contain a sufficient volume of gas or, can produce at a sufficient rate to be economic. 'Pay' zones may be defined by a variety of criteria - usually some combination of porosity, calculated water saturation, permeability (derived from correlation to porosity), and gross interval thickness. Other 'pay' criteria may include reservoir depth, pressure, indications of natural fracturing, etc.

[7] Maximum CO_2 storage as adsorbed CO_2 assumes that all adsorbed methane is replaced by CO_2.

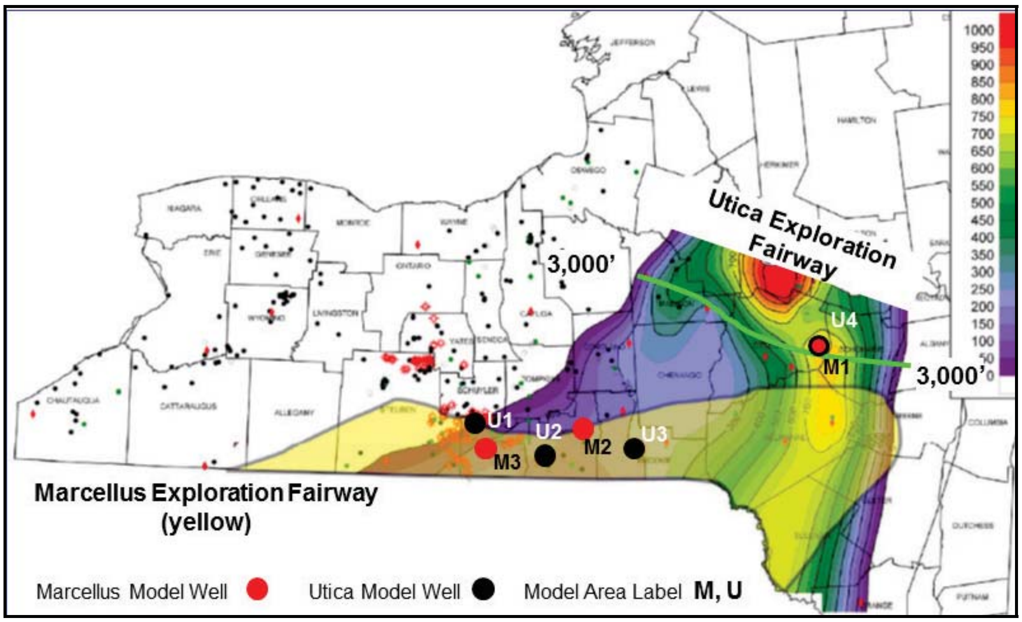
- Calculated TOC (total organic carbon)
- Average water saturation
- Calculated TOC (total organic carbon)
- Average water saturation
- Average effective (gas-filled) porosity
- Net reservoir thickness (after applying a porosity cut-off value)
- Calculated adsorbed methane content
- Calculated CO_2 adsorption capacity
- Non-adsorbed (free gas) methane content
- Calculated volumetric CO_2 storage capacity (non-adsorbed), in net reservoir thickness

Table 3: Log Analysis Variables and Assumptions Used for Marcellus and Utica Gas In-Place and CO_2 Storage Capacity Calculations

Variable	Definition	Marcellus	Utica
ρ_{Shale}	maximum bulk density of gray shale (low organic content), g/cc	2.73	2.74
ρ_{matrix}	matrix grain density, g/cc	2.77	2.75
ρ_{fluid}	density of formation water, g/cc	1.10	1.10
ρ_{TOC}	density of organic matter, g/cc	1.35	1.35
R_w	water resistivity at formation temperature, ohm-m	0.12	0.10
R_{shale}	shale resistivity, ohm-m	25	21
a	Archie tortuosity exponent	1	1
m	Archie cementation exponent	2	2
n	Archie saturation exponent	2	2

Examples of contour maps of calculated reservoir values are included in **Appendix F**. Based on the well log analysis and maps of calculated values, model wells were identified within the Marcellus and Utica exploration fairways for reservoir simulation of enhanced gas recovery under CO_2 injection and maximum CO_2 storage. Three model wells were identified for the Marcellus, and four model wells were identified for the Utica. Areas of forty acres around each model well were identified as model areas M1, M2, and M3 for the Marcellus and areas U1, U2, U3, and U4 for the Utica. General location of the model areas are shown in **Figure 20**.

Figure 20: Location of Marcellus and Utica Model Areas within the Marcellus and Utica Exploration Fairways

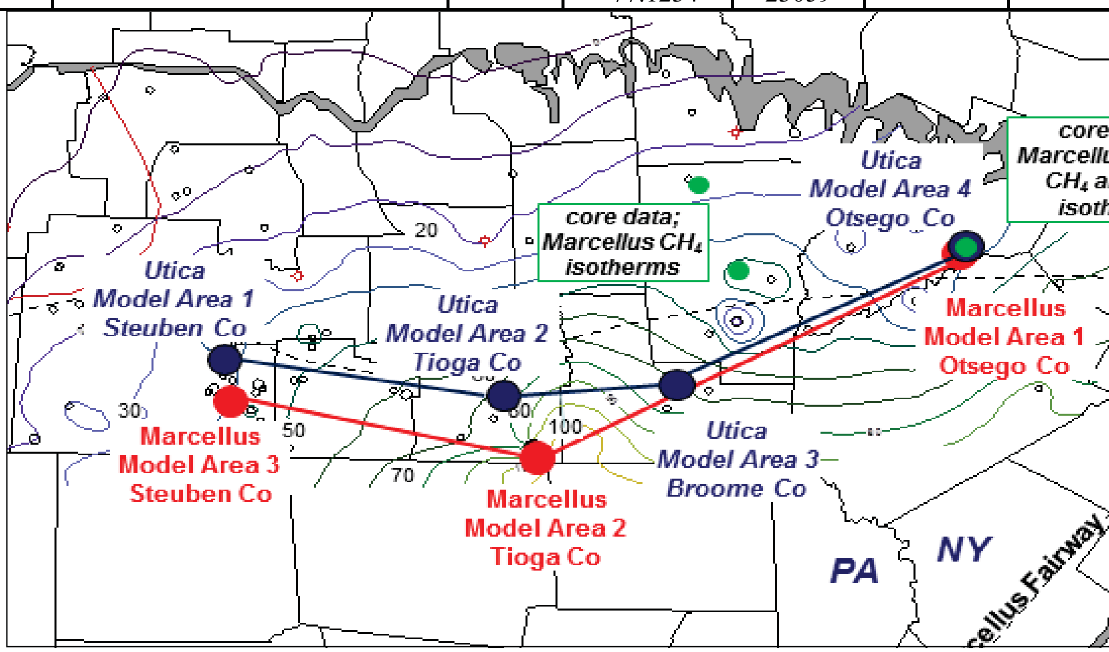


MARCELLUS LOG CALCULATION RESULTS

The three Marcellus model wells are the listed in **Table 4** and shown on a portion of the Figure 8 map that highlights the locations of the Marcellus Model Areas.

Table 4: Marcellus Model Wells

Model Area	Well Name	County	Lat./ Long.	API Number	Elevation, ft.	Total Depth, ft.
M1	Gastem USA, Inc. Ross #1	Otsego	42.5398/ -74.9164	31-077-23783	1,818	4,950
M2	Central NY Oil and Gas, #W8	Tioga	42.0428/ -76.1958	31-107-22932	1,380	4,870
M3	Fortuna Energy, Apenowich #1	Steuben	42.1978/ -77.1234	31-101-23059	1,540	9,613



The log calculation methodology described in the previous section was applied to the digital logs for each study well using the IHS Petra software. The calculations were made for every foot or 0.5 foot, depending on the depth step interval of the digital log data. “Pay” discriminators were applied and calculations were summed to obtain total methane gas in-place or CO_2 storage capacity values for the various reservoir layers.

Table 5 summarizes the average calculated reservoir properties for the Union Springs and Oatka Creek black shale members of the Marcellus. **Table 5** allows comparison of average reservoir characteristics between the three model areas, as well as between the two Marcellus reservoir layers. **Table 5** shows that the best Marcellus reservoir properties for organic content and total and effective porosity reside in the Union Springs member. For example, average calculated TOC for the Union Springs is 4 to 5 percent compared to 3 to 4 percent for the Oatka Creek black shale. Average total porosity is 7 to 8 percent for the Union Springs compared to 5 to 6 percent for the Oatka Creek black shale, and average effective (gas-filled) porosity is 4 to 5 percent for the Union Springs compared to 2 to 3 percent for the Oatka Creek black shale. **Table 5** also shows that several of the average calculated reservoir properties for Model Area 1 and Model Area 3 are similar despite the significant distance between the two areas. As a result, the calculated values of methane gas in-place and theoretical maximum CO_2 storage capacity for model wells 1 and 3 are similar.

In **Table 6**, the average calculated values for adsorbed methane gas in-place, free gas in-place in effective porosity, and theoretical maximum CO_2 storage capacity for each model well are extrapolated to a model area of forty acres and are expressed as Bcf/ 40 acres. Total gas in place for the Marcellus ranges from 2.7 Bcf/40 acres to almost 8.9 Bcf/40 acres. Theoretical maximum CO_2 storage capacity ranges are slightly higher, from 3.1 Bcf/40 acres to 9.3 Bcf/40 acres. The Union Springs contributes 75 percent or more of total gas in-place and at least 71 percent of total CO_2 storage capacity. Approximately 20 percent of the calculated gas in-place in the Marcellus black shales is adsorbed, and 55 percent to more than 60 percent of the CO_2 storage capacity is adsorbed. **Table 6** shows that the total calculated gas in-place and maximum CO_2 storage capacity for model areas 1 and 3 are indeed very similar, while model area 2 represents approximately three times the gas in-place and CO_2 storage capacity as model areas 1 and 3. For this reason, only Marcellus model areas 1 and 2 were simulated using *COMET3*.

The log calculations suggest that although the Union Springs has approximately twice the adsorbed gas in-place as the Oatka Creek black shale, approximately 80 percent of the calculated gas in-place for the Union Springs is non-adsorbed gas in effective porosity. One possible explanation of the relatively large proportion of non-adsorbed gas in-place is that the high organic carbon content of the Union Springs is thought to also have significant microporosity within the kerogen (intra-kerogen porosity)[8], which contains free gas, in addition to gas occupying adsorption sites.

[8] Intra-kerogen porosity is illustrated in the scanning electron microscopy (SEM) image in Figure 15.

Table 5: Marcellus Model Wells: Average Calculated Reservoir Properties of Model Well Layers

Reservoir Properties	Model Area M1 Otsego Co.	Model Area M2 Tioga Co.	Model Area M3 Steuben Co.
Model Layer: Oatka Creek Black Shale			
Depth, ft.	2,394	4,550	3,461
Thickness, ft.	26 ft.	80 ft.	20.5 ft.
Ave. Calculated Total Organic Carbon (TOC), %	2.85	2.75	3.8
Average Total Porosity, %	4.8	4.7	6.1
Average Water Saturation (Simandoux)	0.21	0.62	0.17
Average Effective Porosity, %	3.1	1.8	3.2
Net Pay *(effective porosity > 3 percent)*	14 ft.	14.5 ft.	11 ft.
Average Adsorbed CH_4, scf/ton	47.5	53.5	68.5
Average Adsorbed CO_2, scf/ton	*152.2*	*168.7*	*227.6*
Gas in-Place, Adsorbed, Bcf/acre	0.0044	0.0151	0.0050
Gas In-Place, Free (gas in effective porosity), Bcf/acre	0.0132	0.0187	0.013
Maximum. CO_2 Storage, Adsorbed, Bcf/acre	*0.014*	*0.047*	*0.017*
Maximum CO_2 Storage Effective Porosity, Bcf/acre	*0.009*	*0.009*	*0.007*
Model Layer: Union Springs			
Depth, ft.	2,430	4,650	3,485
Thickness, ft.	37 ft.	87 ft.	37
Ave. Calculated Total Organic Carbon (TOC), %	4.0	5.0	4.6
Average Total Porosity, %	6.6	7.9	7.2
Average Water Saturation (Simandoux)	0.06	0.16	0.10
Average Effective Porosity, %	4.3	5.2	4.2
Net Pay *(effective porosity > 3 percent)*	34.5 ft.	82.5ft	26 ft.
Average Adsorbed CH_4, scf/ton	67.1	96.6	82.6
Average Adsorbed CO_2, scf/ton	*232.8*	*327.7*	*287.8*
Gas in-Place, Adsorbed, Bcf/acre	0.0087	0.0287	0.0100
Gas In-Place, Free (gas in effective porosity), Bcf/acre	0.0402	0.161	0.044
Maximum. CO_2 Storage, Adsorbed, Bcf/acre	*0.030*	*0.097*	*0.035*
Maximum CO_2 Storage in Effective Porosity, Bcf/acre	*0.027*	*0.078*	*0.023*

Table 6: Marcellus Model Areas: Calculated Gas In-Place and Theoretical Maximum CO_2 Storage Capacity, Bcf/40 acres

Gas In-Place and Maximum CO_2 Storage Capacity Bcf/ 40 acres	Model Area M1 Otsego Co.	Model Area M2 Tioga Co.	Model Area M3 Steuben Co.
Marcellus Total			
Total Calculated Gas In-Place (adsorbed & free)	**2.66**	**8.93**	**2.88**
Total Gas In-Place, adsorbed	0.52	1.75	0.60
Total Gas In-Place, free gas in effective porosity	2.14	7.18	2.28
% Total Gas In-Place, adsorbed	20%	20%	21%
% Total Gas In-Place in Union Springs	74%	85%	75%
Theoretical Maximum CO_2 Storage Capacity	***3.21***	***9.30***	***3.26***
Total CO_2 Storage Capacity, adsorbed	*1.77*	*5.79*	*2.06*
Total CO_2 Storage Capacity, in effective porosity	*1.44*	*3.50*	*1.20*
% Total CO_2 Storage Capacity, adsorbed	*55%*	*62%*	*63%*
% Total CO_2 Storage Capacity in Union Springs	71%	76%	71%
Oatka Creek Black Shale			
Total Calculated Gas In-Place (adsorbed & free)	**0.70**	**1.35**	**0.72**
Gas In-Place, adsorbed	0.18	0.60	0.20
Gas In Place, free gas in effective porosity	0.53	0.75	0.52
% Gas In-Place, adsorbed	25%	45%	28%
Theoretical Maximum CO_2 Storage Capacity	***0.92***	***2.26***	***0.94***
Total CO_2 Storage Capacity, adsorbed	0.57	1.9	0.66
Total CO_2 Storage Capacity, in effective porosity	0.36	0.36	0.28
% Total CO_2 Storage Capacity, adsorbed	61%	84%	71%
Union Springs			
Total Calculated Gas In-Place (adsorbed & free)	**1.96**	**7.58**	**2.16**
Gas In-Place, adsorbed	0.35	1.15	0.40
Gas In Place, free gas in effective porosity	1.61	6.43	1.76
% Gas In-Place, adsorbed	18%	15%	19%
Theoretical Maximum CO_2 Storage Capacity	***2.29***	***7.03***	***2.32***
Total CO_2 Storage Capacity, adsorbed	*1.20*	*3.89*	*1.40*
Total CO_2 Storage Capacity, in effective porosity	*1.09*	*3.14*	*0.92*
% Total CO_2 Storage Capacity, adsorbed	*52%*	*51%*	*65%*

UTICA LOG CALCULATION RESULTS

The four Utica model wells are the listed in **Table 7**. Unlike the Marcellus, in which the high organic content of the Union Springs member is widespread throughout the study area, the high TOC zones in the Utica are not as uniform across the region. For example, the clay-rich Indian Castle and the Flat Creek generally appear to contribute the highest TOC to the Utica overall. In areas where the Flat Creek and clay-rich Indian Castle are thin or absent, the other Utica zones, Dolgeville and carbonate-rich Indian Castle, contribute to Utica TOC. The model wells listed in **Table 7** were selected to represent the apparent areal variation in organic content within the Utica Group formations.

Table 7: Utica Model Wells

Model Area	Well Name	County	Lat./ Long.	API Number	Elevation, ft.	Total Depth, ft.
U1	Fortuna Energy, Eolin #1	Steuben	42.1145/ -77.0362	31-101-23105	939	9,992
U2	Chesapeake, TGS Holdings 624831	Tioga	42.1055/ -76.3133	31-107-22974	1,035	10,340
U3	Belden & Blake, Merrill #1	Broome	42.1782/ -75.6703	31-007-22984	1,525	9,874
U4	Gastem USA, Inc., Ross #1	Otsego	42.5398/ -74.9164	31-077-23783	1,818	4,950

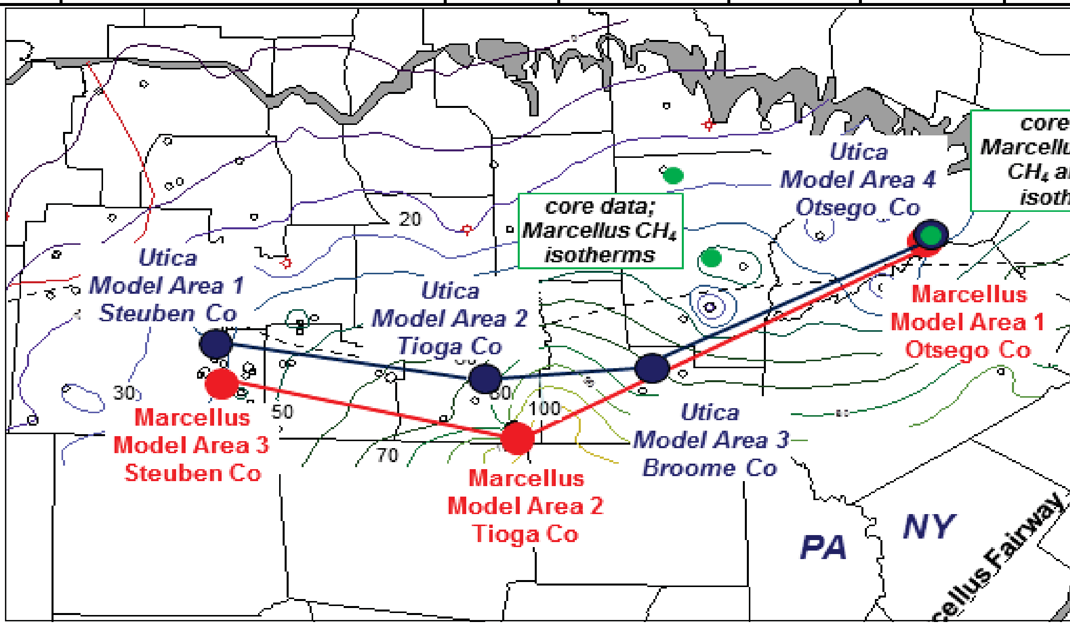


Table 8 summarizes the average calculated reservoir properties for the Utica Indian Castle Formation (clay-rich and carbonate-rich). **Table 9** summarizes the average calculated reservoir properties for the Utica Dolgeville and Flat Creek Formations. **Tables 8** and **9** show that the best Utica reservoir properties for organic content and total and effective porosity reside in the clay-rich Indian Castle for Utica model areas 1 and 2, in the carbonate-rich Indian Castle and Dolgeville for Utica model area 3, and in the Flat Creek Formation for model area 4.

Comparing the Utica to the Marcellus, average calculated TOC for the clay-rich Indian Castle is 3.0 percent to 3.9 percent for Utica model wells 1 and 2, which is comparable to the calculated organic content of the Marcellus Oatka Creek black shale (2.8 percent to 3.8 percent). Average total porosity for the Utica formations in the model wells ranges from 3.0 percent to 6.4 percent. Average calculated effective (gas-filled) porosity ranges from 1.6 percent to 5.0 percent for the Utica formations, compared to 2 percent to 3 percent effective porosity for the Marcellus Oatka Creek black shale.

Tables 8 and **9** show that the Utica differs significantly from the Marcellus in the amount of "net pay," defined as calculated effective porosity greater than 3 percent. Although total porosity is generally lower for the Utica compared to the Marcellus, effective phi-h (effective porosity times thickness) for individual wells may be greater for the Utica overall than for the Marcellus. For example, the total net pay for the Marcellus model wells shown in **Table 4** ranges from 37 ft. to 97 ft., and phi-h estimated by multiplying net pay thickness by the average effective porosity ranges from 1.8 to 4.6 porosity-ft. For the Utica model wells in **Tables 8** and **9**, total net pay ranges from 99 ft. to 166 ft. and estimated phi-h[9] ranges from 3.5 to 5.2 porosity-ft., despite the Utica having generally lower average effective porosity.

The Marcellus and Utica cross-sections in **Figures 9** and **10** suggest that the distribution of effective porosity in the Utica may occur over a larger gross interval than in the Marcellus. Because the Marcellus adsorbed and non-adsorbed methane gas in-place may occur across a more compact depth interval, such a "pay" distribution might be expected to result in greater production efficiency for the Marcellus compared to the Utica. For this reason, future CO_2 injection and storage might be more effective in the Marcellus compared to the Utica, especially if CO_2 can be injected into a single zone in the Marcellus compared to multiple zones for the Utica.

Table 10 shows average calculated values for adsorbed gas in-place, non-adsorbed gas in-place in effective porosity, and theoretical maximum CO_2 storage capacity for each Utica model well, extrapolated to a model area of forty acres. Total gas in place for the Utica ranges from 9.1 Bcf/40 acres to 10.9 Bcf/40 acres. Theoretical maximum CO_2 storage capacity ranges from 8.2 to 10.3 Bcf/40 acres, slightly lower than total methane gas in-place. The Indian Castle contributes most of total gas in-place and total CO_2 storage capacity in all the model areas, but the relative contribution from the Indian Castle varies among the model areas depending upon the thickness and calculated organic content of other Utica formations. For example, **Table 10** shows that the relative contribution of the Indian

[9] phi –h estimated for each reservoir layer as (feet of effective porosity>3.0%) *x* (average effective porosity, fraction)

Castle to total methane gas in-place ranges from 90 percent in Utica Model Area 1 in Steuben County to 46 percent in Utica Model Area 4 in Otsego County, where the organic-rich Flat Creek Formation is present.

Table 10 also shows that adsorbed gas contributes 16 percent to 25 percent of total calculated methane gas in-place, comparable to the 20 percent contribution from adsorbed gas estimated for the Marcellus. For total CO_2 storage capacity in the Utica, adsorption is estimated to contribute 51 percent to 65 percent of theoretical maximum storage capacity. This result is comparable to the 55 to 60 percent of adsorbed CO_2 storage capacity estimated for the Marcellus.

Table 8: Utica Model Wells: Average Calculated Reservoir Properties of Model Well Layers - Lower Indian Castle

Reservoir Properties	Model Area U1 Steuben Co.	Model Area U2 Tioga Co.	Model Area U3 Broome Co.	Model Area U4 Otsego Co.
Model Layer: Lower Indian Castle - Clay Rich				
Depth, ft.	9,213	9,534	9,100	4,442
Thickness, ft.	96 ft.	43 ft.	37 ft.	77 ft.
Ave. Calculated Total Organic Carbon (TOC), %	3.9	3.2	1.8	1.8
Average Total Porosity, %	6.4	5.4	3.2	3.2
Average Water Saturation (Simandoux)	0.21	0.15	0.09	0.15
Average Effective Porosity, %	5.2	4.6	2.9	2.7
Net Pay *(effective porosity > 3 percent)*	89 ft.	39 ft.	25 ft.	19.5 ft.
Average Adsorbed CH_4, scf/ton	90.4	73.6	40.0	34.8
Average Adsorbed CO_2, scf/ton	*226.6*	*186.4*	*103.1*	*92.0*
Gas in-Place, Adsorbed, Bcf/acre	0.0300	0.0111	0.0054	0.0097
Gas In-Place, Free (gas in effective porosity), Bcf/acre	0.185	0.074	0.032	0.024
Maximum. CO_2 Storage, Adsorbed, Bcf/acre	*0.0751*	*0.0281*	*0.0139*	*0.026*
Maximum CO_2 Storage Effective Porosity, Bcf/acre	*0.089*	*0.036*	*0.016*	*0.011*
Model Layer: Lower Indian Castle – Carbonate Rich				
Depth, ft.	9,312	9,577	9,137	4,519
Thickness	39 ft.	82 ft.	126 ft.	159 ft.
Ave. Calculated Total Organic Carbon (TOC), %	1.6	2.6	2.0	1.9
Average Total Porosity, %	3.0	4.4	3.5	3.4
Average Water Saturation (Simandoux)	0.60	0.25	0.08	0.18
Average Effective Porosity, %	1.2	3.3	3.2	2.8
Net Pay *(effective porosity > 3 percent)*	5 ft.	49.5 ft.	82 ft.	51.5
Average Adsorbed CH_4, scf/ton	37.2	58.5	44.5	37.6
Average Adsorbed CO_2, scf/ton	*95.5*	*149.2*	*114.6*	*99.0*
Gas in-Place, Adsorbed, Bcf/acre	0.0053	0.0169	0.020	0.022
Gas In-Place, Free (gas in effective porosity), Bcf/acre	0.0073	0.0735	0.115	0.061
Maximum. CO_2 Storage, Adsorbed, Bcf/acre	*0.013*	*0.043*	*0.052*	*0.057*
Maximum CO_2 Storage in Effective Porosity, Bcf/acre	*0.003*	*0.036*	*0.055*	*0.030*

Table 9: Utica Model Wells: Average Calculated Reservoir Properties of Model Well Layers - Dolgeville and Flat Creek

Reservoir Properties	Model Area U1 Steuben Co.	Model Area U2 Tioga Co.	Model Area U3 Broome Co.	Model Area U4 Otsego Co.
Model Layer: Dolgeville				
Depth, ft.	9,352	9,659	9,262	4,678
Thickness, ft.	138 ft.	86 ft.	80 ft.	85 ft.
Ave. Calculated Total Organic Carbon (TOC), %	1.7	2.5	2.3	1.9
Average Porosity, %	3.1	4.3	3.9	3.4
Average Water Saturation (Simandoux)	0.49	0.43	0.17	0.30
Average Effective Porosity, %	1.6	2.5	3.3	2.4
Net Pay *(effective porosity > 3 percent)*	5.5 ft.	22.5 ft.	59 ft.	15.5 ft.
Average Adsorbed CH_4, scf/ton	38.3	57.1	51.0	38.6
Average Adsorbed CO_2, scf/ton	98.6	*145.3*	*130.8*	*101*.3
Gas in-Place, Adsorbed, Bcf/acre	0.0191	0.0175	0.0146	0.0118
Gas In-Place, Free (gas in effective porosity), Bcf/acre	0.007	0.036	0.082	0.019
Maximum. CO_2 Storage, Adsorbed, Bcf/acre	*0.049*	*0.045*	*0.037*	*0.031*
Maximum CO_2 Storage Effective Porosity, Bcf/acre	*0.003*	*0.017*	*0.039*	*0.009*
Model Layer: Flat Creek				
Depth, ft.	ABSENT	ABSENT	9,449	4,801
Thickness, ft.			40 ft.	112 ft.
Ave. Calculated Total Organic Carbon (TOC), %			1.3	2.5
Average Porosity, %			2.4	4.3
Average Water Saturation (Simandoux)			0.32	0.29
Average Effective Porosity, %			1.6	3.1
Net Pay *(effective porosity > 3 percent)*			0 ft.	59.5 ft.
Average Adsorbed CH_4, scf/ton			28.7	50.8
Average Adsorbed CO_2, scf/ton			*74.5*	*131.8*
Gas in-Place, Adsorbed, Bcf/acre			0.0042	0.0204
Gas In-Place, Free (gas in effective porosity), Bcf/acre			0	0.083
Maximum. CO_2 Storage, Adsorbed, Bcf/acre			*0.011*	*0.053*
Maximum CO_2 Storage in Effective Porosity, Bcf/acre			*0*	*0.041*

Table 10: Utica Model Areas: Gas In-Place and Maximum CO_2 Storage Capacity, Bcf/ 40 acres

Gas In-Place and Maximum CO_2 Storage Capacity Bcf/ 40 acres	Model Area U1 Steuben Co.	Model Area U2 Tioga Co.	Model Area U3 Broome Co.	Model Area U4 Otsego Co.
UTICA TOTAL				
Total Calculated Gas In-Place (adsorbed & free)	**10.14**	**9.14**	**10.94**	**10.02**
Total Gas In-Place, adsorbed	2.18	1.82	1.78	2.54
Total Gas In-Place, free gas in effective porosity	7.96	7.32	9.16	7.48
% Total Gas In-Place, adsorbed	21%	20%	16%	25%
% Total Gas In-Place in Indian Castle	90%	77%	63%	46%
Theoretical Maximum CO_2 Storage Capacity	*9.34*	*8.17*	*8.98*	*10.32*
Total CO_2 Storage Capacity, adsorbed	*5.50*	*4.62*	*4.57*	*6.67*
Total CO_2 Storage Capacity, in effective porosity	*3.84*	*3.55*	*4.40*	*3.65*
% Total CO_2 Storage Capacity, adsorbed	*59%*	*57%*	*51%*	*65%*
% Total CO_2 Storage Capacity in Indian Castle	*77%*	*70%*	*61%*	*48%*
INDIAN CASTLE TOTAL (clay-rich plus carbonate-rich zones)				
Total Calculated Gas In-Place (adsorbed & free)	**9.09**	**7.02**	**6.91**	**4.66**
Gas In-Place, adsorbed	1.41	1.12	1.02	1.25
Gas In Place, free gas in effective porosity	7.68	5.90	5.89	3.40
% Gas In-Place, adsorbed	16%	16%	15%	27%
Theoretical Maximum CO_2 Storage Capacity	*7.23*	*5.70*	*5.47*	*4.97*
Total CO_2 Storage Capacity, adsorbed	*3.52*	*2.84*	*2.64*	*3.31*
Total CO_2 Storage Capacity, in effective porosity	*3.70*	*2.86*	*2.83*	*1.66*
% Total CO_2 Storage Capacity, adsorbed	*49%*	*50%*	*48%*	*67%*
DOLGEVILLE TOTAL				
Total Calculated Gas In-Place (adsorbed & free)	**1.04**	**2.12**	**3.86**	**1.22**
Gas In-Place, adsorbed	0.76	0.70	0.58	0.47
Gas In Place, free gas in effective porosity	0.28	1.42	3.28	0.75
% Gas In-Place, adsorbed	73%	33%	15%	39%
Theoretical Maximum CO_2 Storage Capacity	*2.11*	*2.47*	*3.07*	*1.60*
Total CO_2 Storage Capacity, adsorbed	*1.97*	*1.78*	*1.50*	*1.24*
Total CO_2 Storage Capacity, in effective porosity	*0.14*	*0.69*	*1.57*	*0.36*
% Total CO_2 Storage Capacity, adsorbed	*94%*	*72%*	*49%*	*77%*
FLAT CREEK TOTAL				
Total Calculated Gas In-Place (adsorbed & free)	**absent**	**absent**	**0.17**	**4.15**
Gas In-Place, adsorbed			0.17	0.82
Gas In Place, free gas in effective porosity			0	3.33
% Gas In-Place, adsorbed			100%	20%
Theoretical Maximum CO_2 Storage Capacity	*absent*	*absent*	*0.44*	*3.74*
Total CO_2 Storage Capacity, adsorbed			*0.44*	*2.12*
Total CO_2 Storage Capacity, in effective porosity			0	1.62
% Total CO_2 Storage Capacity, adsorbed			100%	57%

CALCULATED GAS IN-PLACE AND MAXIMUM CO_2 STORAGE CAPACITY – DISCUSSION

Total Gas in-Place and CO_2 Storage Capacity

For the Marcellus and Utica exploration fairways illustrated in **Figure 7**, calculated total adsorbed gas in-place is 127 Tcf for the Marcellus black shales and 188 Tcf for the Utica. Theoretical maximum CO_2 storage capacity as adsorbed CO_2 is 298 Tcf for the Marcellus and 516 Tcf for the Utica. This assumes that all adsorbed methane is replaced by CO_2. These results imply an effective adsorption ratio of CO_2 to CH_4 of 2.35:1 for the Marcellus and 2.75:1 for the Utica. Despite the lower organic content of the Utica, this result may reflect the fact that the subsurface depth of the Utica is more than twice the depth of the Marcellus with more favorable pressure for CO_2 adsorption.

Total gas in-place as non-adsorbed gas is estimated as 272 Tcf for the Marcellus and 578 Tcf for the Utica. The Utica black shale is significantly thicker than the Marcellus black shale across much of the study area. A net pay cut-off of 3.0 percent effective porosity was applied to both the Marcellus and the Utica, resulting in higher phi-h for the Utica overall than the Marcellus, which drives the result of a high proportion of calculated free gas in-place and maximum CO_2 storage capacity as non-adsorbed gas for the Utica compared to the Marcellus.

For the Marcellus model areas, 71 to 76 percent of calculated maximum CO_2 storage capacity (2.3 to 7.0 Bcf/40 acres) resides in the most organic-rich zone, the Union Springs black shale member at the base of the Marcellus. For the Marcellus overall, adsorbed CO_2 accounts for 55 to 63 percent of total maximum CO_2 storage capacity (1.8 to 5.8 Bcf/40 acres). The remaining calculated CO_2 storage capacity (1.2 to 3.5 Bcf/40 acres) resides in the effective porosity and would require replacing non-adsorbed methane in these pores.

For the Utica model areas, most of the calculated maximum CO_2 storage capacity resides in the Indian Castle Formation, from 46 to 90 percent (5.0 to 7.2 Bcf/40 acres) depending on what other Utica formations are present. If thick Flat Creek Formation is present, the Flat Creek may provide nearly as much CO_2 storage capacity as the Indian Castle. Similar to the Marcellus, 51 to 65 percent of calculated maximum CO_2 storage capacity in the Utica overall would be as adsorbed CO_2 (4.6 to 6.7 Bcf/40 acres).

Concentration of Gas in-Place and CO_2 Storage Capacity

For the Marcellus study area of approximately 3,387,000 acres (or 5,292 mi^2), the estimated average methane gas in-place concentration for the Marcellus is 75 Bcf/mi^2, of which 24 Bcf/mi^2 is estimated as adsorbed gas and 51 Bcf/mi^2 is estimated as free gas. Maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 56.4 Bcf/mi^2, which is approximately equivalent to 3.3 MMt CO_2/mi^2 (or 1.3 MMt/km^2). For the Utica study area of 3,809,000 acres (or 5,951 mi^2), the estimated average gas in-place concentration for the Utica is 129 Bcf/mi^2, of which 32 Bcf/mi^2 is adsorbed gas and 97 Bcf/mi^2 is free gas. Maximum CO_2 storage capacity as adsorbed CO_2 is estimated to be 86.7 Bcf/mi^2, which is approximately equivalent to 5 MMt CO_2/mi^2 or (1.9 MMt/km^2).

The calculated gas in-place and theoretical maximum storage capacity values for the Marcellus and Utica offer first approximations of the potential shale gas resource in the exploration fairways, as well as the maximum CO_2 injection and storage potential. Average calculated values for parameters such as TOC, porosity, water saturation, and adsorbed methane content appear to be supported by limited public and private sector data for reservoir properties of the Marcellus and Utica shales.[10] The calculated methane gas in-place and CO_2 storage capacity values provide useful starting points from which to evaluate reservoir simulation forecasts of gas production and CO_2 storage, despite the caveats and assumptions listed below.

Caveats and Assumptions Regarding Data Used in this Assessment:

- Limited well data set. Although 81 wells for the Utica and 104 wells for the Marcellus provided the basis for this resource characterization, this is a relatively limited well data set for the study area. Some counties within the study area had no wells with a complete digital log suite, so calculated values for these areas are extrapolations from the nearest data points.

- Limited data set of methane and CO_2 isotherms. Methane isotherms were available for the Marcellus from three wells in Chenango and Otsego Counties. CO_2 isotherms for the Marcellus and Utica and methane isotherms for the Utica were available from a single well in Otsego County. The analysis could be improved if more isotherm data were available from other locations within the study areas.

- Normally-pressured reservoir. A normal reservoir pressure gradient was assumed for both the Marcellus and Utica throughout the study area. This assumption impacts both the adsorbed gas and free gas estimates and should be refined, especially for future site-specific evaluations. An area of over-pressured Marcellus shale in Pennsylvania likely extends into New York. Lacking reservoir data to define the area of over-pressure, normal reservoir pressures were assumed.

- Single porosity algorithms applied for the Marcellus and Utica. A single porosity algorithm was applied in both the Marcellus and the Utica. The Marcellus and Utica porosity calculations are differentiated by different variables for matrix grain density and organic content. Bulk density cutoff values and other discriminators were also varied between the Marcellus and Utica. Within the Marcellus and Utica, however, the same approach to calculate porosity was assumed to apply everywhere. For example, a single porosity algorithm was applied to both the Marcellus Union Springs and the Marcellus Oatka Creek black shale throughout the entire Marcellus study area. Similarly, for the Utica a single porosity algorithm was applied to the Indian Castle, Dolgeville, and Flat Creek Formations throughout the entire Utica study area. Calculated density porosity was corrected for organic content, but the correction may not be universally appropriate across the range of apparent organic carbon content, possibly over-correcting porosity for kerogen content in low-TOC zones.

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[10] Advanced Resources International characterization of Marcellus and Utica outside New York State. Also, Richard Nyahay, Gastem USA, Inc., personal communication.

- Single Simandoux water saturation with default Archie model parameters. This is similar to the porosity algorithm caveat. Default Archie model parameters were applied for saturation exponent, tortuosity exponent, and cementation factor, because no other data are available. Simandoux equation inputs for shale resistivity and formation water resistivity were differentiated between the Marcellus and the Utica, but then applied uniformly across all sub-horizons throughout the study areas. The Simandoux algorithm is expected to work best in zones where clay shale volume is in the range of 50 to 85 percent, defaulting to a pure Archie equation as clay shale volume approaches zero and possibly over-correcting (water saturation too low) when clay shale volume exceeds 80 to 90 percent.

- Immobile formation water saturation assumed. Annual production data are available for only a small number of vertical Marcellus wells in New York and very little water production is reported for these wells. This produced water is assumed to represent mobile water in natural fractures within the Marcellus. Based on these data plus a computed petrophysical analysis of the EOG Resources Beaver Meadows #1 well[11], calculated water saturation is assumed to be immobile, representing both clay-bound water and water immobilized by capillary forces in microporosity. Effective porosity is assumed to be equivalent to the gas-filled pore volume. An estimated effective porosity cut-off of three percent is applied in both the Marcellus and Utica to estimate the net reservoir thickness available for non-adsorbed gas production and CO_2 storage capacity.

- Calibration of individual well gas in-place calculations. The calculated values for individual wells are not calibrated or compared to other independent estimates of resource in-place or estimated ultimate recovery for individual wells. Opportunity for calibration with producing gas shale wells would help to validate or refine the methane gas in-place and/or CO_2 storage capacity calculations.

