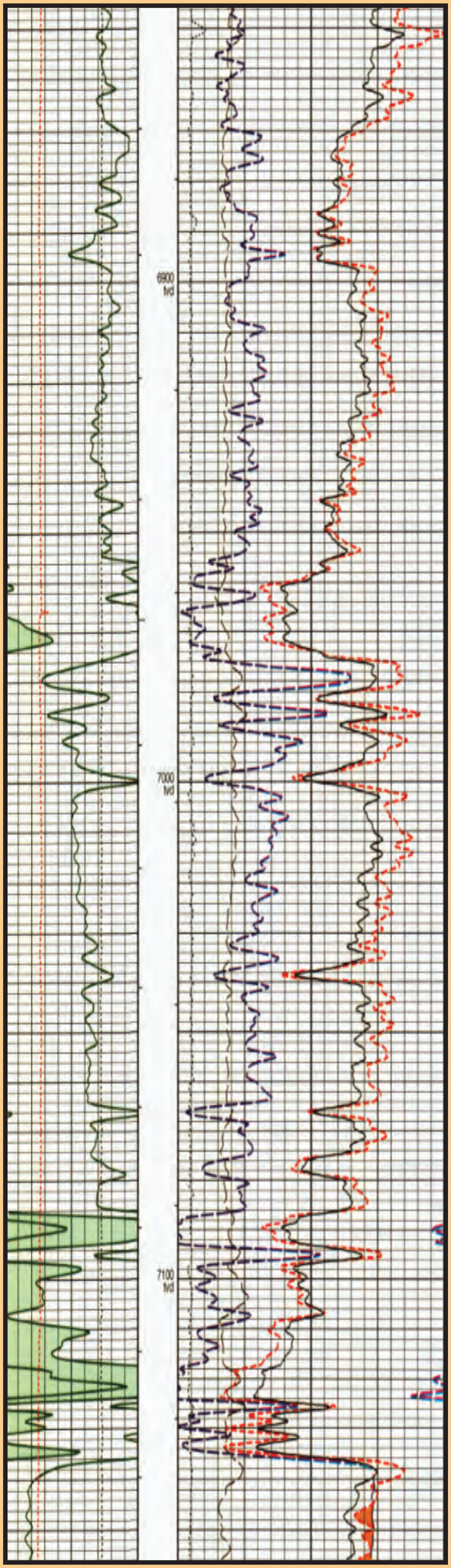

West Virginia

Geological and Economic Survey

ESTIMATES OF NATURAL GAS RESOURCES AND RECOVERY EFFICIENCY ASSOCIATED WITH MARCELLUS DEVELOPMENT IN WEST VIRGINIA

S.E. Pool, R.M. Boswell, J.T. Saucer, B.J. Carney

WVGES Reports of Investigation -- 36

2021

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West Virginia Geological & Economic Survey

Reports of Investigation 36

Estimates of Natural Gas Resources and Recovery Efficiency Associated with Marcellus Development in West Virginia

Susan E. Pool[1], Ray M. Boswell[2], John T. Saucer[1], B. J. Carney[3]

[1]WVGES; [2]National Energy Technology Laboratory; [3]Northeast Natural Energy, LLC

Recommended Citation:

Pool, S. E., Boswell, R. M., Saucer, J. T., Carney, B. J., 2021, Estimates of Natural Gas Resources and Recovery Efficiency Associated with Marcellus Development in West Virginia: West Virginia Geological & Economic Survey, Reports of Investigation RI-36.

Available Online:

http://www.wvgs.wvnet.edu/www/MUDvnnSh/MUDvnnSh.htm

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List of Symbols, Abbreviations, and Acronyms

(*symbols listed first followed by Greek letter abbreviations followed by other abbreviations and acronyms in alphabetical order*)

Abbreviation	Description
&	and
~	approximately
º	degrees
ºF	degrees Fahrenheit
‘	feet
+	plus; and greater; and more
-	minus; to
x	times
/	divided by; per; and; or
=	equals
>	greater than
<	less than
#	number
%	percent
ϕ_e	porosity, effective
ρ_f	density, fluid
ρ_k	density, kerogen
ρb_{log}	density—bulk, geophysical well log(s)
ρ_m	density, matrix
ρ_{mc}	density, matrix corrected
A	area
AAPG	American Association of Petroleum Geologists
AGS	Appalachian Geological Society
API, api	American Petroleum Institute (API units for measuring gamma ray)
Bcf	billion cubic feet
Bcf/mi^2	billion cubic feet per square mile
Bcfge	billion cubic feet gas equivalent
C1	constant one (proprietary)
C2	constant two (proprietary)
C_{ads}	constant, adsorbed original gas-in-place
C_{free}	constant, free original gas-in-place
cc	cubic centimeter
Ch	chapter
Co.	County
DOE	Department of Energy
E	east
EIA	Energy Information Administration

e.g.	exempli gratia (for example)
EGSP	Eastern Gas Shale Project
eq.	equation(s)
et al.	et alia (and others)
EUR	estimated ultimate recovery
F	Fahrenheit
Fm(s)	Formation(s)
Ft, ft	feet, foot
Frac, frac	fracture
FVF	formation volume factor
G, g	grams
g/cc	grams per cubic centimeter
GBRU	Geneseo-Burket Reservoir Unit
GC	gas content
GIP (or OGIP)	original gas-in-place
GP	gas parameter
GR	gamma ray
H	thickness
HRU	Huron Reservoir Unit
In, in	inches
K	kerogen
L.	Lower
LLC	Limited Liability Company
log	geophysical well log
LOM	level of organic maturity
Ls	Limestone
Mbr(s)	Member(s)
mi^2	square mile
MMbbl	million barrels
MRU	Marcellus Reservoir Unit
MSEEL	Marcellus Shale Energy and Environment Laboratory
NETL	National Energy Technology Laboratory
NMR	nuclear magnetic resonance
NNE	Northeast Natural Energy
OGIP (or GIP)	original gas-in-place
$OGIP_{ads}$	original gas-in-place, adsorbed gas
$OGIP_{free}$	original gas-in-place, free gas
$OGIP_{total}$	original gas-in-place, total gas
ohm-m	ohm-meters
p.	pages
P_{grad}	pressure gradient
P_r	pressure, reservoir
PA	Pennsylvania
Phi	porosity
psi	pounds per square inch
psi/ft	pounds per square inch per foot

Q_n	gas, non-combustible
RE	recovery efficiency
Res	resistivity
RHO-B, rho-b	bulk density
RI	Reports of Investigation
RRU	Rhinestreet Reservoir Unit
rTRR	remaining technically recoverable resource(s)
RU	reservoir unit
Scf	standard cubic feet
Sh	Shale
S_g	saturation, gas
S_w	saturation, water
Tcf	trillion cubic feet
Tcfg	trillion cubic feet gas
Tcfge	trillion cubic feet gas equivalent
TOC	total organic carbon
TOC_{den}	total organic carbon, as determined from density data
T_r	temperature, reservoir
TRR	technically recoverable resource(s)
USGS	United States Geological Survey
uTRR	ultimate technically recoverable resource(s)
V, v	volume
v/v	volume to volume
W	west
WV	West Virginia
WVGES	West Virginia Geological and Economic Survey
Z	compressibility
Z_g	compressibility, gas

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Estimates of Natural Gas Resources and Recovery Efficiencies Associated with Marcellus Development in Northern West Virginia

Susan E. Pool (WVGES), Ray M. Boswell (NETL), John T. Saucer (WVGES), and B.J. Carney (NNE, LLC)

Abstract

Evaluation of more than 270 digital well log suites has been conducted to provide a first order estimate of the original in-place natural gas resources associated with the Marcellus and Geneseo-Burket organic-rich shales in West Virginia. It is determined that original gas-in-place (OGIP) resources exceed 40 Bcf/mi^2 over much of the State and exceed 150 Bcf/mi^2 in northcentral West Virginia. These volumes represent substantial increases from prior estimates, reflecting not only improved data volume and quality, but also the calibration of in-place estimates via comparison to observed and predicted well production. Where input assumptions and parameters are poorly constrained (for example grain density or water saturation), they were set at reasonable values that enable resulting OGIP to exceed expected well recovery at any specific location. A primary contributor to increased OGIP volumes is the shift in focus from assessment of a single given lithostratigraphic unit to broader "Reservoir Units" (RUs). Two RUs are deemed to be present within the current area of shale gas development in northern West Virginia. The Marcellus Reservoir Unit (MRU) includes resources within the Marcellus and bounding formations and is defined to extend upwards to either 300 ft above the top of the Marcellus or to the base of the Tully Limestone where the Tully is judged to be a likely fracture (frac) barrier. A separate Geneseo-Burket Reservoir Unit (GBRU) exists wherever the Geneseo-Burket organic-rich shales are not included within the MRU. The GBRU similarly extends upwards 300 ft from the top of the Geneseo-Burket. At present, only the MRU has been a target of significant development using modern horizontal drilling and hydraulic fracturing methods. Additional RUs associated with the Rhinestreet Shale and the Huron Member of the Ohio Shale are present in parts of West Virginia but are not assessed in this report.

Total OGIP resources are estimated at 878 Tcf for the MRU and 115 Tcf for the GBRU. Stratigraphically, 532 Tcf is assigned to the Marcellus Formation, with additional substantial volumes in overlying formations including the Mahantango (125 Tcf) primarily in the northeastern portion of the State, along with the Genesee-Harrell (281 Tcf) and Sonyea (122 Tcf) in the northcentral and northwestern areas. Primary controls on resources are the thickness and organic-richness of the units and distribution of overpressure. In-place resource density is observed to vary significantly within each RU. Within the MRU, strongly-delineated northeast-to-southwest trends of in-place resources correlate well with increased thickness, porosity, and organic-richness of the various units, with likely connection to known basement structures. The study OGIP/mi^2 estimates for the MRU are compared with previously reported estimates of technically recoverable resource density (TRR/mi^2) to provide an initial estimate of the scale and variation in potential ultimate recovery efficiency (RE) associated with ongoing Marcellus development. It is estimated that RE likely exceeds 50% within the core of the play and declines to less than 10% along the play margins.

Introduction

Over the past decade, the Marcellus Formation has been the primary focus of gas drilling in West Virginia. In 2019, wells targeting the Marcellus produced 1,895.1 Bcf of natural gas and 61.2 MMbbl of natural gas liquids (Dinterman, 2020). The gas volume represents 87.9% of all gas production in the State and an increase of 290 Bcf over 2018 (**Figure 1**). At the end of 2019, 4,182 wells were reported as producing from the Marcellus reservoir, with horizontal wells accounting for 2,758 of that total.

To assess the capacity for continued and sustained Marcellus production, the WVGES has undertaken periodic review of play geology and production performance. An initial assessment of original gas-in-place (OGIP) resources that was conducted in 2013, utilized standard volumetric procedures (shale-adjusted) and resulted in a total estimate for the State of 122 Tcf (Pool et al., 2013). Updated pressure data revised that estimate to 142 Tcf in 2015 (Hohn et al., 2015). Resource density within the developing core of the play (northcentral West Virginia) was, at that time, estimated to range from 9 to 25 Bcf/mi^2.

Regional works from others, that address West Virginia, include: 1) in 2014, Range Resources published a Marcellus map showing an estimated gas-in-place resource density of ~25 to 100 Bcf/mi^2 in northern West Virginia and 2) in 2018, Ikonnikova et al. mapped OGIP at ~30 to 60 Bcf/mi^2 in the primary play area. Although the resource distribution varies locally on the two maps and neither work provided a total OGIP estimate, both maps suggest roughly 370 Tcf OGIP for the Marcellus Play in the State.

In recent years, as production has continued to expand, it has become clear that Marcellus wells are extracting much greater volumes per unit area than the prevailing in-place estimates. Therefore, WVGES determined that a renewed effort to assess resources was appropriate, including refinement of the OGIP approach to determine potential sources for the under-estimation apparent in the original 2013 assessment. A preliminary step was to review the lithostratigraphy of the units potentially contributing to Marcellus Play production (see Boswell and Pool, 2018). Another preliminary step was to review production data—in 2013, only 114 wells in northern West Virginia had accumulated more than 2 years of production data; however, by 2020, that number had grown to more than 1,250 wells. The expanding quality and quantity of production data provide the opportunity to ground-truth in-place resource estimates via comparison to reported and projected production volumes. Boswell et al. (2020) describe this effort to normalize well production by both well length and well spacing to produce a map of technically recoverable resource density (TRR/mi^2).

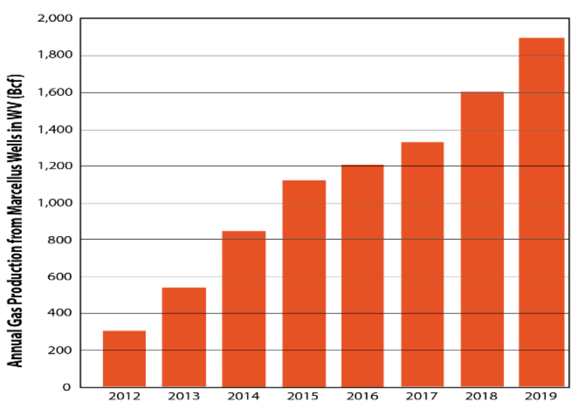


Figure 1. *Annual production reported for wells targeting the Marcellus Formation in West Virginia. Data from Dinterman (2020).*

This report reviews the data, methodology, and results of the present gas-in-place assessment followed by a summary of the sensitivity of the OGIP results. There is then a comparison of the revised OGIP values with recently reported TRR volumes to indicate the nature of recovery efficiency (RE) from the play followed by a discussion on remaining resources.

OGIP Assessment

The OGIP assessment includes the following primary efforts: 1) define the stratigraphic boundaries of the rock volumes to assess, 2) gather well data, 3) conduct a deterministic volumetric assessment for free gas and evaluate the potential adsorbed gas component, 4) map the results and note potential geologic controls on resource density and distribution, and 5) examine sensitivity of key parameters.

Reservoir Unit Identification

A primary goal of the OGIP assessment is to include all the gas with potential to contribute to production from wells targeting a specific unit, regardless of the formal lithostratigraphic formation in which that gas might reside. This volume of rock is referred to here as a "Reservoir Unit" (RU) (**Figure 2**).

Four RUs related to Devonian shale-gas development are recognized in West Virginia. The Huron Shale of the greater Big Sandy field has been a focus of development since the 1930s (Boswell, 1996). Through the 1970s and 1980s, the Rhinestreet Shale commonly has been co-produced with numerous other zones (Sweeney et al., 1986), but was rarely a primary target. More recently, the Huron RU (HRU) was a target for early horizontal well development (Lewis et al., 2011), including several hundred wells in southern and western West Virginia and more than 400 wells in Kentucky (Wozniak et al., 2010). However, there have been very few hori-

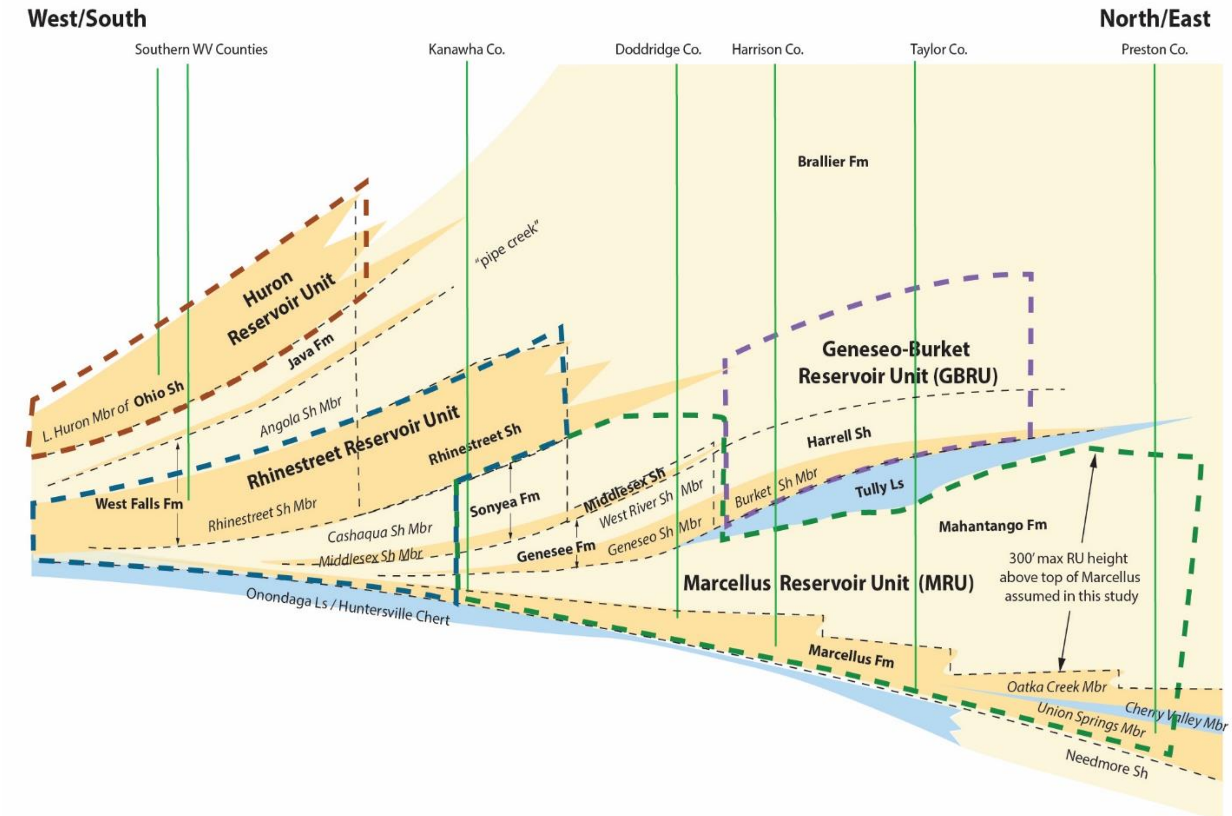


Figure 2. *Schematic cross-section showing the general occurrence of Devonian shale gas RUs in West Virginia. The green dashes outline the MRU; purple the GBRU, blue the RRU, and red the HRU.*

zontal wells targeting the Huron since 2014. Similarly to date, there have been only a few horizontal wells testing the Rhinestreet RU (RRU). Most recently, the "Marcellus Reservoir Unit" (MRU) has been the focus of well development in the State. While additional gas resources exist in virtually every other lithostratigraphic unit, only the Geneseo-Burket and Middlesex shales have been landing zone targets in West Virginia. In many areas, these shales are found to occur within the MRU (as discussed below). At present, a "Geneseo-Burket Reservoir Unit" (GBRU) is a target of standalone development in Pennsylvania (Wrightstone, 2015); however, development in West Virginia remains limited.

Two primary factors in assessing the dimensions of an RU are: 1) the location and nature of potential fracture (frac) barriers that would limit the vertical extent of the contributing rock volume and 2) an estimate of the most reasonable vertical extent of the contributing rock volume where no frac barriers are present. The Onondaga Limestone and equivalent units are a consistent lower frac barrier throughout most of the State. It is recognized that this may not be the case in all locations, particularly along the eastern margin of the basin where pre-existing natural fractures and faults are common or where the subjacent units are particularly shale rich (Bowers, 2018). The area where the Tully Limestone is judged to serve as a potential upper frac barrier is shown in **Figure 3**. This determination is approximate and is based on combined reference to Tully thickness (minimum threshold of 40 ft), the stratigraphic separation between the Tully and the Marcellus (minimum threshold of 100 ft), and the nature (shale content) of the Tully unit.

Microseismic data from the Marcellus Play consistently show limited downward fracture growth, with upward growth extending a