Despite the caveats, some interesting conclusions can be drawn from the gas in-place and CO_2 storage capacity calculations. Adsorbed methane represents approximately 20 percent of calculated gas-in-place. Free gas present within intra-kerogen porosity is likely accounted for in the non-adsorbed component of total calculated methane gas in-place; however, this gas might be expected to be produced with desorbed gas. Intra-kerogen porosity is thought to be significant, especially in the high-TOC zones within the Marcellus Union Springs, so free gas might be an important component of gas produced from the most organic-rich zones. Recovery factors for adsorbed and non-adsorbed methane are likely different. In addition to recovery of adsorbed gas in highly fractured, organic-rich zones, the recovery of non-adsorbed gas in organic rich zones is also expected to be much greater than the recovery of the non-adsorbed (free) gas in zones that have lower TOC.

Approximately 50 to 60 percent of the estimated theoretical storage capacity for CO_2 is adsorbed CO_2 replacing adsorbed methane. If sufficient injectivity can be introduced via natural and induced fractures, a component of injected CO_2 is also expected to be stored as non-adsorbed CO_2 in microporosity. The percentage of pore volume occupied by free methane that will be available to injected CO_2 is likely to be small, although not enough data are

[11] Schlumberger ELAN log representing an integrated petrophysical interpretation of the wireline logs for the Beaver Meadows #1.

available to make a quantitative estimate. In qualitative terms, sustained methane production from gas shale is expected to provide adsorption sites for CO_2, and sustained production of non-adsorbed methane from intra-kerogen and intergranular porosity will provide additional pore volume for CO_2 storage in a non-adsorbed or free phase. If reservoir compaction occurs with gas withdrawal, as well as hysteresis effects on capillary entry pressure and relative permeability to CO_2, then the effective pore volume available for non-adsorbed CO_2 storage may be significantly less than the actual effective pore volume drained by the production of free gas. For future CO_2 storage, it may be important to estimate separate storage capacity factors for CO_2 storage as an adsorbed phase (expected to be comparatively "large") and CO_2 storage as non-adsorbed, free phase (which might be comparatively "small").

Outside the state of New York, horizontal wells and multiple-stage massive hydraulic fracturing have been effective for developing the Marcellus. In New York, the Union Springs and overlying Oatka Creek black shales appear to offer a similar geographically widespread, but vertically compact target reservoir. This suggests that horizontal wells with multi-stage hydraulic fractures might be similarly effective for developing the Marcellus in New York, which could improve potential estimates of both methane recovery and CO_2 storage.

A similar development strategy employing horizontal wells and multiple hydraulic fractures may be problematic for the Utica because the methane gas in-place (and potential CO_2 storage capacity) may be distributed over a thicker vertical section. The high values of methane gas in-place and theoretical CO_2 storage capacity calculated for the total Utica (**Table 10**) assume that all of the effective porosity across the entire Utica thickness contributes to methane production and CO_2 storage. If, in practice, only a single Utica zone with the highest TOC and gas in-place were developed in each well, then effective gas in-place and maximum CO_2 storage capacity would likely be significantly less than calculated in this analysis. For example, if only the Indian Castle Formation were developed in Model Area 2 (**Table 10**), and the Dolgeville Formation by-passed, then calculated total methane gas in-place would be reduced by more than 2 Bcf to 7 Bcf.

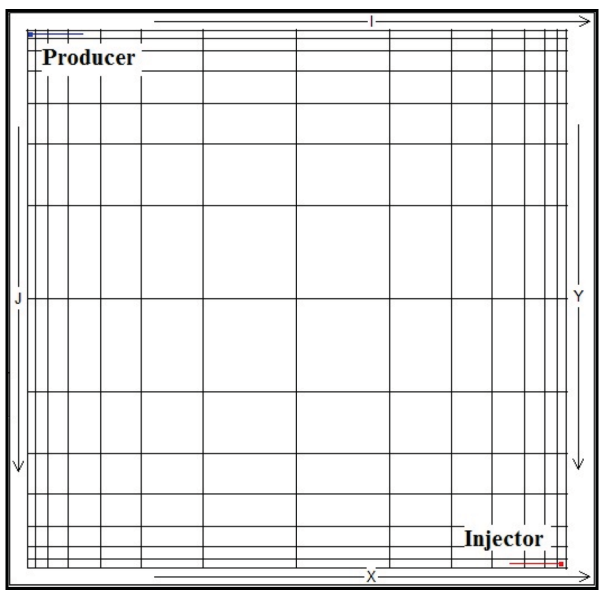
RESERVOIR SIMULATION OF GAS PRODUCTION AND CO_2 STORAGE

METHODOLOGY

As discussed in the foregoing sections, based on the geologic characterization of the Marcellus and Utica organic-rich shale, seven model areas were defined (three Marcellus and four Utica areas), of which six were selected to investigate with the reservoir simulation and production forecasting model *COMET3*. *COMET3* is a dual porosity, single permeability, fractured reservoir simulator designed to forecast production for adsorption-controlled fractured reservoirs. Porosity and permeability are implemented in *COMET3* as single values representing the combined effective porosity and permeability of the reservoir fracture system plus matrix.

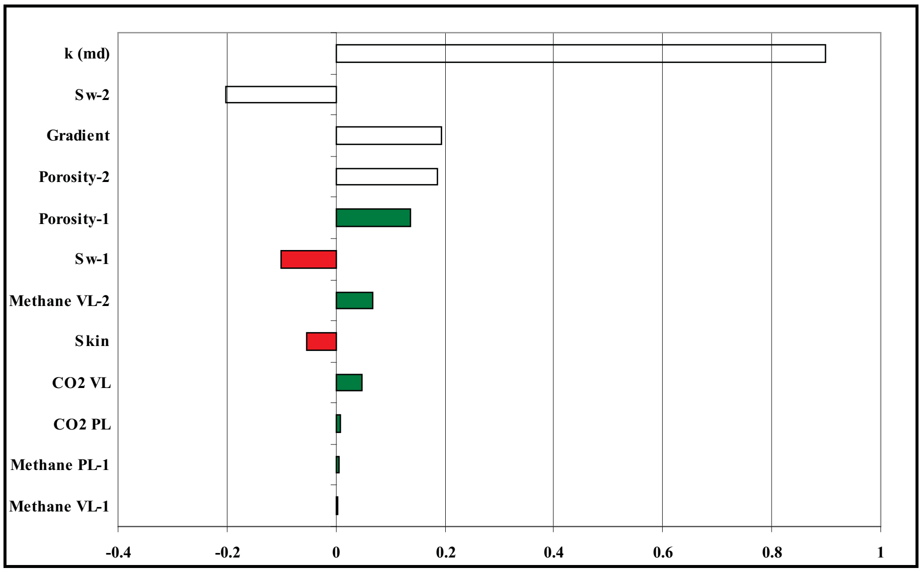
A model was built for each of the six areas of interest, which assumed a 10-acre, normally pressured (0.433 psi/ft.) grid consisting of one quarter-well producing well and one quarter-well injection well. The production and injection wells are vertical, 6-inch boreholes. Each model layer in both the producer and injector are assumed to be fractured with a 90-ft half-length fracture. An example of the grid is provided in **Figure 21.**

Figure 21: *COMET3* Grid Pattern



Sustained historical production data were not available for the Marcellus and Utica for history matching, so a Monte-Carlo simulation was explored using reasonable input ranges for a number of critical inputs: isotherms, permeability, porosity, water saturation, and pressure gradient. Each of the six model areas was run through a 500-iteration Monte-Carlo simulation to compare the influence of each model input on the final result. **Figure 22** is an example of a tornado plot which illustrates that permeability is the model parameter with the greatest impact on gas recovery. Given the constraints on production data with which to calibrate the model output, a deterministic approach was used to investigate gas production and CO_2 injection for three reservoir quality cases, in which parameters of porosity, permeability, and water saturation were varied to represent "best" reservoir attributes with greatest effective pore volume and permeability; "middle" reservoir quality with somewhat lower porosity, higher water saturation, and lower permeability; and "lesser" reservoir quality with the least porosity and permeability and higher water saturation. Because permeability is the apparent leading control of gas production and CO_2 storage, the three reservoir quality cases were named, respectively, the "high-permeability," "mid-permeability," and "low-permeability" cases.

Figure 22: Example of Monte-Carlo Input Tornado Chart



Simulations for each model area were run for 30 years (10,950 days). The production well was produced at a 25 psi bottom-hole pressure during the entire time. An initial simulation without CO_2 injection determined primary production rate and forecast cumulative gas recovery. A second simulation was run with CO_2 injection starting at year 10 and continuing through year 30. During the first 10 years of simulation the reservoir was produced normally without injection. Delaying CO_2 injection for 10 years allows depletion of free gas in the fractures, desorption of matrix gas as the reservoir pressure declines, and helps prevent unwanted reservoir fracturing and/or premature CO_2 breakthrough. CO_2 injection begins at year 10 and continues through year 30 to determine sequestration potential and enhanced gas recovery (EGR) if any. CO_2 was continuously injected at a 0.5 psi/ft. gradient, except for Marcellus Model Area 1, where CO_2 was injected at normal pressure (0.433 psi/ft.) because of the relatively shallow depth. The simulation provided production and injection rates and recoveries, average reservoir pressure, and CO_2 movement through the formation. Formation water was assumed to be immobile, so no water recovery was considered. Fixed model inputs are summarized in **Table 11**.

Table 11: Fixed Model Inputs

Reservoir Parameters	Units	Input Value
Well Spacing	Acres	40
Temperature	F	68
Initial Pressure Gradient	psi/ft.	0.433
Pore Compressibility	psi-1	$3x10^{-5}$
Matrix Compressibility	psi-1	$1x10^{-7}$
Methane Sorption Time	days	1000
Permeability Exponent		3
Fluid Parameters		
Gas Gravity		0.6
Water Viscosity	cp	0.7
Water Formation Volume Factor	RB/STB	1.01
Water Density	lb/ft^3	62.4
Gas Composition	% CH_4	100
Well Parameters		
Wellbore Radius	ft.	0.27
Wellhead Pressure	psi	25
Skin		0

Marcellus Models

Two representative model wells were selected for the Marcellus and 40 acres surrounding each model well was designated as the model area. Model areas 1 and 2 are assumed to represent a range of Marcellus reservoir quality within the Marcellus exploration fairway. The two model areas are distinguished by depth and net pay thickness. **Table 12** summarizes the Marcellus model inputs by model layer and model area. Model inputs are based on the log calculations and geologic characterization previously described. The *COMET3* model input for porosity represents the pore volume of the fracture system, so is at least an order of magnitude less than the matrix porosity calculated from well logs.

Table 13 summarizes the Marcellus isotherm model inputs. The isotherm data was constant for each Marcellus model area. **Table 14** summarizes the permeability inputs for the Marcellus model areas, which distinguish the three model cases. The permeability inputs are intended to represent the permeability of the fracture-matrix system. Measured reservoir matrix permeability from core samples ranges from 10^{-4} to 10^{-6} millidarcies. Clearly, fracture permeability dominates the reservoir matrix-fracture system, but what permeability input best represents reservoir behavior under production and CO_2 injection is unknown and is the greatest source of uncertainty.

Table 12: Marcellus Model Inputs

	Units	Area M1	Area M2
Layer 1 **Oatka Creek Black Shale**			
Depth	ft.	2394	4550
Thickness	ft.	14	14.5
Porosity	fraction	0.004	0.003
Water Saturation	fraction	0.2	0.25
Layer 2 **Cherry Valley**			
Depth	ft.	2419	4631
Thickness	ft.	1	7.5
Porosity	fraction	0.0005	0.001
Water Saturation	fraction	0.5	0.5
Layer 3 **Union Springs**			
Depth	ft.	2430	4650
Thickness	ft.	34.5	82.5
Porosity	fraction	0.006	0.007
Water Saturation	fraction	0.06	0.16

Table 13: Marcellus Isotherm Inputs

Methane (in-situ)	V_L	P_L
	scf/ft^3	psia
Oatka Creek	5.05	591.8
Cherry Valley	5.05	591.8
Union Springs	11.85	582.4
CO_2 (in-situ)	V_L	P_L
	scf/ft^3	psia
Oatka Creek	27.1	247
Cherry Valley	27.1	247
Union Springs	27.1	247

Table 14: Marcellus Permeability Inputs

	Permeability (md)		
	High	**Mid**	**Low**
Layer 1 - Oatka Creek	0.0250	0.0125	0.0060
Layer 2 - Cherry Valley	0.0010	0.0005	0.0001
Layer 3 - Union Springs	0.0500	0.0250	0.0125

Utica Models

Four representative model wells were selected for the Utica. As with the Marcellus, 40 acres surrounding each model well was designated as the model area. **Table 15** summarizes the Utica model inputs by model layer and model area. Model inputs are based on the log calculations and geologic characterization previously described. **Table 15** shows that the model areas are distinguished by depth and net pay thickness. Model areas 1-3 have three layers that are deeper than 9,000 ft. The Utica in Model Area 4 is shallower, at 4,400 ft., and also has a fourth layer, the Flat Creek Formation, that is absent in the other model areas.

Table 16 summarizes the Utica isotherm model inputs. Few methane and CO_2 isotherm data are available for the Utica in New York. As with the Marcellus, the available isotherm data are applied as constant model inputs across all Utica model areas and Utica reservoir layers, with the exception of the Flat Creek Formation, which has its own isotherm. Assuming constant isotherm inputs for all Utica reservoir layers is a source of uncertainty because of the wide range in sample depth and the geographic variation in Utica organic content, clay and carbonate content, and reservoir thickness.

Table 15: Utica Model Inputs

	Units	**Area U1**	**Area U2**	**Area U3**	**Area U4**
Layer 1 - Indian Castle (Clay)					
Depth	ft.	9213	9534	9100	4442
Thickness	ft.	89	39	25	19.5
Porosity	fraction	0.005	0.0045	0.0025	0.0025
Water Saturation	fraction	0.15	0.15	0.15	0.15
Layer 2 - Indian Castle					
Depth	ft.	9312	9577	9137	4519
Thickness	ft.	5	49.5	82	51.5
Porosity	fraction	0.001	0.003	0.003	0.0025
Water Saturation	fraction	0.20	0.20	0.20	0.20
Layer 3 - Dolgeville					
Depth	ft.	9352	9659	9262	4678
Thickness	ft.	5.5	22.5	59	15.5
Porosity	fraction	0.001	0.0025	0.003	0.0025
Water Saturation	fraction	0.25	0.25	0.25	0.25
Layer 4 - Flat Creek					
Depth	ft.				4801
Thickness	ft.		**Not Present**		59.5
Porosity	fraction				0.003
Water Saturation	fraction				0.30

Table 16: Utica Isotherm Inputs

Methane (in-situ)	**V_L**	**P_L**
	scf/ft^3	psia
Indian Castle	6.08	613.4
Indian Castle	6.08	613.4
Dolgeville	6.08	613.4
Flat Creek	7.72	545.2
CO_2 (in-situ)	**V_L**	**P_L**
	scf/ft^3	psia
Indian Castle	13.7	470.0
Indian Castle	13.7	470.0
Dolgeville	13.7	470.0
Flat Creek	14.2	482.3

Table 17 summarizes the permeability inputs that distinguish the three model cases for the Utica model areas. The permeability inputs are intended to represent the permeability of the fracture-matrix system. Measured reservoir matrix permeability from Utica core samples ranges are typically lower than the Marcellus, generally about 10^{-5} millidarcies. As with the Marcellus, fracture permeability dominates the Utica reservoir matrix-fracture system, but adequately characterizing the fracture system in the model, without the benefit of production history matching for calibration, is a significant source of uncertainty.

Table 17: Utica Permeability Inputs

Reservoir Layer	**Permeability (md)**			
	Area 1	**Area 2**	**Area 3**	**Area 4**
Layer 1 **Indian Castle (Clay-Rich)**	0.050 0.025 0.010	0.050 0.025 0.010	0.025 0.0125 0.006	0.0125 0.006
Layer 2 **Indian Castle (Carbonate – Rich)**	0.010 0.005 0.0025	0.025 0.0125 0.006	0.025 0.0125 0.006	0.0125 0.006
Layer 3 **Dolgeville**	0.0100 0.005 0.0025	0.025 0.0125 0.006	0.0300 0.015 0.0075	0.0125 0.006
Layer 4 **Flat Creek**	Not Present			0.015 0.0075

COMET3 RESERVOIR SIMULATION RESULTS

Vertical Wells

Thirty-four simulations of vertical wells were run. The models were run simulating a quarter well on a 10-acre, normally-pressured (0.433 psi/ft.) grid, and the results were scaled up to represent full wells on 40-acre spacing. The production and injection wells are vertical, 6-inch boreholes. Each model layer in both the producer and injector are assumed to be frac'd with a 180 ft. fracture (90-ft fracture half-length).

The following **Tables 18** through **21** summarize total cumulative gas production, total net CO_2 injected (net CO_2 stored) and total enhanced gas recovery (EGR) after 30 years. Note that for the high and mid permeability cases, the net volume of CO_2 stored is greater than the volume of gas produced, which is attributed to the preferential adsorption of CO_2 over CH_4. To determine enhanced gas recovery resulting from 20 years of CO_2 injection, methane gas recoveries forecast with CO_2 injection for each model area were compared to the recoveries forecast without CO_2 injection.

Table 18: Cumulative Methane Production at Year 30 with CO_2 Injection, per 40 acres

Permeability Case	Marcellus		Utica			
	Area 1	Area 2	Area 1	Area 2	Area 3	Area 4
	MMscf	MMscf	MMscf	MMscf	MMscf	MMscf
High	283	1080	1011	880	1174	
Medium	202	762	867	720	928	663
Low	139	550	608	539	727	466

Within each permeability case, the permeability applied varies by reservoir layer and model area.
Marcellus perm ranges: High k= 0.001 - 0.05 md; Med k =0.0005 - 0.025 md; Low k =0.0001-0.0125 md
Utica perm ranges: High k = 0.01 - 0.05 md; Med k =0.005 - 0.025 md; Low k =0.0025-0.01 md

Table 19: Total Net CO_2 Injection at Year 30, per 40 acres

Permeability Case	Marcellus		Utica			
	Area 1	Area 2	Area 1	Area 2	Area 3	Area 4
	MMscf	MMscf	MMscf	MMscf	MMscf	MMscf
High	447	2224	1900	1278	1325	
Medium	225	1160	1366	789	713	731
Low	105	590	604	370	376	358

Within each permeability case, the permeability applied varies by reservoir layer and model area.
Marcellus perm ranges: High k= 0.001 - 0.05 md; Med k =0.0005 - 0.025 md; Low k =0.0001-0.0125 md
Utica perm ranges: High k = 0.01 - 0.05 md; Med k =0.005 - 0.025 md; Low k =0.0025-0.01 md

Table 20: Cumulative Methane Production at Year 30, without CO_2 Injection

Permeability Case	Marcellus		Utica			
	Area 1	Area 2	Area 1	Area 2	Area 3	Area 4
	MMscf	MMscf	MMscf	MMscf	MMscf	MMscf
High	233	730	726	675	984	
Medium	182	615	641	593	838	562
Low	132	489	523	489	684	427

Within each permeability case, the permeability applied varies by reservoir layer and model area.
Marcellus perm ranges: High k= 0.001 - 0.05 md; Med k =0.0005 - 0.025 md; Low k =0.0001-0.0125 md
Utica perm ranges: High k = 0.01 - 0.05 md; Med k =0.005 - 0.025 md; Low k =0.0025-0.01 md

Table 21: Cumulative Enhanced Gas Recovery at Year 30, with CO_2 Injection

Permeability Case	Marcellus		Utica			
	A-1	A-2	A-1	A-2	A-3	A-4
	MMscf	MMscf	MMscf	MMscf	MMscf	MMscf
High	50	350	285	205	189	
Medium	19	147	226	126	90	101
Low	7	60	85	50	43	39

Within each permeability case, the permeability applied varies by reservoir layer and model area.
Marcellus perm ranges: High k= 0.001 - 0.05 md; Med k =0.0005 - 0.025 md; Low k =0.0001-0.0125 md
Utica perm ranges: High k = 0.01 - 0.05 md; Med k =0.005 - 0.025 md; Low k =0.0025-0.01 md

Horizontal Wells – Sensitivity Case

A horizontal well model was built as a sensitivity case to compare with the vertical well results. The horizontal well was completed in the Utica Model Area 1 for the clay-rich Indian Castle (Layer 1), which appears to be the primary Utica reservoir in this model area. The horizontal well model simulates quarter wells on 20-acre spacing and is scaled up to model a full producer and a full injector on 80-acre spacing. The full lateral lengths for both wells are assumed to be 2,000 feet. Three horizontal models were built; one completed with no fractures, one with a "small" frac, (100-ft fracture half-length; 200-ft total length), and one with a "large" frac (275-ft fracture half-length; 550-ft total length). The fractures are spaced every 200 ft. for a total of 8 fractures per well. The three models were run using the same high-, medium-, and low-permeability cases as the vertical well models. All other reservoir inputs were kept constant with the vertical models.

Six horizontal simulations were run for the medium- and low-permeability cases for Utica Model Area 1. The high-permeability was initially included, but the simulation results were unrealistic. The results from this model run imply that the high-permeability case is not a realistic representation of the reservoir, and the focus was shifted to the medium- and low-permeability cases. **Table 22** shows the cumulative production forecast for the medium and low permeability cases. Because of the close proximity of the injection well to the production well, all simulations encountered CO_2 return at varying points during the simulation. However, except for the "large" frac model (550-ft fracture length), the low-permeability simulations did not produce enough CO_2 to be considered breakthrough.

Table 22: 30-Year Horizontal Well Production Forecast with CO_2 Injection

Permeability Case	Utica Area 1		
	No Fracture	Small Frac (200' Fracture Length)	Large Frac (550' Fracture Length)
	MMscf	MMscf	MMscf
Mid	1937	1957	1998
Low	1614	1684	1851
Within each permeability case, the permeability applied varies by reservoir layer. Utica perm ranges: Med k =0.005 - 0.025 md; Low k =0.0025-0.01 md			

RESERVOIR SIMULATION RESULTS - DISCUSSION

Vertical Wells

For each model run, the cumulative gas production after 30 years was compared to the gas in-place calculated from well logs for each model area to estimate the percentage of calculated gas in-place recovered during the model period. Similarly, total net CO_2 injection for each model run was compared to the calculated theoretical maximum CO_2 storage capacity calculated from well logs for each model area to estimate the percentage CO_2 stored during the model period. **Appendix G** contains the summary graphs for all the model runs. The summary graphs compare the results for the three permeability cases (high, mid, and low) for each model area, as well as compare the results by model area for each permeability case. Lacking suitable production data for history matching and model calibration, we investigated whether the cumulative gas production and CO_2 storage as a percentage of calculated methane gas in-place or theoretical CO_2 storage capacity appear reasonable for vertical shale wells. For the Marcellus model areas, simulated gas production after one year to five years was compared to the cumulative gas production data reported in New York's production data base for fifteen vertical Marcellus wells. **Figure 23** summarizes cumulative gas production for the fifteen New York Marcellus wells. **Figure 24** shows annual production rates for the New York Marcellus wells.

Figure 23: Marcellus Cumulative Gas Production

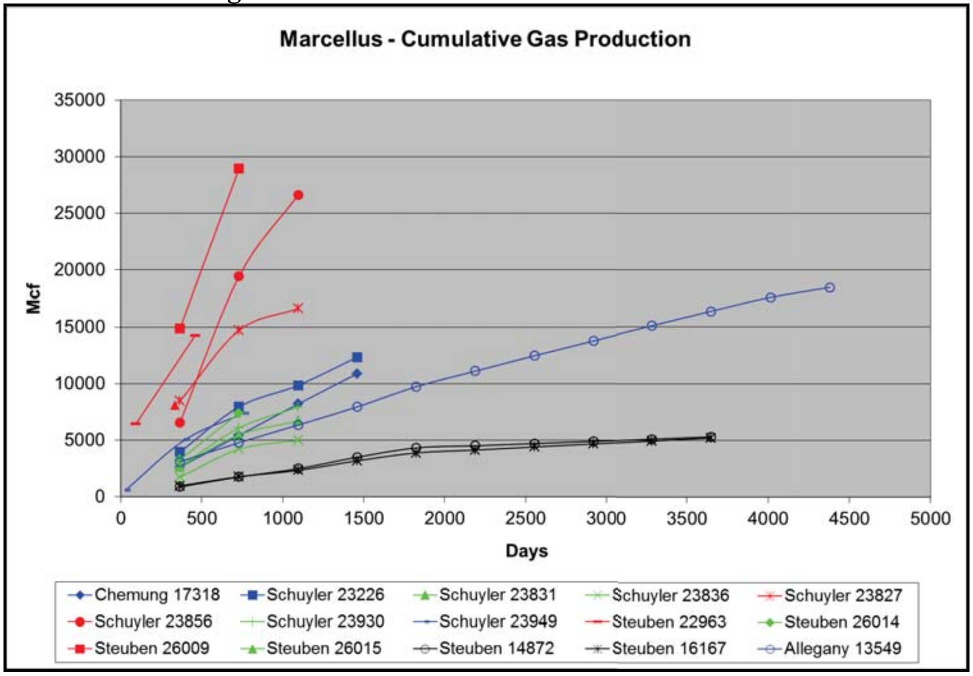
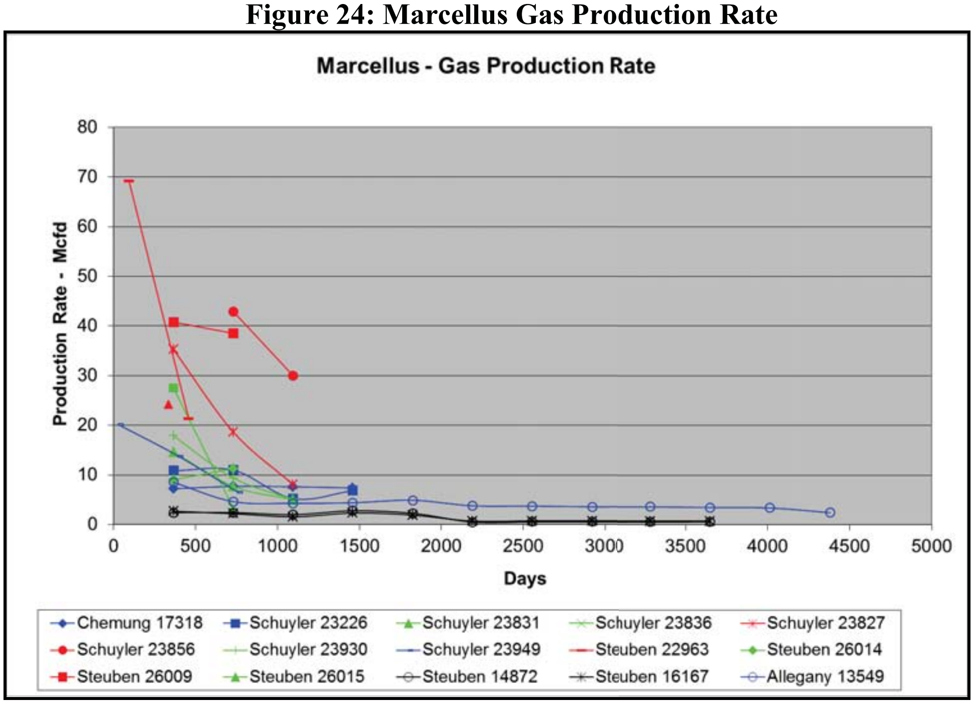


Figure 24: Marcellus Gas Production Rate



It appears from the model results presented in **Appendix G** and **Tables 18** through **21** that the reservoir simulation results for the high- and mid-permeability cases are very optimistic and are likely unrealistic representations of the Marcellus and Utica reservoirs. For example, the modeled cumulative Marcellus production and modeled Marcellus production rates are orders of magnitude greater than data shown in **Figures 21** and **22** for actual vertical Marcellus wells. For the Marcellus high-permeability case, 11 to 12 percent of total calculated gas in-place is recovered and 14 to 24 percent of theoretical CO_2 storage capacity is filled. For the Utica high-permeability case, 10 to 11 percent of total calculated gas in-place is recovered and 15 to 20 percent of theoretical CO_2 storage capacity is filled. Furthermore, if only the calculated adsorbed gas in-place and calculated adsorbed CO_2 storage capacity are compared to the *COMET3* simulation results for the high-permeability cases, the apparent methane recovery factors and CO_2 storage capacity factors as a percentage of adsorbed gas in-place or adsorbed storage capacity are substantial.[12] Considering only adsorbed gas in-place and adsorbed CO_2 storage, the Marcellus high-permeability case recovers 54 percent to 62 percent of adsorbed gas in-place and uses 25 percent to 38 percent of theoretical CO_2 storage capacity. The Utica high-permeability case recovers 46 percent to 60 percent of calculated gas in-place, and 28 percent to 35 percent of theoretical adsorbed CO_2 storage capacity is filled.

The reservoir simulation results for the mid-permeability case are lower than the high case but still thought to be too optimistic. The low-permeability case appears to be the best representation for both the Marcellus and Utica reservoirs, although more work is needed to refine the representation of reservoir permeability in the model and interaction between the matrix and fracture system porosity and permeability. For the Marcellus, **Table 23** summarizes the reservoir simulation results for the low-permeability case compared to calculated methane gas in-place and theoretical maximum CO_2 storage capacity. **Table 24** compares the reservoir simulation results for the Utica to the calculated values.

Table 23 shows that for the Marcellus low-permeability case, total cumulative gas production at thirty years (0.14 Bcf/ 40 acres for Model Area 1 and 0.55 Bcf/ 40 acres for Model Area 2) represents recovery of 5 to 6 percent of total calculated gas in-place. Cumulative CO_2 storage at thirty years (0.1 Bcf/ 40 acres for Model Area 1 and 0.6 Bcf/40 acres for Model Area 1) represents 3 to 6 percent of theoretical maximum CO_2 storage capacity. Enhanced gas recovery (EGR) from CO_2 injection is 7 MMcf/40 acres for Marcellus Model Area 1 and 61 MMcf/40 acres for Model Area 2. This EGR component represents 5 to 11 percent of the cumulative total gas production at year 30, which corresponds to approximately 0.3 percent to 0.7 percent of calculated total methane gas in-place.

Table 24 shows that for the Utica low-permeability case, total cumulative gas production at thirty years ranges from 0.47 Bcf/40 acres for Utica Model Area 1 to 0.73 Bcf/40 acres for Model Area 3. This represents 5 to 7 percent of total calculated gas in-place. Cumulative CO_2 storage at thirty years (net CO_2 injected) ranges from a low of 0.36 Bcf/40 acres for Utica Model Area 4 to a high of 0.6 Bcf/40 acres for Utica Model Area 1. This range of values represents 3 to 6 percent of total theoretical CO_2 storage capacity. Enhanced gas recovery (EGR) from CO_2

[12] It may be more accurate to compare only the calculated adsorbed gas in-place and adsorbed CO_2 storage capacity with *COMET3* results, because *COMET3* is designed to model production of an adsorbed gas component, as well as free gas in fractures, but not production of non-adsorbed (free) gas in reservoir matrix porosity. Consequently, calculated non-adsorbed gas in-place and theoretical non-adsorbed CO_2 storage capacity may not be adequately represented in the *COMET3* reservoir simulations results.

injection ranges from a low of 39 MMcf/40 acres for Utica Model Area 4 to a high of 85 MMcf/40 acres for Utica Model Area 1. The range of EGR represents 6 percent to 14 percent of total cumulative gas production at year 30, which corresponds to approximately 0.4 to 0.8 percent of calculated total methane gas in-place.

If the reservoir simulation results are compared only to total adsorbed gas in-place and maximum adsorbed CO_2, this scenario that excludes any contribution to gas production from free gas in-place, and excludes any contribution of non-adsorbed CO2 storage. Considering only adsorbed gas in-place and adsorbed CO_2 storage, the Marcellus vertical low-permeability case recovers 27 percent of adsorbed gas in-place in Model Area 1 and 31 percent of calculated adsorbed gas in-place in Marcellus Model Area 2. Cumulative net CO_2 storage at 30 years represents 6 percent of calculated adsorbed CO_2 storage capacity for Marcellus Model Area 1 and 10 percent of adsorbed CO_2 storage capacity in Marcellus Model Area 2. Considering only adsorbed gas in-place and adsorbed CO_2 storage, the Utica vertical well low-permeability case recovers 28 percent of adsorbed gas in-place in Utica Model Area 1, 30 percent of calculated adsorbed gas in-place in Utica Model Area 2, 41 percent of calculated adsorbed gas in-place in Utica Model Area 3, and 18 percent in Utica Model Area 4. Cumulative net CO_2 storage at 30 years represents 11 percent of calculated adsorbed CO_2 storage capacity for Utica Model Area 1, 8 percent of calculated adsorbed CO_2 storage capacity for Utica Model Areas 2 and 3, and 5 percent in Model Area 4.

The reservoir simulation results presented for the low-permeability case appear to better represent the Marcellus and Utica gas shales than the medium and high permeability cases, but may still be too optimistic for vertical wells. The comparison of model results compared to calculated gas in-place and theoretical storage capacity presented in Tables 23 and 24 suggests that within the New York exploration fairways, characterization of stratigraphic features and well log analyses alone may not be sufficient to discriminate the most promising areas for gas production and CO_2 storage. Other criteria such as reservoir pressure trends and fracture permeability corresponding to fracture spacing, density, and orientation may be the critical determinants for economic CO_2 injection and storage.

Table 23: Marcellus Reservoir Simulation Results for Low Permeability Case Compared to Calculated Gas in-Place and Theoretical Maximum CO_2 Storage Capacity

Gas In-Place and CO_2 Storage Capacity, Bcf/ 40 acres ***Low Permeability Case***	**Model Area M1 Otsego Co.**	**Model Area M2 Tioga Co.**
Total Calculated Gas In-Place (adsorbed & 'free')	**2.66**	**8.93**
Total Gas In-Place, adsorbed	0.52	1.75
Theoretical Maximum CO_2 Storage Capacity	***3.21***	***9.30***
Total CO_2 Storage Capacity, adsorbed	*1.77*	*5.79*
Low Permeability Case – Vertical Wells		
Cumulative Gas Production @ 30 Years, Bcf/40 acres	**0.139**	**0.550**
As % of Calculated Total Gas In-Place	5%	6%
Cumulative CO_2 Storage @ 30 Years, Bcf/ 40 acres	***0.105***	***0.590***
As % of Total CO_2 Storage Capacity	3%	6%
Cumulative Enhanced Gas Recovery, Bcf/40 acres	**0.007**	**0.061**
As % of Cumulative Gas Production @ 30 Yrs.	*5%*	*11%*
As % of Calculated Total Gas In-Place	*0.3%*	*0.7%*
Note: CO_2 injection commences at Year 10. CO_2 cumulative enhanced gas recovery represents 20 years of production		

Table 24: Utica Reservoir Model Results for Low Permeability Case Compared to Calculated Gas in-Place and Calculated Theoretical Maximum CO_2 Storage Capacity

Gas In-Place and CO_2 Storage Capacity, Bcf/ 40 acres ***Low Permeability Case***	**Model Area U1 Steuben Co.**	**Model Area U2 Tioga Co.**	**Model Area U3 Broome Co.**	**Model Area U4 Otsego Co.**
Total Calculated Gas In-Place (adsorbed & 'free')	**10.14**	**9.14**	**10.94**	**10.02**
Total Gas In-Place, adsorbed	2.18	1.82	1.78	2.54
Theoretical Maximum CO_2 Storage Capacity	***9.34***	***8.17***	***8.98***	***10.32***
Total CO_2 Storage Capacity, adsorbed	*5.50*	*4.62*	*4.57*	*6.67*
Low Permeability Case – Vertical Wells				
Cumulative Gas Production @ 30 Years, Bcf/40 acres	**0.61**	**0.54**	**0.73**	**0.47**
As % of Calculated Total Gas In-Place (adsorbed + 'free')	6%	6%	7%	5%
Cumulative CO_2 Storage @ 30 Years, Bcf/ 40 acres	***0.60***	***0.37***	***0.38***	***0.36***
As % of Total CO_2 Storage Capacity	6%	5%	4%	3%
Cumulative Enhanced Gas Recovery, Bcf/40 acres	**0.085**	**0.05**	**0.043**	**0.039**
As % of Cumulative Gas Production @ 30 Yrs.	*14%*	*9%*	*6%*	*8%*
As % of Calculated Total Gas In-Place	*0.8%*	*0.5%*	*0.4%*	*0.4%*
Note: CO_2 injection commences at Year 10. CO_2 cumulative enhanced gas recovery represents 20 years of production				

Horizontal Wells

As described above, horizontal well simulation was investigated for Utica Model Area 1, where most of the Utica potential resides in the organic-rich Indian Castle Formation. Reservoir simulation results are provided in **Table 22** for the mid- and low-permeability cases. **Table 25** summarizes the reservoir simulation results for the low-permeability case compared to calculated methane gas in-place and theoretical maximum CO_2 storage capacity.

A horizontal well provides a significant boost in gas recovery and net CO_2 injection and storage. A horizontal well without hydraulic fracturing increases cumulative gas production by 32 percent over 30 years, compared to the vertical well case. Hydraulic fracturing of the horizontal well recovers an additional 6 to 20 percent of gas depending on the size of the frac. For Utica Model Area 1, the low-permeability vertical well case recovers 0.61 Bcf/40 acres after 30 years compared to the horizontal well, large hydraulic fracture case, which recovers 0.93 Bcf/40 acres after 30 years.

The horizontal well case boosts total net CO_2 storage from 6 percent of theoretical maximum CO_2 storage capacity for vertical wells to 13 to 17 percent of total CO_2 storage capacity, depending on the size of the fracs applied to the horizontal well. For Utica Model Area 1, this represents an increase in net CO_2 storage from 0.6 Bcf/40 acres for vertical to 1.57 Bcf/40 acres for horizontal wells with large fracs.

If the reservoir simulation results are compared only to the calculated adsorbed gas in-place and calculated maximum adsorbed storage capacity, (excluding the estimated “free” methane gas in-place) the horizontal well case for Utica Model Area 1 recovers 37 percent of adsorbed gas in-place in the “no frac” case, 39 percent with the “small frac” case and 42 percent of adsorbed gas in-place with the “large frac” case. Net CO_2 storage after 30 years represents 23 percent of maximum CO_2 adsorbed storage capacity in the “no frac” case, 25 percent with the “small frac” case and 28 percent of maximum adsorbed storage capacity with the “large frac” case. For a corresponding vertical well, cumulative gas recovery at 30 years represents 28 percent of adsorbed gas in-place,[13] and net CO_2 injection at 30 years represents 11 percent of maximum adsorbed CO_2 storage capacity.