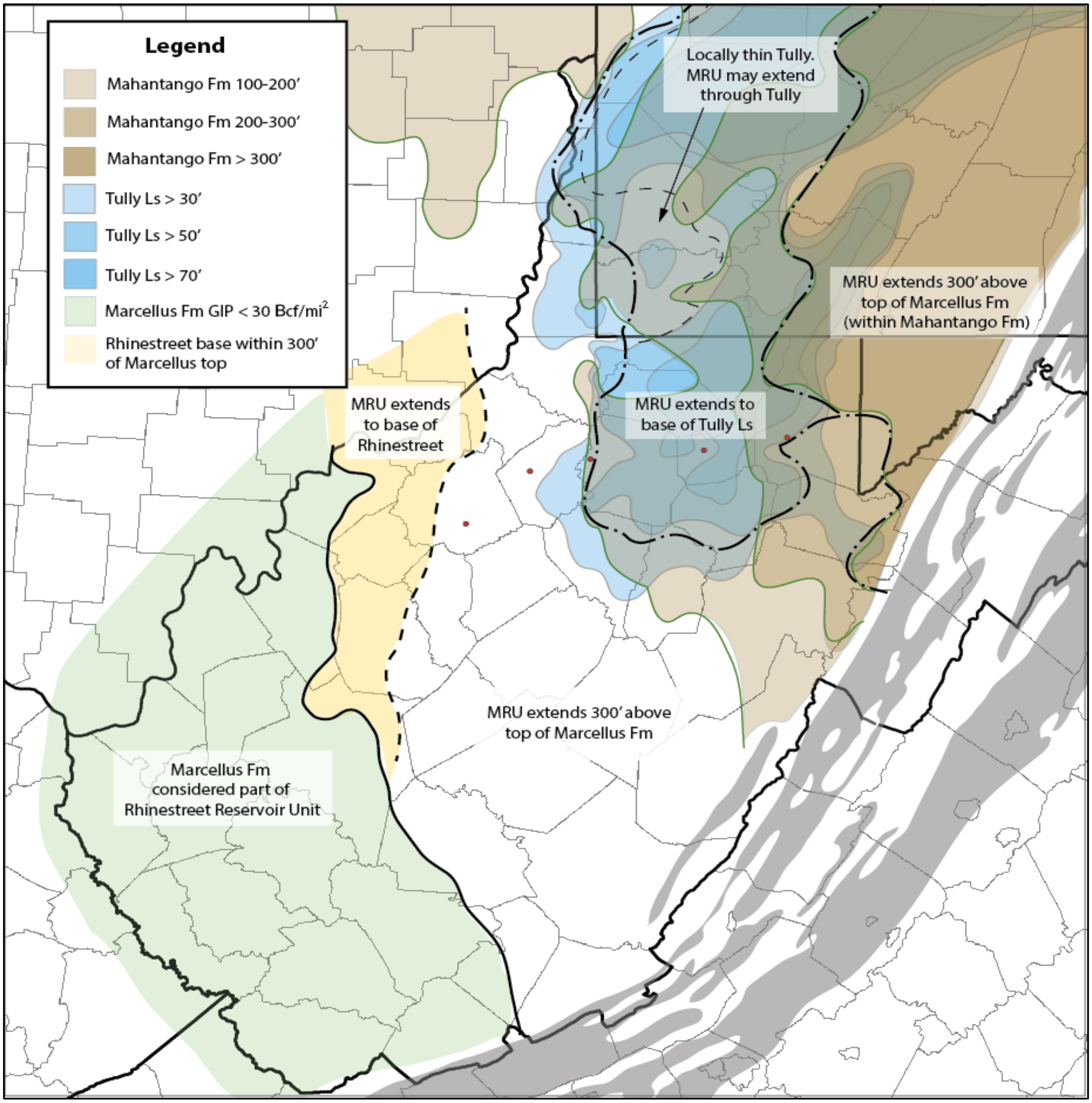


Figure 3. *MRU extent map. The MRU extent is controlled by the combination of three factors: 1) the presence of thick Tully Limestone that could act as a barrier to upward fracture growth (shown by blue color indicating Tully thickness), 2) the stratigraphic separation between the top of the Marcellus Formation and the Tully Limestone (shown by brown color indicating thickness of the Mahantango Formation), and 3) the occurrence of the base of the RRU. In northcentral West Virginia, the MRU extends to the base of the Tully. In a small area of northern Preston County, the Mahantango is more than 300 ft thick, so the top of the MRU lies within the Mahantango Formation. To the south (green shading), the MRU is not recognized, with the Marcellus Formation being a part of the RRU. Yellow shading shows the area where both the MRU and RRU occur. Red dots indicate wells shown in **Figure 6**.*

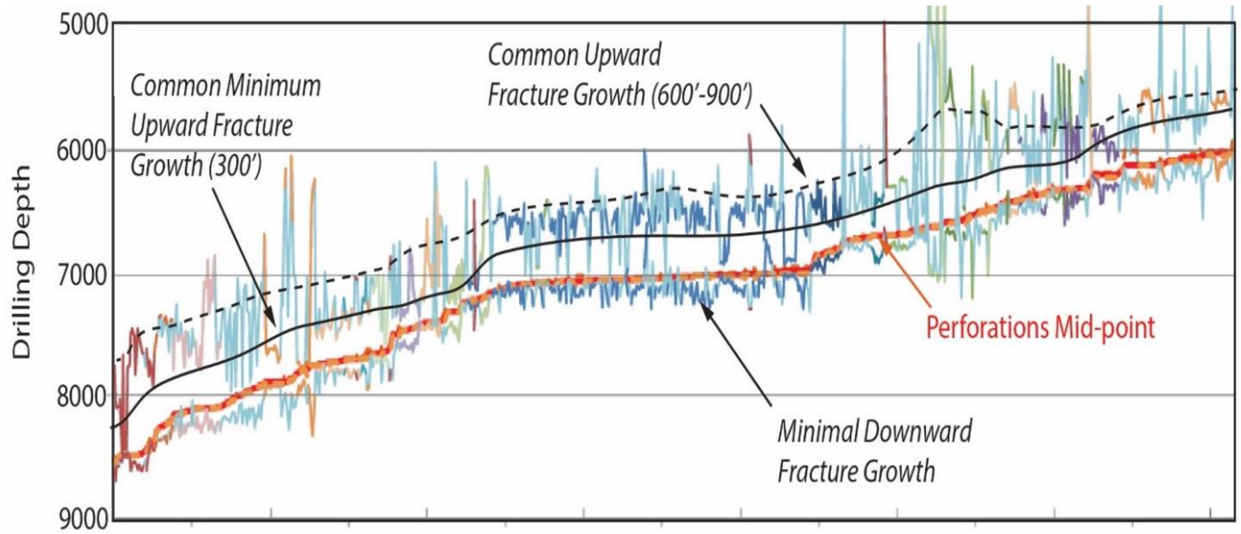


Figure 4. *Fracture growth data Fisher and Warpinski (2012) indicating the variable vertical extent of microseismic events initiated during Marcellus fracture stimulation. The data indicate virtually all fracture height growth is upwards, and that at every depth, stimulation commonly extends 300 ft above the average depth of perforations.*

minimum of ~300 ft (**Figure 4**, as modified from Fisher and Warpinski, 2012) while often reaching 600 to 900 ft. While the link between microseismic data and actual productivity are uncertain, the maximum vertical extent of any RU is set at 300 ft above the top of the target formation. This extent is used wherever there is no intervening frac barrier. The determination of the upper extent of the RUs and the areal distribution of frac barriers is clearly approximate and impacted by numerous factors, including the specifics of how any particular well is completed. For example, fracture stimulation sporadically passes through thick Tully (e.g., Hart, 2015), likely related to through-going faults.

While the full rock volume of the RU is included in the OGIP estimate, the pervasiveness and effectiveness of stimulation, and therefore, the recovery of gas from that volume, will generally degrade with distance away from the well. Nonetheless, the assumption is that standard horizontal drilling and completion in an RU will "develop," at minimum, the rock volume assigned to the MRU. In other words, it would not be expected that future drilling would target any resources with the designated RU volume.

In central and southern West Virginia, the Rhinestreet Shale Member of the West Falls Formation occurs within 300 ft of the Marcellus Formation (see schematic Kanawha County well in **Figure 2**); however, the Rhinestreet was excluded from the MRU. Farther to the south, where the Marcellus Formation is quite thin and Rhinestreet well developed, the Marcellus is included as part of the RRU (**Figure 3**).

As defined, each RU contains a primary development target (in which the well is typically landed) plus any associated overlying litho-stratigraphic units from which additional resources may be accessed. For example, locally within the MRU, the Mahantango Formation contains numerous zones of high resistivity and low-density rock that are interpreted to be gas-bearing (**Figure 5a**). To the west and south, the Genesee Formation contributes significant gas-bearing zones, particularly in the Geneseo Shale Member but also in the West River Shale Member (**Figures 5b, 5c**). Where the Tully is assessed to be a frac barrier, the Geneseo and the correlative Burket Shale Member of the Harrell Shale would require dedicated wells to produce and would also potentially access gas within overlying Harrell Shale, Brallier Formation, or equivalent units (**Figure 5d**). In summary, an overview cross-section of the MRU as it changes across the northern part of the State is shown in **Figure 6**.

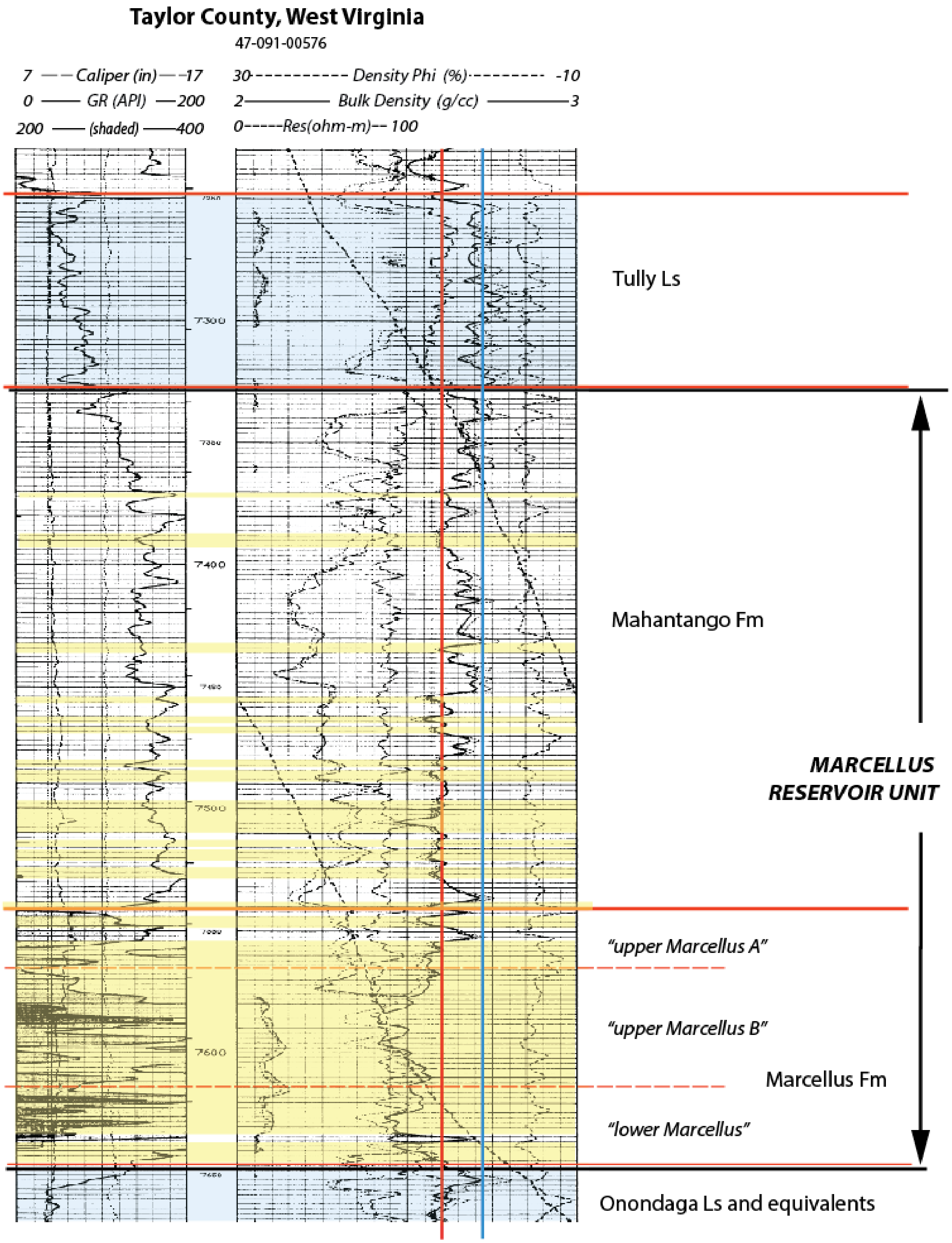


Figure 5a. *Example log from Taylor County showing MRU limited by thick Tully above. Apparent gas accumulations (yellow shading) as defined by bulk density of less than 2.6 g/cc (vertical red line) are concentrated in the Marcellus Formation but also occur through the overlying Mahantango Formation. These Mahantango units are up-dip equivalents of Marcellus strata farther westward into the basin. Blue vertical line is bulk density of 2.72 g/cc.*

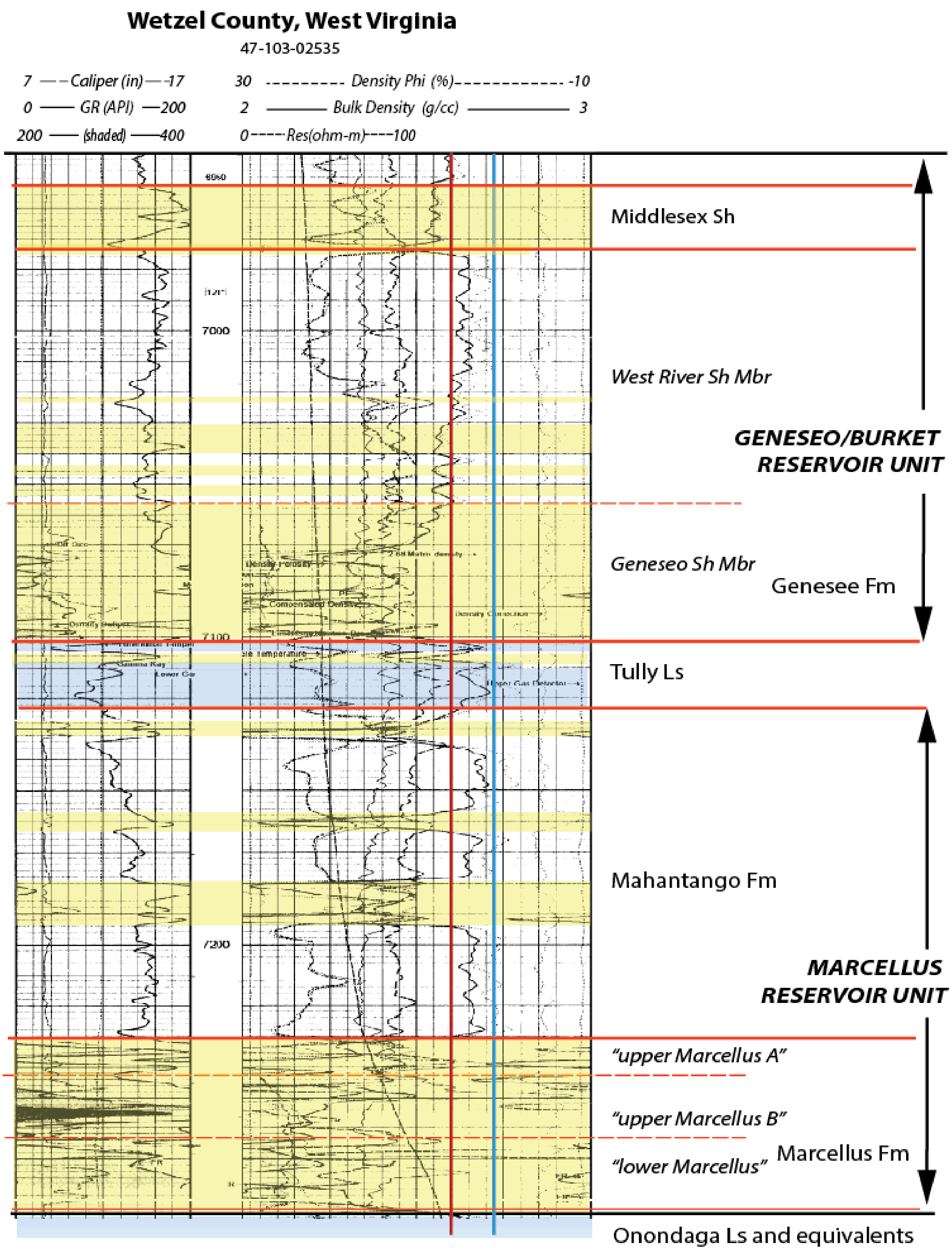


Figure 5b. *Example log from Wetzel County showing MRU not constrained by Tully frac barrier. Apparent gas accumulations (yellow shading) as defined by bulk density of less than 2.6 g/cc (vertical red line) are concentrated throughout the section in the Marcellus, Mahantango, Genesee, and Middlesex units. Blue vertical line is bulk density of 2.72 g/cc.*

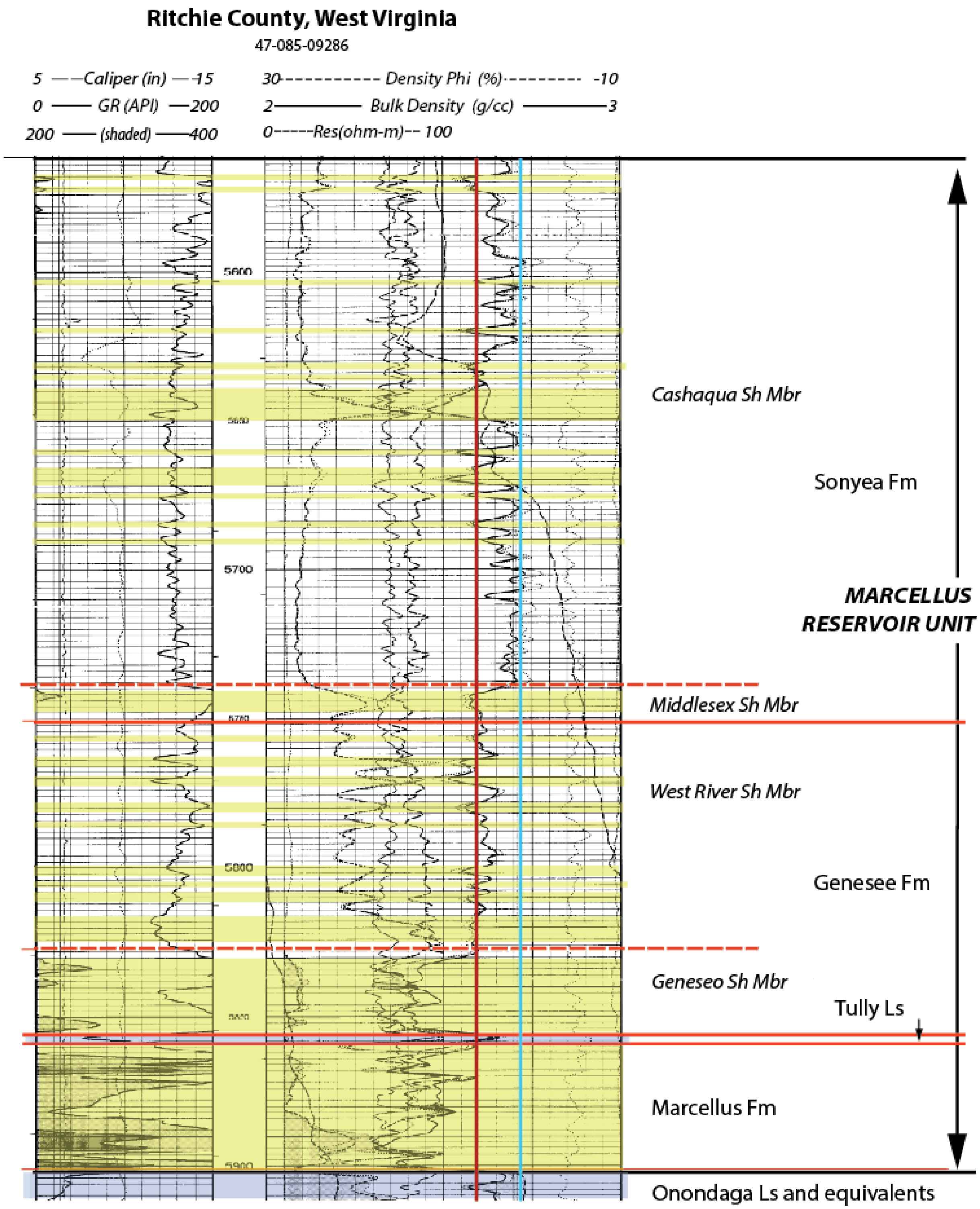


Figure 5c. *Example log from Ritchie County showing MRU not constrained by Tully frac barrier or intervening Mahantango Formation. Apparent gas accumulations (yellow shading) as defined by bulk density of less than 2.6 g/cc (vertical red line) are concentrated throughout the section in the Marcellus, Genesee, and Sonyea formations. Blue vertical line is bulk density of 2.72 g/cc.*

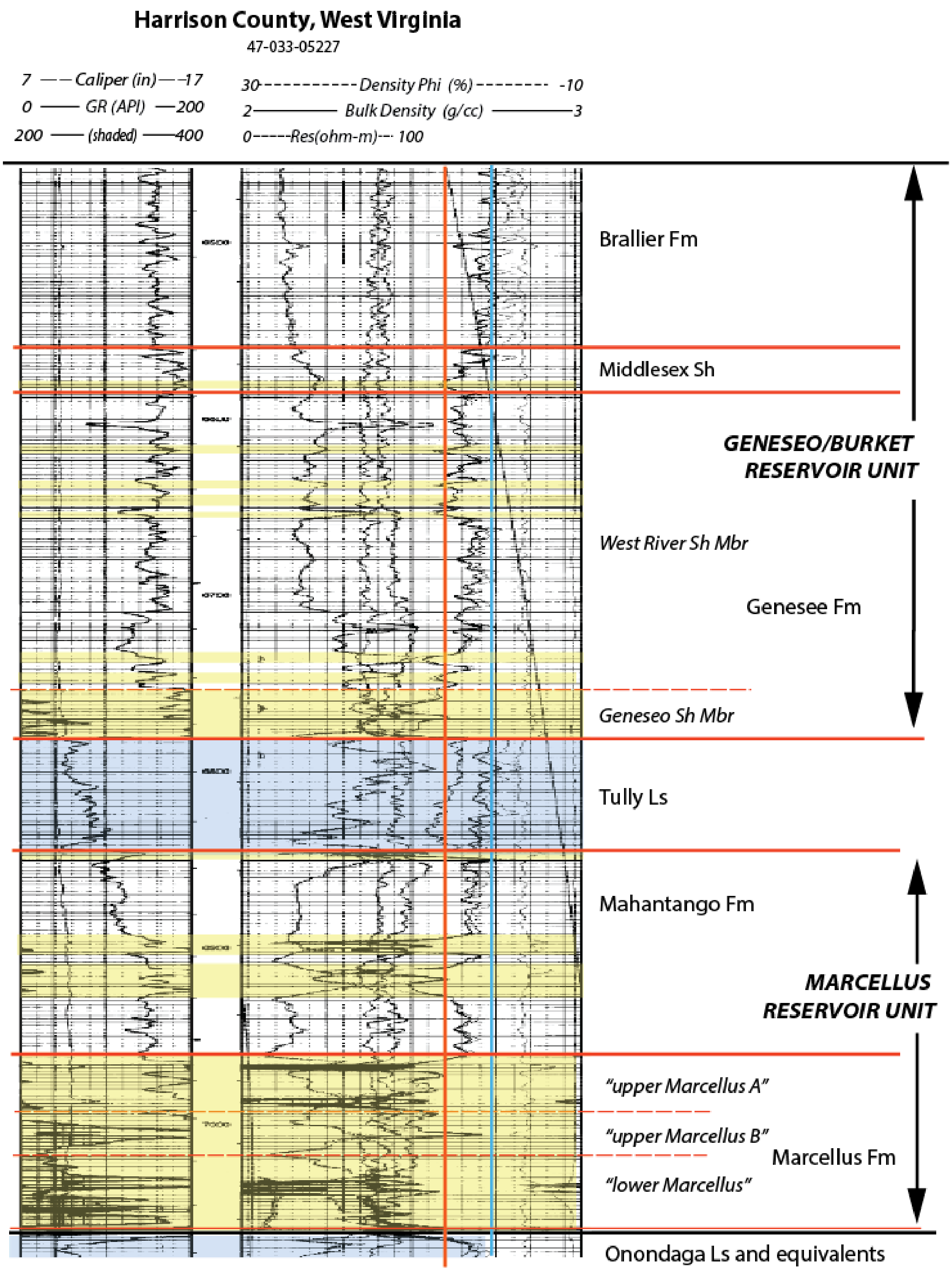


Figure 5d. *Example log from Harrison County showing MRU and GBRU separated by thick Tully Limestone. Apparent gas accumulations (yellow shading) as defined by bulk density of less than 2.6 g/cc (vertical red line) are concentrated throughout the section in the Marcellus and Genesee formations. Blue vertical line is bulk density of 2.72 g/cc.*