Although the scope of the horizontal well sensitivity case was limited to a single Utica model area, the results nevertheless demonstrate that horizontal wells and some amount of artificial fracture stimulation will likely be needed for efficient production from New York gas shale formations and maximum CO_2 storage. Further analysis will be required to determine the optimal development scenarios to maximize methane gas production and net CO_2 injection.

[13] This compares cumulative gas production only to adsorbed gas in-place. Estimated “free” gas in-place is excluded.

Table 25: Utica Reservoir Model Results for Horizontal Wells; Model Area 1; Low-Permeability Case, Bcf/ 80 acres

Gas In-Place and CO_2 Storage Capacity, Bcf/ 80 acres *Low-Permeability Case*	**Model Area U1 Steuben Co.**
Total Calculated Gas In-Place (adsorbed & free)	**20.28**
Total Gas In-Place, adsorbed	4.36
Theoretical Maximum CO_2 Storage Capacity	***18.68***
Total CO_2 Storage Capacity, adsorbed	*11.0*
Horizontal Well – No Hydraulic Fracture	
Cumulative Gas Production @ 30 Years, Bcf/ 80 ac	**1.61**
% Calculated Total Gas In-Place (adsorbed + free)	8%
% Calculated Adsorbed Gas In-Place	37%
Net CO_2 Storage @ 30 Years, Bcf/ 80 acres	***2.52***
% Total CO_2 Storage Capacity	*13%*
% Adsorbed CO_2 Storage Capacity	*23%*
Horizontal Well – Small Hydraulic Fracture **(200' Total Fracture Length)**	
Cumulative Gas Production @ 30 Years, Bcf/ 80 ac	**1.68**
% Calculated Total Gas In-Place (adsorbed + free)	8%
% Calculated Adsorbed Gas In-Place	39%
Net CO_2 Storage @ 30 Years, Bcf/ 80 acres	***2.70***
% Total CO_2 Storage Capacity	*14%*
% Adsorbed CO_2 Storage Capacity	*25%*
Horizontal Well – Large Hydraulic Fracture **(550' Total Fracture Length)**	
Cumulative Gas Production @ 30 Years, Bcf/ 80 ac	**1.85**
% Calculated Total Gas In-Place (adsorbed + free)	9%
% Calculated Adsorbed Gas In-Place	42%
Net CO_2 Storage @ 30 Years, Bcf/ 80 acres	***3.13***
% Total CO_2 Storage Capacity	*17%*
% Adsorbed CO_2 Storage Capacity	*28%*

CONCLUSIONS AND RECOMMENDATIONS

This project represents a first approximation of total methane gas in-place and theoretical maximum CO_2 storage capacity within the Marcellus and Utica shale exploration fairways identified by the NYSM. Both the Marcellus and Utica shales appear to have significant gas in-place and potential storage capacity for CO_2. Both adsorbed phase and non-adsorbed, or free, gas in-place and theoretical maximum CO_2 storage capacity were estimated. The recovery factors for adsorbed and free gas in-place are unknown but likely to be different, with the recovery of adsorbed gas in-place estimated to be greater than recovery of free gas in-place. Consequently, the accessibility of potential adsorbed and non-adsorbed CO_2 storage capacity may be vastly different.

Two Marcellus model areas and four Utica model areas were characterized for reservoir simulation using *COMET3* to forecast cumulative methane production, total net CO_2 injection and storage and enhanced gas recovery due to CO_2 injection. Significant sources of uncertainty that impact the gas in-place and CO_2 storage capacity calculations and the reservoir model include: 1) limited CO_2 and methane isotherm data for the Marcellus and Utica; 2) lack of reservoir test data and sustained production data for calibration of the reservoir simulation; 3) representation of reservoir matrix and fracture properties in *COMET3*.

Recommendations for further work to refine and expand this analysis are focused on reducing or eliminating these uncertainties by acquiring additional reservoir and engineering data to improve the reservoir characterization, and industry input to investigate hypothetical development scenarios.

Specific recommendations include the following:

- Obtain additional isotherm data for the Marcellus and Utica, particularly CO_2 isotherms
- Improve the representation of Marcellus and Utica regional fracturing in the model characterization of reservoir permeability and porosity. This would incorporate the latest understanding of Marcellus and Utica fracture density, fracture trends, fracture orientation, and in situ fracture widths
- Obtain industry input for more accurate representation of reservoir pressure. Investigate possible extent of Marcellus 'overpressure fairway' into southern New York
- Obtain sustained Marcellus production data and reservoir test data to calibrate *COMET3* results and improve model representation of reservoir permeability
- With industry and New York State regulator input, identify hypothetical development scenarios. Focus on one or two most likely Marcellus and Utica development approaches and investigate options to optimize gas recovery with CO_2 storage. For example, if horizontal wells are allowed, but massive hydraulic

fracturing is not an option, under what scenarios might gas shale production with CO_2 storage be economic?

- Further investigate potential limitations of reservoir depth on CO_2 storage in New York. Current analysis computes CO_2 storage capacity for reservoir depths greater than 3,000 ft. Potential depth limits to economic CO_2 storage were not explicitly addressed in this analysis. These include potential shallow depth limits for horizontal wells and fracture stimulation, as well as deep depth limits for cost-effective drilling and CO_2 injection.

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APPENDIX A

CO_2 ADSORPTION ISOTHERMS

Carbon Dioxide Adsorption Isotherm Summary

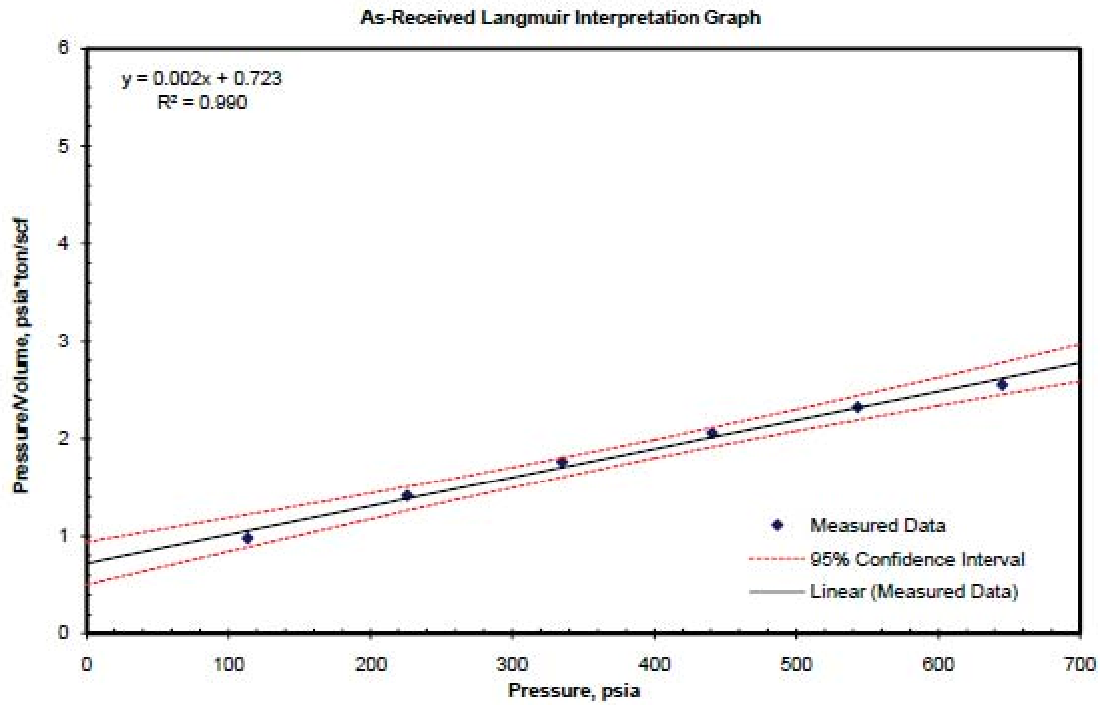
Well: **Ross #1**
Reservoir: **Marcellus**
Sample Number: 45051-1
Sample Type: shale
Drill Depth, feet: 2,457.00-2,460.00
Temperature, °F: 60.98

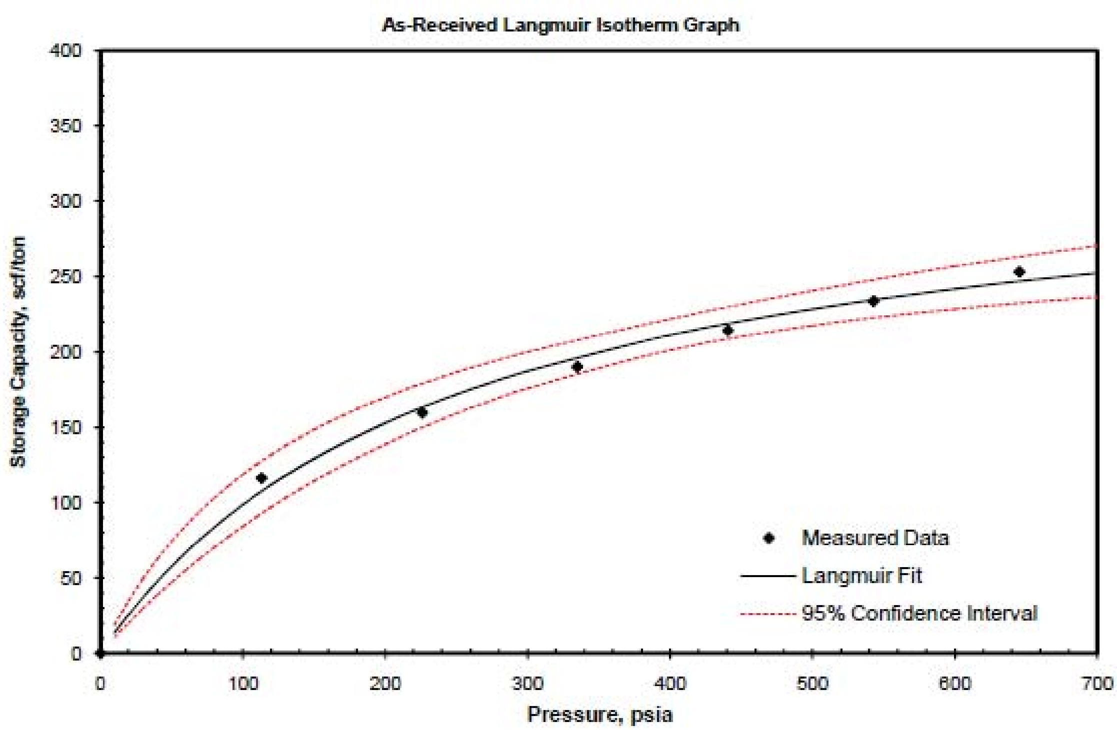
Pressure	Carbon Dioxide Storage Capacity, scf/ton	
psia	As-Received	
	Measured	Calculated
0.0	0.0	0.0
113.5	116.1	107.5
226.2	159.3	163.2
334.9	190.0	196.4
440.9	214.1	218.7
543.1	233.7	234.6
645.3	253.1	246.8

Parameters	Carbon Dioxide Langmuir Parameters (U.S. Units)
	As-Received
Slope:	0.00
Intercept:	0.72
Regression Coefficient (squared):	0.99
Intercept Variation, psia*ton/scf:	0.22
Slope Variation, ton/scf:	0.00
G_{sL} Variation, scf/ton:	11.43
P_L Variation, psia:	60.83
Langmuir Volume, scf/ton:	341.16
Langmuir Pressure, psia:	246.75
Langmuir Equation:	$G_s = (G_{sL}*p)/(P_L+p)$
Pressure (Midpoint), psia:	1,300.00
Storage Capacity, scf/ton:	286.73

G_s Gas Storage Capacity
G_{sL} Langmuir Gas Storage Capacity
P_L Langmuir Pressure
p Relevant Pressure (Reservoir Pressure)

Carbon Dioxide Adsorption Isotherm Summary Graphs





Carbon Dioxide Adsorption Isotherm Summary

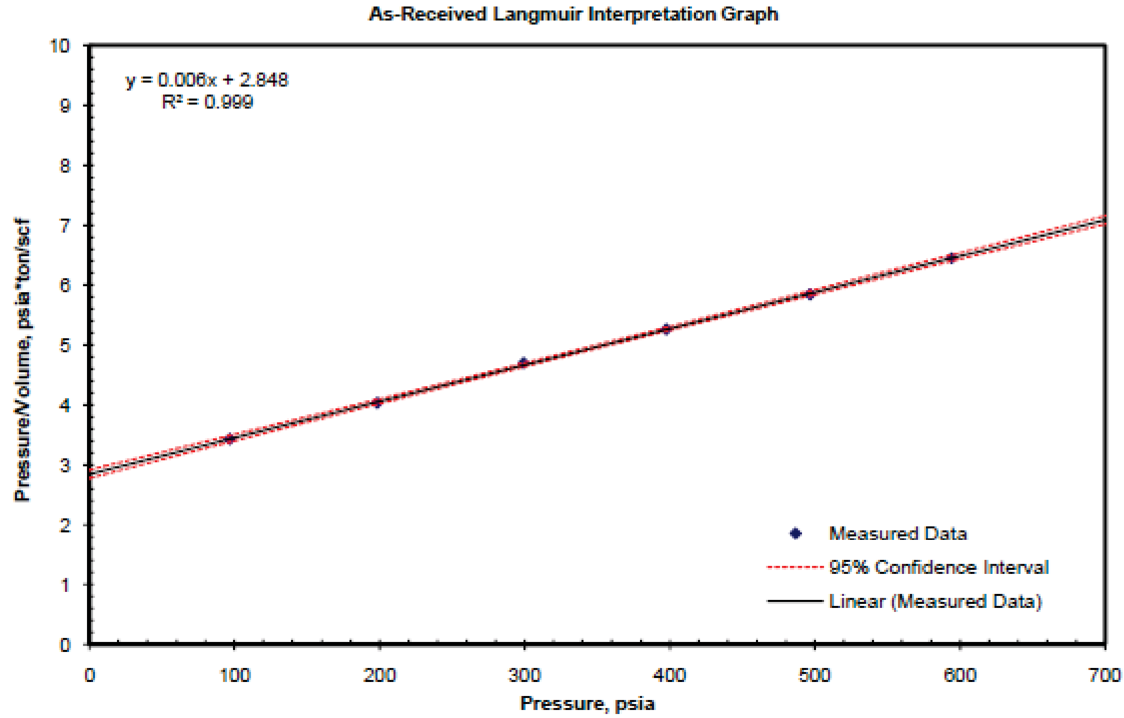
Well: Ross #1
Reservoir: Utica
Sample Number: 45051-2
Sample Type: shale
Drill Depth, feet: 4,454.00-4,455.00
Temperature, °F: 76.55

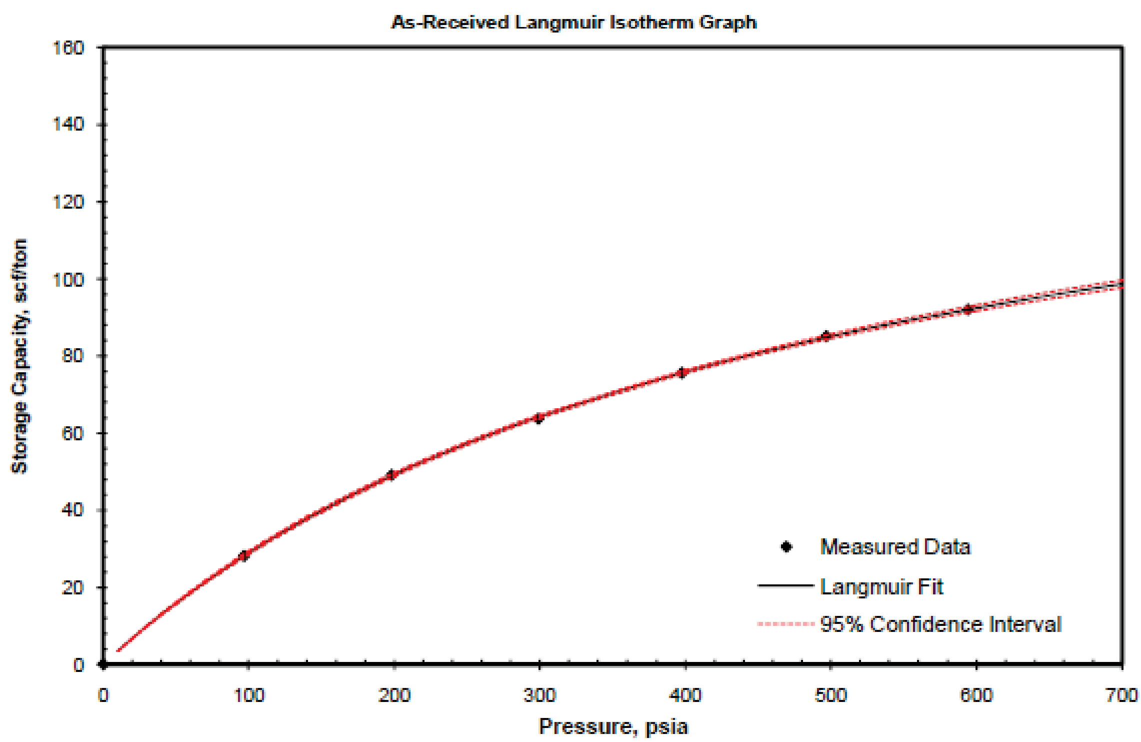
Pressure	Carbon Dioxide Storage Capacity, scf/ton	
psia	As-Received	
	Measured	Calculated
0.0	0.0	0.0
96.8	28.2	28.2
198.2	49.1	48.9
299.2	63.7	64.2
397.4	75.5	75.6
496.8	85.0	84.8
594.0	92.1	92.1

Parameters	Carbon Dioxide Langmuir Parameters (U.S. Units)
	As-Received
Slope:	0.01
Intercept:	2.85
Regression Coefficient (squared):	1.00
Intercept Variation, psia*ton/scf:	0.07
Slope Variation, ton/scf:	0.00
G_{sL} Variation, scf/ton:	0.56
P_L Variation, psia:	9.22
Langmuir Volume, scf/ton:	165.01
Langmuir Pressure, psia:	470.03
Langmuir Equation:	$G_s = (G_{sL}*p)/(P_L+p)$
Pressure (Midpoint), psia:	1,300.00
Storage Capacity, scf/ton:	121.19

G_s Gas Storage Capacity
G_{sL} Langmuir Gas Storage Capacity
P_L Langmuir Pressure

Carbon Dioxide Adsorption Isotherm Summary Graphs





Carbon Dioxide Adsorption Isotherm Summary

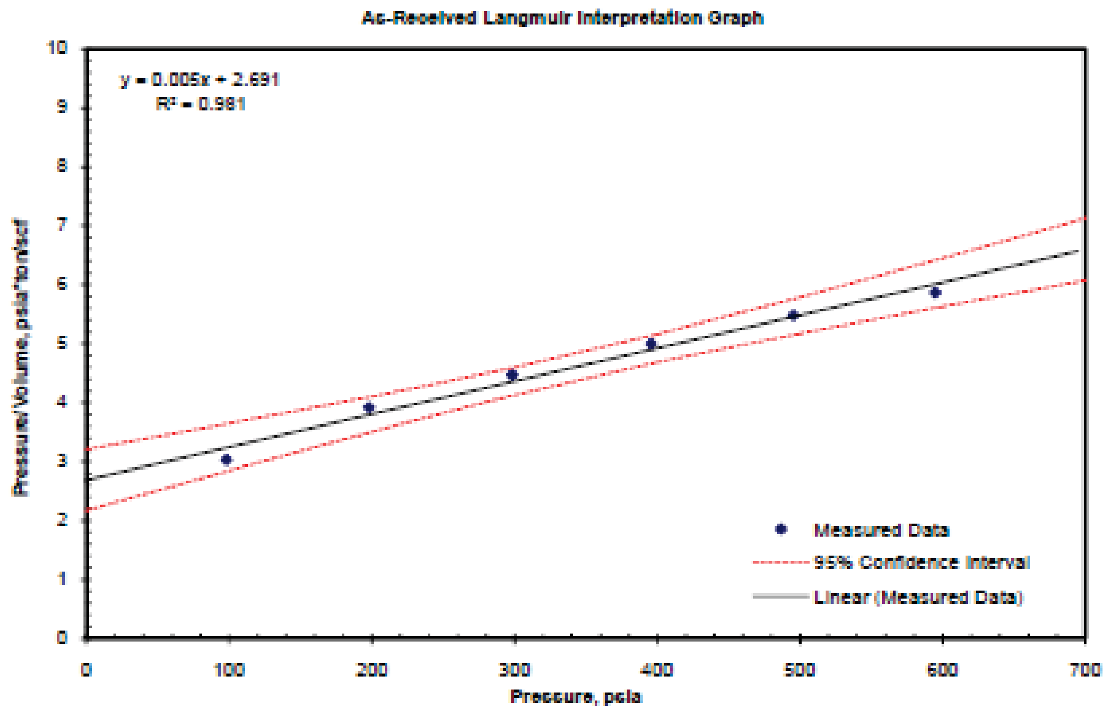
Well: **Ross #1**
Reservoir: **Utica**
Sample Number: 45051-3
Sample Type: shale
Drill Depth, feet: 4,889.00-4,890.00
Temperature, °F: 76.55

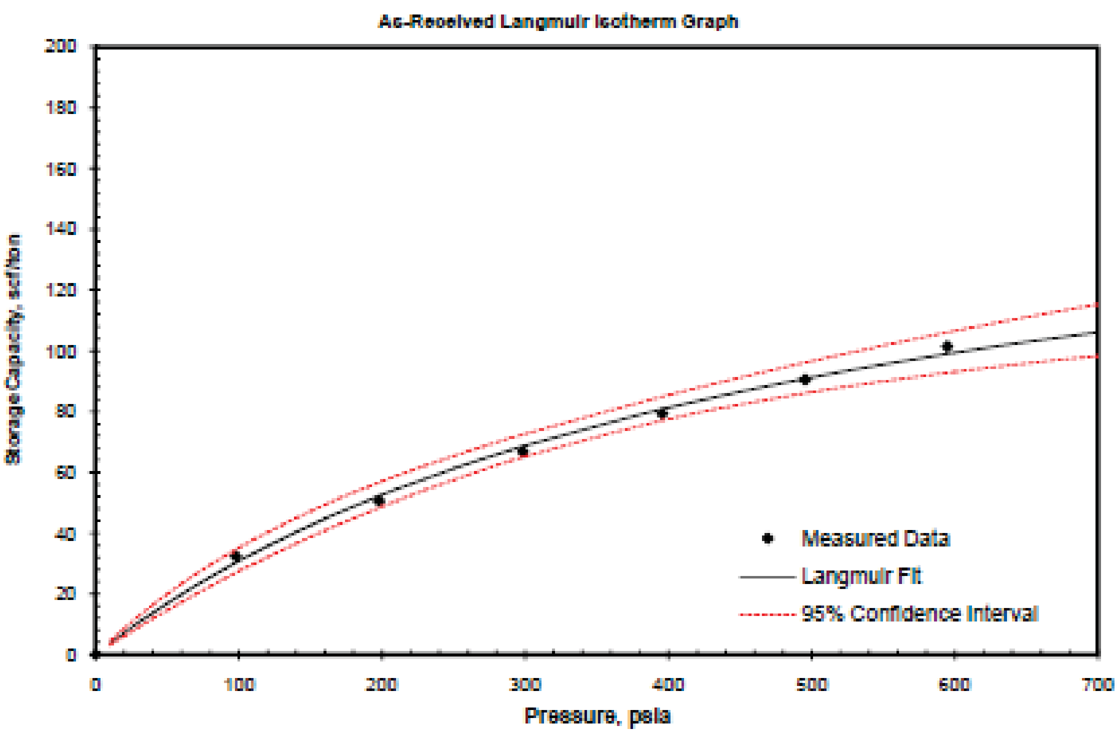
Pressure	Carbon Dioxide Storage Capacity, scf/ton	
psia	As-Received	
	Measured	Calculated
0.0	0.0	0.0
97.9	32.3	30.2
198.0	50.5	52.1
298.3	66.7	68.5
395.8	79.2	80.8
495.5	90.4	90.8
594.6	101.4	98.9

Parameters	Carbon Dioxide Langmuir Parameters (U.S. Units)
	As-Received
Slope:	0.01
Intercept:	2.69
Regression Coefficient (squared):	0.98
Intercept Variation, psia*ton/scf:	0.52
Slope Variation, ton/scf:	0.00
G_{sL} Variation, scf/ton:	4.92
P_L Variation, psia:	75.56
Langmuir Volume, scf/ton:	179.18
Langmuir Pressure, psia:	482.31
Langmuir Equation:	$G_s = (G_{sL}*p)/(P_L+p)$
Pressure (Midpoint), psia:	1,300.00
Storage Capacity, scf/ton:	130.69

G_s Gas Storage Capacity
G_{sL} Langmuir Gas Storage Capacity
P_L Langmuir Pressure

Carbon Dioxide Adsorption Isotherm Summary Graphs





APPENDIX B

CONTOUR MAPS OF CALCULATED GAS IN-PLACE AND CO_2 STORAGE CAPACITY

Figure B-1: Marcellus Union Springs Calculated Adsorbed Methane Gas In-Place, Bcf/ac

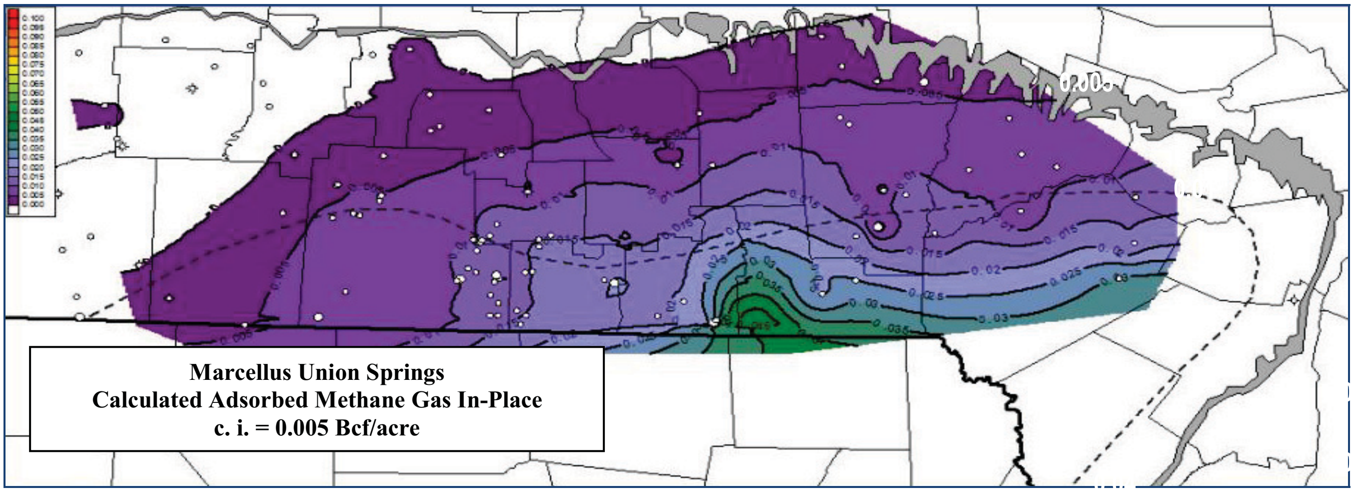


Figure B-2: Marcellus Union Springs Calculated Non-Adsorbed ('Free') Methane Gas In-Place, Bcf/ac

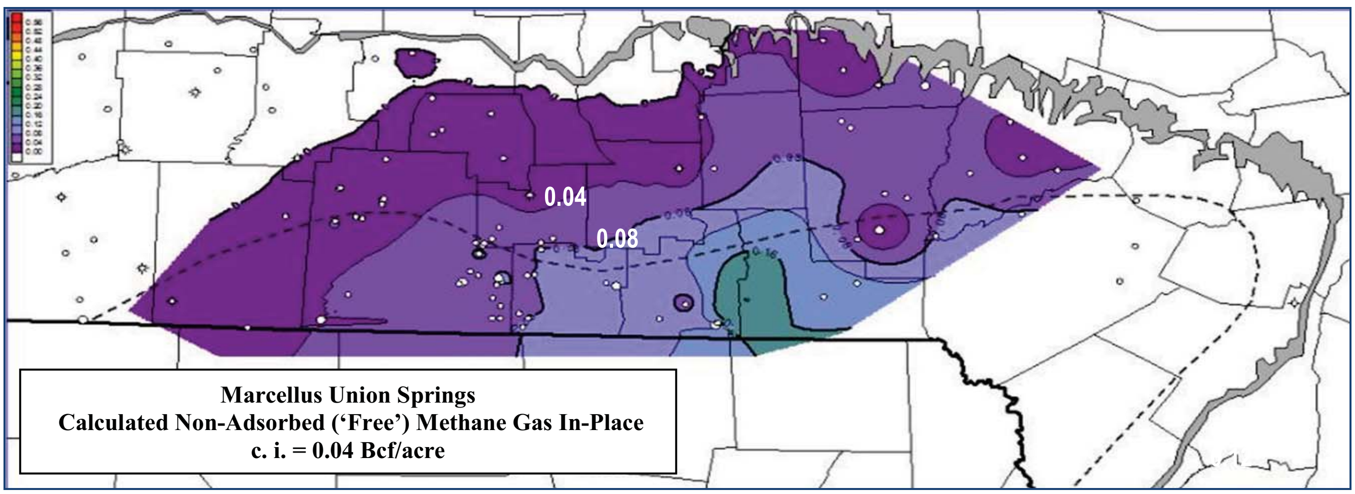


Figure B-3: Marcellus Oatka Creek 'Black Shale' Calculated Adsorbed Methane Gas In-Place, Bcf/ac

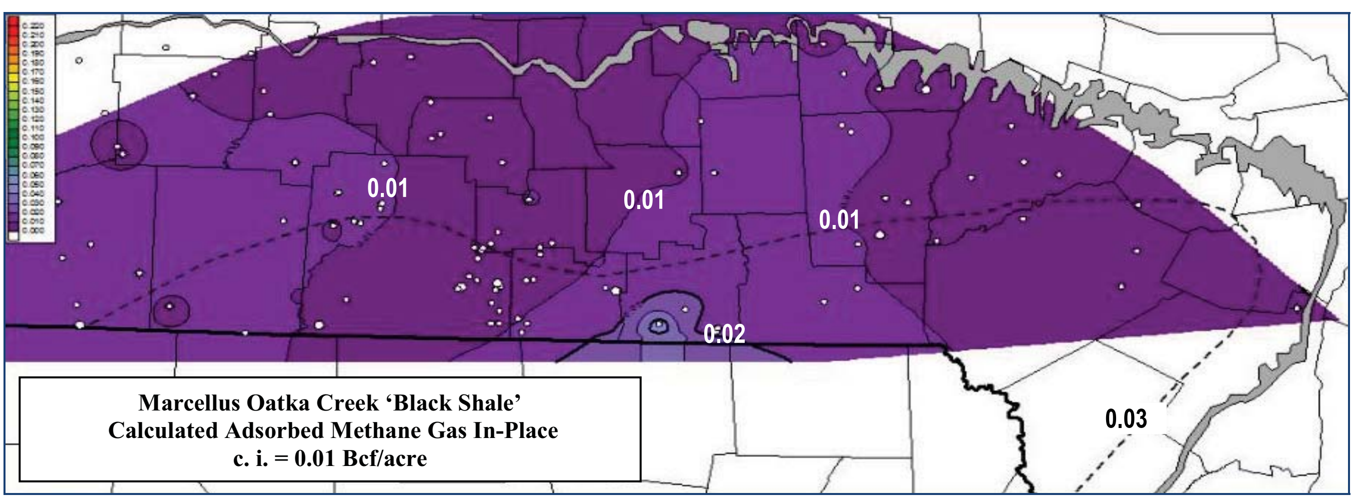


Figure B-4: Marcellus Oatka Creek 'Black Shale' Calculated Non-Adsorbed ('Free') Gas In-Place, Bcf/ac

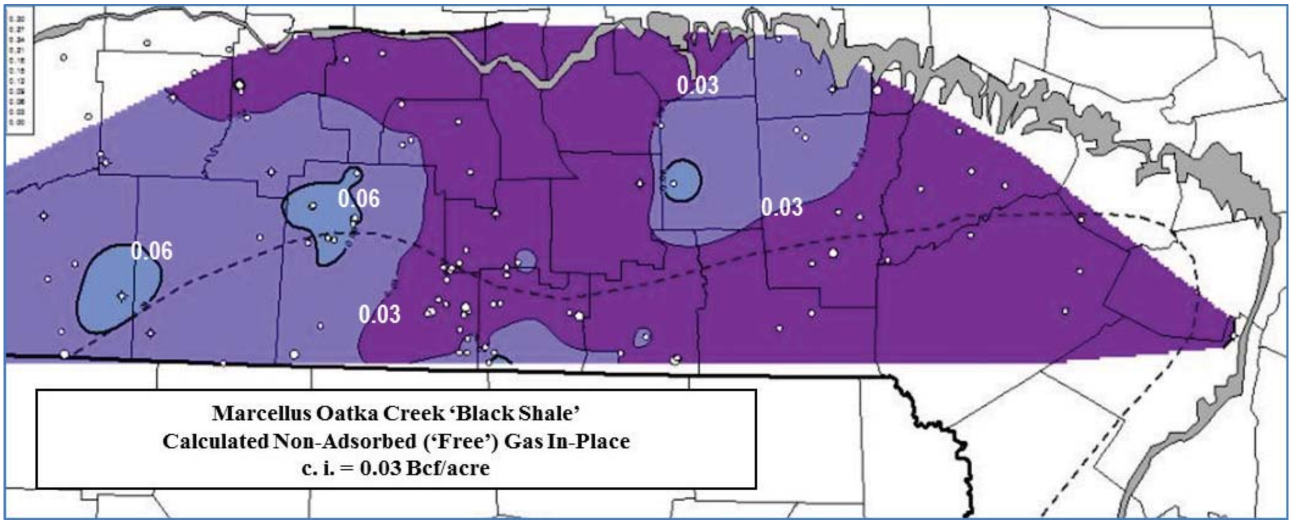


Figure B-5: Marcellus Union Springs Calculated Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

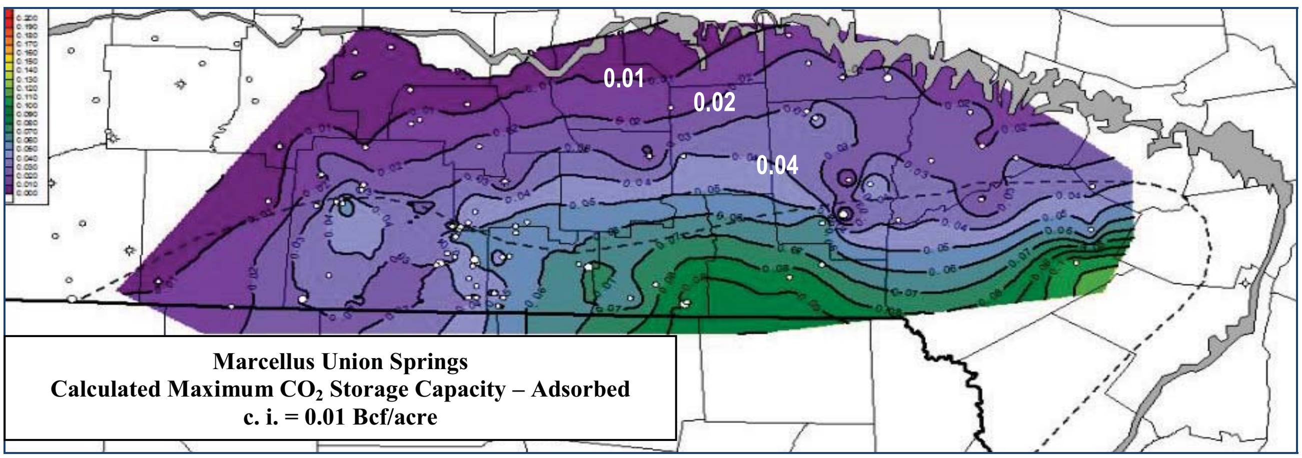


Figure B-6: Marcellus Oatka Creek Black Shale Calculated Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

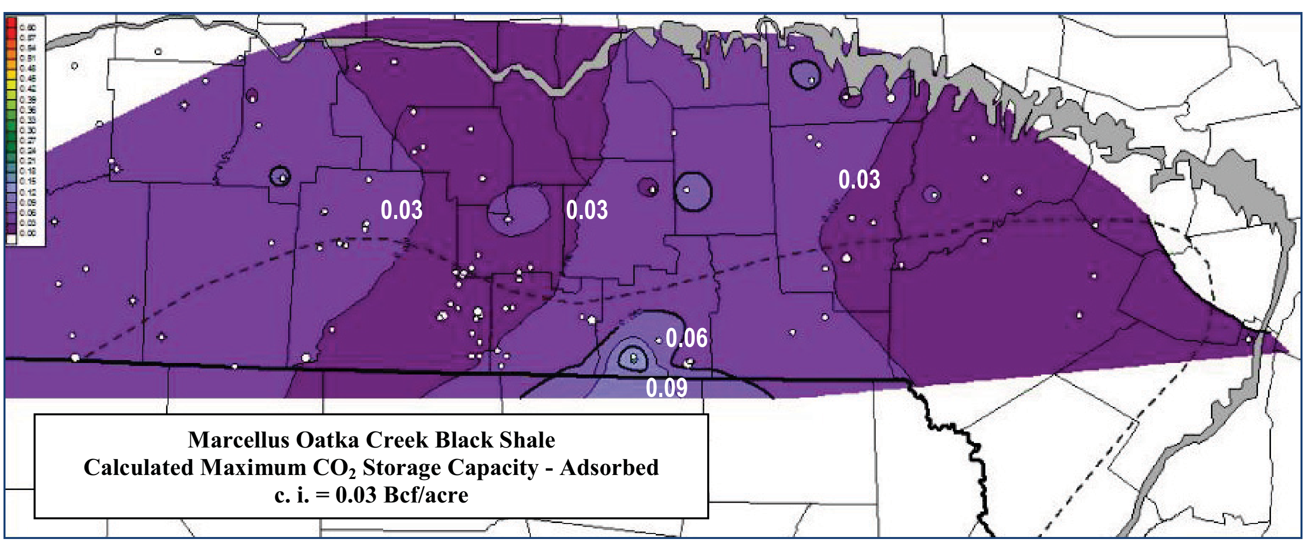


Figure B-7: Marcellus Union Springs Maximum CO_2 Storage Capacity – Non-Adsorbed ('Free') Phase, Bcf/ac