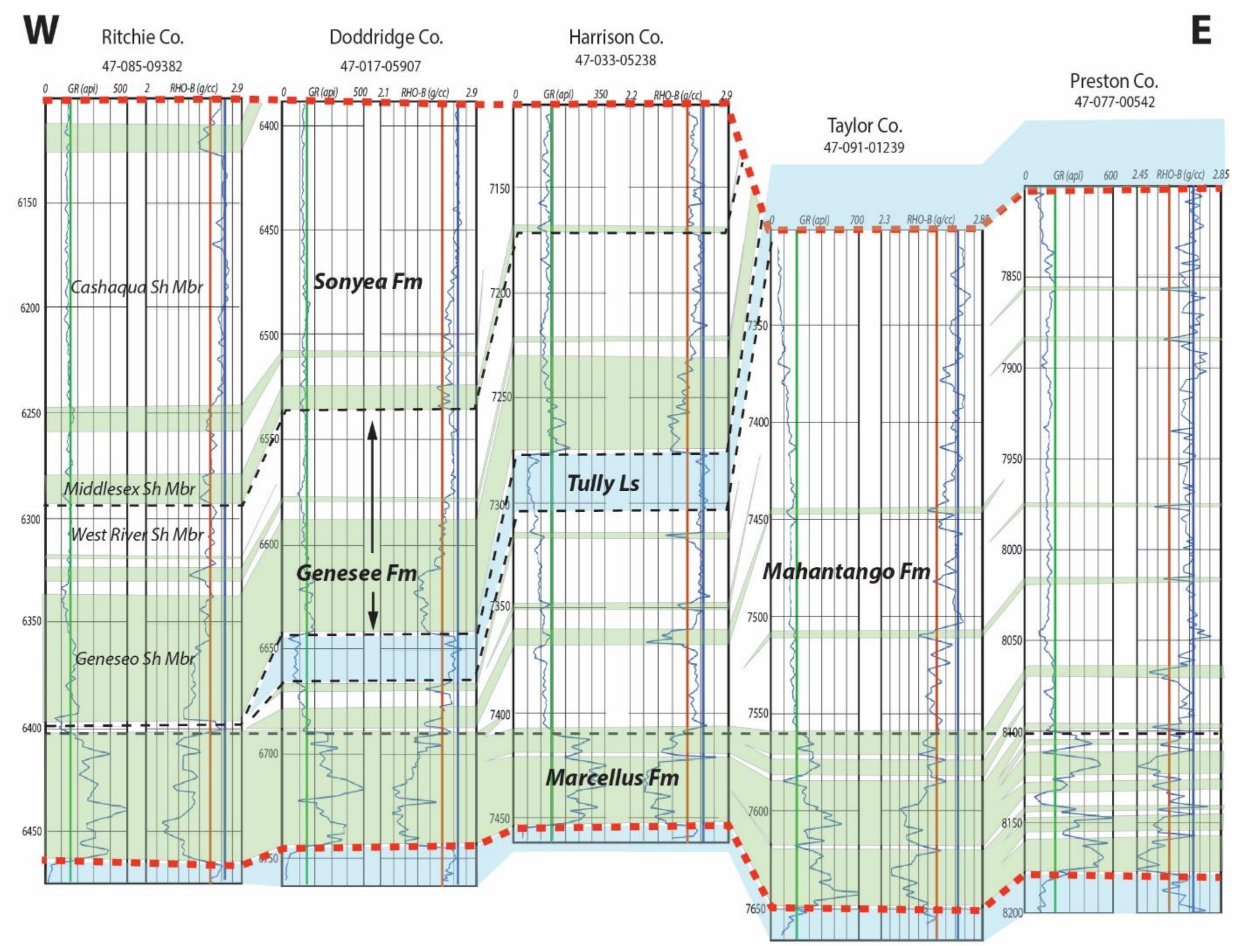


Figure 6. *Gamma ray cross-section across northcentral West Virginia showing the various lithostratigraphic units that occur within the MRU. Green vertical lines are gamma ray baselines indicating 100% shale (Piotrowski and Harper, 1979). Green shading denotes interpreted gas-bearing units as indicated by a bulk density of 2.6 g/cc (vertical red lines) or less. Blue vertical lines show bulk density of 2.72 g/cc. Potential frac barriers are shown with blue shading. As traced to the west, the Mahantango Formation and Tully Limestone thin and the Tully is lost as a frac barrier. As a result, gas-bearing strata of the Genesee and Sonyea formations are in increasing proximity to the Marcellus Formation and contribute substantial gas resources to the MRU (see red dots on* ***Figure 3*** *for well locations). Fine black dashed lines are lithostratigraphic boundaries; heavy red dashed lines are RU boundaries.*

Data

OGIP assessment was conducted using digital geophysical well log (log) data for over 270 vertical penetrations of the Marcellus Formation. The distribution of these wells is shown in **Figure 7**. Log data were either digitized or obtained in digital form from WVGES or IHS. Digital logs were inspected to ensure proper recording of log depths, types, and scales. Log data were also reviewed for quality—most notably reliable porosity data as indicated by stable density measurements and minimal hole enlargement.

For each well, gamma ray and density log data were used to assign formation tops and establish the extent of the RUs. Digital data at 0.5 foot increments for gamma ray, density, and resistivity logs were input into WVGES-developed volumetric software to perform the OGIP calculations.

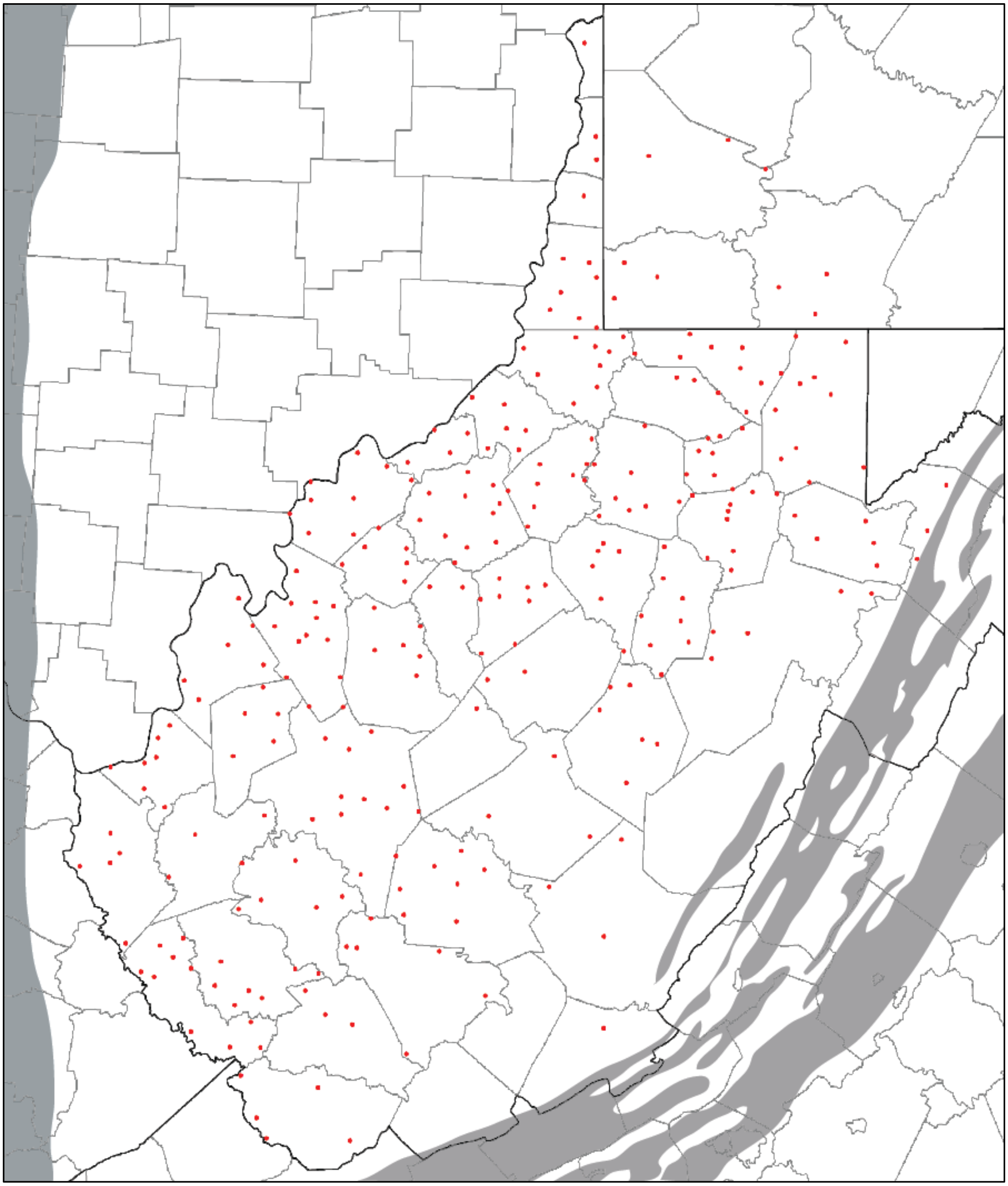


Figure 7. *Well distribution map showing the 270+ vertical wells in West Virginia and southwestern Pennsylvania used in the study. Each well included, at a minimum, digital gamma ray and bulk density or density porosity data through the full extent of the mapped RUs present at that location.*

Methodology

Given the regional scope of the effort, the approach is based primarily on the use of publicly available log data calibrated as is feasible with data derived from cores acquired within the State. Total OGIP ($OGIP_{total}$) is calculated on a per square mile basis as the sum of separate estimates for OGIP within porosity ($OGIP_{free}$) and OGIP as adsorbed onto the surface of matrix components ($OGIP_{ads}$). Basic equations are given below along with parameter details; OGIP values are calculated in Bcf/mi^2.

1. $\mathbf{OGIP_{total}=OGIP_{free}+OGIP_{ads}}$
2. $\mathbf{OGIP_{free}=(AxHx\phi_e x(1-S_w)x(1-Q_n)xC_{free})/FVF}$
3. $\mathbf{OGIP_{ads}=AxHxGCx\rho_m xC_{ads}}$

with A as area (acres), H as thickness (ft), ϕ_e as effective porosity (v/v), S_w as water saturation (v/v), Q_n as non-combustible gas (v/v), FVF as formation volume factor, GC as gas content (Scf/ton), ρ_m as matrix density (g/cc), and C_{free} and C_{ads} as conversion constants. Further, FVF is determined by

4. $\mathbf{FVF=(14.7x(T_r+460))/(P_r x510)xZ_g}$

with T_r as reservoir temperature (^oF), P_r as reservoir pressure (psi), and Z_g as gas compressibility. For this study, Q_n was set to 1%. C_{free} was set to $4.356x10^{-5}$ and C_{ads} set to $1.359x10^{-6}$. All other parameters varied and are discussed in greater detail below.