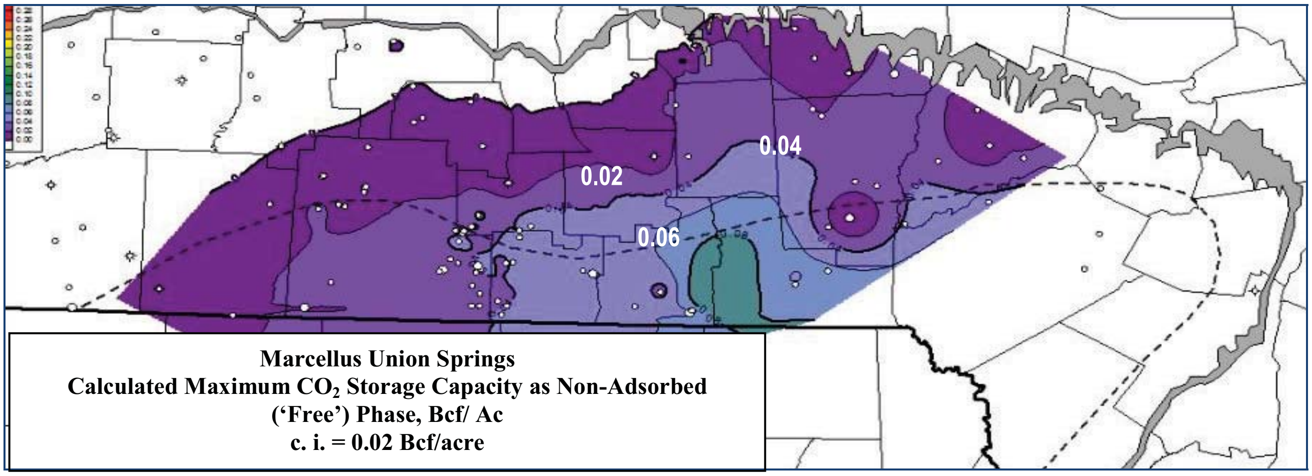


Figure B-8: Marcellus Oatka Creek 'Black Shale' Maximum CO_2 Storage Capacity - Non-Adsorbed ('Free') Phase, Bcf/ac

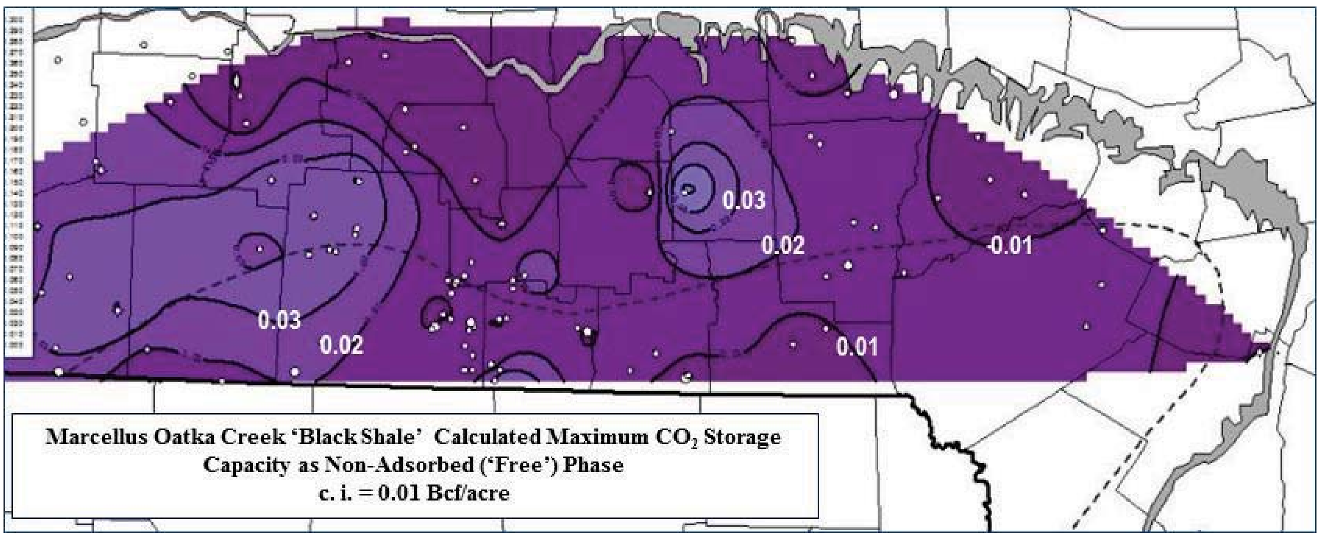


Figure B-9: Utica Indian Castle, Clay-Rich Member, Adsorbed Methane Gas In-Place, Bcf/ac

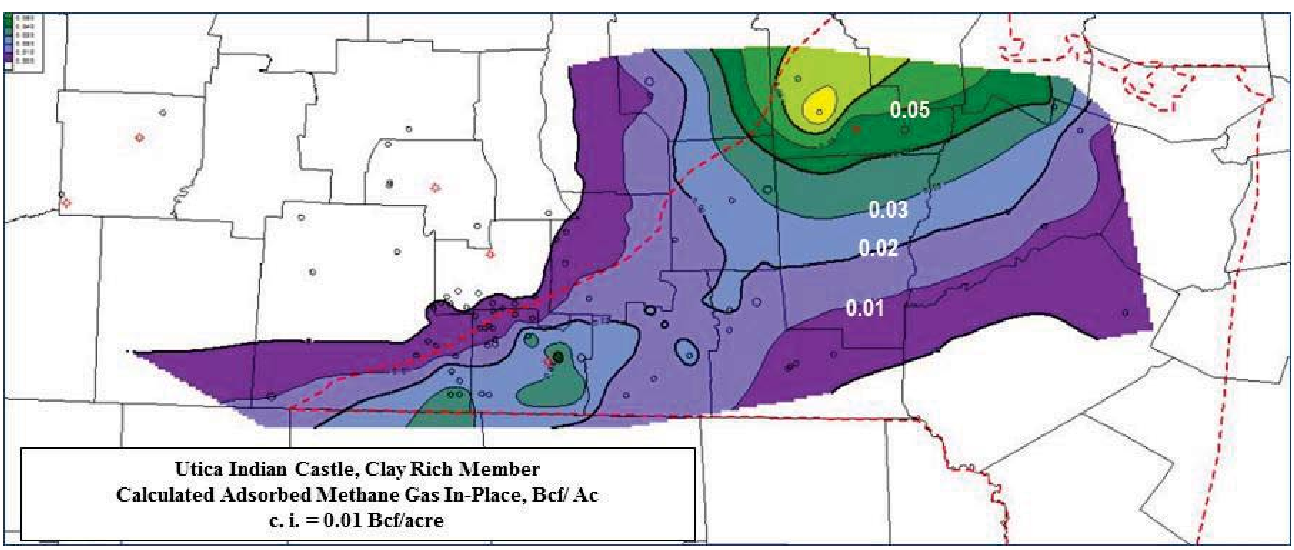


Figure B-10: Utica Indian Castle, Clay-Rich Member, Non-Adsorbed ('Free') Methane Gas In-Place, Bcf/ac

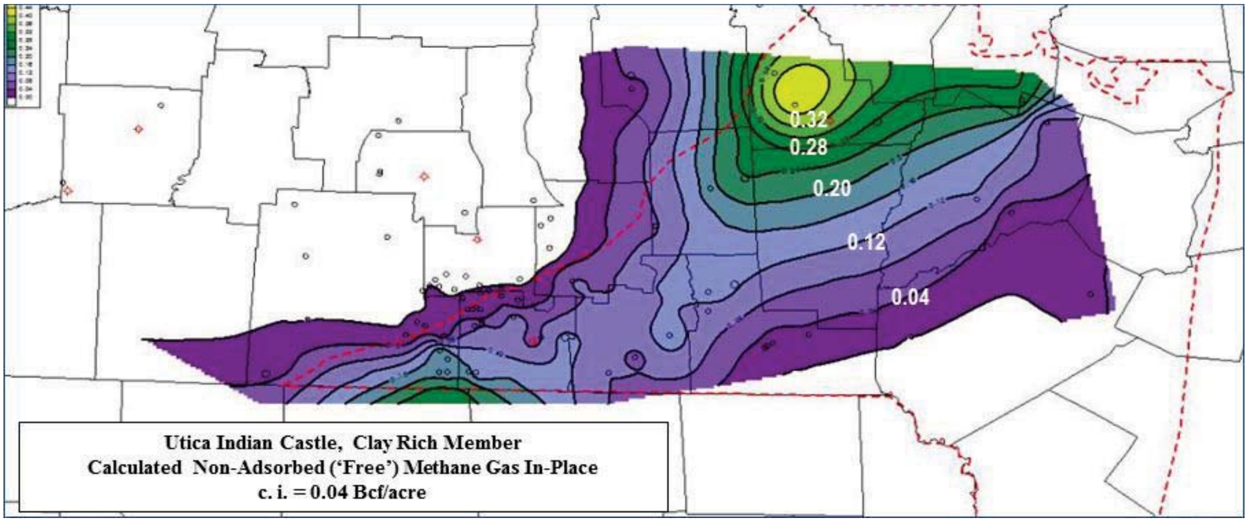


Figure B-11: Utica Indian Castle, Clay-Rich Member, Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

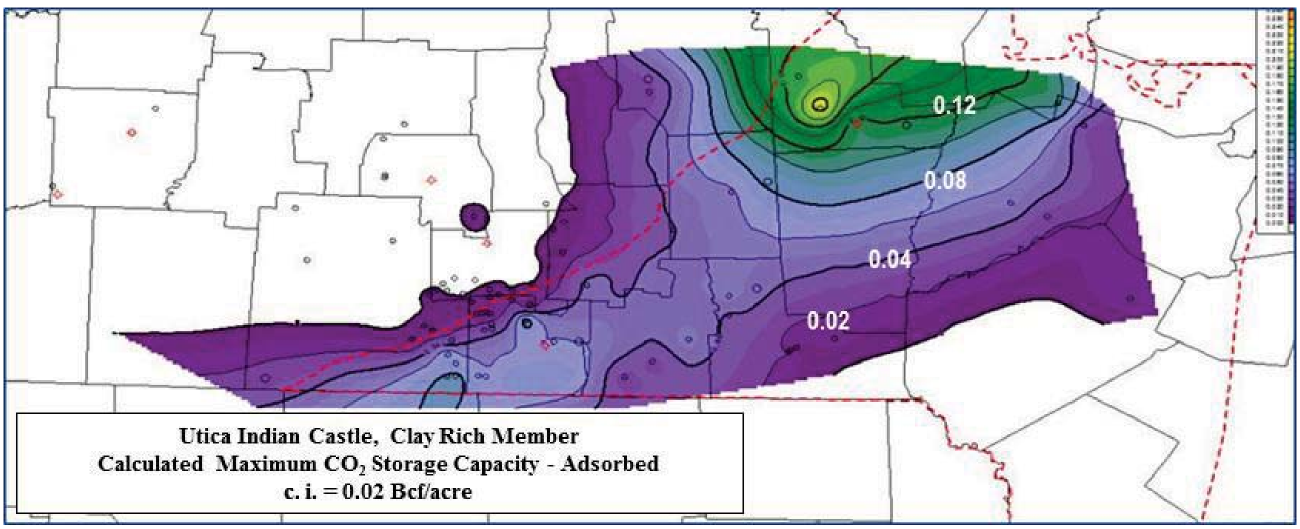


Figure B-12: Utica Indian Castle, Clay-Rich Member, Maximum CO_2 Storage Capacity as Non-Adsorbed ('Free') Phase, Bcf/ac

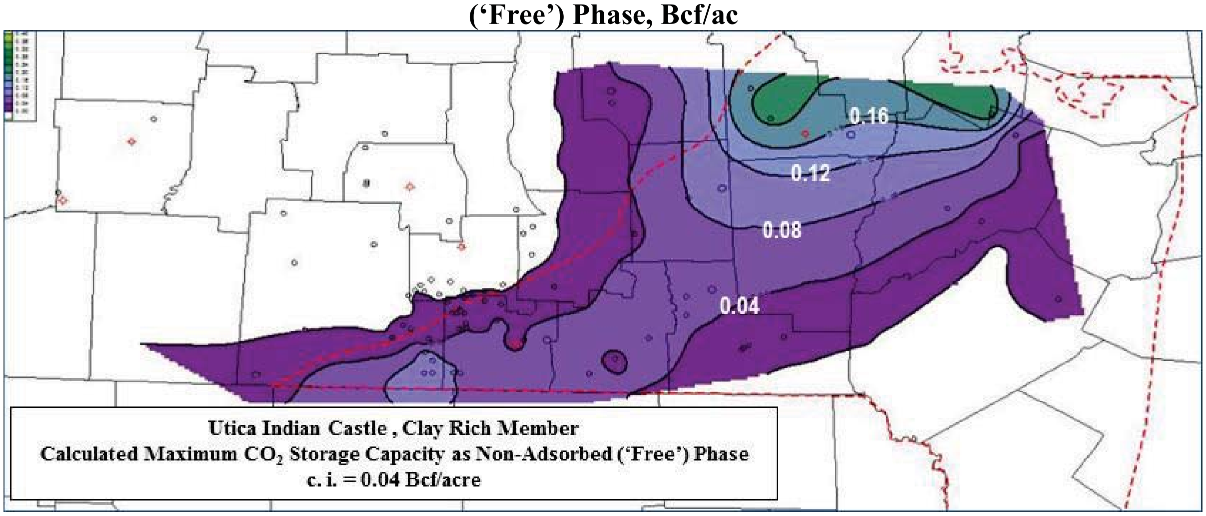


Figure B-13: Utica Indian Castle, Carbonate Rich Member, Adsorbed Methane Gas In-Place, Bcf/ac

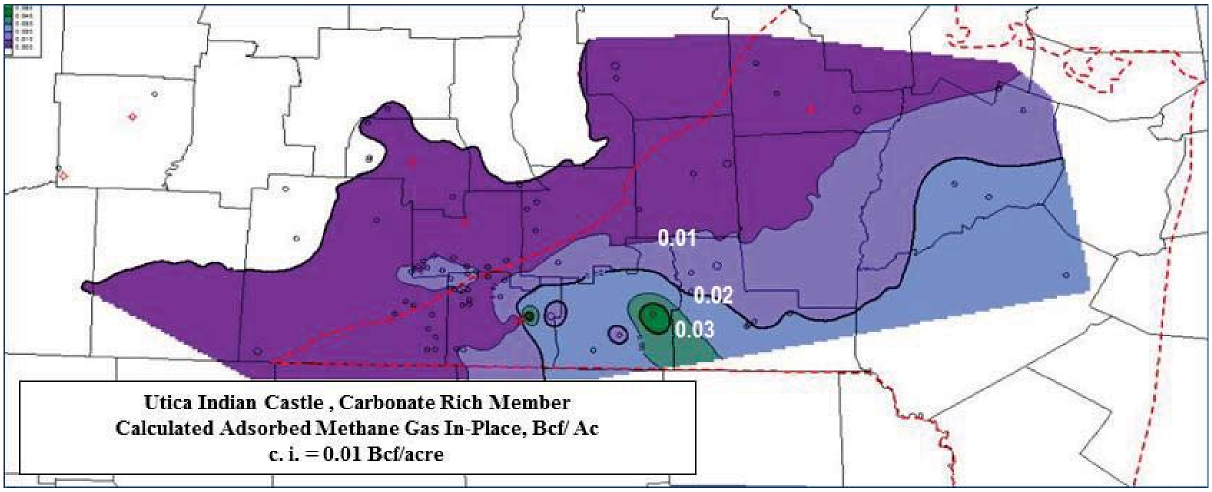


Figure B-14: Utica Indian Castle, Carbonate Rich Member, Calculated Non-Adsorbed ('Free') Methane Gas In-Place, Bcf/ac

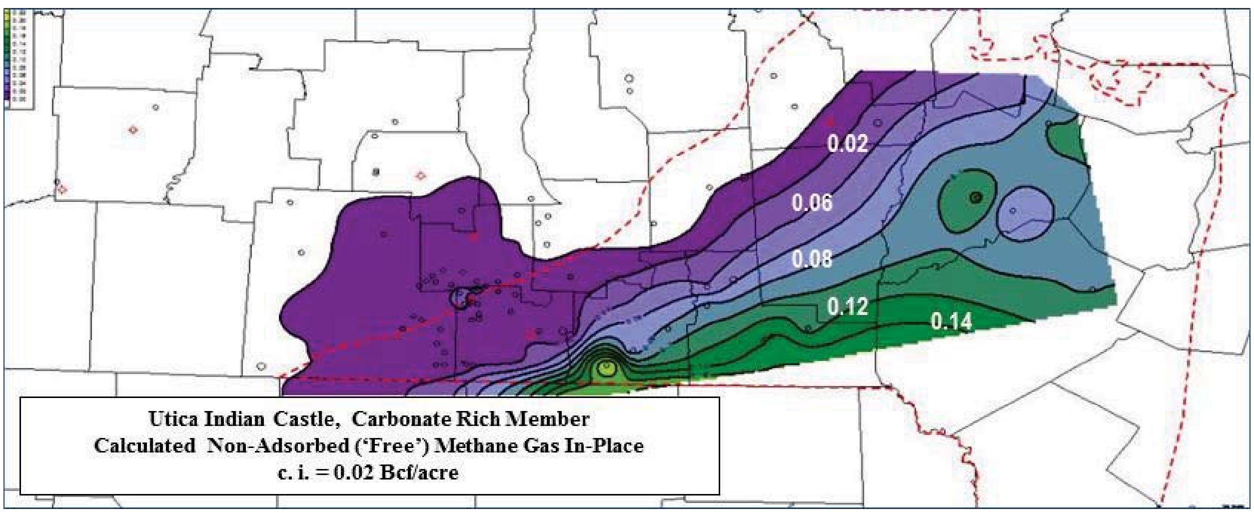


Figure B-15: Utica Indian Castle Carbonate Rich Member, Calculated Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

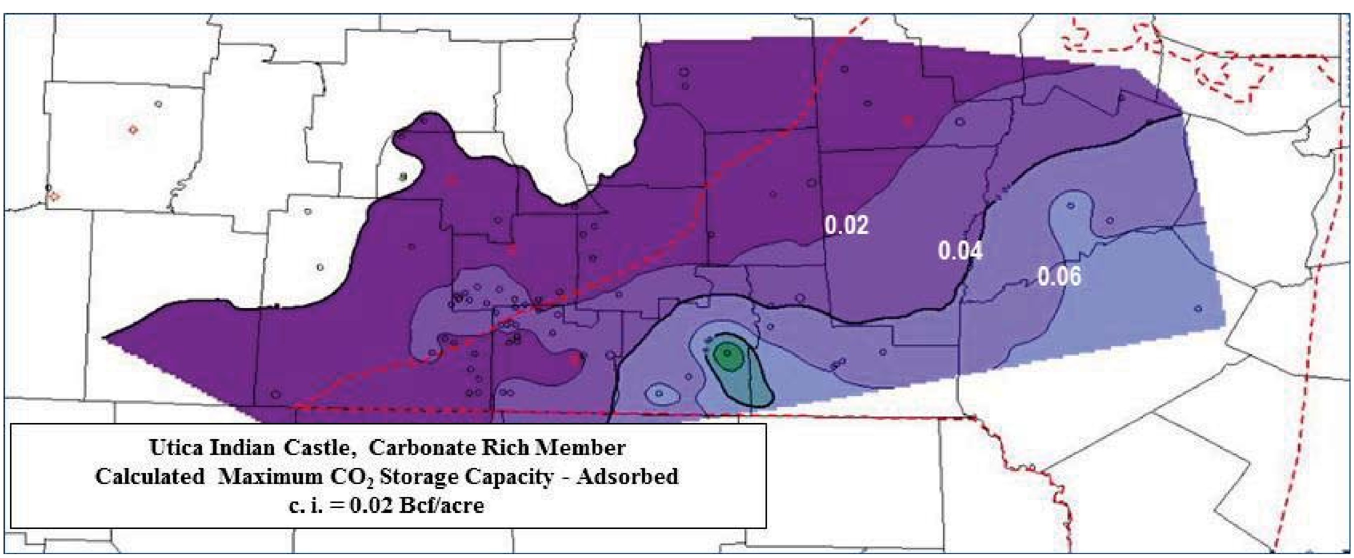


Figure B-16: Utica Indian Castle Carbonate Rich Member, Calculated Maximum CO_2 Storage Capacity as Non-Adsorbed ('Free') Phase, Bcf/ac

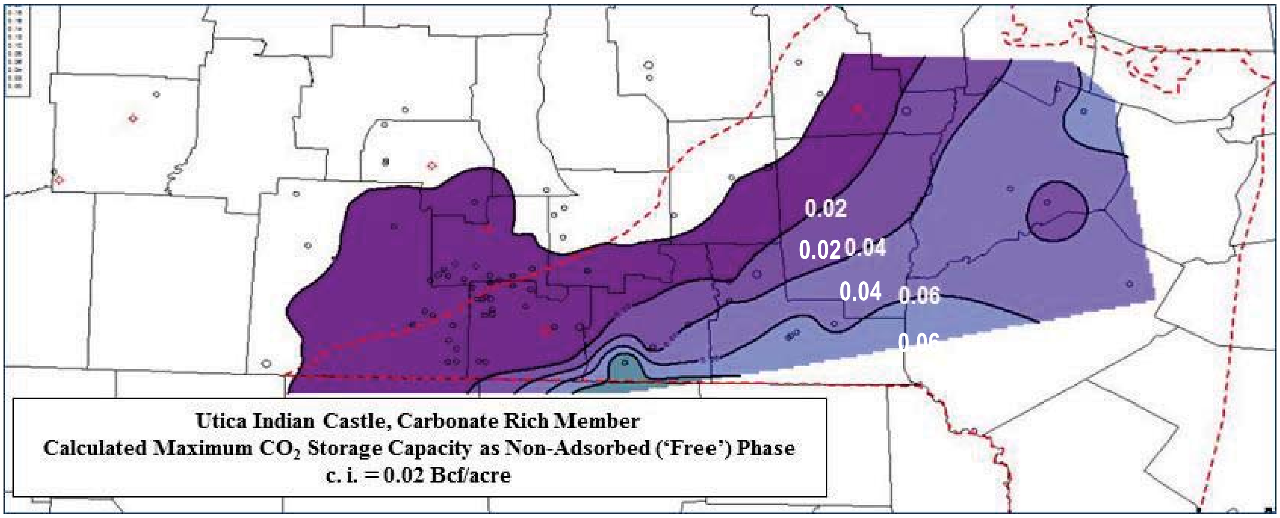


Figure B-17: Utica Dolgeville Fm., Adsorbed Methane Gas In-Place, Bcf/ac

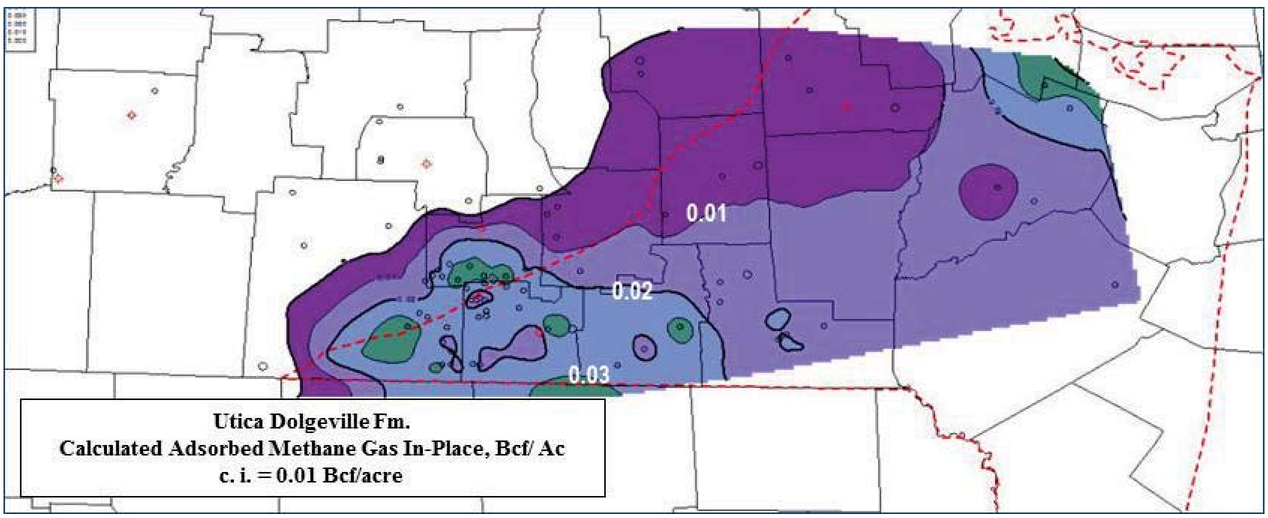


Figure B-18: Utica Dolgeville Fm., Non-Adsorbed ('Free') Methane Gas In-Place, Bcf/ac

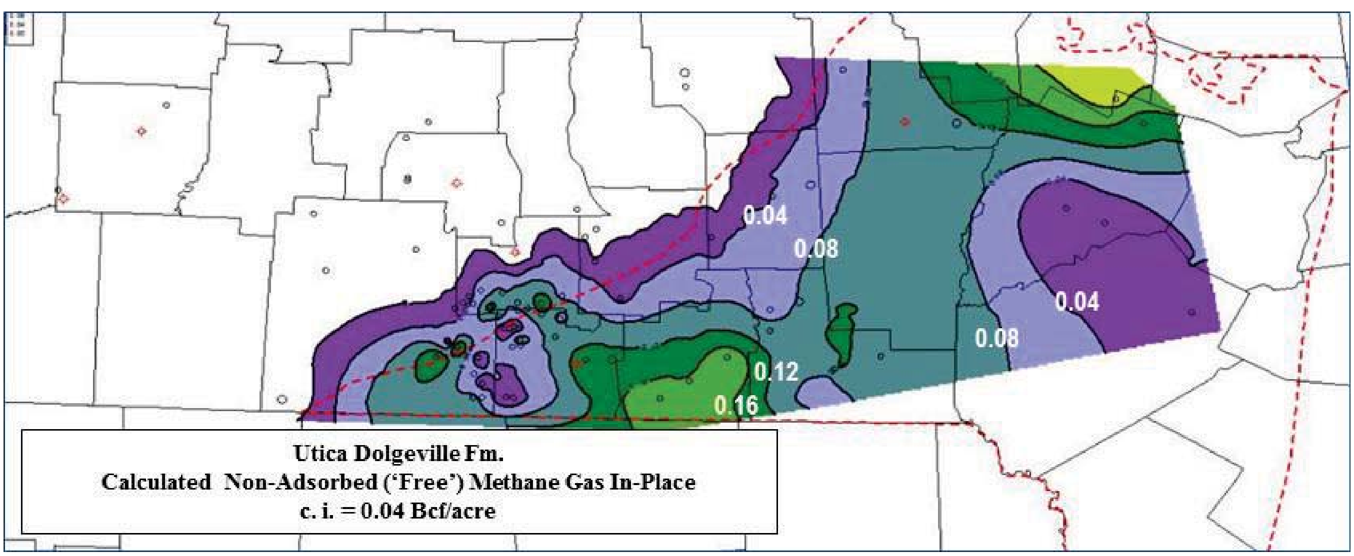


Figure B-19: Utica Dolgeville Fm., Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

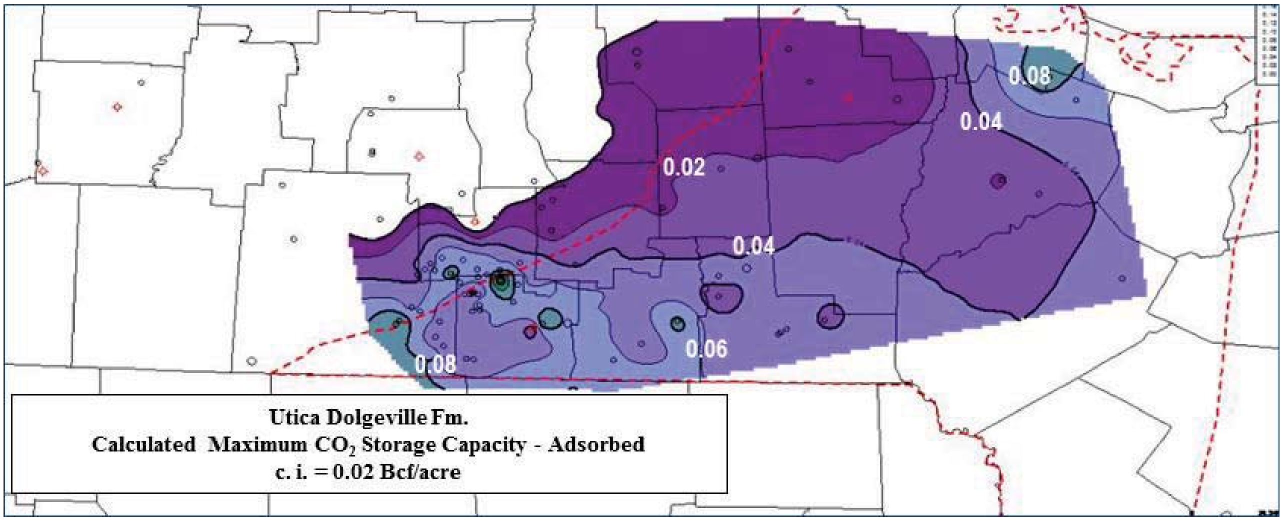


Figure B-20: Utica Dolgeville Fm., Maximum CO_2 Storage Capacity as Non-Adsorbed ('Free') Phase, Bcf/ac

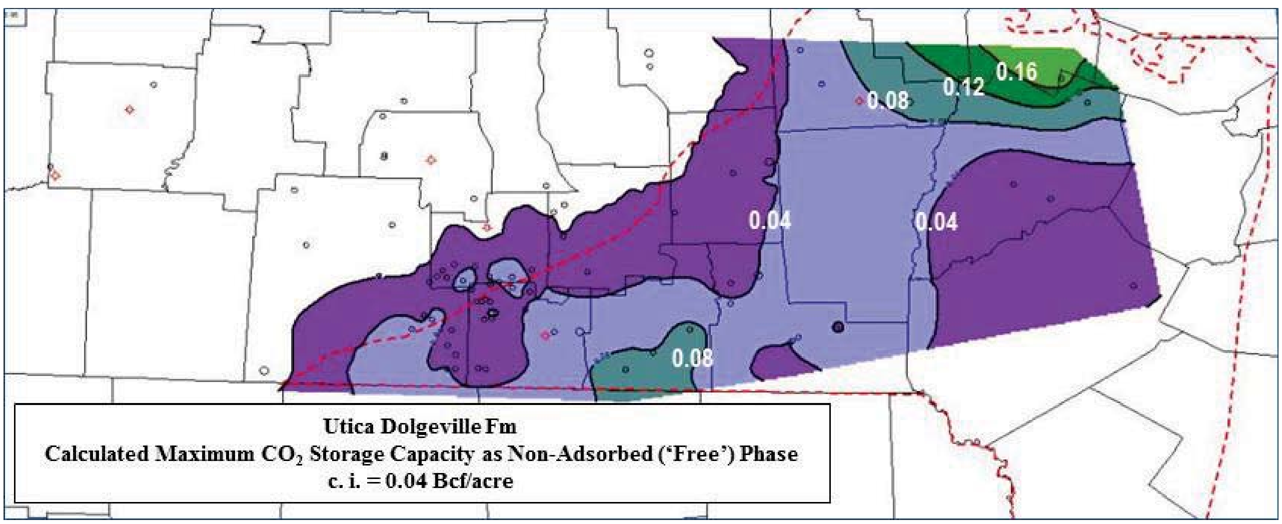


Figure B-21: Utica Flat Creek Fm., Adsorbed Methane Gas In-Place, Bcf/ac

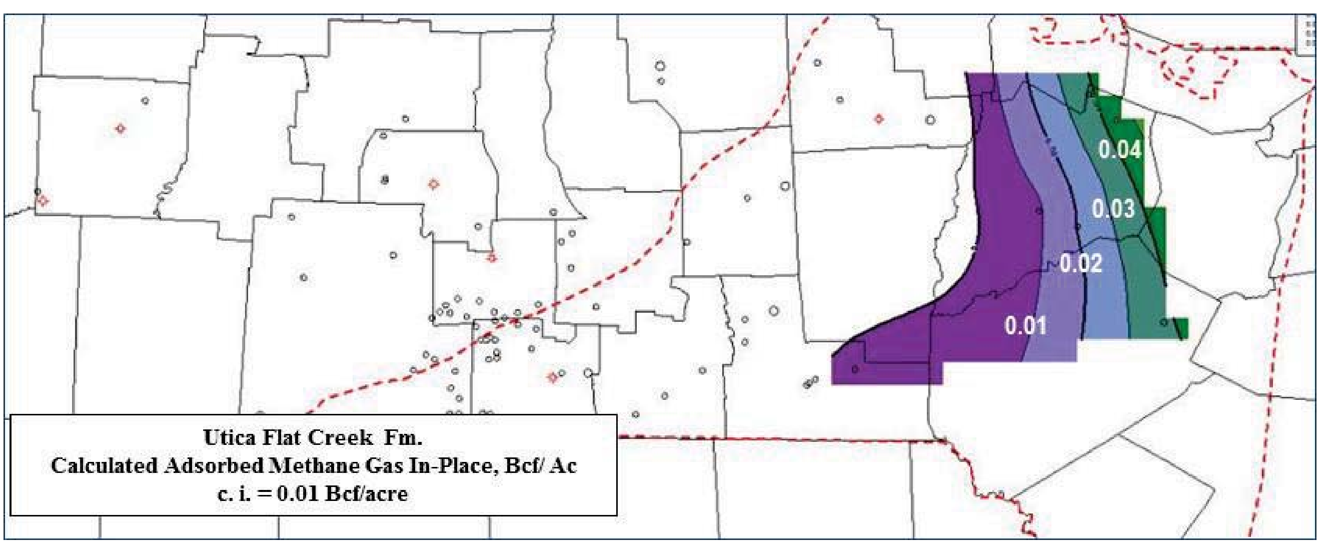


Figure B-22: Utica Flat Creek Fm., Non-Adsorbed ('Free') Methane Gas In-Place, Bcf/ac

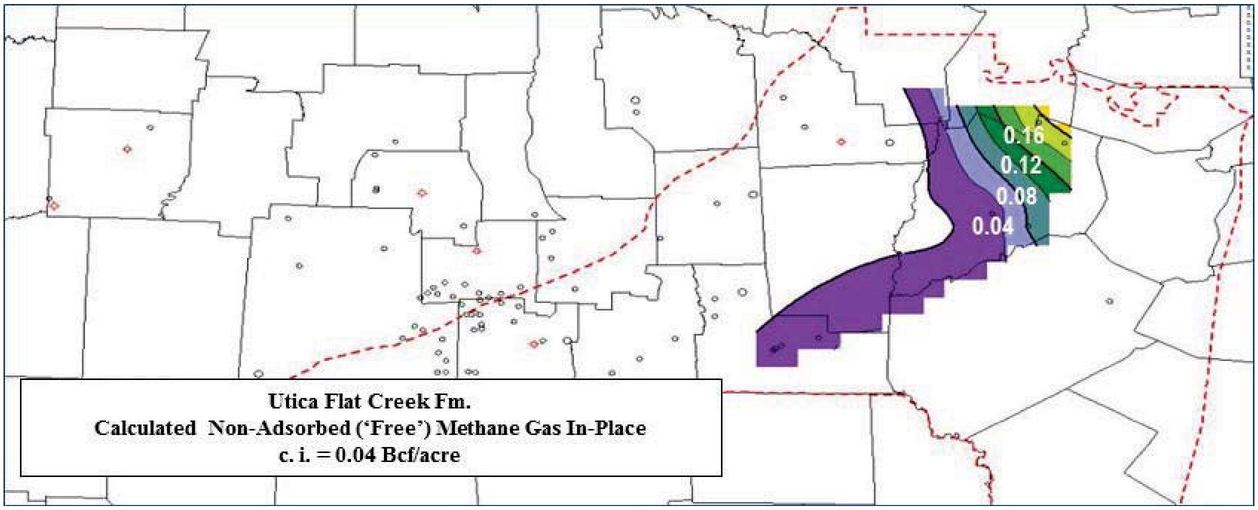


Figure B-23: Utica Flat Creek Fm., Maximum CO_2 Storage Capacity - Adsorbed, Bcf/ac

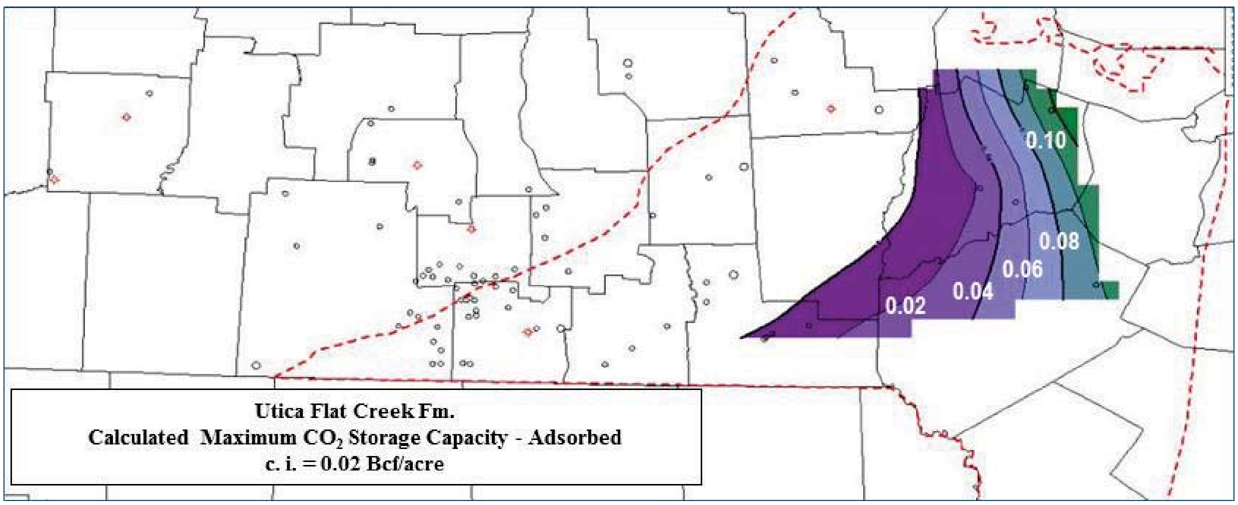
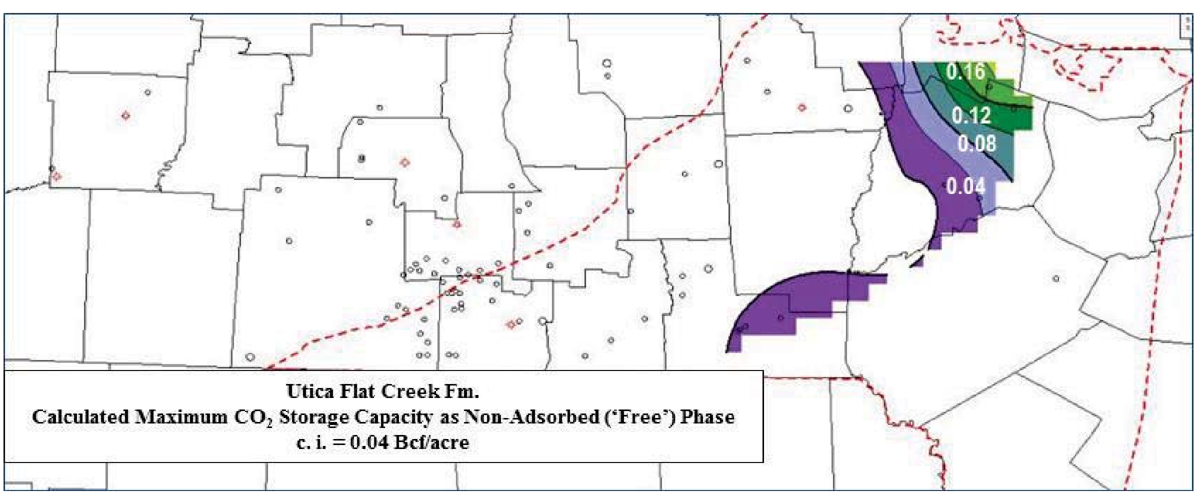