In regional studies, a reasonable order-of-magnitude calculation of OGIP can be made rather simply from basic volumetric parameters (e.g., Engelder and Lash, 2008). Such studies provide an important point of calibration for further detailed local assessments. In contrast, site-specific calculation of OGIP from local well and core data can become extremely complex in shale formations. For example, the most basic parameter, reservoir volume, is highly uncertain due to the lack of the traditional reservoir/seal dichotomy and the uncertain reach of well stimulation both vertically and laterally. Porosity and water saturation are also difficult to define and measure in shale formations due to the range of pore sizes present, their dynamic relationship to in situ conditions, and the high potential for drilling and sampling procedures to impact intrinsic properties. The situation is further complicated by the variable density of free and adsorbed components in exceedingly small pores (Pitakbunkate et al., 2016) as well as the need to properly allocate the pore space between the free and adsorbed components (Ambrose et al., 2012).

Given these conditions, a highly precise assessment of in-place resources in shale formations is impossible. Rigorously addressing the issues requires more data than are typically available, particularly in the public domain. Nonetheless, reasonable assumptions and methods should return a useful first-order approximation of resource volumes that is in support with the goal of providing OGIP estimates that address recent findings (Blood et al., 2020b; Boswell et al., 2020) that "traditional" OGIP efforts have been overly conservative, producing results that cannot be reconciled with emerging production histories. The following section outlines general methods. A later section describes the sensitivity of OGIP results to the various assumptions and conventions described below.

Parameters—Free and Adsorbed Gas

Reservoir Volume (A, H): OGIP is assessed for each 0.5 foot of section within the RUs for each study well. The totals are summed both by RU and for each lithostratigraphic unit. As each study well is assumed to lie at the center of a square mile area through which reservoir conditions are consistent, each log analyzed provides an estimate of OGIP per square mile of surface area. The point estimates of OGIP/mi^2 are then mapped statewide.

The "H" value (eq. 2, 3) is a major source of uncertainty, especially in certain locations, within the OGIP calculation. As noted above, prior OGIP studies have generally limited H to the thickness of the target formation as defined by lithostratigraphic criteria. It is unlikely, however, that distribution of gas or the distribution of effective stimulation is controlled by these same lithostratigraphic criteria. This issue may be quite significant in select regions. For this study, reservoir volume (e.g., for the MRU) is determined by setting H as equal to the thickness of the target formation plus 300 ft (or less where a frac barrier is present or where the base of the Rhinestreet Shale is encountered) as described above.

Parameters—Free Gas

Porosity (ϕ_e): For virtually every well, porosity is determined directly from bulk density log data. For each 0.5 foot interval in each RU, the recorded bulk density (ρb_{log}) is compared to the corrected matrix density (ρ_{mc}) and the set fluid density (ρ_f) to estimate ϕ_e.

5. $$\phi_e=(\rho_{mc}-\rho b_{log})/(\rho_{mc}-\rho_f)$$

Fluid density is set at 1.0 g/cc. The corrected matrix density is calculated as follows.

6. $$\rho_{mc}=(2.72x(1\text{-}K))+(\rho_k xK)$$

Equation 6 uses an initial matrix density of 2.72 g/cc. 2.72 is used, rather than 2.71 for instance, as a form of calibration—a. to help prevent negative porosity values in organic-poor units and b. to help prevent unreasonable recovery efficiencies when comparing OGIP and production. In addition, 2.72 g/cc was confirmed as reasonable with rock sample analysis. 2.72 g/cc represents the density of all non-organic grains which is then reduced by accounting for the volume (K) and density (ρ_k) of organic matter estimated at each 0.5 foot increment (calculation of K is described below). ρ_{mc} varies with respect to kerogen volume and properties; there was no attempt to model variable grain density due to vertical mineralogical changes. The value of ρ_k at each well is determined based on the relationship between kerogen density and level of organic maturity (LOM) as reported by Ward (2010) **(Figure 8).** Wherever negative porosity values remain, porosity is set to 0.0001.

The correction for kerogen content can be significant. For example, in one typical well—Harrison 5227 (**Figure 5d**), average ρ_{mc} for the MRU was 2.65 g/cc, with average ρ_{mc} for the Marcellus Formation calculated at 2.603 g/cc.

Porosity is a major source of uncertainty in the OGIP calculation. As mentioned, a major issue is uncertainty in the matrix density determination. Another issue is data quality—porosity is subject to significant overestimation in poor (enlarged) boreholes. Where log density data are suspect over a modest depth interval within a well, the porosity for that interval is set at a regional maximum value as determined by reference to local wells where density data is of high quality. This convention is based on the concept that well breakouts may be closely correlated to zones of low formation density. However, wells were excluded whenever a substantial portion of the data were suspect or where a higher quality nearby well could be substituted.

Many factors can contribute to inconsistent density response between wells, including highly variable tool vintage or performance, or wellbore conditions. **Figure 9** shows a more extreme example of the potential variation in density log data that is possible due to differences in drilling method. In an attempt to compensate for these issues, all density logs were normalized (bulk shifted) in a manner designed to render a 2.72 g/cc reading in zones inferred as having minimal organic matter and minimal porosity. This process is somewhat subjective and represents a source of potential error in the porosity calculation.

Calibration of log-derived porosity estimates to values obtained from cores would be of great value. However, such core data are limited, potentially highly site- and sample-specific, and complicated by difficulty in precise correlation between logging and coring depths. Further, it is not clear how representative porosity values obtained from crushed samples might be of in situ conditions.

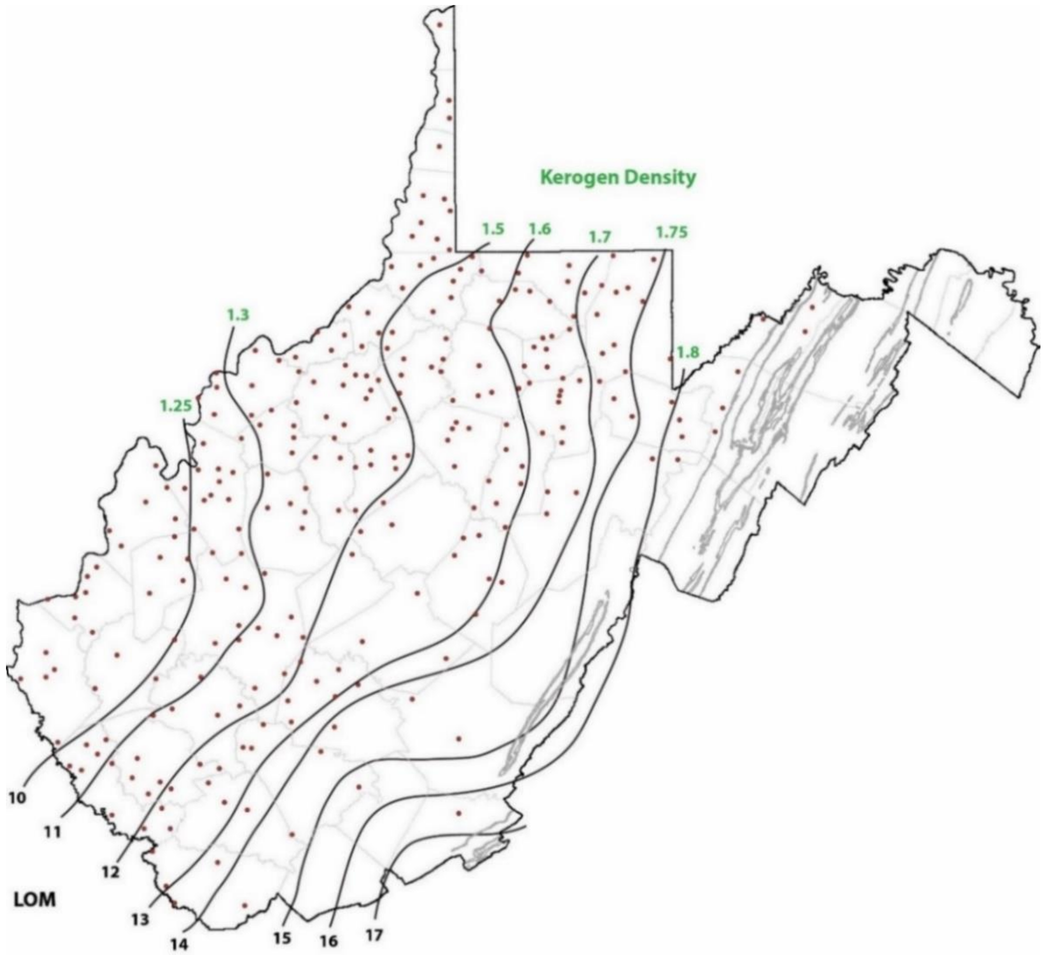


Figure 8. *LOM and kerogen density map. Assigned values for LOM (black values) are based on data published by Milici and Swezey (2014). The correlative value for the density of organic matter (green values) is based on the relationship published by Ward (2010).*

For the purposes of this study, it was elected to trust the log-based values (as it is a critical parameter in generating OGIP estimates that exceed likely well recovery as described below); however, porosity calculation remains a significant potential source of uncertainty in this study. For example, published core-based porosity data generally show relatively low values (e.g., maximum values from 7 to 9%; Song et al., 2019) when compared to log-based estimates, and both log and core porosity may underestimate porosity based on NMR methods (see Boyce and Gawankar, 2019). **Figures 10 and 11** illustrate average porosity for the Marcellus Formation and Geneseo-Burket shale members. **Figures 12 and 13** are cumulative porosity-feet maps for the MRU and the GBRU.

Water Saturation (S_W): Water saturation is typically calculated based on resistivity using modifications to the basic Archie equation (Archie, 1942) to account for the conductivity of clay minerals (e.g., Simandoux, 1963; "Indonesian method"; Poupon and Leveaux, 1971). These methods have been observed to return high S_W in organic-rich shales when compared to core data. More recent methods attempt to further condition results based on variable total organic carbon (TOC) content (e.g., Xu et al., 2017).

Detailed evaluations of water chemistry in Marcellus shale cores have indicated that a significant share of the apparent water content measured in cores is emplaced, and not present in situ (Douds et al., 2017, 2019). Blood et al.