Figure B-24: Utica Flat Creek Fm., Maximum CO_2 Storage Capacity as Non-Adsorbed ('Free') Phase, Bcf/ac



APPENDIX C

CALCULATED GAS IN-PLACE AND CO_2 STORAGE CAPACITY FOR MARCELLUS AND UTICA STUDY WELLS IN EXPLORATION FAIRWAY

Table C-1: Marcellus Calculated Adsorbed CH_4 In-Place, Bcf/ac

Study Wells Marcellus Exploration Fairway API No.	Union Springs Adsorbed CH_4 Gas In-Place, Bcf/ac	Cherry Valley Adsorbed CH_4 Gas In-Place, Bcf/ac	Oatka Creek Black Shale Adsorbed CH_4 Gas In-Place, Bcf/ac
3100322126	0.002	0.001	0.009
3100321150	0.002	0.002	0.010
3100321875	0.005	0.002	0.012
3100723083	0.025	0.005	0.016
3101523023	0.017	0.001	0.012
3101523186	0.017	0.001	0.012
3101523134	0.016	0.001	0.008
3101523146	0.021	0.000	0.009
3101523212	0.010	0.001	0.009
3101523017	0.016	0.001	0.006
3101523076	0.018	0.001	0.012
3101523028	0.013	0.000	0.007
3101710607	0.015	0.006	0.005
3101723061	0.007	0.006	0.012
3101723005	0.004	0.002	0.001
3101710608	0.019	0.008	0.012
3101723006	0.010	0.009	0.013
3101710609	0.004	0.004	0.001
3102322818	0.010	0.002	0.020
3102319484	0.004	0.002	0.012
3102521005	0.006	0.004	0.003
3102510096	0.030	0.009	0.062
3102510227	0.016	0.007	0.004
3105321699	0.004	0.001	0.008
3105319485	0.011	0.002	0.010
3105320411	0.004	0.002	0.018
3105309578		0.001	0.008
3107710725	0.007	0.003	0.009
3107710834	0.006	0.000	0.002
3107710838	0.011	0.006	0.003
3107710138	0.006	0.002	0.003
3110122758	0.003	0.002	0.011
3110121496	0.006	0.002	0.010
3110123105	0.013	0.001	0.006
3110123054	0.015	0.001	0.006
3110111135	0.005	0.001	0.013
3110123055	0.015	0.001	0.007
3110123101	0.007	0.006	0.004
3110123059	0.010	0.001	0.005
3110112075	0.003	0.001	0.012
3110121506	0.010	0.002	0.010
3110123040	0.014	0.001	0.009
3110122963	0.012	0.001	0.008
3110123833	0.015	0.001	0.005
3110121570	0.007	0.002	0.009
3110123085	0.012	0.001	0.005
3110121459	0.007	0.001	0.012
3110121623	0.005	0.002	0.010

Study Wells Marcellus Exploration Fairway API No.	Union Springs Adsorbed CH_4 Gas In-Place, Bcf/ac	Cherry Valley Adsorbed CH_4 Gas In-Place, Bcf/ac	Oatka Creek Black Shale Adsorbed CH_4 Gas In-Place, Bcf/ac
3110123211	0.012	0.001	0.009
3110123038	0.012	0.001	0.008
3110122861	0.008	0.001	0.006
3110121627	0.006	0.002	0.012
3110123155	0.011	0.001	0.006
3110722931	0.040	0.005	0.089
3110722974	0.022	0.001	0.023
3110722934	0.019	0.004	0.044
3110722821	0.028	0.001	0.003
3110722887	0.026	0.003	0.015
3110722932	0.029	0.003	0.015

Table C-2: Marcellus Calculated Non-Adsorbed ('Free') CH_4 In-Place, Bcf/ac

Study Wells Marcellus Exploration Fairway API No.	Union Springs Non-Adsorbed CH_4 Gas In-Place Bcf/ac	Cherry Valley Non-Adsorbed CH_4 Gas In-Place Bcf/ac	Oatka Creek Black Shale Non-Adsorbed CH_4 Gas In-Place Bcf/ac
3100322126	0.01132	0.00641	0.03996
3100321150	0.00799	0.00938	0.04718
3100321875	0.02680	0.00796	0.0321
3100723083	0.12458		0.0097
3101523023	0.08630	0.00241	0.02885
3101523186	0.08180	0.00164	0.05404
3101523134	0.08707	0.0045	0.02829
3101523146	0.11568	0.00081	0.01513
3101523212	0.04850	0.00076	0.02507
3101523017	0.08643	0.00569	0.02157
3101523076	0.09332	0.00417	0.05989
3101523028	0.06086		0.01479
3101723006	0.04926	0.03521	0.04248
3101710609	0.00894	0.00048	
3102322818	0.04977		0.07780
3105320411	0.01907	0.00390	0.03612
3107710834	0.02114		0.00382
3110122758	0.00621	0.01443	0.06175
3110121496	0.02311	0.00914	0.05906
3110123105	0.07054	0.00065	0.00582
3110123054	0.08597	0.0017	0.01991
3110123055	0.08363	0.00449	0.02063
3110123101	0.00025		
3110123059	0.04431	0.00263	0.01314
3110112075	0.01884	0.00608	0.06291
3110121506	0.02468	0.01125	0.06115
3110123040	0.07803	0.0029	0.03605
3110123833	0.08725	0.00354	0.0196
3110121570	0.04172	0.01307	0.05251
3110123085	0.06983		0.01754
3110121459	0.02539		0.07375
3110121623	0.02972	0.00718	0.05996
3110123211	0.05184	0.00176	0.03312
3110123038	0.06449	0.00193	0.01939
3110121627	0.01837	0.01548	0.07055
3110123155	0.06109	0.00691	0.03272
3110722931	0.21934	0.02168	0.19786
3110722974	0.06861	0.00317	0.03154
3110722934	0.09429	0.02725	0.20783
3110722821	0.14603	0.00972	0.01022
3110722887	0.08855	0.01423	0.00724
3110722932	0.16079	0.01000	0.01874

Table C-3: Utica Calculated Adsorbed CH_4 In-Place, Bcf/ac

Study Wells Utica Exploration Fairway API No.	Indian Castle - Clay Rich; Adsorbed CH_4 GIP, Bcf/ac	Indian Castle - Carbonate Rich; Adsorbed CH_4 GIP, Bcf/ac	Dolgeville; Adsorbed CH_4 GIP, Bcf/ac	Flat Creek; Adsorbed CH_4 GIP, Bcf/ac
3100723032	0.01532	0.01904	0.01038	
3100723056	0.00531	0.02079	0.02574	
3100723030	0.0207	0.01504	0.01849	
3100723078	0.00322	0.018	0.01799	
3100722984	0.00541	0.02017	0.0146	0.00424
3100722995	0.00774	0.02282	0.01644	
3101522890	0.00527	0.01231	0.08744	
3101522933	0.0438	0.0467	0.03603	
3101523097	0.02637	0.00959	0.02213	
3101522891	0.0005	0.00778	0.01788	
3101522975	0.00227	0.00778	0.0175	
3101523186	0.02477	0.01092	0.01922	
3101522901	0.00177	0.01498	0.0269	
3101522960	0.00118	0.01261	0.01364	
3101523134	0.01309	0.0047	0.02194	
3101522880	0.00786	0.00797	0.06368	
3101522911	0.02386	0.00797	0.01236	
3101522918	0.01018	0.00627	0.03019	
3101522919	0.0015	0.01213	0.01555	
3101523228	0.03378	0.01166		
3101523146	0.02347	0.01432	0.00148	
3101522924	0.00384	0.01033	0.0239	
3101523028	0.01234	0.00467		
3102322798	0.02272	0.00222	0.00842	
3102323035	0.01537	0.00208	0.00701	
3102321500	0.03243	0.00292	0.00756	
3102510227	0.00537	0.02777	0.01855	0.03781
3105319485	0.04439	0.00881	0.00388	
3105309578	0.06317	0.0044	0.00434	
3105320411	0.07909	0.00327	0.00336	
3105321699	0.04327	0.00504	0.00417	
3106712163	0.01178	0.00215	0.00343	
3106722965	0.00941	0.00075	0.00267	
3107710834	0.01997	0.02562	0.00716	0.0075
3107723759	0.03836	0.01011	0.03458	0.03845
3107723760	0.01241	0.01506	0.02423	0.04477
3107723783	0.00975	0.0216	0.01179	0.02044
3109722830	0.00031	0.0061	0.02277	
3109722829		0.00946	0.01821	
3109723086		0.01343	0.0257	
3109722942	0.00003	0.01204	0.03755	
3109722886		0.00934	0.03262	
3109722841		0.0099	0.02834	
3109722893	0.00244	0.01079	0.02699	

Study Wells Utica Exploration Fairway API No.	Indian Castle - Clay Rich; Adsorbed CH_4 GIP, Bcf/ac	Indian Castle - Carbonate Rich; Adsorbed CH_4 GIP, Bcf/ac	Dolgeville; Adsorbed CH_4 GIP, Bcf/ac	Flat Creek; Adsorbed CH_4 GIP, Bcf/ac
3109723053		0.00902	0.0681	
3109722935	0.00011	0.004	0.01976	
3110123105	0.02996	0.00526	0.01912	
3110122978	0.0098	0.00404		
3110123101	0.00075	0.01322	0.01188	
3110123059	0.00299	0.00751	0.0214	
3110123040	0.02737	0.00477	0.01993	
3110123151		0.00201		
3110122963	0.17167	0.00522	0.03166	
3110123211	0.03291	0.004	0.01873	
3110123038	0.01049	0.00446	0.0036	
3110122861	0.00142	0.00855	0.04036	
3110123155	0.00134	0.00778	0.02644	
3110722974	0.01111	0.01693	0.01747	
3110722934	0.01067	0.02572	0.02618	
3110723116	0.02137	0.04949	0.03424	
3110922997	0.01652		0.01533	
3110922767	0.00106	0.00188	0.00313	
3110922998	0.00003	0.00417	0.00461	
3110922753	0.00037	0.00075	0.00136	

Table C-4: Utica Calculated Non-Adsorbed ('Free') CH_4 In-Place, Bcf/ac

Study Wells Utica Exploration Fairway API No.	Indian Castle - Clay Rich; Non-Adsorbed CH_4 GIP, Bcf/ac	Indian Castle - Carbonate Rich; Non-Adsorbed CH_4 GIP, Bcf/ac	Dolgeville; Non-Adsorbed CH_4 GIP, Bcf/ac	Flat Creek; Non-Adsorbed CH_4 GIP, Bcf/ac
3100723032	0.09541	0.08582	0.02844	
3100723056	0.03159	0.13972	0.09719	
3100723030	0.15191	0.0435	0.06905	
3100723078	0.01625	0.14057	0.12289	
3100722984	0.03241	0.11485	0.08188	0.03289
3100722995	0.02979	0.13739	0.08323	0.01186
3101522890	0.01814	0.02528	0.30727	
3101522933	0.24561	0.13476	0.14214	
3101523097	0.18024	0.00057	0.0191	
3101522975			0.03167	
3101523186	0.1249	0.01572		
3101522901	0.0062			
3101522960	0.00072	0.00816	0.01376	
3101523134	0.08275		0.04255	
3101522880	0.03528	0.00658	0.32558	
3101522911	0.07035	0.00068		
3101522918	0.0374	0.00181	0.12377	
3101522919	0.00753	0.02071	0.03176	
3101523228	0.09135	0.08685		
3101523146	0.12937	0.00183		
3101522924	0.00438	0.00836	0.07512	
3101523028	0.07045			
3102323035	0.07778			
3102321500	0.23785	0.0012		
3102510227	0.02799	0.09946	0.03467	
3102504364				0.05545
3102521070				0.05284
3105320411	0.42098			
3106712163	0.04734			
3106722965	0.01305			
3107710834	0.1136	0.12201	0.00344	0.00873
3107723759	0.26008	0.05973	0.21329	0.23248
3107723760	0.06988	0.09892	0.1398	0.22184
3107723783	0.02356	0.06153	0.0187	0.08331
3109722830	0.00038	0.00812	0.01434	
3109722881	0.00064	0.01011	0.16007	
3109722829		0.00401	0.023	
3109723086		0.01609	0.05946	
3109722942		0.01054	0.13661	
3109722886		0.00486	0.09309	
3109722841			0.05678	
3109722893	0.0072	0.01561	0.0929	
3109722935		0.00312	0.07549	
3110123105	0.18474	0.00825	0.00702	

Study Wells Utica Exploration Fairway API No.	Indian Castle - Clay Rich; Non-Adsorbed CH_4 GIP, Bcf/ac	Indian Castle - Carbonate Rich; Non-Adsorbed CH_4 GIP, Bcf/ac	Dolgeville; Non-Adsorbed CH_4 GIP, Bcf/ac	Flat Creek; Non-Adsorbed CH_4 GIP, Bcf/ac
3110122978	0.02776			
3110123101		0.01988	0.01277	
3110123059		0.01068	0.03267	
3110123040	0.18406		0.02778	
3110123151		0.01546		
3110122963	0.79911	0.0016	0.0878	
3110122859	0.01411			
3110123211	0.17354			
3110123038	0.02201		0.02472	
3110122861	0.00608	0.01563	0.01563	
3110123155	0.00518	0.01558	0.16365	
3110722974	0.07389	0.07345	0.03563	
3110722934	0.08088	0.19774	0.18106	
3110723116	0.14372	0.29281	0.18045	
3110922997	0.07952		0.03351	
3110922998			0.00274	

Table C-5: Marcellus Calculated Theoretical Maximum CO_2 Storage - Adsorbed, Bcf/ac

Study Wells Marcellus Exploration Fairway API No.	Union Springs; Max Adsorbed CO_2 Capacity, Bcf/ac	Cherry Valley Mbr.; Max Adsorbed CO_2 Capacity, Bcf/ac	Oatka Creek Black Shale.; Max Adsorbed CO_2 Capacity, Bcf/ac
3100322126	0.00870	0.00354	0.01926
3100321150	0.00618	0.00553	0.02708
3100321875	0.01643	0.00559	0.01488
3100723083	0.08470	0.01470	0.00472
3101523023	0.06010	0.00366	0.04006
3101523186	0.05640	0.00190	0.04018
3101523134	0.05900	0.00386	0.02746
3101523146	0.07400	0.00281	0.03010
3101523212	0.03520	0.00202	0.02950
3101523017	0.05760	0.00491	0.02021
3101523076	0.06020	0.00322	0.04007
3101523028	0.04350	0.00171	0.02086
3101710607	0.04966	0.01992	0.01628
3101723061	0.02872	0.02051	0.03923
3101723005	0.01300	0.00722	0.00169
3101710608	0.06940	0.02644	0.03874
3101723006	0.04305	0.03293	0.04469
3101710609	0.01341	0.01162	0.00409
3102322818	0.04087		0.05810
3102319484	0.01656		
3102521005	0.01991	0.01065	0.00913
3102510096	0.10568	0.02975	0.22078
3102510227	0.05272	0.02282	0.01197
3105320411	0.023	0.00526	0.0638
3105319485	0.02241	0.0055	0.03398
3105321669	0.02216	0.00416	0.02738
3105309578		0.00335	
3107710725	0.02510	0.00805	0.03129
3107710834	0.01993	0.00113	0.00743
3107710838	0.03745	0.00483	0.00749
3107710138	0.02231	0.01935	0.00929
3110122758	0.01097	0.00831	0.04693
3110121496	0.02809	0.00587	0.04035
3110123105	0.04541	0.00218	0.0183
3110123054	0.05166	0.00243	0.02009
3110111135	0.02286	0.00226	0.05049
3110123055	0.0541	0.00376	0.02275
3110123101	0.02314	0.01843	0.01298
3110123059	0.03477	0.00374	0.01658
3110112075	0.01105	0.00429	0.04606
3110121506	0.0623	0.00665	0.03946
3110123040	0.04926	0.00286	0.02974
3110122963	0.04044	0.00271	0.02505
3110123833	0.05674	0.00316	0.01617
3110121570	0.02662	0.00663	0.03626

Study Wells Marcellus Exploration Fairway API No.	Union Springs; Max Adsorbed CO_2 Capacity, Bcf/ac	Cherry Valley Mbr.; Max Adsorbed CO_2 Capacity, Bcf/ac	Oatka Creek Black Shale.; Max Adsorbed CO_2 Capacity, Bcf/ac
3110123085	0.04323	0.00346	0.01689
3110121459	0.0346	0.00319	0.04648
3110121623	0.01963	0.00502	0.04189
3110123211	0.03805	0.00278	0.02985
3110123038	0.04401	0.00205	0.02381
3110122861	0.02806	0.00302	0.01802
3110121627	0.04295	0.00822	0.04756
3110123155	0.03914	0.00341	0.01888
3110722931	0.14613	0.02047	0.45342
3110722974	0.0783	0.00363	0.07495
3110722934	0.06231	0.01471	0.15104
3110722821	0.09427	0.00372	0.00993
3110722887	0.08682	0.0099	0.04546
3110722932	0.0973	0.0108	0.04747

Table C-6: Marcellus Calculated Theoretical Maximum CO_2 Storage – Non-Adsorbed ('Free'), Bcf/ac

Study Wells Marcellus Exploration Fairway API No.	Union Springs; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Cherry Valley; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Oatka Creek Black Shale; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac
3100322126	0.00546	0.00309	0.0218
3100321150	0.00459	0.00539	0.0201
3100321875	0.01242	0.00369	0.0155
3100723083	0.0609		0.0047
3101523023	0.0452	0.00126	0.01511
3101523186	0.0425	0.00085	0.02807
3101523134	0.05112	0.00264	0.01661
3101523146	0.06112	0.00043	0.00799
3101523212	0.02357	0.00037	0.01218
3101523017	0.04555	0.00300	0.01137
3101523076	0.04877	0.00218	0.0313
3101523028	0.03208		0.00779
3101723006	0.02043	0.01461	0.01762
3101710609	0.0047	0.00025	
3102322818	0.03	0.01	0.05
3102319484	0.00	0.00	0.00
3105320411	0.00306	0.0028	0.0058
3107710834	0.00553		0.001
3110122758	0.00417	0.00969	0.04148
3110121496	0.01341	0.00531	0.03428
3110123105	0.03726	0.00034	0.00308
3110123054	0.04401	0.00087	0.01019
3110123055	0.04369	0.00235	0.01077
3110123101	0.00013		
3110123059	0.02333	0.00263	0.00692
3110112075	0.01098	0.00354	0.03668
3110121506	0.01303	0.00594	0.03228
3110123040	0.03768	0.0014	0.01741
3110123833	0.04948	0.00201	0.01112
3110121570	0.02397	0.00751	0.03017
3110123085	0.03676		0.00923
3110121459	0.01328	0.00138	0.03857
3110121623	0.01735	0.00419	0.03499
3110123211	0.02545	0.00086	0.01626
3110123038	0.033877	0.00101	0.01015
3110121627	0.01068	0.009	0.04103
3110123155	0.03196	0.00361	0.01712
3110722931	0.1076	0.01064	0.09706
3110722974	0.0229	0.00167	0.01659
3110722934	0.04362	0.01322	0.10085
3110722821	0.07134	0.00475	0.00499
3110722887	0.04315	0.00694	0.00353
3110722932	0.07855	0.00489	0.00915

Table C-7: Utica Calculated Theoretical Maximum CO_2 Storage - Adsorbed, Bcf/ac

Study Wells in Utica Exploration Fairway API No.	Indian Castle Clay-Rich; Max Adsorbed CO_2 Capacity, Bcf/ac	Indian Castle Carbonate-Rich; Max Adsorbed CO_2 Capacity, Bcf/ac	Dolgeville; Max Adsorbed CO_2 Capacity, Bcf/ac	Flat Creek; Max Adsorbed CO_2 Capacity, Bcf/ac
3100723032	0.03901	0.04884	0.02663	
3100723056	0.01362	0.05302	0.06563	0
3100723030	0.05292	0.03887	0.04734	
3100723078	0.00826	0.04612	0.04604	
3100722984	0.01394	0.05187	0.03743	0.01100
3100722995	0.01993	0.05848	0.04159	0
3101522890	0.01313	0.03054	0.18452	
3101522933	0.11029	0.11461	0.09064	
3101523097	0.06687	0.02463	0.05652	
3101522891	0.00131	0.02021	0.04595	
3101522975	0.00593	0.02022	0.04482	
3101523186	0.06286	0.02767	0.04911	
3101522901	0.00454	0.03839	0.06839	
3101522960	0.00306	0.03261	0.03512	
3101523134	0.03353	0.0122	0.05628	
3101522880	0.02005	0.02047	0.14638	
3101522911	0.0607	0.01597	0.03171	
3101522918	0.02623	0.01619	0.07441	
3101522919	0.00377	0.03097	0.03986	
3101523228	0.08577	0.02925		
3101523146	0.06001	0.03679	0.00378	
3101522924	0.00994	0.02662	0.06015	
3101523028	0.03163	0.01209		
3102322798	0.05844	0.00582	0.02202	
3102323035	0.03964	0.00545	0.01833	
3102321500	0.08335	0.0076	0.01983	
3102510227	0.01384	0.07187	0.0477	0.097
3105319485	0.11538	0.0236	0.01024	
3105309578	0.16648	0.01176	0.01159	
3105320411	0.20499	0.00868	0.00888	
3105321699	0.11312	0.01347	0.01113	
3106712163	0.0311	0.0058	0.00918	
3106722965	0.02466	0.00201	0.00718	
3107710834	0.05217	0.06674	0.01891	0.02
3107723759	0.10232	0.02753	0.09307	0.102
3107723760	0.03317	0.03987	0.06379	0.117
3107723783	0.02574	0.05686	0.03098	0.0503

Study Wells in Utica Exploration Fairway API No.	Indian Castle Clay-Rich; Max Adsorbed CO_2 Capacity, Bcf/ac	Indian Castle Carbonate-Rich; Max Adsorbed CO_2 Capacity, Bcf/ac	Dolgeville; Max Adsorbed CO_2 Capacity, Bcf/ac	Flat Creek; Max Adsorbed CO_2 Capacity, Bcf/ac
3109722830	0.0008	0.01567	0.05884	
3109722881	0.00102	0.01183	0.07164	
3109722829		0.02464	0.04709	
3109723086	0	0.03458	0.06603	
3109722942	0.00007	0.03097	0.0903	
3109723004		0.0242		
3109722886		0.02585	0.08028	
3109722841		0.02759	0.07201	
3109722893	0.00621	0.02352	0.06518	
3109723053	0	0.01041	0.17057	
3109722935	0.00028		0.04755	
3110123105	0.07509	0.01347	0.04927	
3110122978	0.02511	0.01045		
3110123101	0.00195	0.0337	0.03067	
3110123059	0.00742	0.01927	0.05506	
3110123040	0.06923	0.01235	0.05098	
3110123151		0.00498		
3110122963	0.29356	0.01336	0.08021	
3110123211	0.0834	0.01033	0.0479	
3110123038	0.02695	0.01158	0.00892	
3110122861	0.00361	0.02192	0.10022	
3110123155	0.00345	0.02004	0.06777	
3110722974	0.02813	0.0432	0.04449	
3110722934	0.02698	0.06551	0.06652	
3110723116	0.05302	0.11826	0.08376	
3110922997	0.04234		0.03902	
3110922767	0.00277	0.00486	0.00811	
3110922998	0.00008	0.01094	0.01199	
3110922753	0.00096	0.00197	0.00357	

Table C-8: Utica Calculated Theoretical Maximum CO_2 Storage – Non-Adsorbed ('Free') Phase, Bcf/ac

Study Wells in Utica Exploration Fairway API No.	Indian Castle Clay-Rich; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Indian Castle Carbonate-Rich; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Dolgeville; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Flat Creek; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac
3100723032	0.04358	0.0392	0.01299	
3100723056	0.01526	0.0675	0.04695	
3100723030	0.06938	0.01987	0.03154	
3100723078	0.00795	0.06876	0.06012	
3100722984	0.01557	0.05519	0.03935	0.01842
3100722995	0.01444	0.06661	0.04035	0.00575
3101522890	0.00252	0.01649	0.17383	
3101522933	0.12242	0.06717	0.07085	
3101523097	0.09119	0.00029	0.00966	
3101522891			0.00732	
3101522975			0.01453	
3101523186	0.06292	0.00792		
3101522901	0.00268	0.01171	0.03809	
3101522960	0.00033	0.00375	0.00632	
3101523134	0.03803		0.01956	
3101522880	0.01579	0.00294	0.14572	
3101522911	0.03384	0.00033		
3101522918	0.01718	0.00083	0.05683	
3101522919	0.00346	0.00952	0.0146	
3101523228	0.04441	0.04222		
3101523146	0.0625	0.00089		
3101522924	0.00201	0.00384	0.03449	
3101523028	0.03391			
3102323035	0.03561	0		
3102321500	0.10225	0.00052		
3102510227	0.01353	0.04822	0.01673	0.019461213
3105320411	0.20701			
3106712163	0.02876			
3106722965	0.00637			
3107710834	0.0554	0.0595	0.00168	0.00426
3107723759	0.21365	0.04907	0.17522	0.19098
3107723760	0.048	0.06795	0.09604	0.15239
3107723783	0.01148	0.02988	0.00911	0.0406
3109722830	0.00017	0.00364		
3109722881	0.00028	0.00447		
3109722829		0.00177		
3109723086		0.00711		
3109722942		0.00484		
3109722886		0.00215	0.04122	
3109722841			0.02499	
3109722893	0.00319	0.00692	0.04118	
3109722935	0	0.00138	0.03334	
3110123105	0.08954	0.00398	0.00339	

Study Wells in Utica Exploration Fairway API No.	Indian Castle Clay-Rich; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Indian Castle Carbonate-Rich; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Dolgeville; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac	Flat Creek; Max CO_2 Capacity - 'Non-Adsorbed' Phase, Bcf/ac
3110122978	0.01348	0	0	
3110123101	0	0.00897	0.00576	
3110123059	0.00649	0.00491	0.01502	
3110123040	0.09256		0.01397	
3110123151		0.00705		
3110122963	0.3835	0.00075	0.0408	
3110123211	0.08803			
3110123038	0.0106		0.01191	
3110122861	0.00292	0.00751	0.07185	
3110123155	0.00249	0.00749	0.07871	
3110722974	0.03579	0.03558	0.01726	
3110722934	0.04103	0.10031	0.09185	
3110723116	0.06944	0.14147	0.08718	
3110922997	0.03645		0.01536	
3110922998	0		0.00135	

APPENDIX D

EXTRAPOLATED COUNTY-LEVEL ESTIMATES OF GAS IN-PLACE AND CO_2 STORAGE CAPACITY FOR THE MARCELLUS AND UTICA EXPLORATION FAIRWAYS

Table D-1: Marcellus Exploration Fairway – Estimated CH_4 Gas In-Place by County

MARCELLUS		Adsorbed Gas In-Place		Non-Adsorbed ('Free') Gas In-Place	
County	Approximate Acres in Marcellus Exploration Fairway	Average Adsorbed CH_4 (Bcf/ac)	Estimated Total Adsorbed CH_4 (Tcf)	Average Non-Adsorbed CH_4 GIP (Bcf/Ac)	Estimated Total 'Free' CH_4 GIP (Tcf)
Marcellus Fairway - North					
Chenango	188,889	0.0231	4.36	0.0427	8.06
Otsego	64,179	0.0145	0.93	0.0284	1.82
Schoharie	39,809	0.0143	0.57	0.0284	1.13
Marcellus Fairway - South					
Allegany	217,582	0.0150	3.26	0.0630	13.71
Steuben	534,774	0.0193	10.32	0.0930	49.74
Chemung	235,106	0.0262	6.16	0.1163	27.34
Tioga	222,414	0.0617	13.73	0.1762	39.19
Broome	361,892	0.0444	16.06	0.1343	48.59
Delaware	833,109	0.0470	39.11	0.0539	44.92
Greene	136,805	0.0470	6.42	0.0539	7.38
Ulster	180,237	0.0470	8.46	0.0539	9.72
Sullivan	372,369	0.0470	17.5	0.0539	20.1
Totals	**3,387,165**		***127***		***272***

Table D-2: Marcellus Exploration Fairway – Estimated Maximum CO_2 Storage Capacity by County

MARCELLUS		Max. CO_2 Storage Capacity - Adsorbed		Max. CO_2 Storage Capacity - Non-Adsorbed	
County	Approximate Acres in Marcellus Exploration Fairway	Estimated Adsorbed CO_2 Storage Capacity (Bcf/ac)	Estimated Total Adsorbed CO_2 Storage Capacity (Tcf)	Estimated Non-Adsorbed CO_2 Storage Capacity (Bcf/ac)	Estimated Total Non-Adsorbed CO_2 Storage Capacity (Tcf)
Marcellus Fairway - North					
Chenango	188,889	0.0679	12.82	0.0293	5.54
Otsego	64,179	0.0429	2.75	0.0270	1.73
Schoharie	39,809	0.0360	1.43	0.0270	1.07
Marcellus Fairway - South					
Allegany	217,582	0.0357	7.77	0.0300	6.52
Steuben	534,774	0.0708	37.86	0.0372	19.88
Chemung	235,106	0.0898	21.12	0.0594	13.95
Tioga	222,414	0.1721	38.28	0.0842	18.73
Broome	361,892	0.1041	37.67	0.0656	23.73
Delaware	833,109	0.0980	81.66	0.0197	16.39
Greene	136,805	0.0769	10.53	0.0197	2.69
Ulster	180,237	0.0980	17.67	0.0197	3.55
Sullivan	372,369	0.0769	28.7	0.0197	7.3
Totals	***3,387,165***		***298***		***121***

Table D-3: Utica Exploration Fairway – Estimated CH_4 Gas In-Place by County

UTICA		Adsorbed Gas In-Place		Non-Adsorbed ('Free') Gas In-Place	
County	Approximate Acres in Utica Exploration Fairway	Average Adsorbed CH_4 (bcf/Ac)	Estimated Total Adsorbed CH_4 (Tcf)	Average Non-Adsorbed CH_4 GIP (bcf/Ac)	Estimated Total 'Free' CH_4 GIP (Tcf)
Utica Fairway - North					
Cortland	239,832	0.0336	8.1	0.0790	18.9
Onondaga	24,969	0.0148	0.4	0.0249	0.6
Madison	209,875	0.0668	14.0	0.1390	29.2
Chenango	572,390	0.0384	22.0	0.1374	78.6
Otsego	430,001	0.0735	31.6	0.2140	92.0
Schoharie	131,371	0.0691	9.1	0.1997	26.2
Utica Fairway - South					
Steuben	222,822	0.0307	6.84	0.0273	6.1
Schuyler	21,037	0.0402	0.85	0.0881	1.9
Tompkins	121,869	0.0066	0.81	0.0184	2.2
Chemung	235,106	0.0379	8.90	0.0959	22.5
Tioga	298,765	0.0711	21.2	0.1070	32.0
Broome	384,510	0.0476	18.3	0.2180	83.8
Delaware	740,541	0.0508	37.6	0.2023	149.8
Greene	41,456	0.0560	2.32	0.1568	6.5
Ulster	72,095	0.0474	3.42	0.2023	14.6
Sullivan	62,061	0.0474	2.94	0.2023	12.6
Totals	***3,808,702***		***188***		***578***

Table D-4: Utica Exploration Fairway – Estimated Maximum CO_2 Storage Capacity by County

UTICA		Max. CO_2 Storage Capacity - Adsorbed		Max. CO_2 Storage Capacity - Non-Adsorbed	
County	Approximate Acres in Utica Exploration Fairway	Estimated Adsorbed CO_2 Storage Capacity (Bcf/ac)	Estimated Total Adsorbed CO_2 Storage Capacity (Tcf)	Estimated Non-Adsorbed CO_2 Storage Capacity (Bcf/ac)	Estimated Total Non-Adsorbed CO_2 Storage Capacity (Tcf)
Utica Fairway - North					
Cortland	239,832	0.0840	20.2	0.0915	22.0
Onondaga	24,969	0.0400	1.0	0.0141	0.4
Madison	209,875	0.1555	32.6	0.0834	17.5
Chenango	572,390	0.1357	77.7	0.1128	64.5
Otsego	430,001	0.1934	83.2	0.1217	52.3
Schoharie	131,371	0.1819	23.9	0.1139	15.0
Utica Fairway - South					
Steuben	222,822	0.0759	16.90	0.0390	8.7
Schuyler	21,037	0.0873	1.84	0.0385	0.8
Tompkins	121,869	0.0172	2.10	0.0410	5.0
Chemung	235,106	0.0908	21.34	0.0534	12.6
Tioga	298,765	0.1665	49.7	0.1582	47.3
Broome	384,510	0.1150	44.2	0.1138	43.8
Delaware	740,541	0.1541	114.1	0.0979	72.5
Greene	41,456	0.1819	7.54	0.1568	6.5
Ulster	72,095	0.1409	10.16	0.0844	6.1
Sullivan	62,061	0.1541	9.56	0.0844	5.2
Totals	***3,808,702***		***516***		***380***

APPENDIX E

SIMANDOUX EQUATION FOR WATER SATURATION IN SHALY SANDS

This algorithm developed by E. R. Crain (1986) is a three part linear solution to the Simandoux equation for implementation in log analysis software such as PETRA. This solution requires a computation of shale volume or V_{shale}. For 'clean' sandstones, with V_{shale} approaching zero, the solution reverts to the standard Archie equation for water saturation.