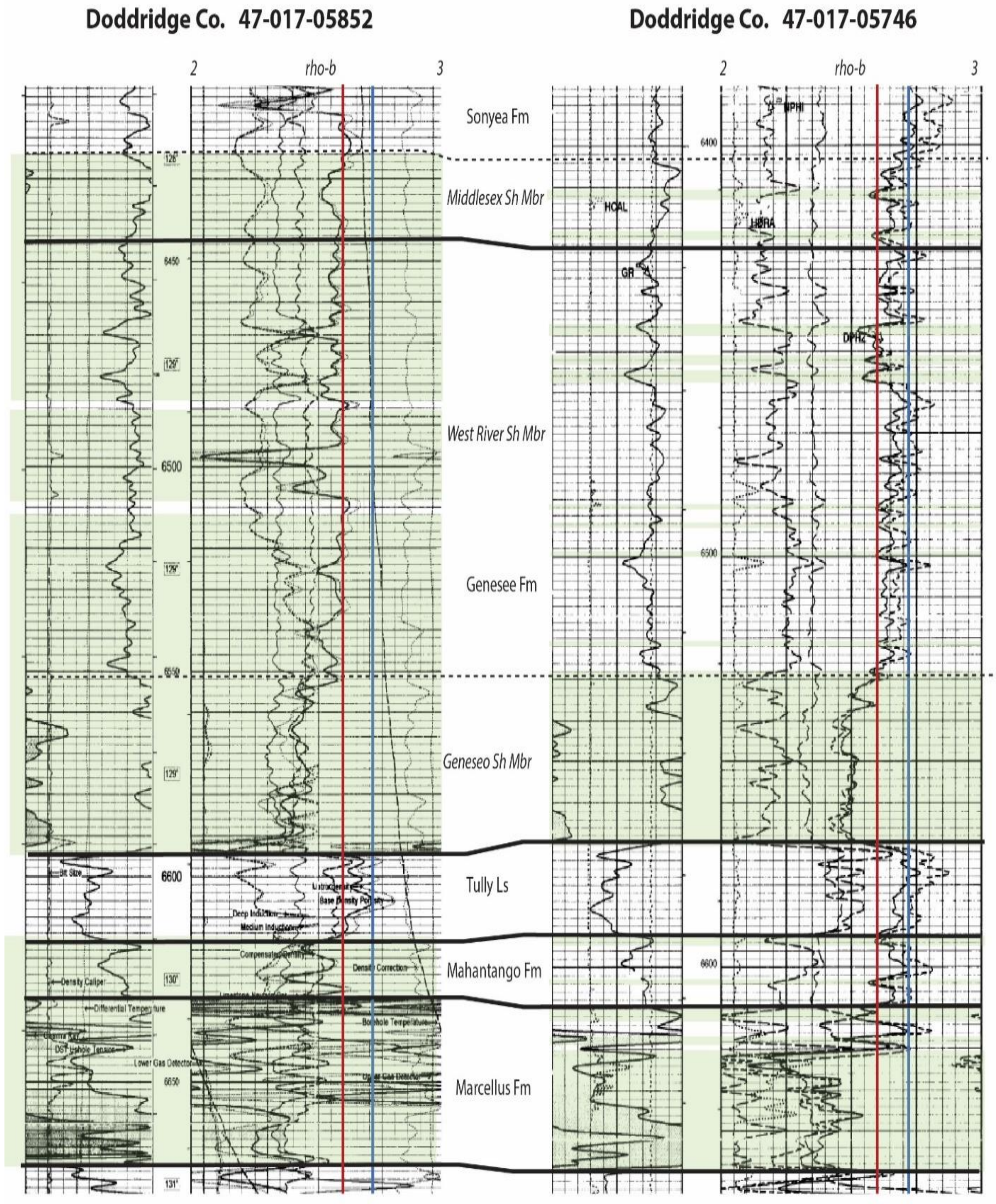


Figure 9. *Log suites from two neighboring wells in Doddridge County showing data differences due to drilling differences. Red line is 2.6 g/cc; blue line is 2.72 g/cc. The well on the left was air drilled whereas the well on the right was drilled with oil-based mud. Green shading shows apparent zones with density less than 2.60 g/cc. Density data for a well such as that on the left would need to be normalized so that reservoir conditions were similar to those on the right. This is an extreme example of shifted log data—typical normalization was ~0.02 to 0 .03 g/cc*.

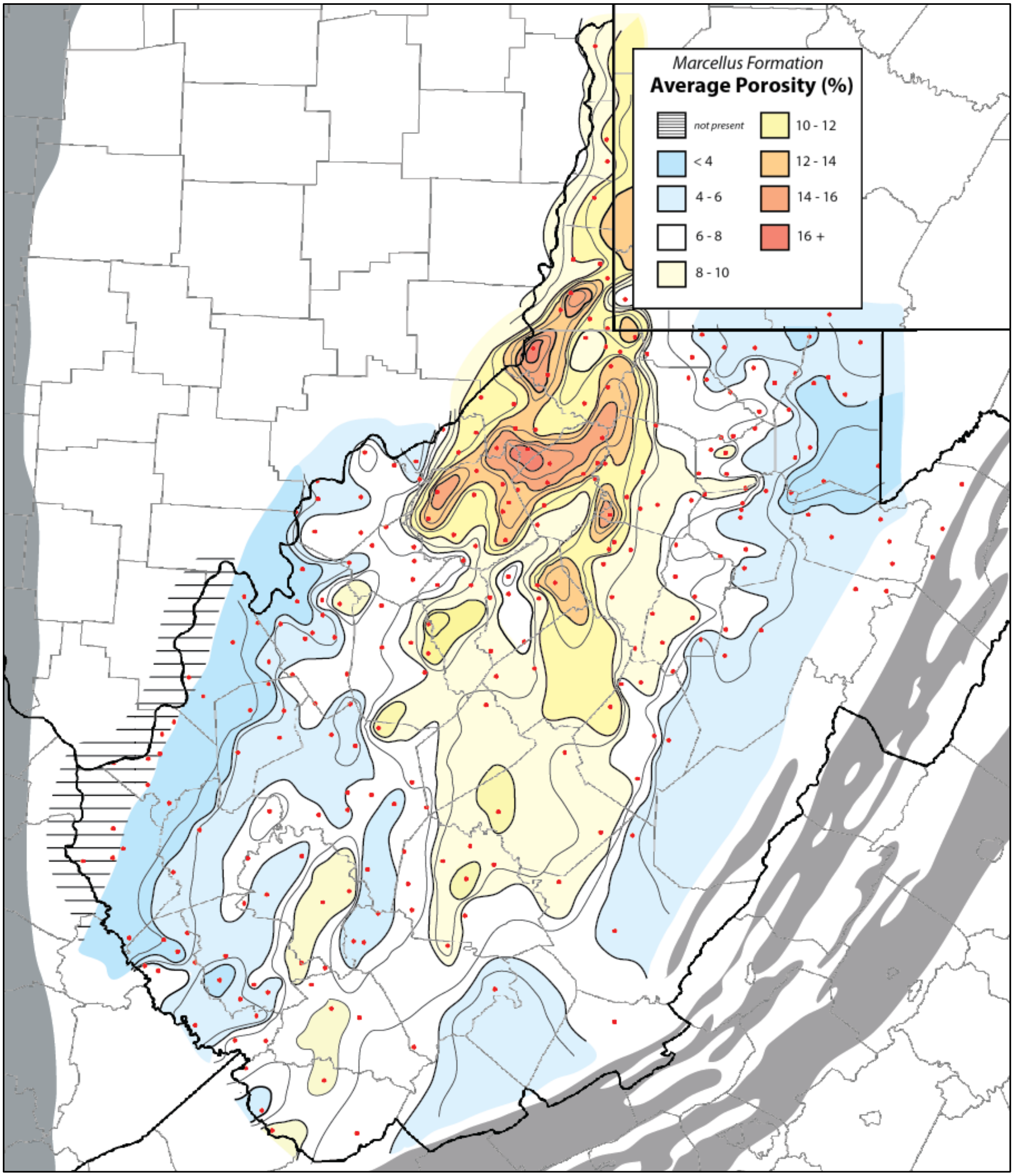


Figure 10. *Average porosity map for the Marcellus Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments.*

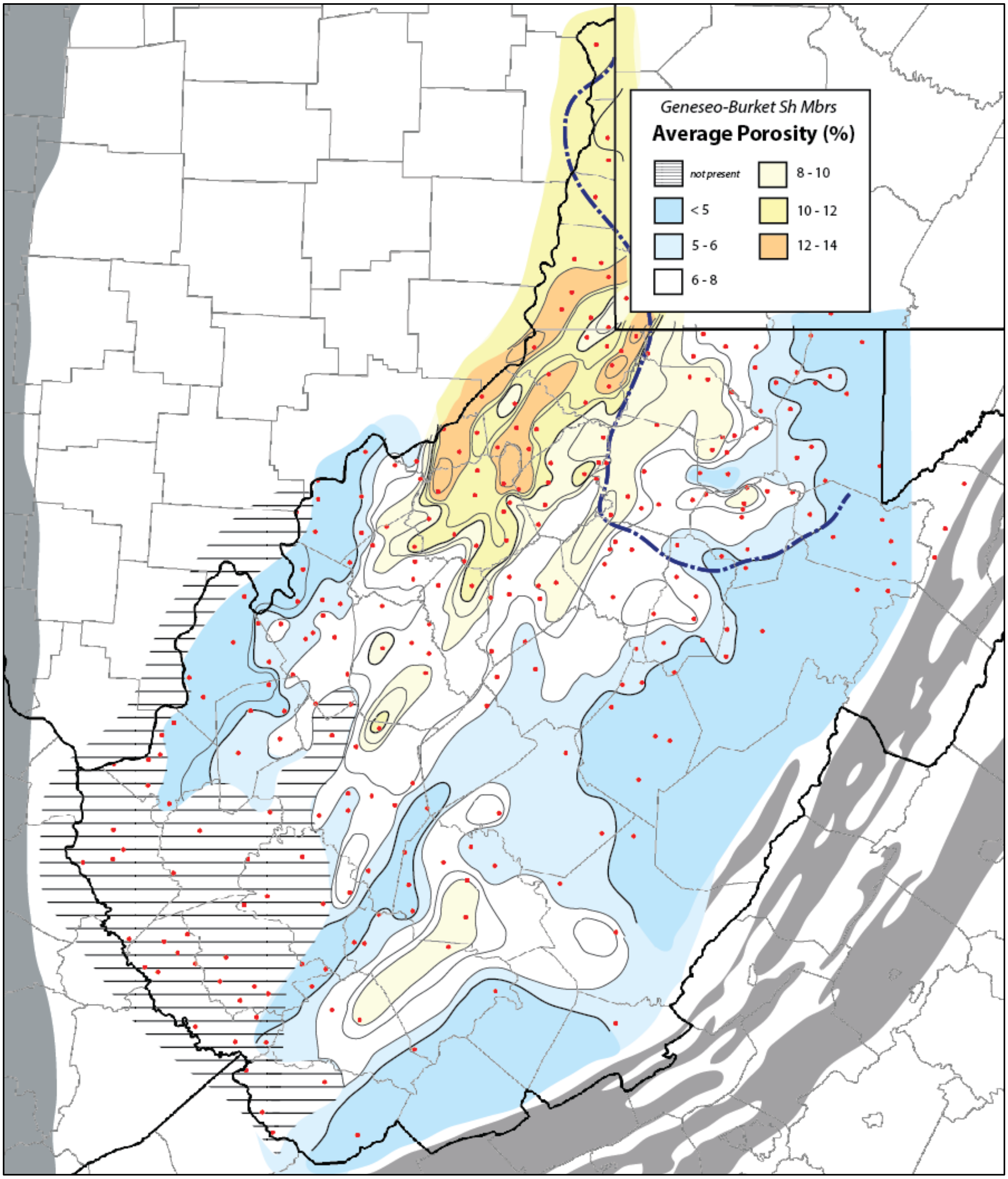


Figure 11. *Average porosity map for the Geneseo Shale Member of the Genesee Formation and the equivalent strata of the Burket Shale Member of the Harrell Shale. Data are interpreted from logs with some core calibration and with shale-related adjustments. The dashed blue line indicates the limit of the GBRU.*