Part 1, Simandoux 'C' term:

$$\mathbf{C = ((1- V_{shale})\ \mathit{x}\ a\ \mathit{x}\ R_w) / \phi^m}$$

Part 2, Simandoux 'D' term:

$$\mathbf{D = (C\ \mathit{x}\ V_{shale}) / (2\ \mathit{x}\ R_{sh})}$$

Part 3, Simandoux 'E' term:

$$\mathbf{E = C / (R_t)}$$

And,

$$\mathbf{S_w = [(D^2 + E)^{0.5} - D]^{(2/n)}}$$

Where:

a = Archie tortuosity exponent (fraction); common default value = 1

m = Archie cementation exponent (fraction); common default value = 2

n = Archie saturation exponent (fraction); common default value = 2

R_{sh} = resistivity of the shale fraction (ohm-m)

R_t = deep resistivity log reading (ohm-m)

R_w = water resistivity at formation temperature (ohm-m)

S_w = water saturation

V_{shale} = shale volume (fraction)

ϕ = porosity (fraction)

APPENDIX F

CONTOUR MAPS OF VARIOUS CALCULATED VALUES FOR MARCELLUS AND UTICA

Figure F-1: Marcellus Union Springs Total Thickness

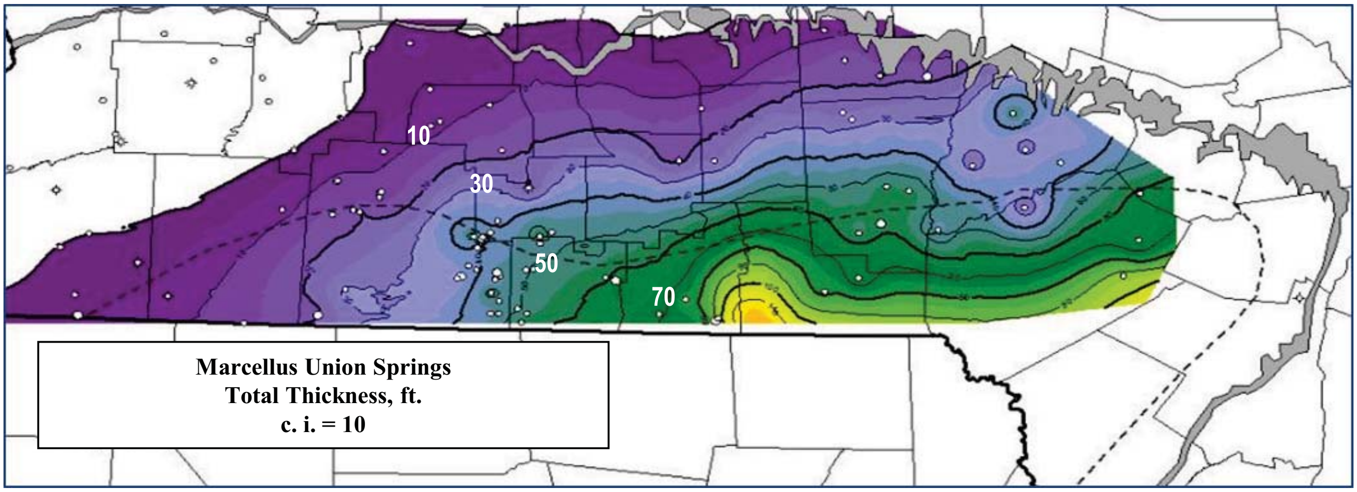


Figure F-2: Marcellus Union Springs Average Calculated Total Organic Content (TOC)

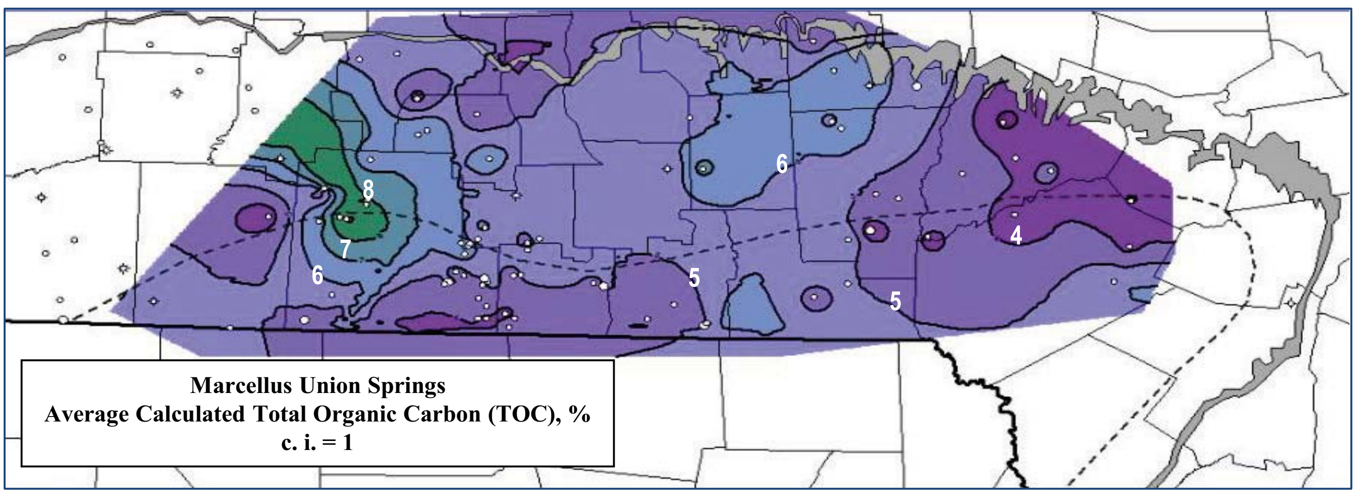


Figure F-3: Marcellus Union Springs Average Porosity

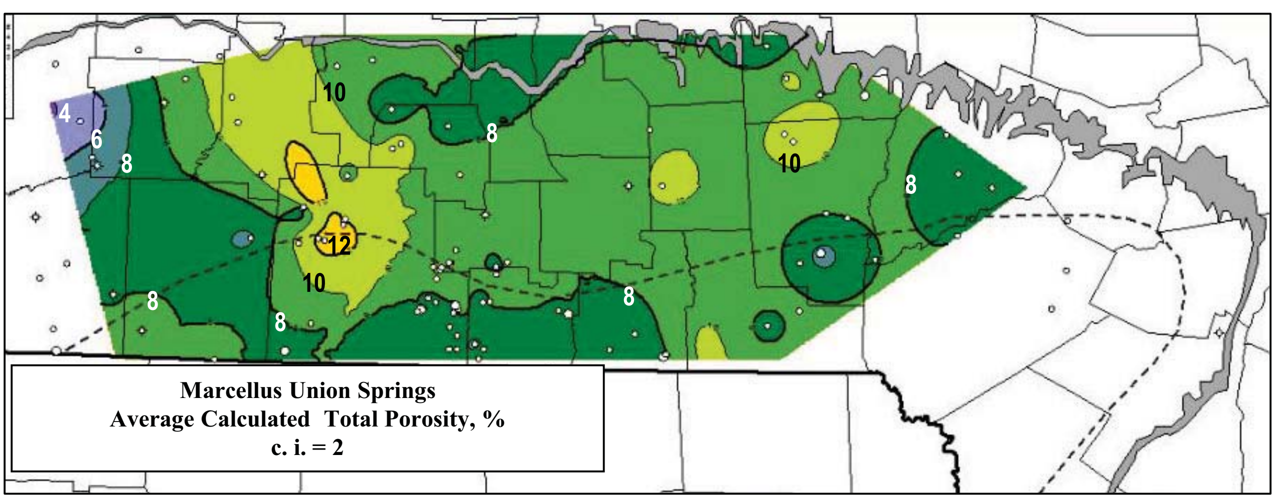


Figure F-4: Marcellus Union Springs Average Water Saturation (Sw), fraction

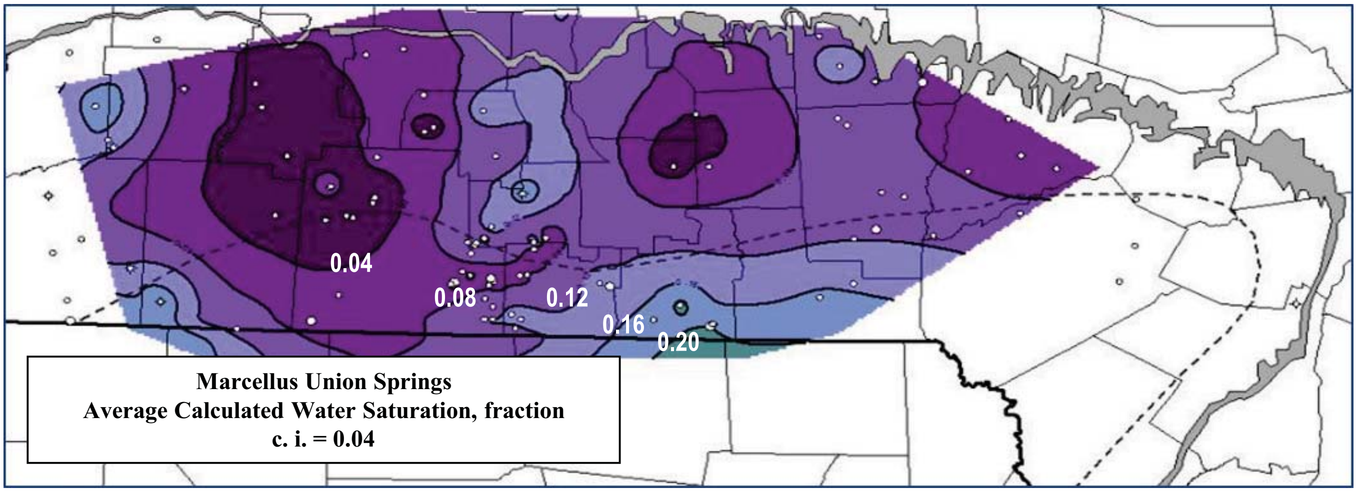


Figure F-5: Marcellus Union Springs Average Calculated Adsorbed Methane Content, scf/ton

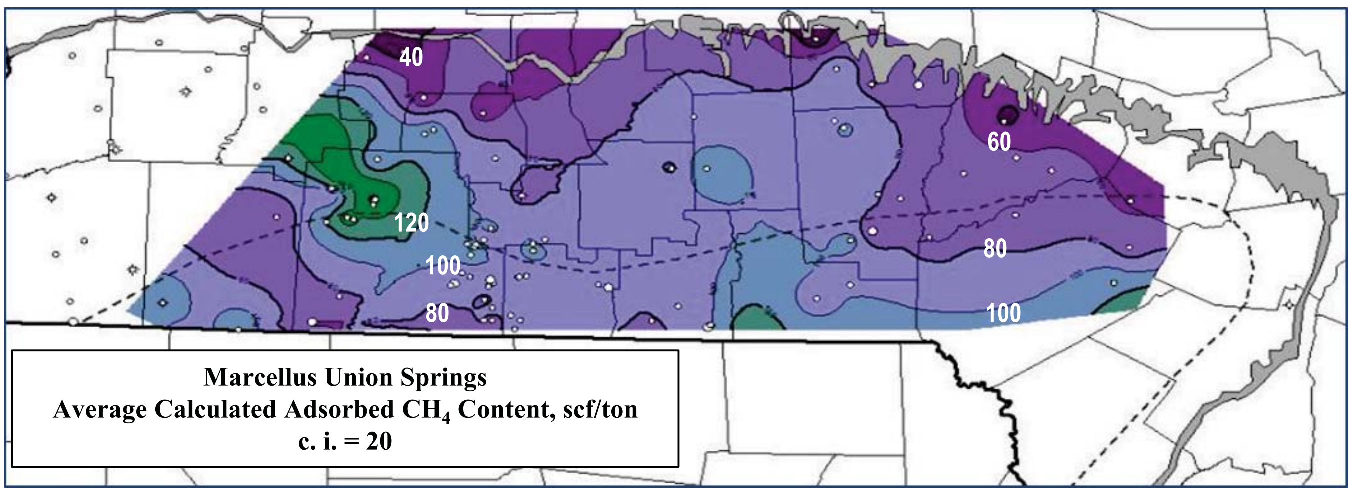


Figure F-6: Marcellus Oatka Creek 'Black Shale' Total Thickness

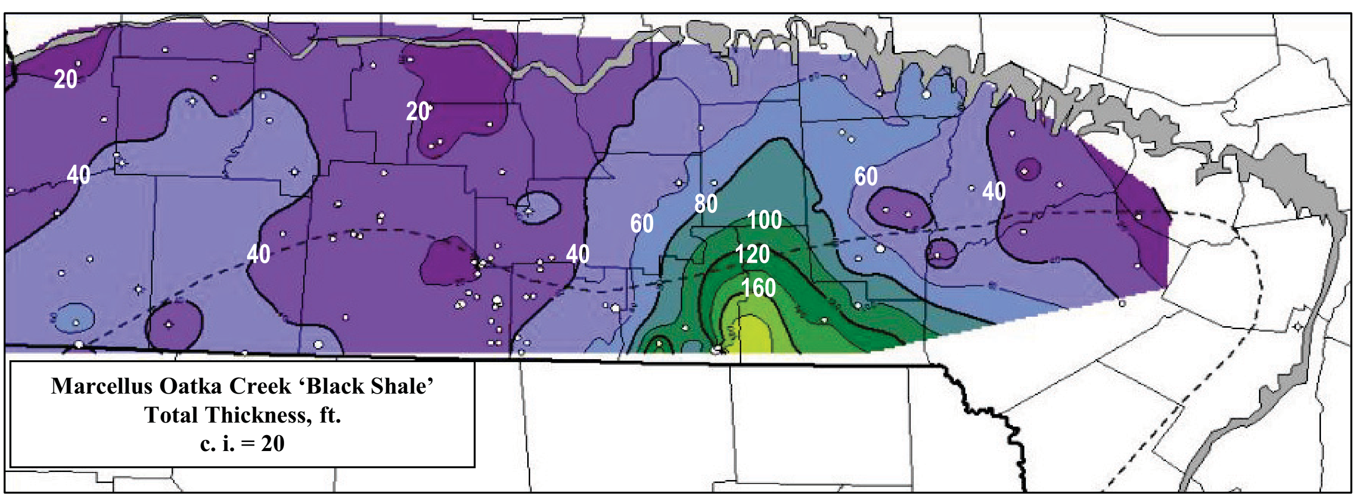


Figure F-7: Marcellus Oatka Creek 'Black Shale' Average Calculated Total Organic Content (TOC)

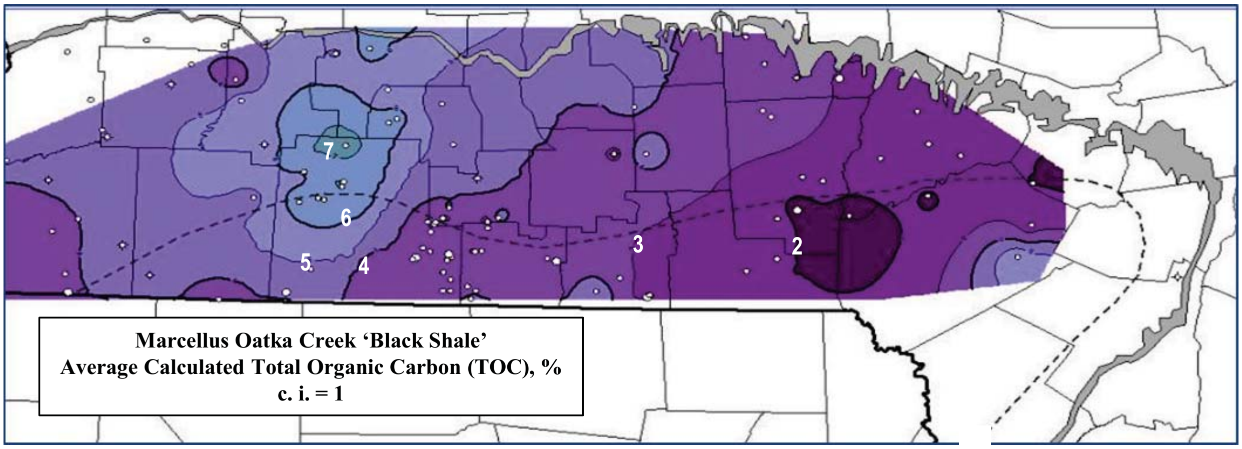


Figure F-8: Marcellus Oatka Creek 'Black Shale' Average Calculated Adsorbed Methane Content, scf/ton

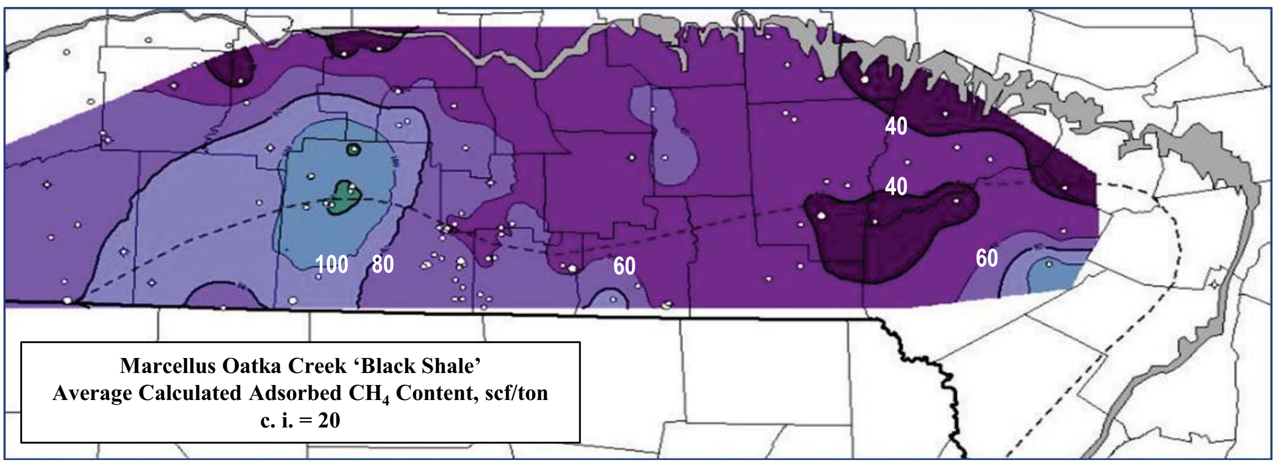


Figure F-9: Utica Indian Castle, Clay-Rich Member, Total Thickness

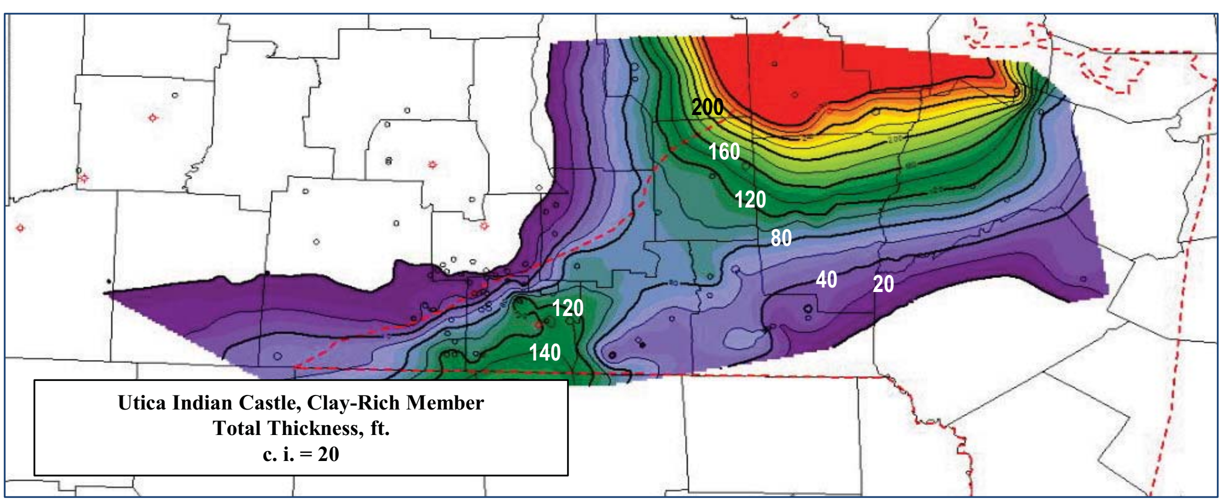


Figure F-10, Utica Indian Castle, Carbonate Rich Member, Total Thickness

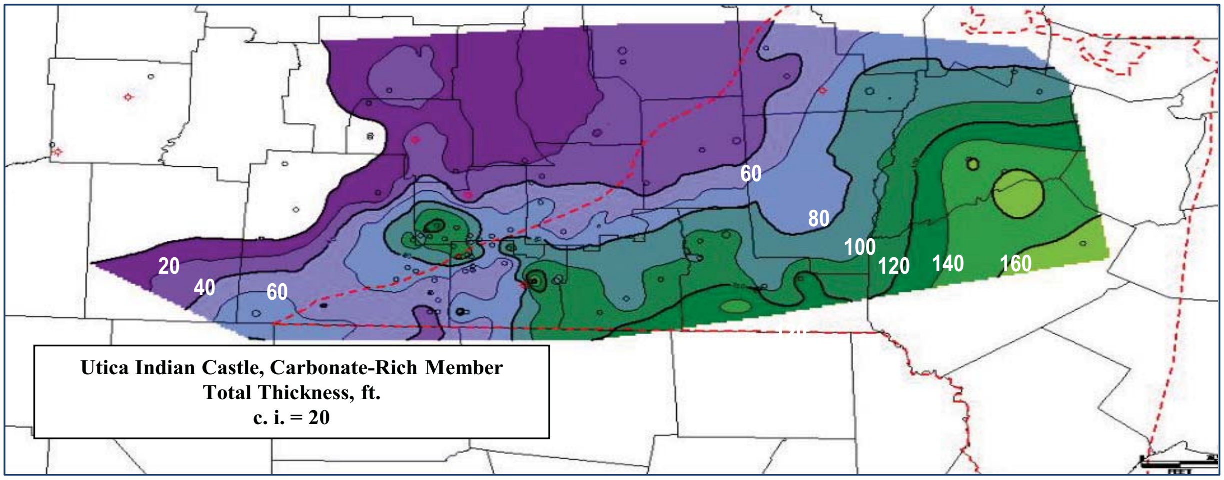


Figure F-11, Utica Dolgeville Fm., Total Thickness

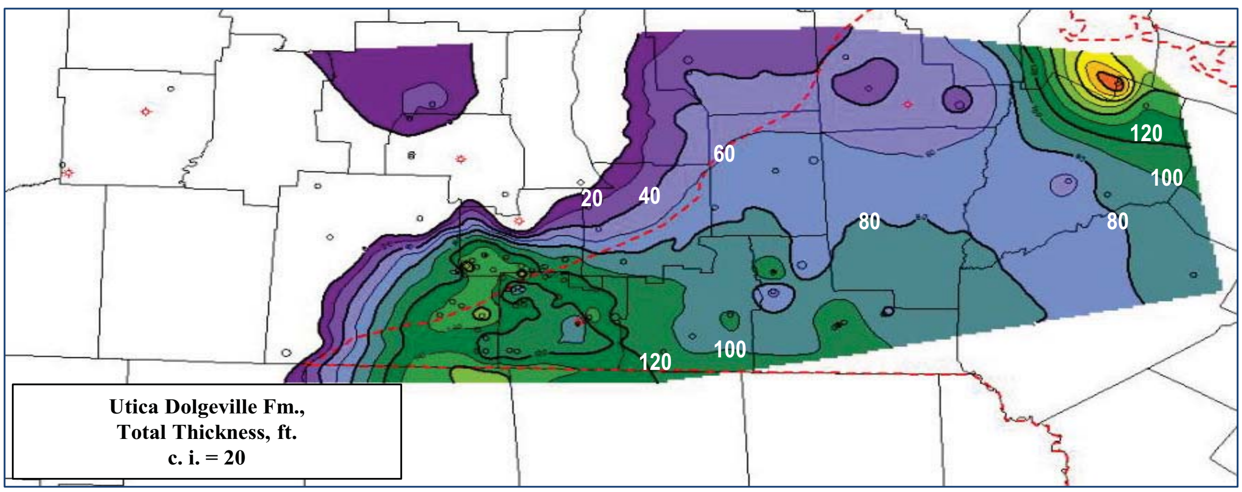


Figure F-12: Utica Flat Creek Fm., Total Thickness

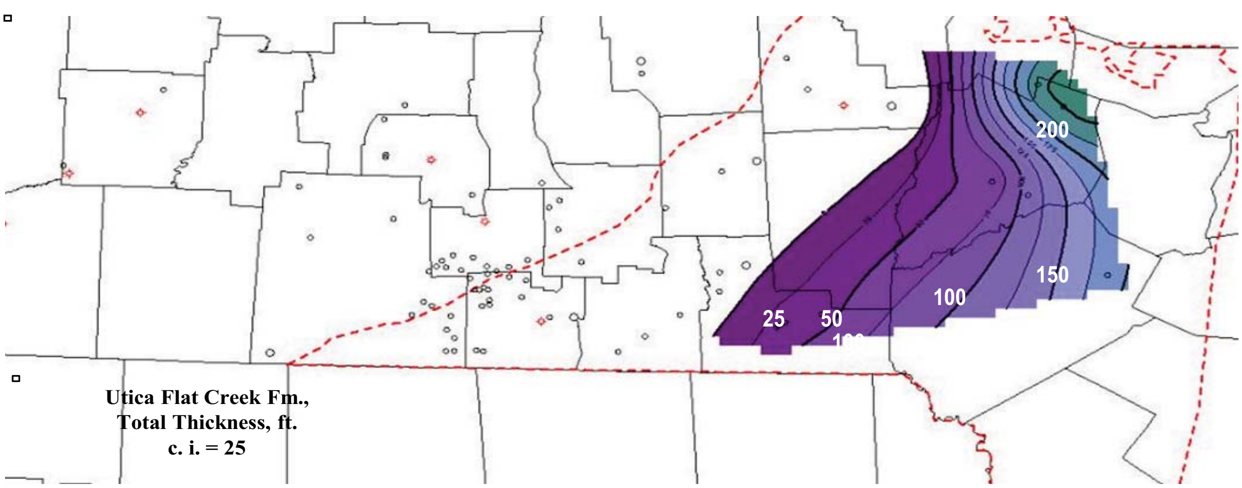


Figure F-13: Utica Indian Castle, Clay-Rich Member, Average Calculated Total Organic Content (TOC)

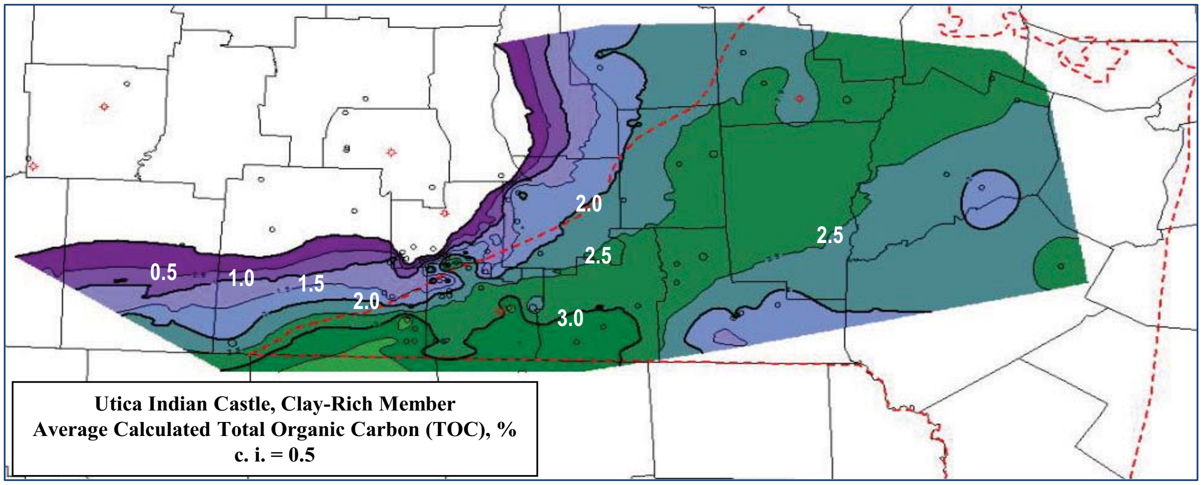


Figure F-14: Utica Indian Castle, Carbonate Rich Member, Average Total Organic Content (TOC)

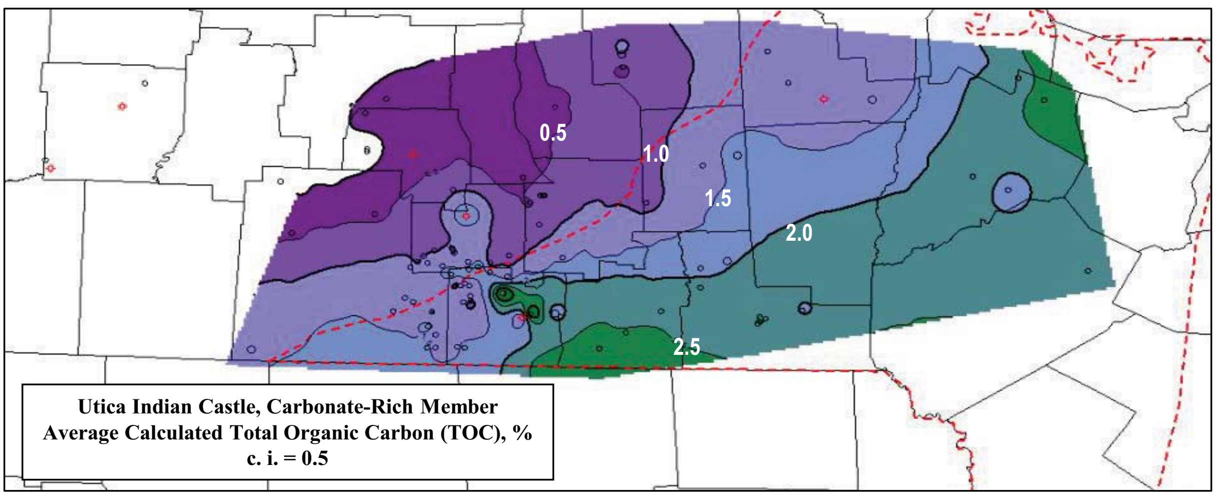


Figure F-15: Utica Dolgeville Fm., Average Calculated Total Organic Content (TOC)

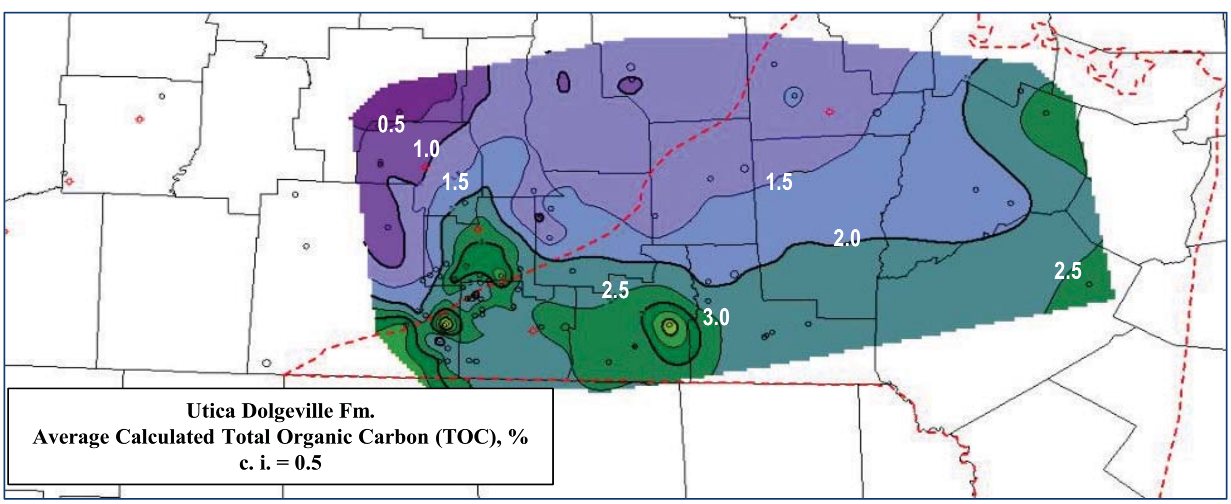


Figure F-16: Utica Flat Creek Fm., Average Calculated Total Organic Content (TOC)

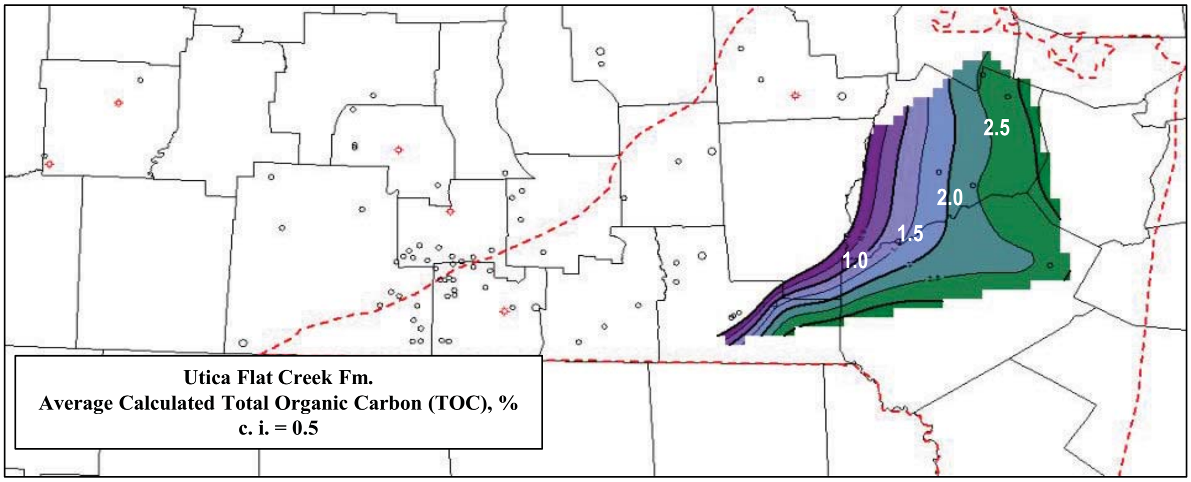


Figure F-17: Utica Indian Castle, Clay-Rich Member, Average Calculated Total Porosity

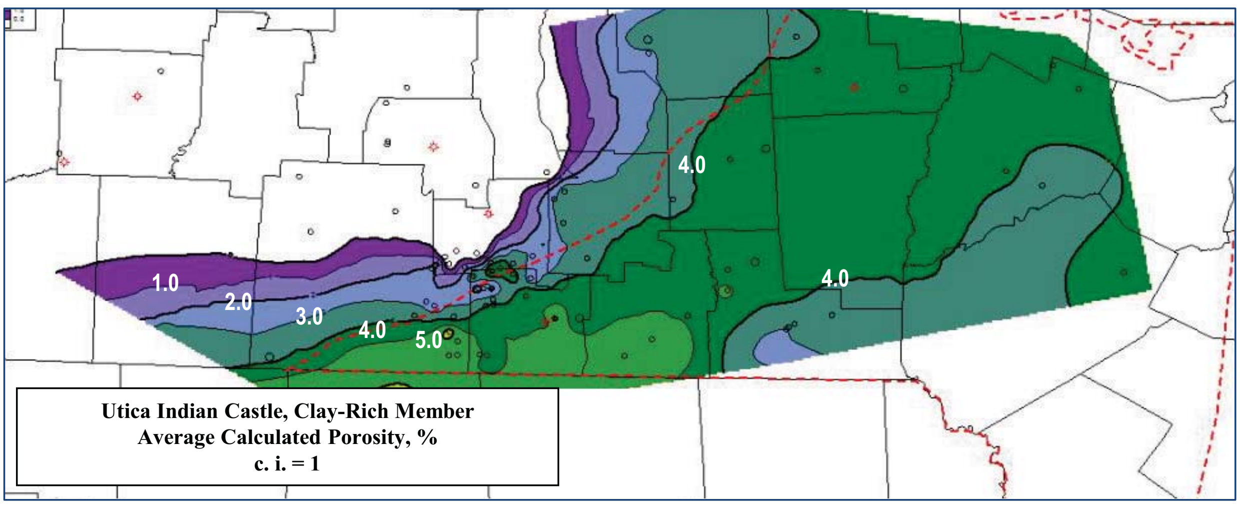


Figure F-18: Utica Indian Castle, Carbonate-Rich Member, Average Calculated Total Porosity

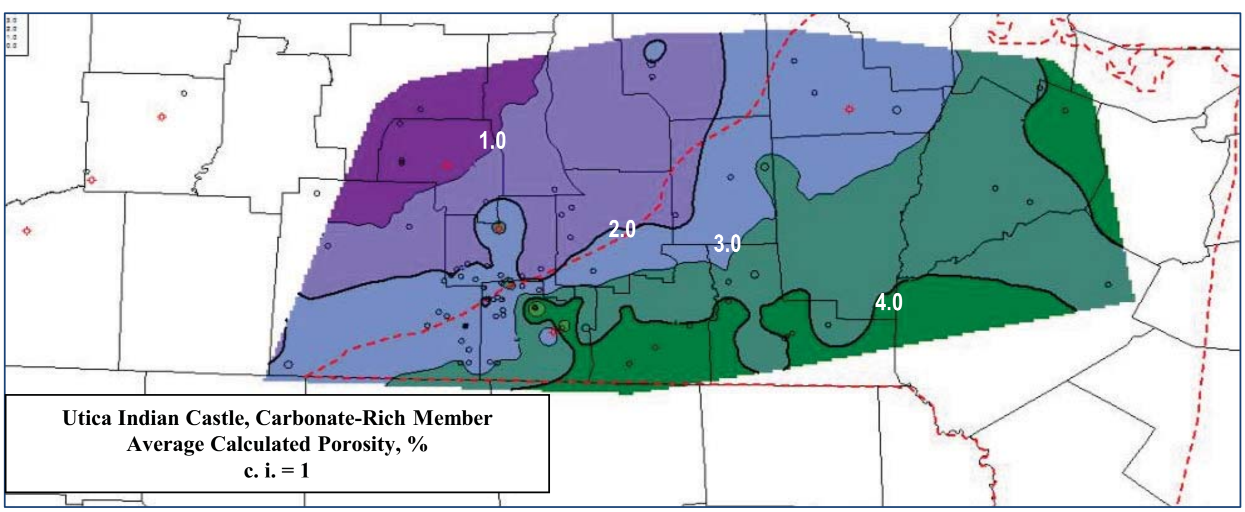


Figure F-19: Utica Dolgeville Fm, Average Calculated Total Porosity

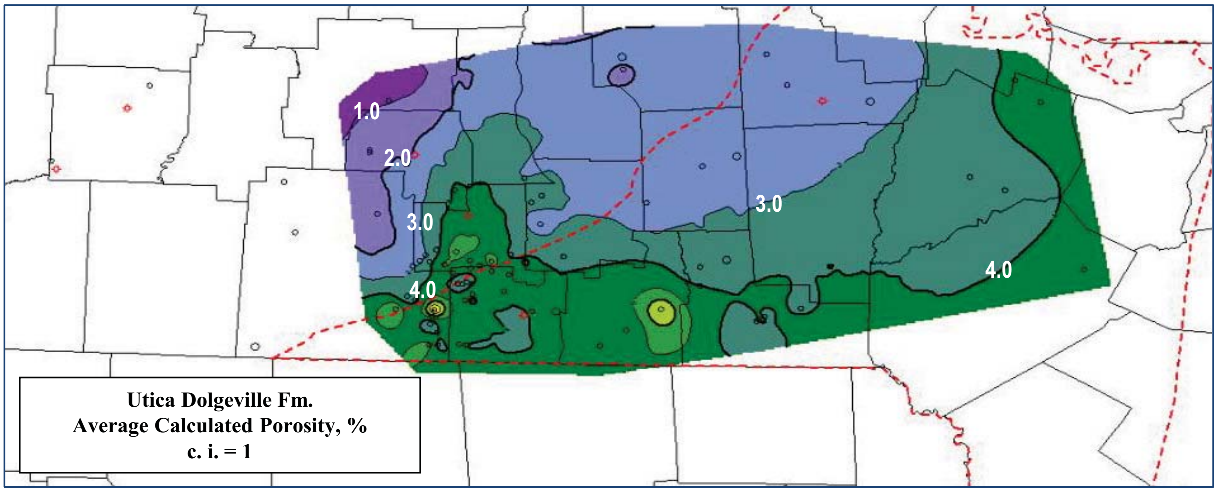


Figure F-20: Utica Flat Creek Fm, Average Calculated Total Porosity

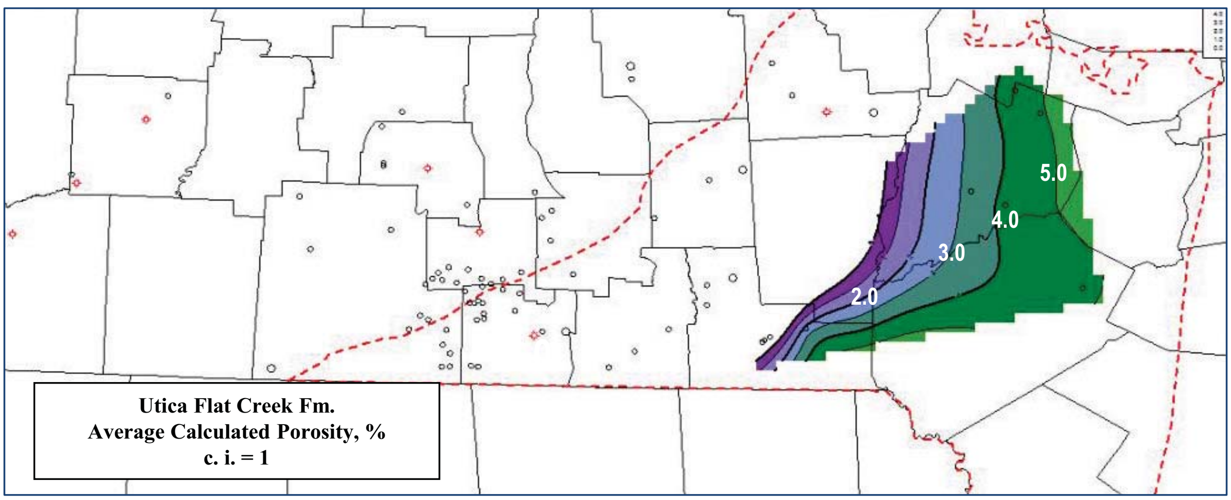


Figure F-21: Utica Indian Castle, Clay-Rich Member, Average Adsorbed Methane Content, scf/ton

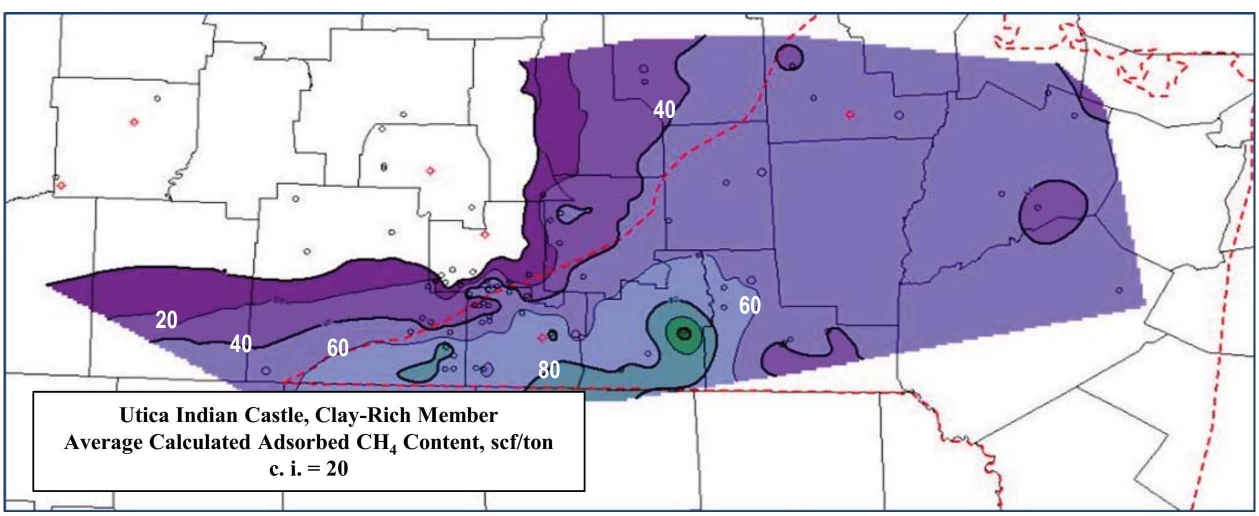


Figure F- 22: Utica Indian Castle, Carbonate-Rich Member, Average Calculated Adsorbed Methane Content, scf/ton

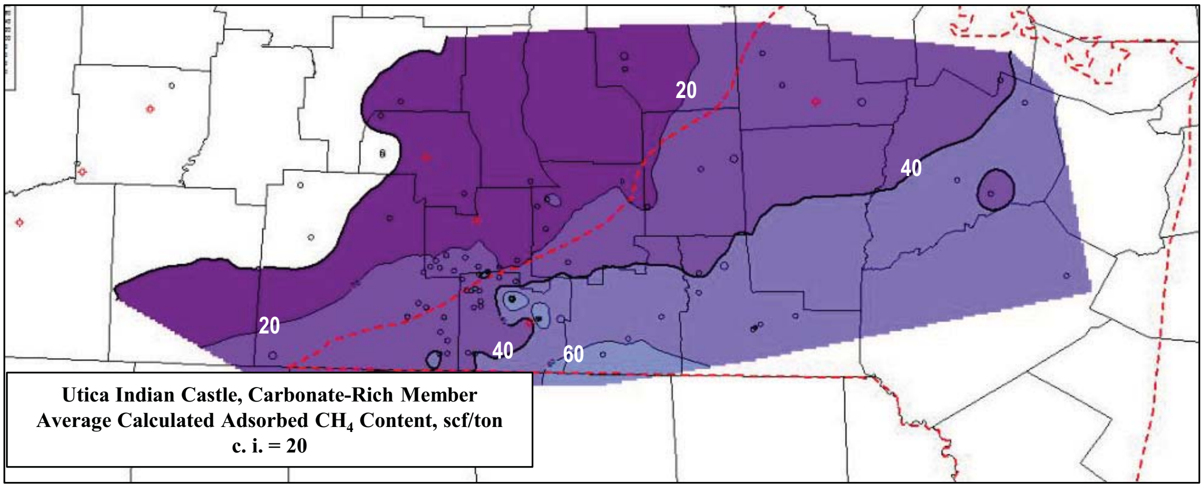


Figure F-23: Utica Dolgeville Fm., Average Calculated Adsorbed Methane Content, scf/ton

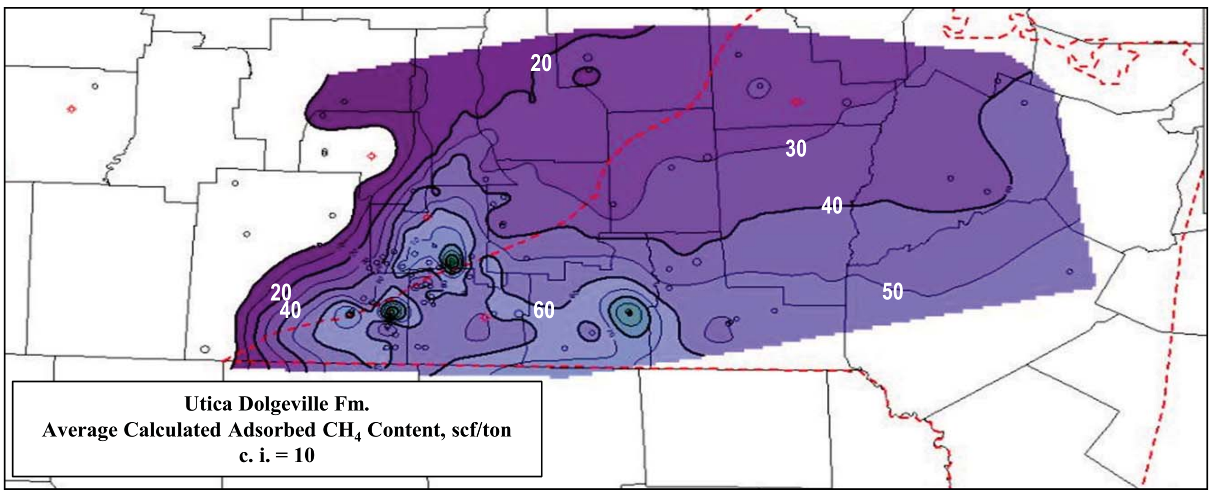
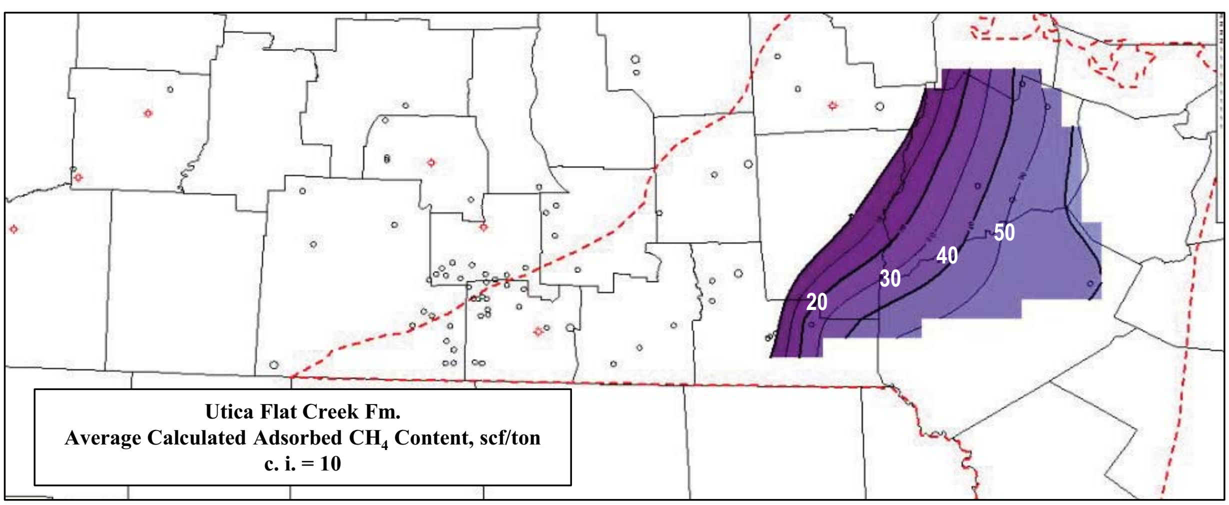


Figure F-24: Utica Flat Creek Fm., Average Calculated Adsorbed Methane Content, scf/ton



Appendix G

SUMMARY OF *COMET3* RESERVOIR SIMULATION RESULTS

This Appendix contains charts summarizing the *COMET3* reservoir simulation results forecasting methane production, CO_2 injection and reservoir pressure for all permeability cases (high, mid, and low) and all model areas. Results are compared two ways: 1) for each permeability case results are compared by model area, and 2) for each model area results are compared across permeability cases.

MARCELLUS RESULTS SUMMARY

Low Permeability Case – Comparison of Model Areas

Figure G-1: Marcellus Methane Production Forecast – Low Permeability Case

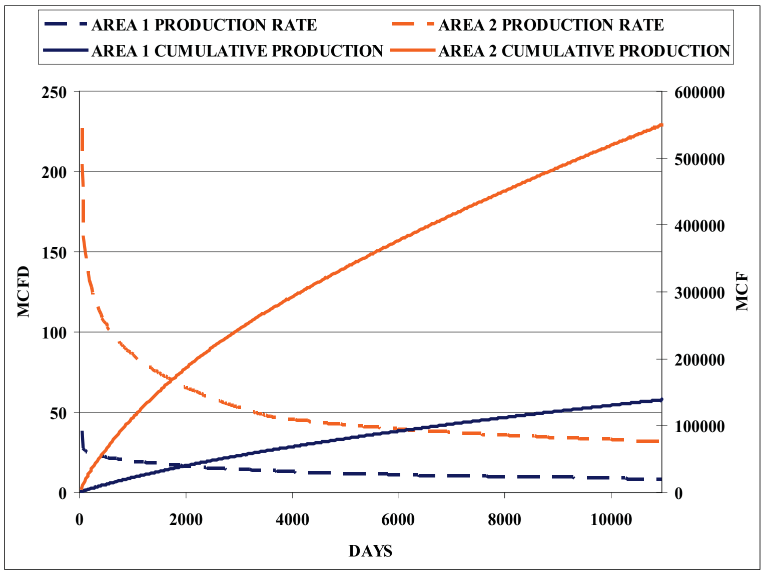


Figure G-2: Marcellus CO_2 Injection Forecast – Low Permeability Case

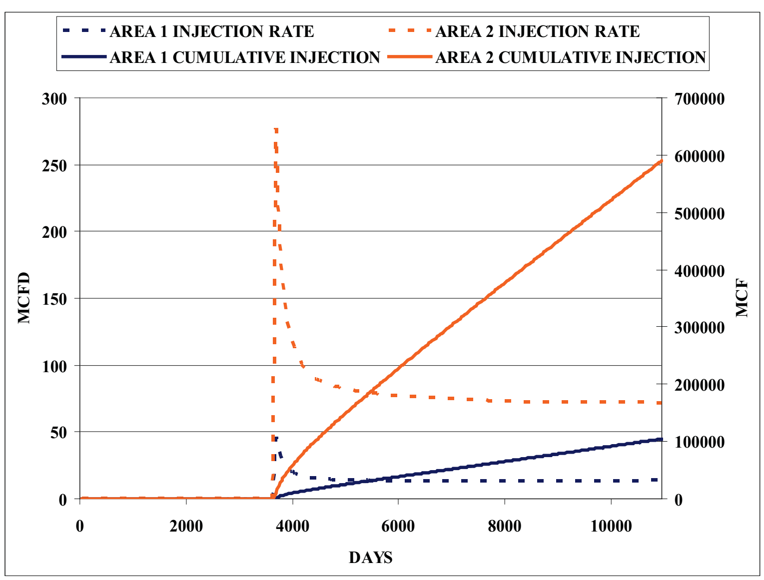
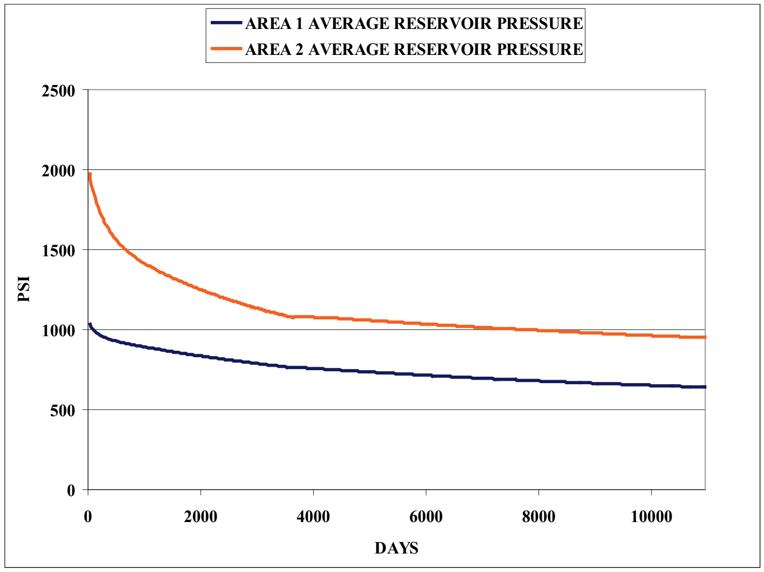


Figure G-3: Marcellus Reservoir Pressure Forecast – Low Permeability Case



Mid Permeability Case – Comparison of Model Areas

Figure G-4: Marcellus Methane Production Forecast – Mid Permeability Case

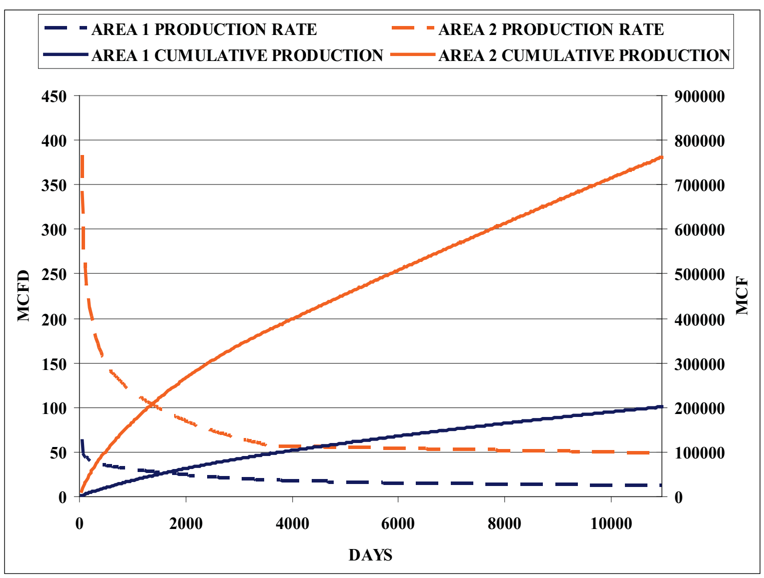


Figure G-5: Marcellus CO_2 Injection Forecast – Mid Permeability Case

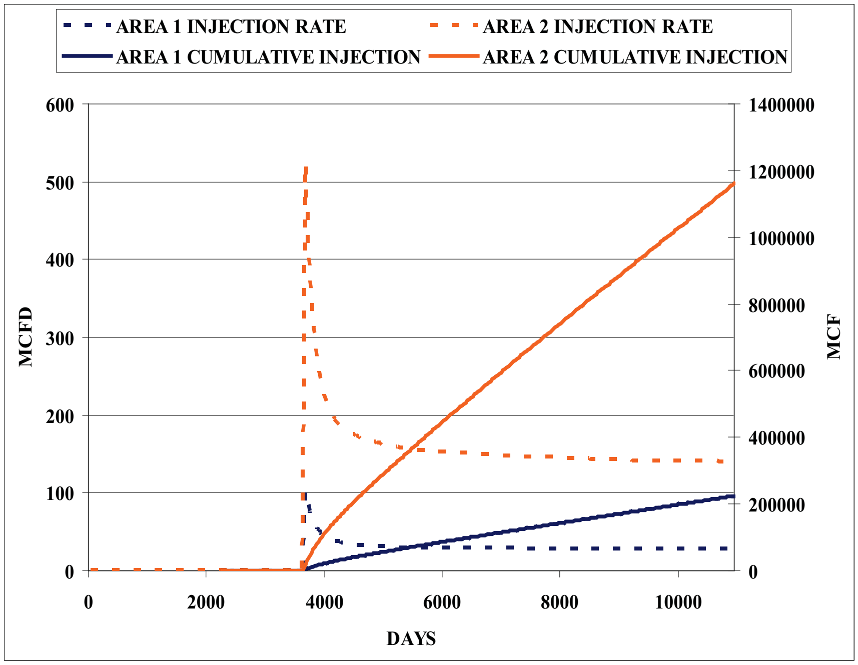
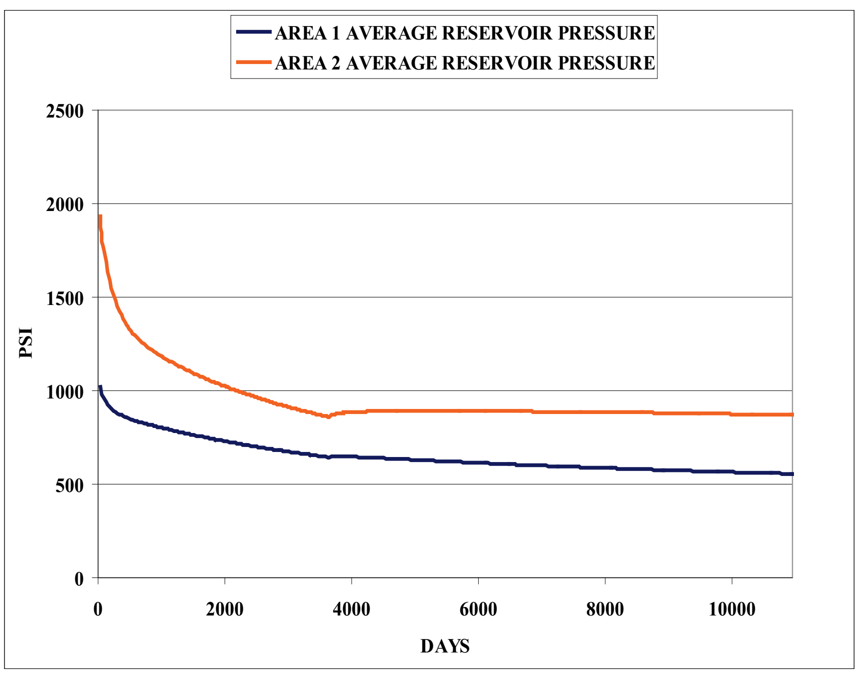


Figure G-6: Marcellus Reservoir Pressure Forecast – Mid Permeability Case



High Permeability Case – Comparison of Model Areas

Figure G-7: Marcellus Methane Production Forecast – High Permeability Case

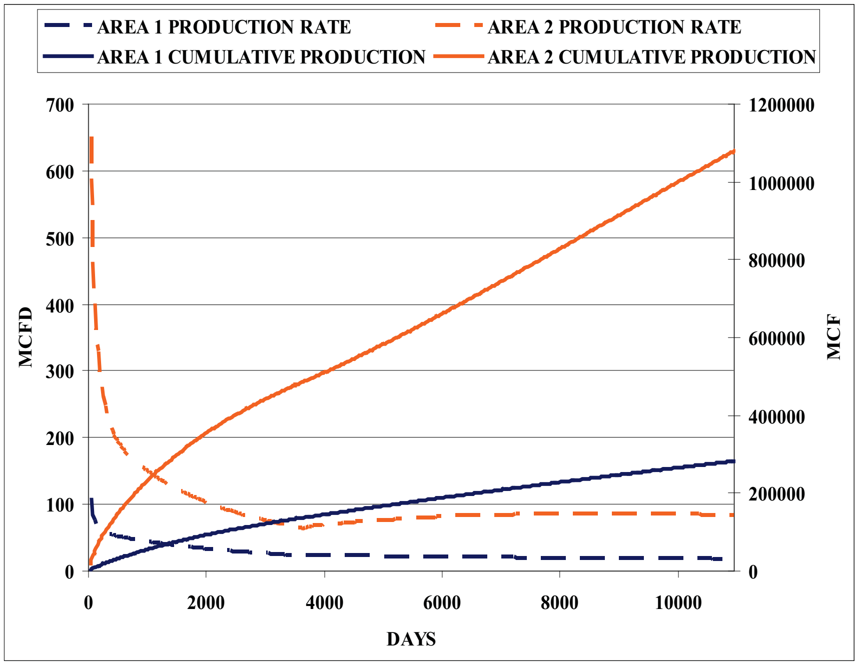


Figure G-8: Marcellus CO_2 Injection Forecast – High Permeability Case

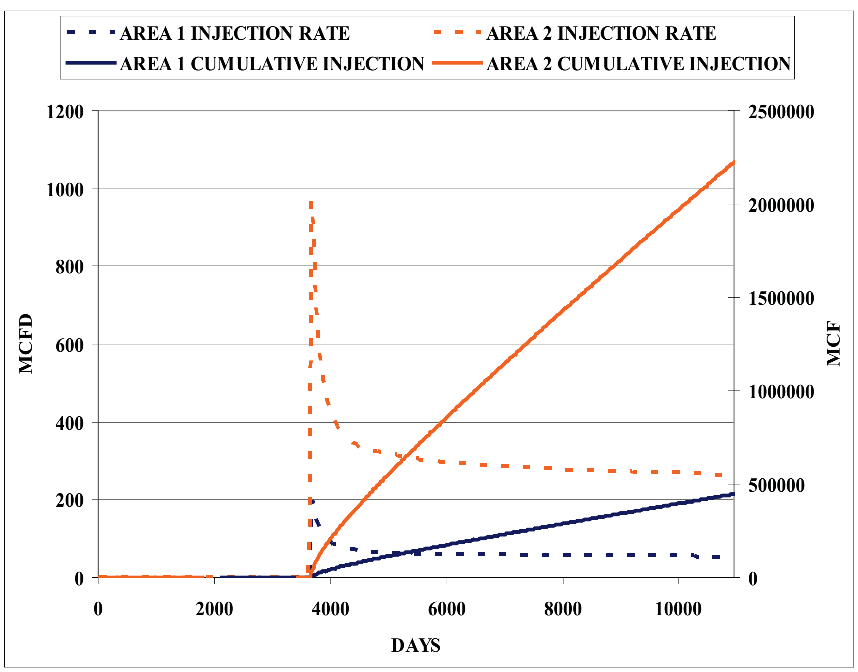
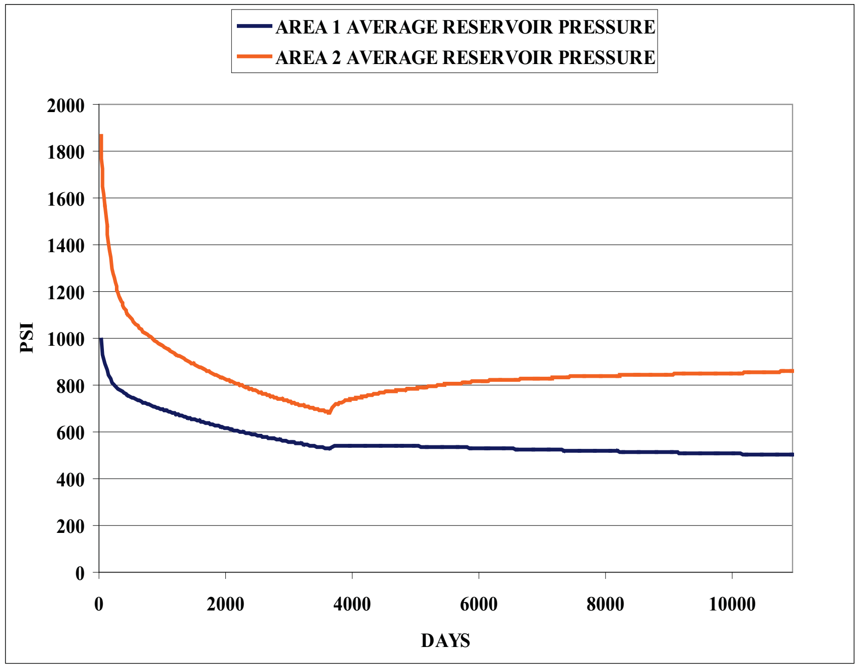


Figure G-9: Marcellus Reservoir Pressure Forecast –High Permeability Case



<u>Marcellus Model Area 1 – Comparison of Permeability Cases</u>

Permeability cases are compared within each model area. Unless noted otherwise, they key for the plots is below:

Figure G-10: Plot Line Type Key

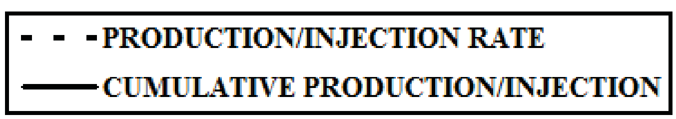


Figure G-11: Plot Color Key

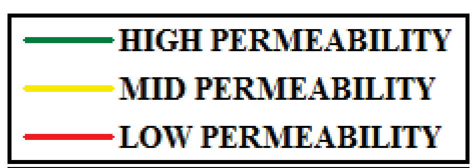


Figure G-12: Marcellus Methane Production Forecast – Model Area 1

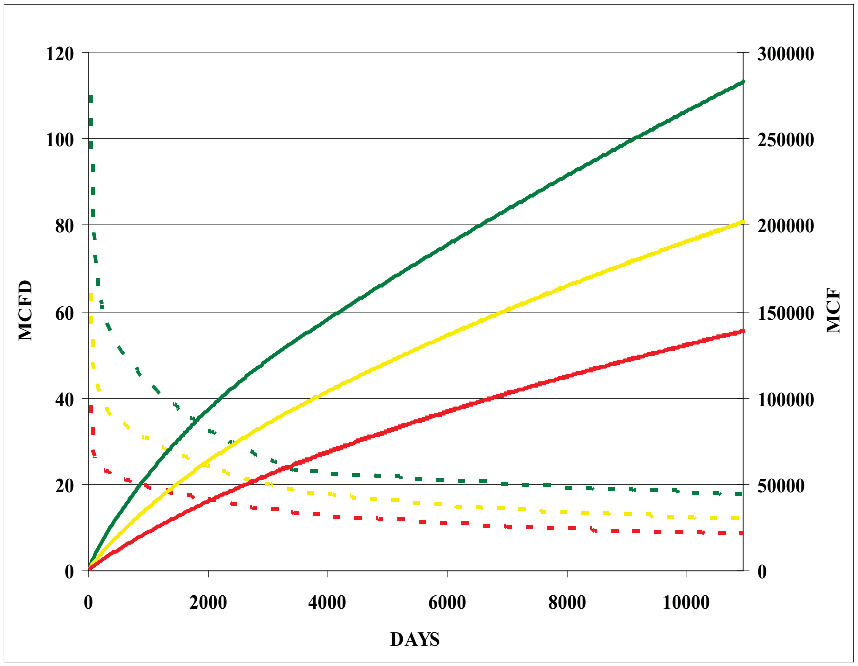


Figure G-13: Marcellus CO_2 Injection Forecast – Model Area 1

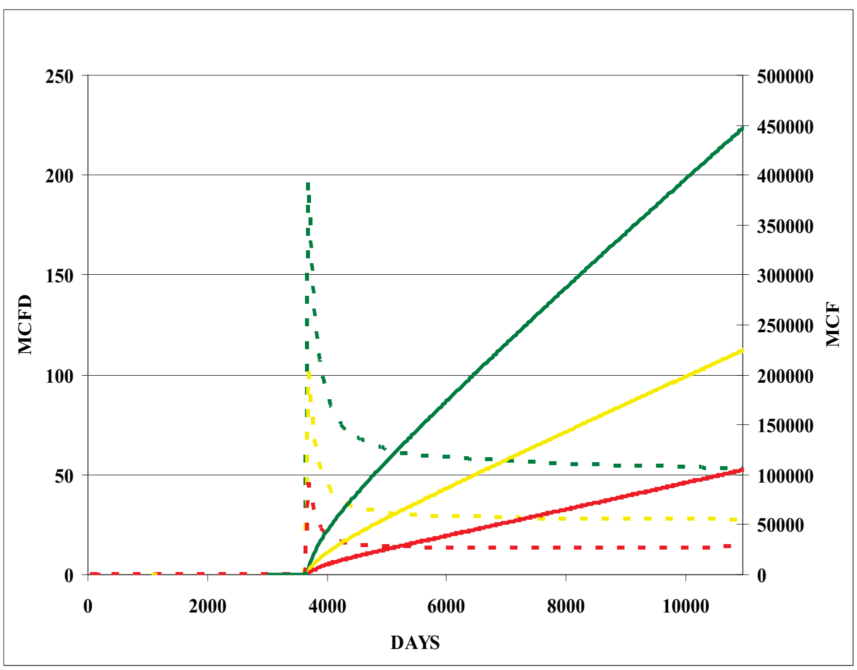
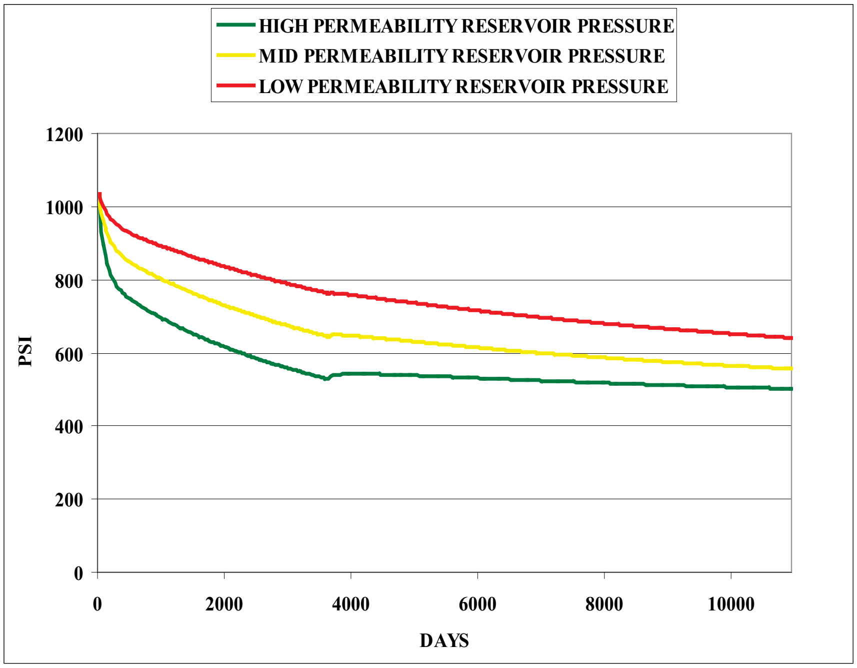


Figure G-14: Marcellus Reservoir Pressure Forecast – Model Area 1



Marcellus Model Area 2 – Comparison of Permeability Cases

Figure G-15: Marcellus Methane Production Forecast – Model Area 2

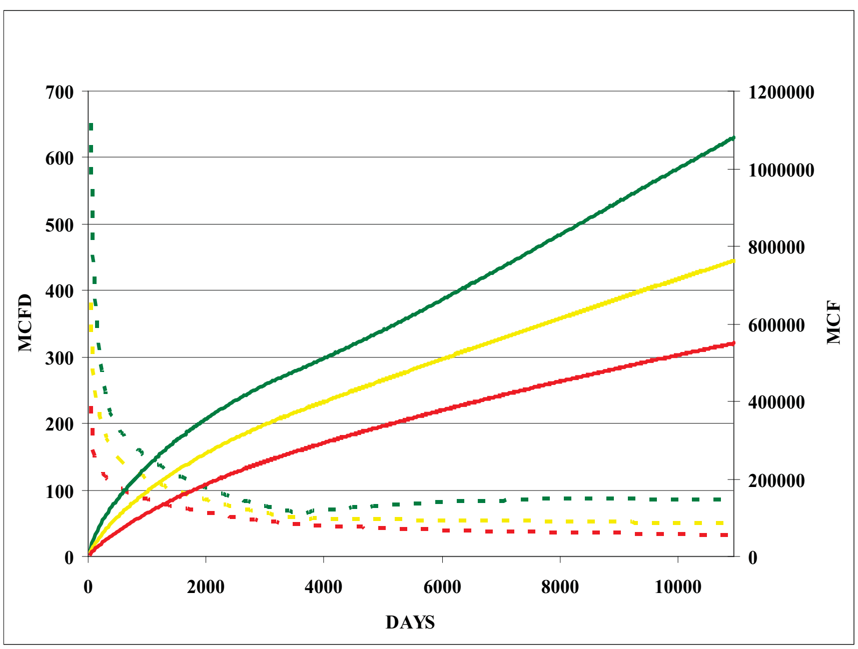


Figure G-16: Marcellus CO_2 Injection Forecast – Model Area 2

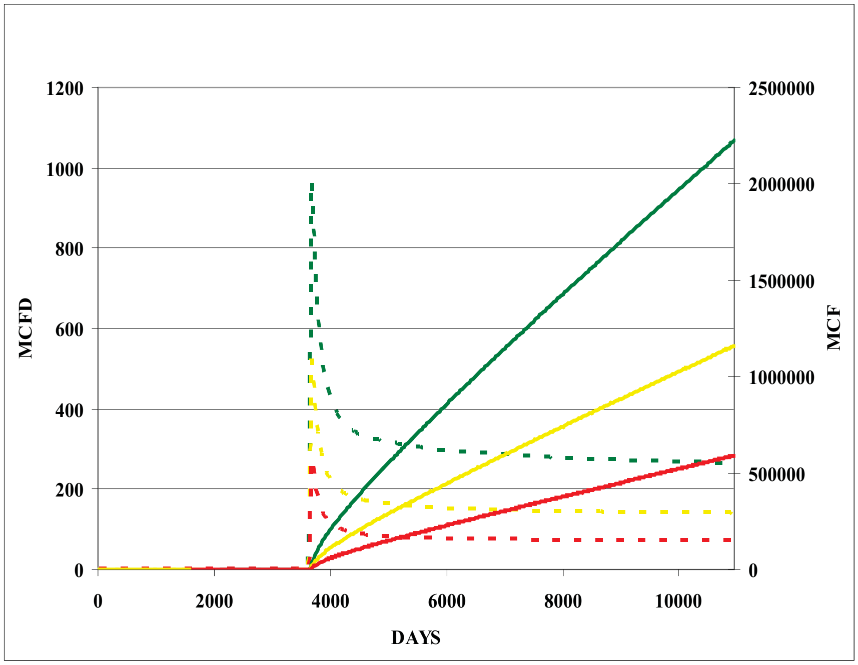
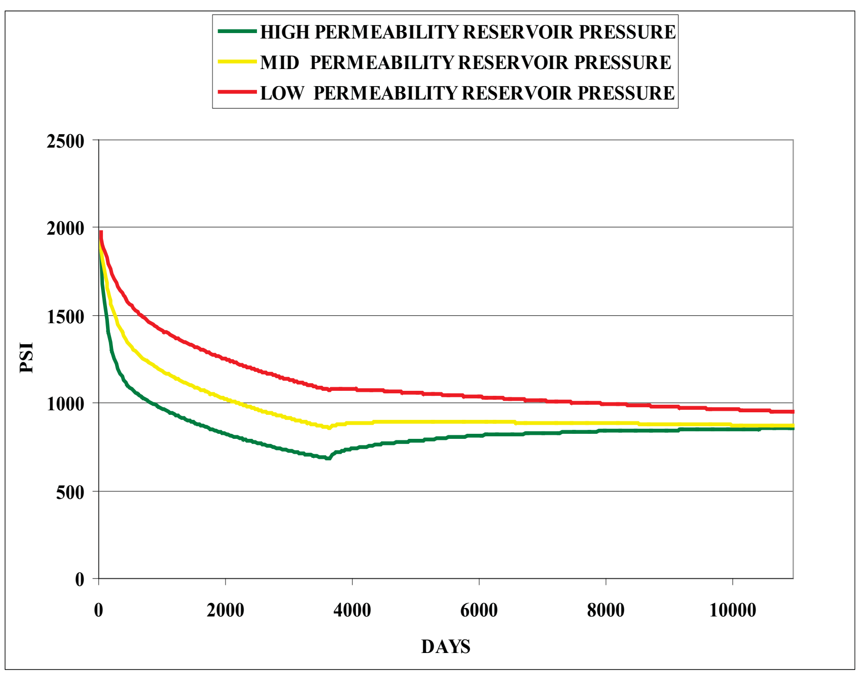


Figure G-17: Marcellus Reservoir Pressure Forecast – Model Area 2



UTICA RESULTS SUMMARY

<u>Low Permeability Case – Comparison of Model Areas</u>

Figure G-18: Utica Methane Production Forecast – Low Permeability Case

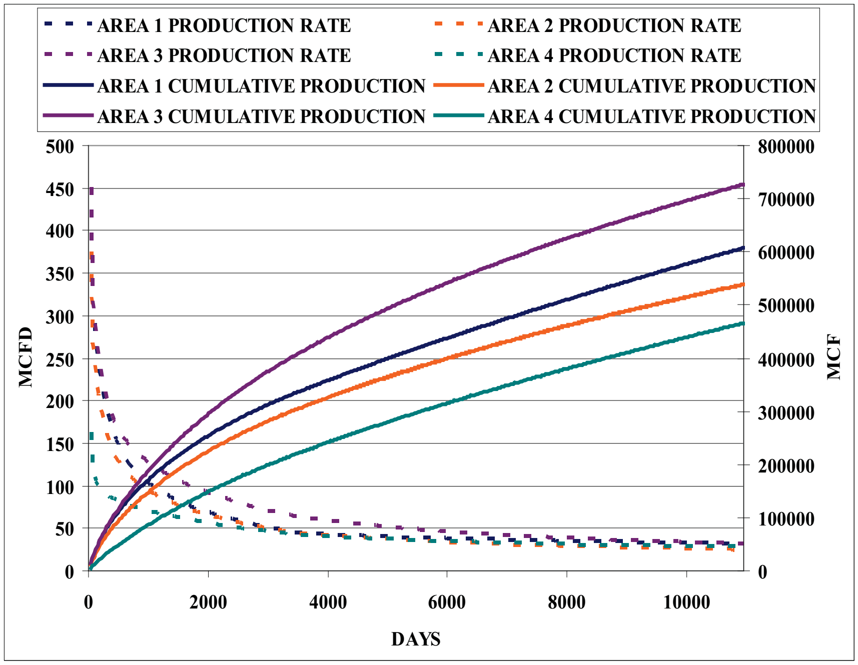


Figure G-19: Utica CO_2 Injection Forecast – Low Permeability Case

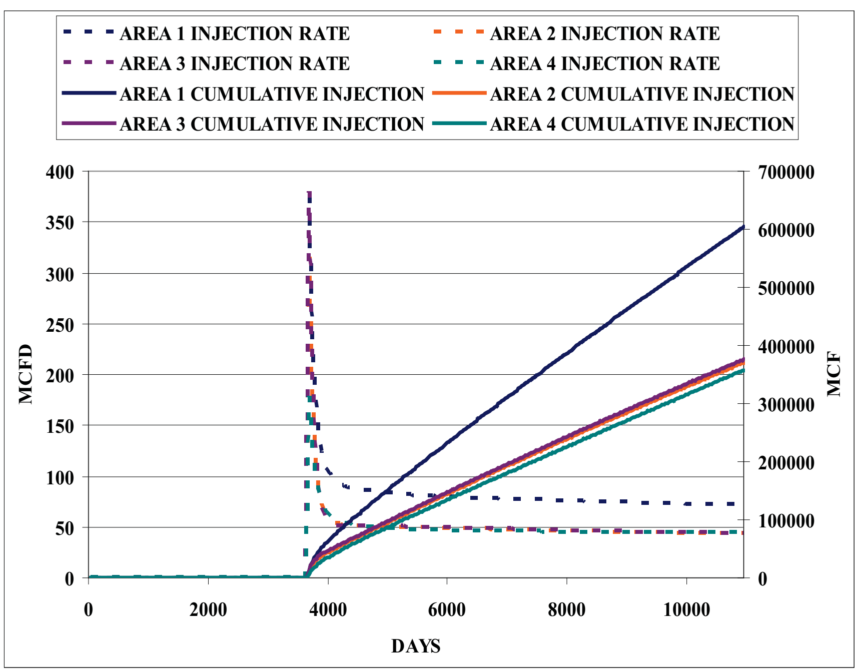
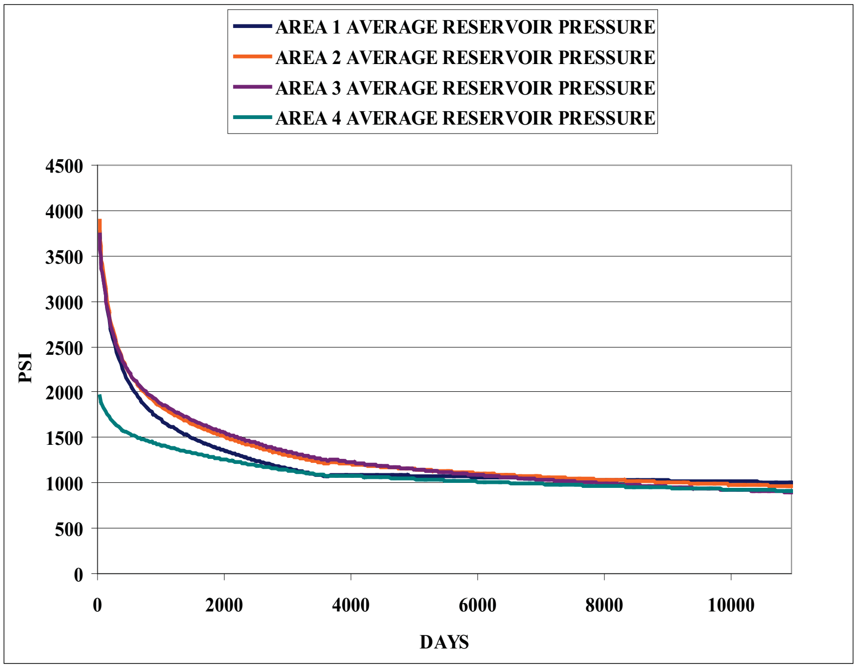


Figure G-20: Utica Reservoir Pressure Forecast – Low Permeability Case



Mid Permeability Case – Comparison of Model Areas

Figure G-21: Utica Methane Production Forecast – Mid Permeability Case

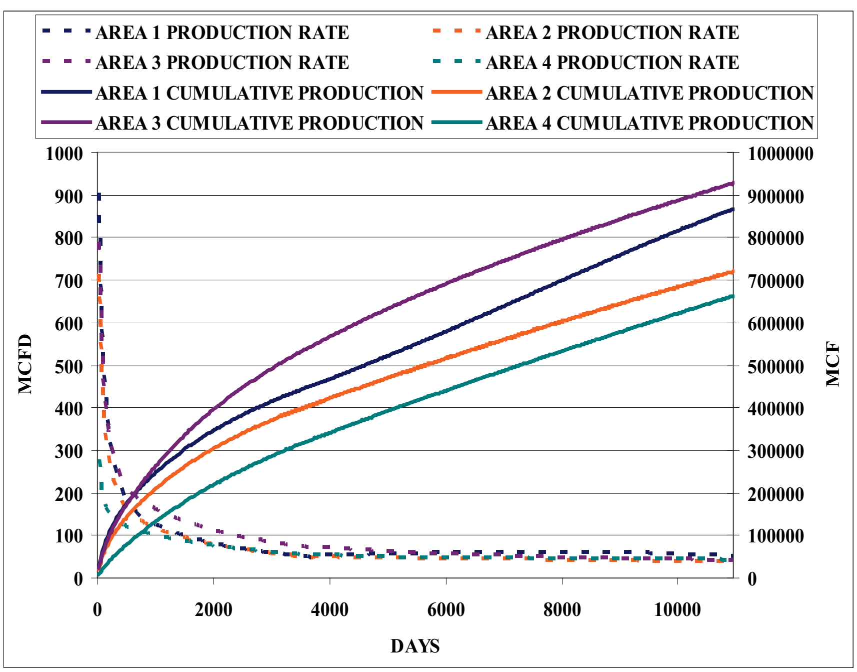


Figure G-22: Utica CO_2 Injection Forecast – Mid Permeability Case

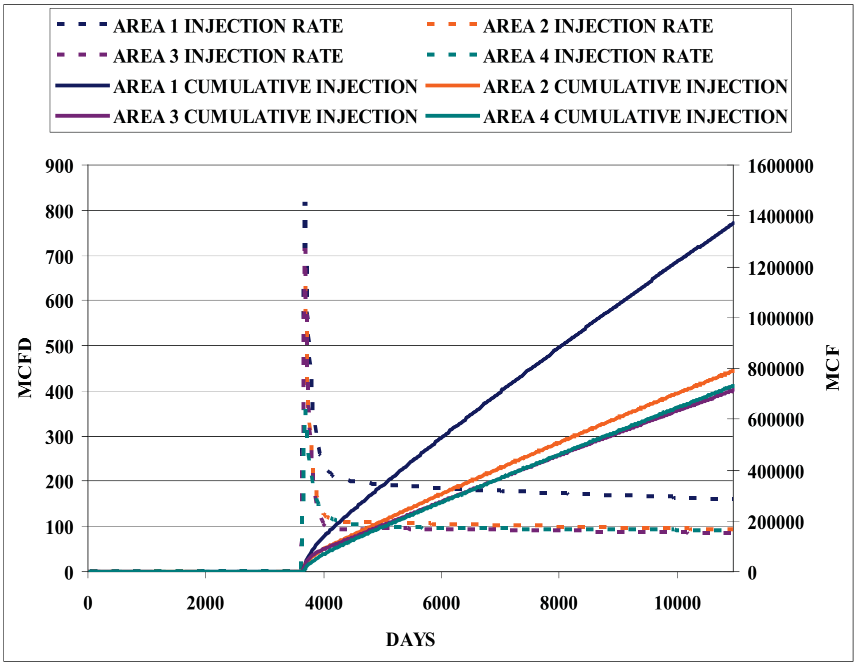
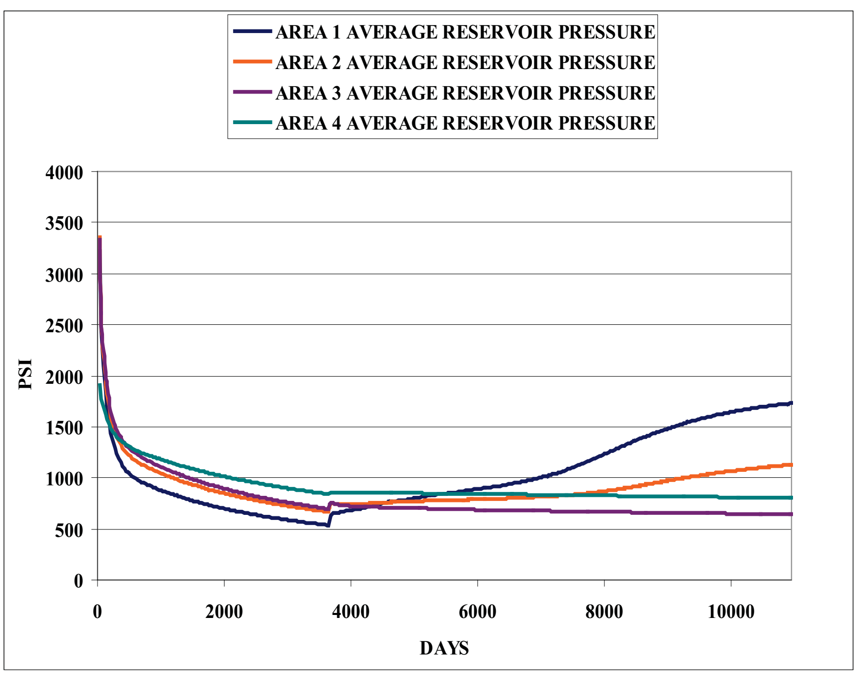


Figure G-23: Utica Reservoir Pressure Forecast – Mid Permeability Case



High Permeability Case – Comparison of Model Areas

Figure G-24: Utica Methane Production Forecast – High Permeability Case

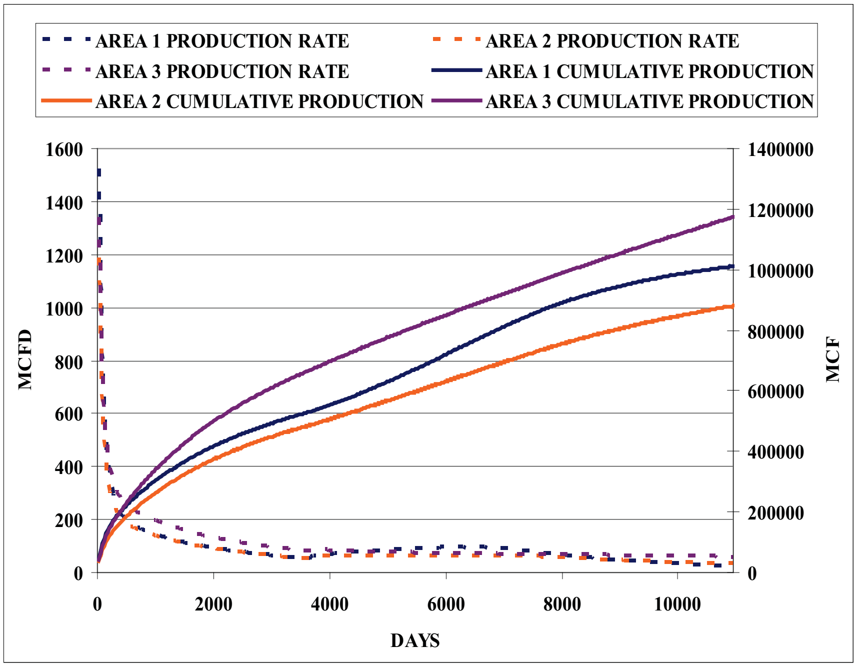


Figure G-25: Utica CO_2 Injection Forecast - High Permeability Case

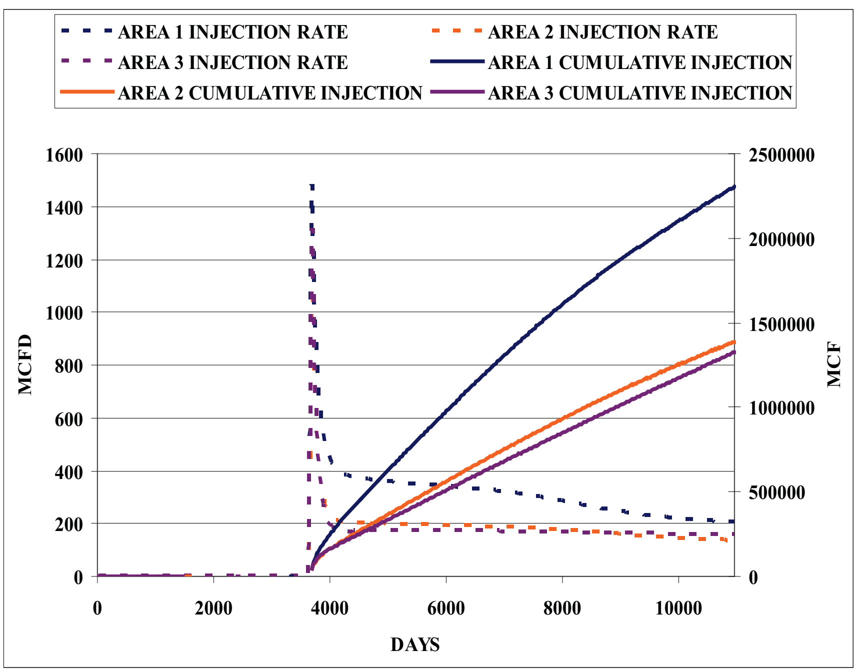
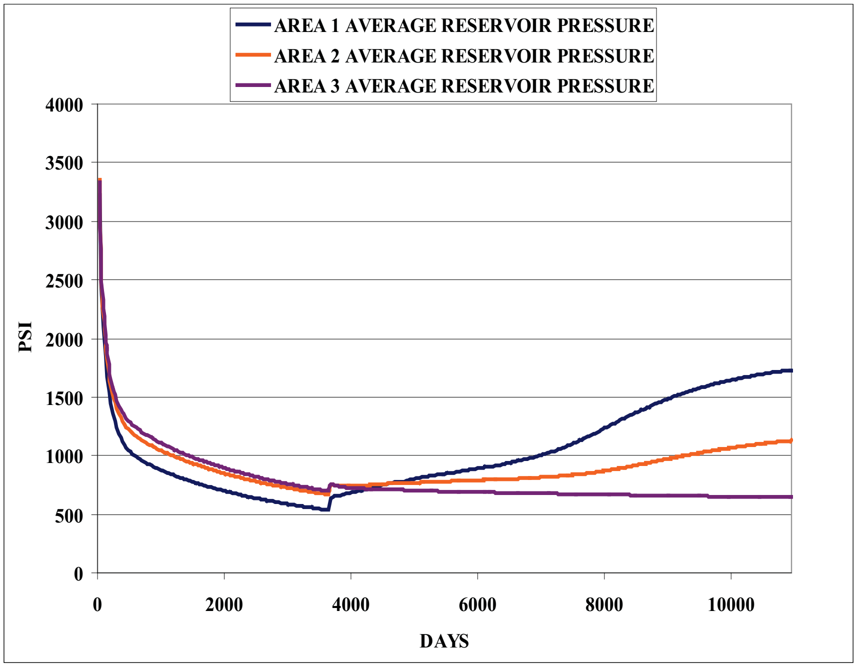


Figure G-26: Utica Reservoir Pressure Forecast – High Permeability Case



Utica Model Area 1 – Comparison of Permeability Cases

Figure G-27: Utica Methane Production Forecast – Model Area 1

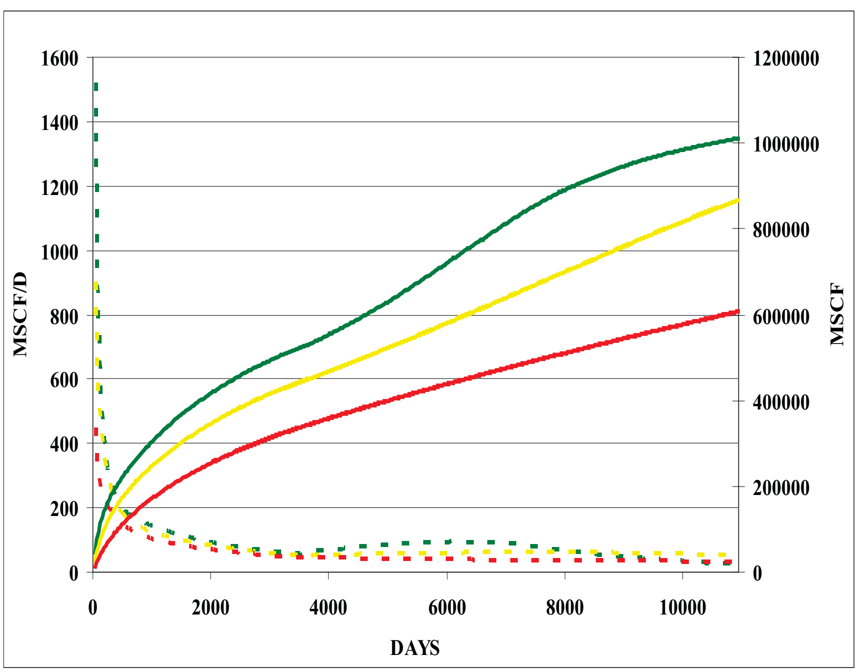


Figure G-28: Utica CO_2 Injection Forecast – Model Area 1

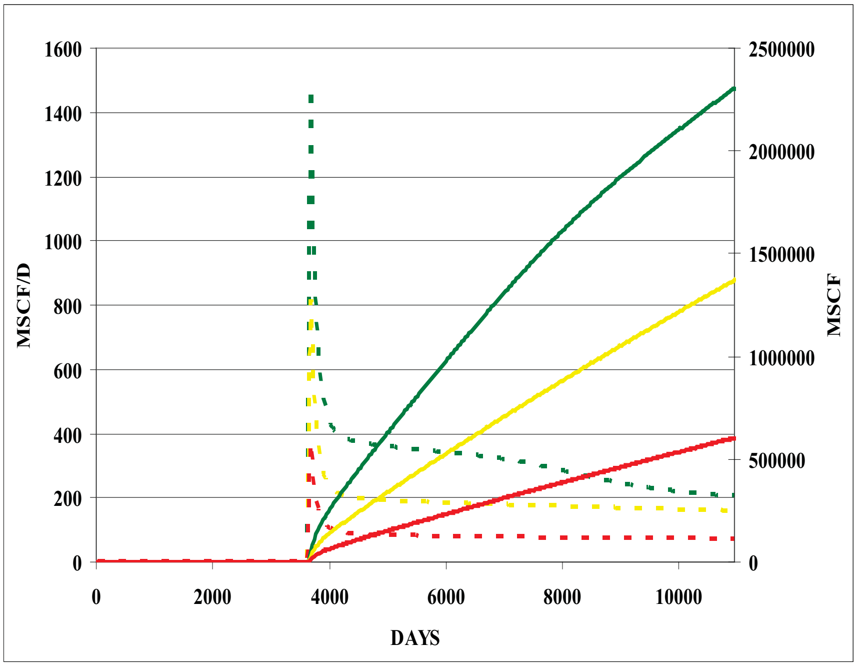
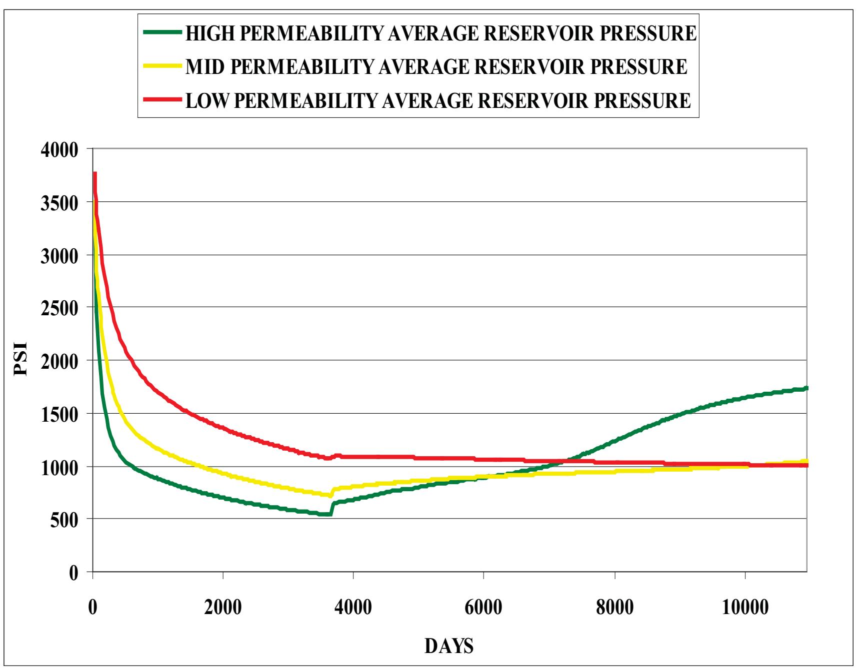


Figure G-29: Utica Reservoir Pressure Forecast – Model Area 1



Utica Model Area 2 – Comparison of Permeability Cases

Figure G-30: Utica Methane Production Forecast – Model Area 2

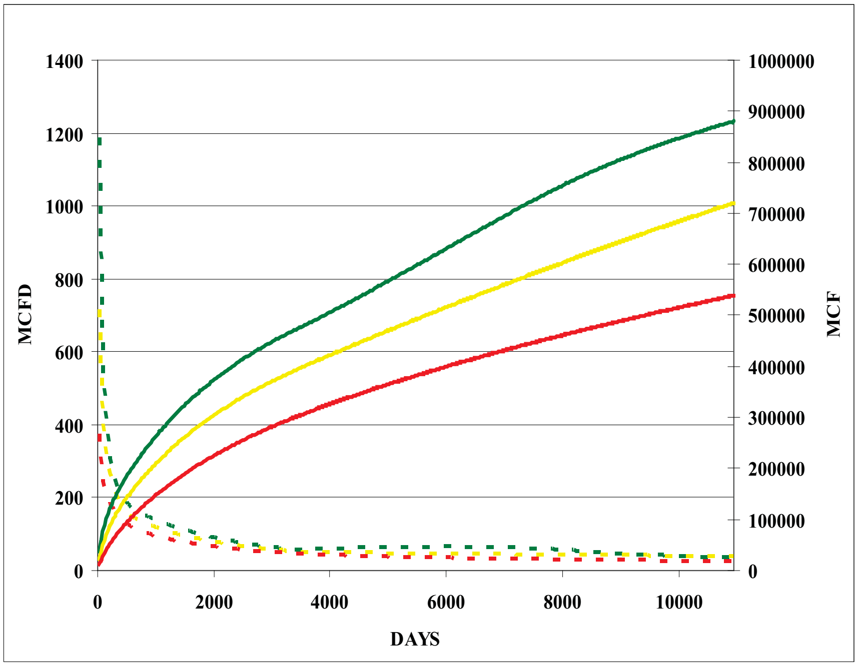


Figure G-31: Utica CO_2 Injection Forecast – Model Area 2

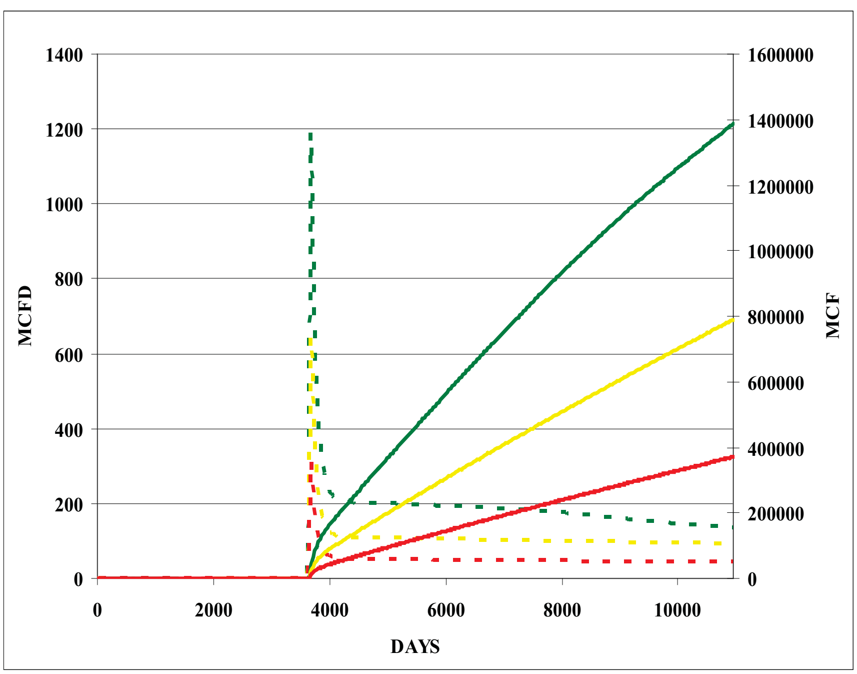
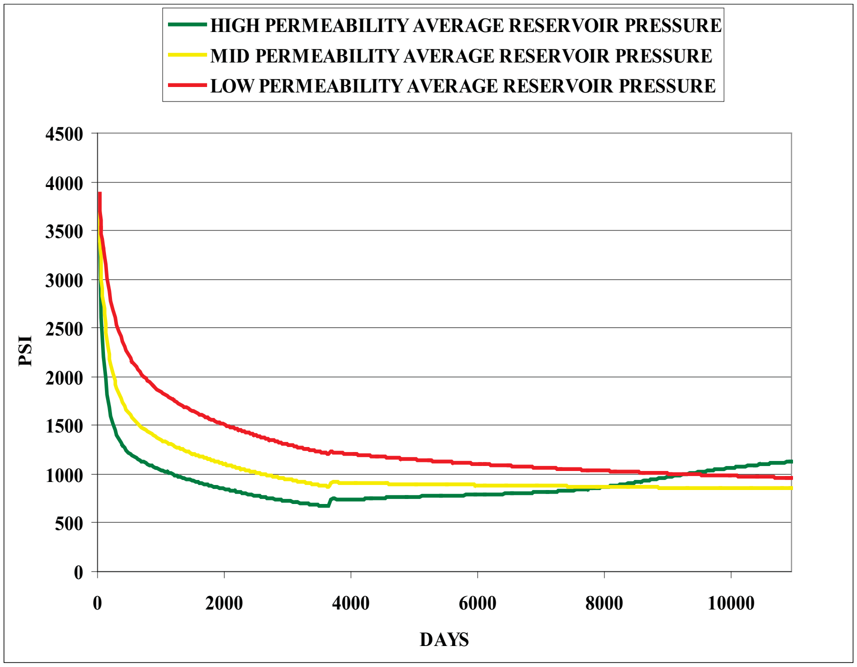


Figure G-32: Utica Reservoir Pressure Forecast – Model Area 2



Utica Model Area 3 – Comparison of Permeability Cases

Figure G-33: Utica Methane Production Forecast – Model Area 3

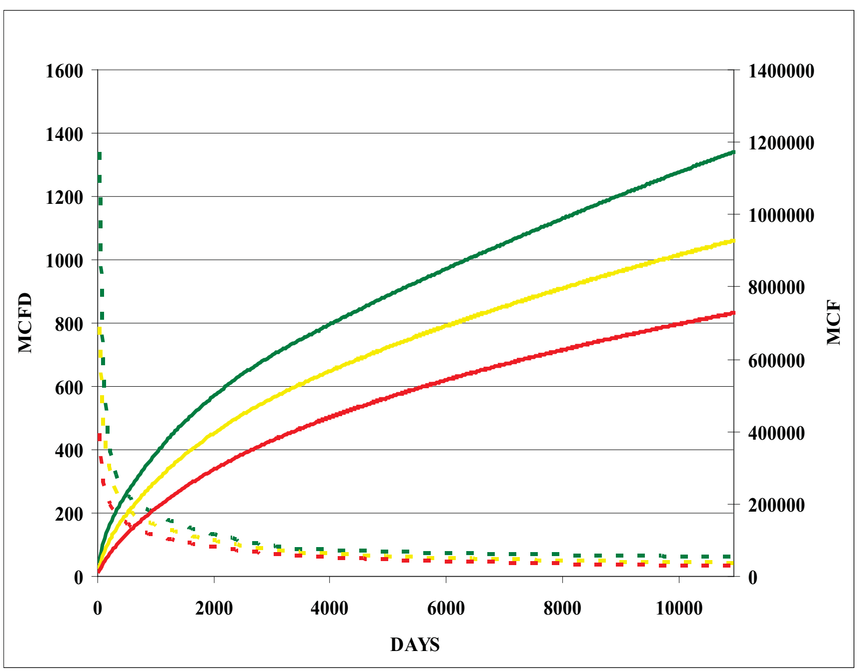


Figure G-34: Utica CO_2 Injection Forecast – Model Area 3

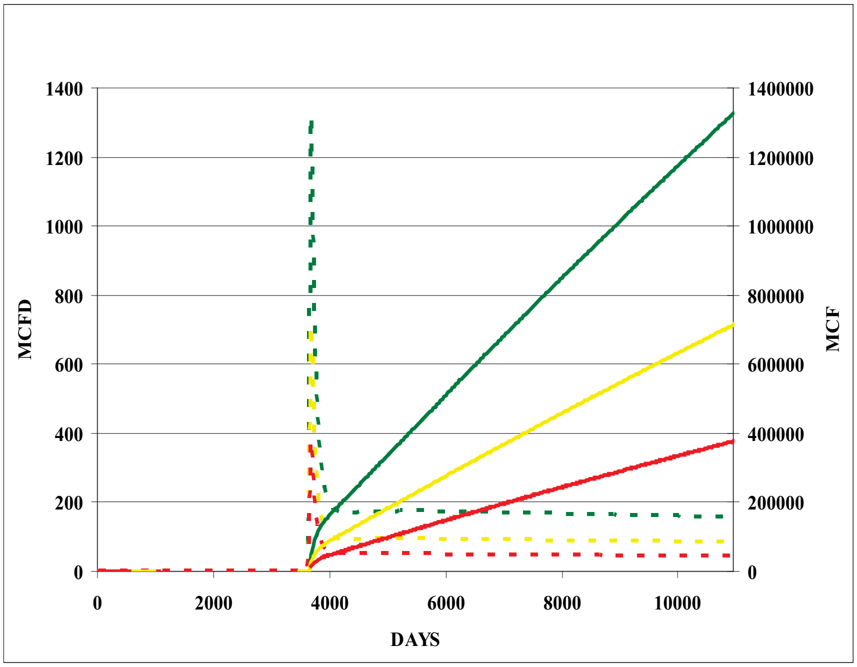
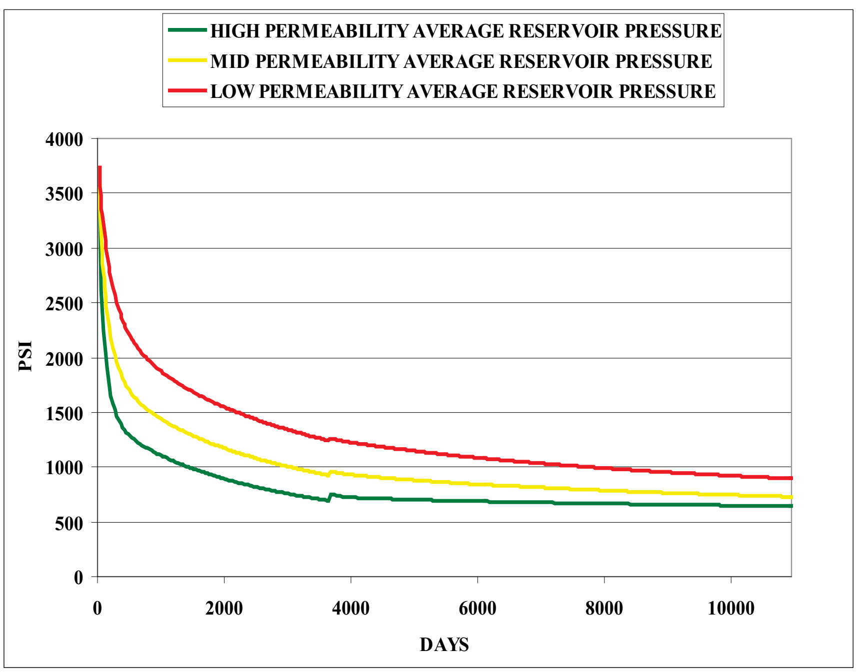


Figure G-35: Utica Reservoir Pressure Forecast – Model Area 3



Utica Model Area 4 – Comparison of Permeability Cases

Figure G-36: Utica Methane Production Forecast – Model Area 4

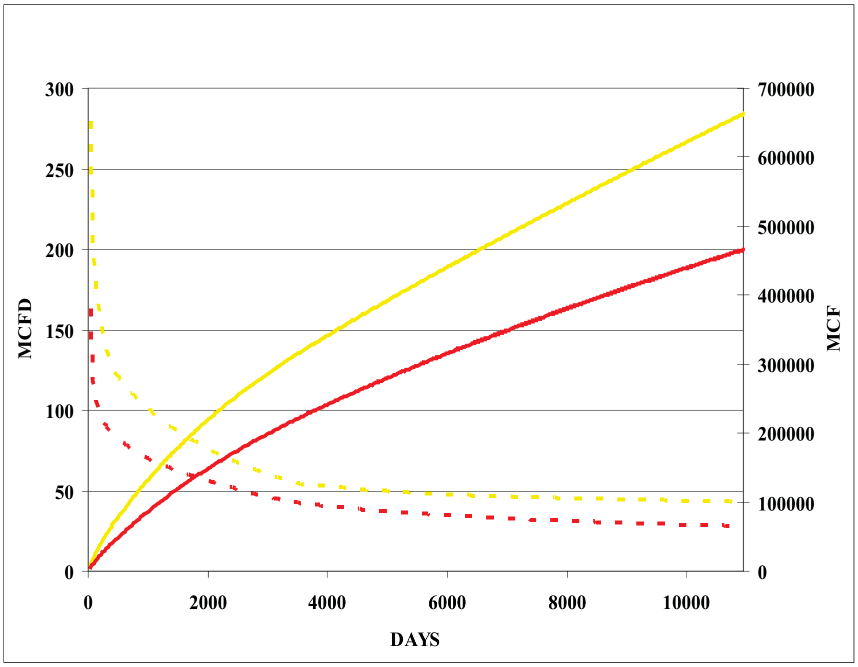


Figure G-37: Utica CO_2 Injection Forecast – Model Area 4

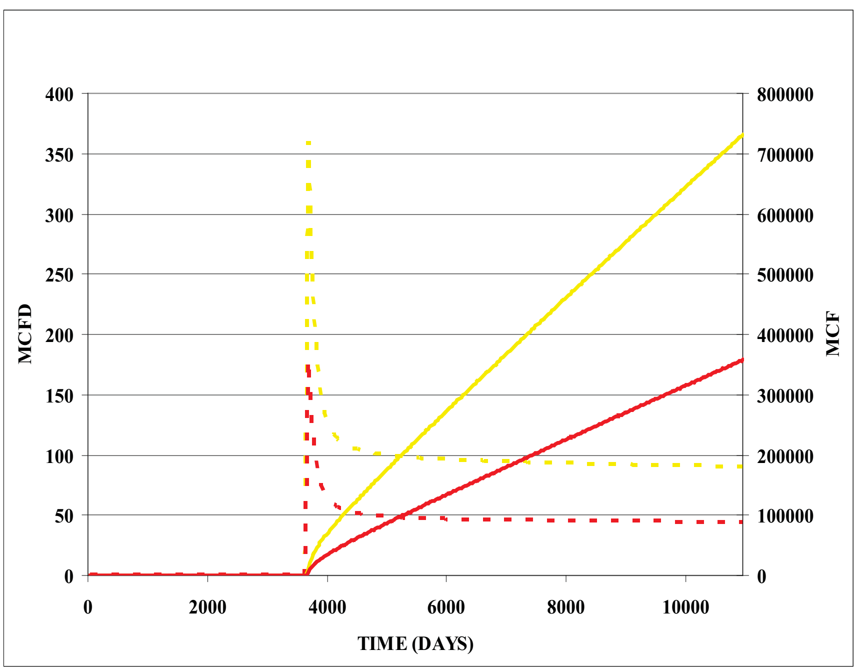
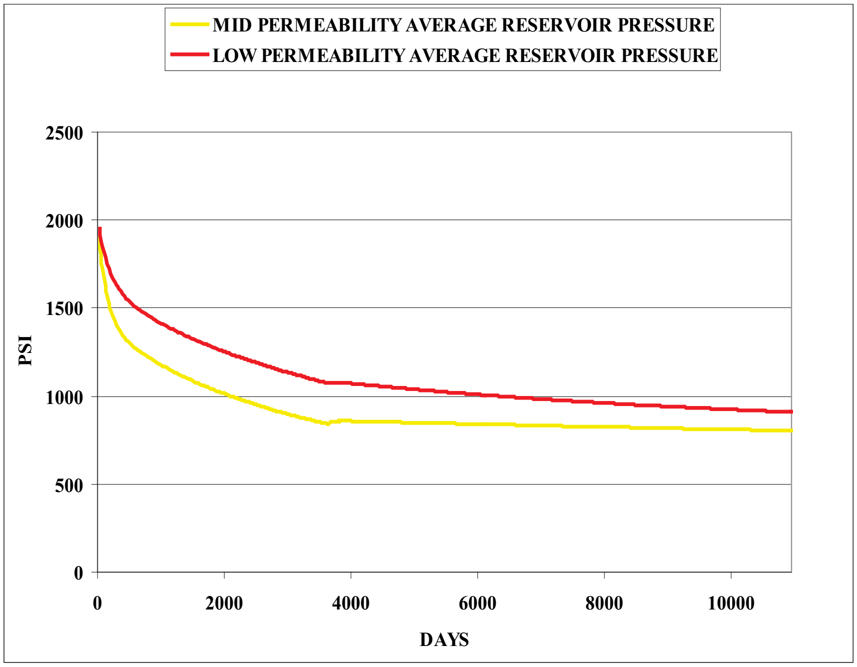


Figure G-38: Utica Reservoir Pressure Forecast – Model Area 4



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New York State Energy Research and Development Authority

17 Columbia Circle
Albany, New York 12203-6399

toll free: 1 (866) NYSERDA
local: (518) 862-1090
fax: (518) 862-1091

info@nyserda.org
nyserda.ny.gov

Geologic, Engineering, and Economic Evaluation of the CO_2 Sequestration Capacity of New York's Gas Shales

Final Report
December 2011

State of New York
Andrew M. Cuomo, Governor

New York State Energy Research and Development Authority
Francis J. Murray, Jr., President and CEO