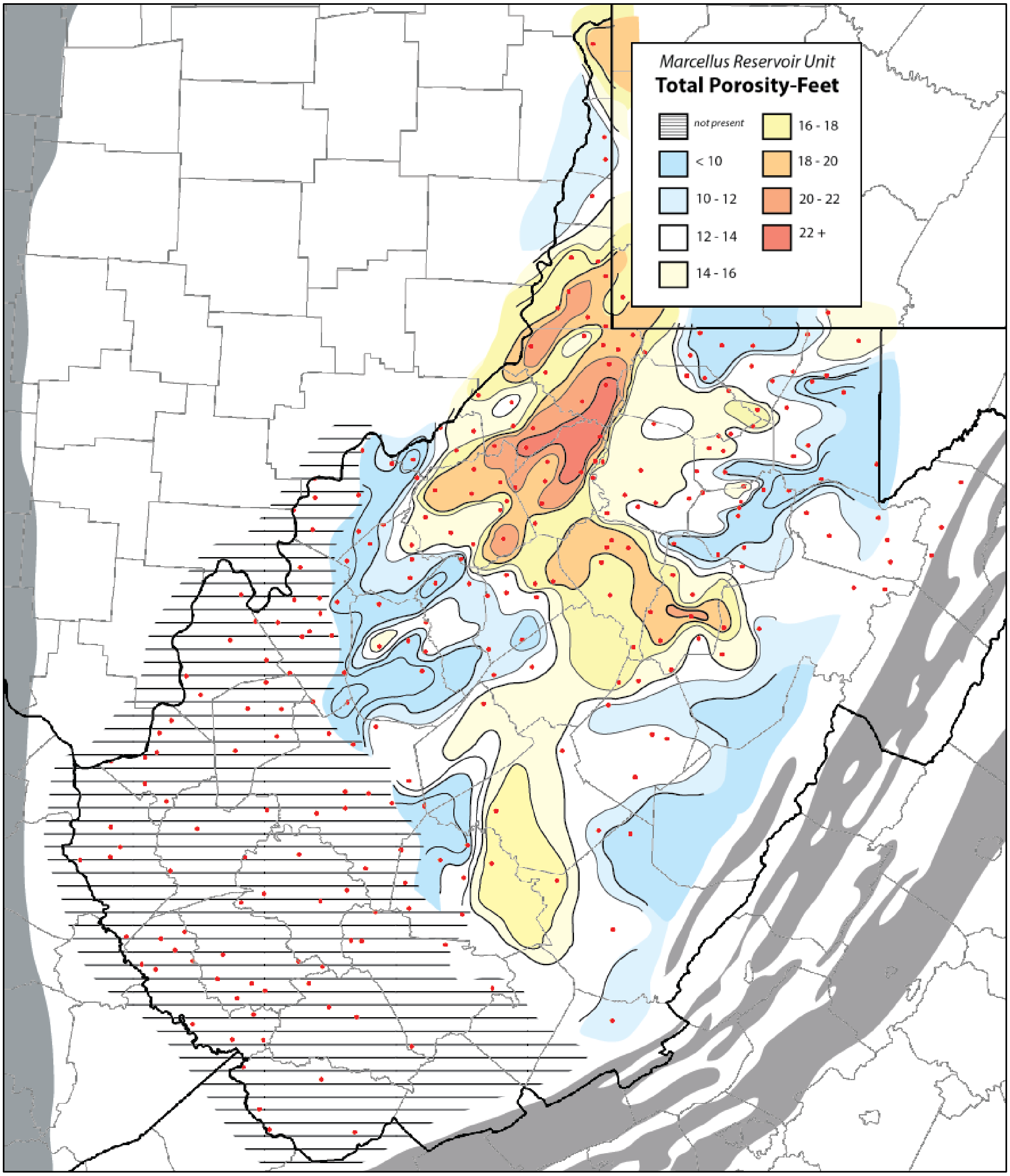


Figure 12. *Total porosity-feet map for the MRU. Mapped values represent the product of average porosity (fraction) and unit thickness. Data are interpreted from logs with some core calibration and with shale-related adjustments.*

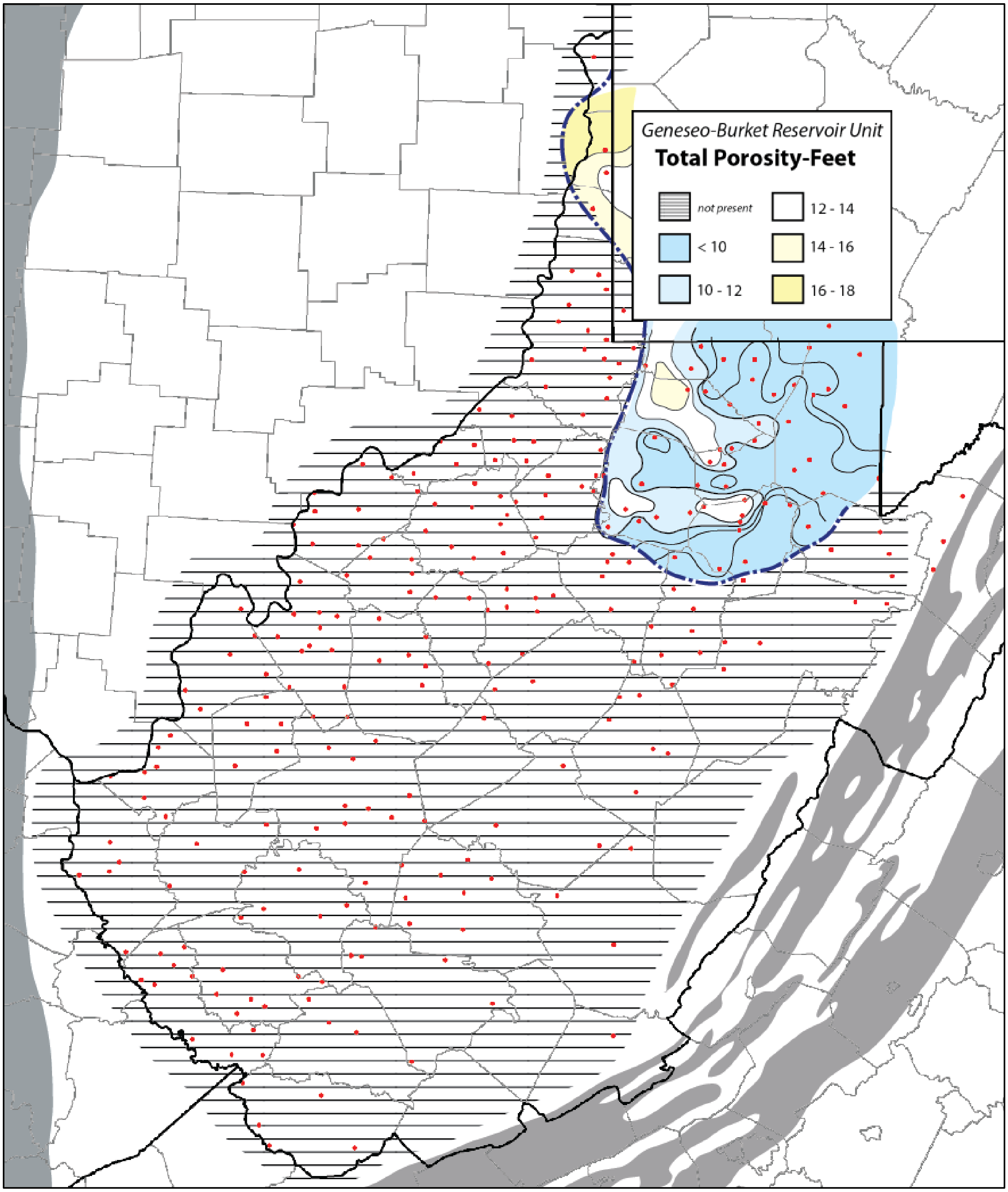


Figure 13. *Total porosity-feet map for the GBRU. Mapped values represent the product of average porosity (fraction) and unit thickness. Data are interpreted from logs with some core calibration and with shale-related adjustments. The dashed blue line indicates the limit of the GBRU.*

(2020b) use these data to indicate that S_w can be considered zero. Given the inability to develop a quantitative S_w estimate using data available for this study, it is determined to assume a S_w of 5%—a slightly more conservative value than suggested by Blood et al. In addition, it is assumed that all hydrocarbon in the reservoir is in the gas phase; therefore, gas saturation (S_g) is set for the Marcellus Formation at 95%. While it does appear likely that the S_w value is low, it is uncertain what that value might be and how much it may vary spatially, therefore, S_w remains a moderate source of uncertainty in the OGIP calculation.

Gas Chemistry (Qn): To the west, increasing amounts of heavier hydrocarbons are inferred based on observed production trends; however, this evaluation treats all hydrocarbons in the reservoir as gas. When OGIP values are compared to production, produced liquid volumes are converted to gas equivalent using a standard ratio of one barrel liquid equivalent equals 6,000 Scf of gas.

Reservoir Temperature (Tr): Temperature gradient (°F/ft) data are largely obtained from wireline temperature logs. These data contain many high and low temperature outliers that are individually reviewed to assess data reliability. The final interpretation of reservoir temperature gradient, based solely on wells that reach the depth of the Marcellus Formation, is shown in **Figure 14**.

Reservoir Pressure (Pr): Pressure gradient data (psi/ft) are derived from operator reports provided to the State of West Virginia. Pressure data are notoriously variable due to inherent measurement difficulties, reservoir conditions, and other factors. As a check, State data are compared to published pressure gradient maps by Zagorski et al. (2012, 2017). The resultant best estimate of pressure gradients in West Virginia is provided as **Figure 15**.

Gas Compressibility (Zg): Recent work has shown that the compressibility of natural gas deviates from standard values when housed in very small pores (Pitakbunkate et al., 2016). However, this effect is most critical only where a substantial share of pores and pore throats are very small. While this subject deserves further study, recent work by Tran and Sakhaee-Pour (2019), indicate that this phenomenon is likely not important for the Marcellus Play.

<u>Parameters—Adsorbed Gas</u>

Adsorbed gas is generally viewed as a significant component of gas-in-place in shale reservoirs (Cipolla et al., 2010; Yu et al., 2016). While the role of adsorbed gas in determining the commercial success of a well is highly limited, adsorbed gas is an important element of both the OGIP and the potential long-term estimated ultimate recovery (EUR).

However, determination of adsorbed gas volumes is complex and dependent on parameters that are not obtainable from publicly available log data. The standard equation for GC relies on determination of the "gas parameter" (GP) that calibrates TOC to measured desorbed gas volumes.

Gas Content (GC): Gas content is determined as

7. GC=TOCx100xGP

with TOC as detailed below and GP being set by formation as follows: Marcellus Formation, GP=12; Geneseo-Burket units, GP=10; and all other units, GP=5. These values were based on calibration to reported adsorbed gas volumes at reservoir conditions at the Marcellus Shale Energy and Environment Laboratory (MSEEL).

Total Organic Carbon (TOC): A variety of log-based methods have been proposed for the estimation of TOC. One widely-used equation (Schmoker, 1981) based on Appalachian basin data derives TOC from gamma ray data and its relation to an inferred gamma ray baseline in association with the slope of a cross-plot of gamma ray and bulk density. Schmoker recommended his formula particularly for the

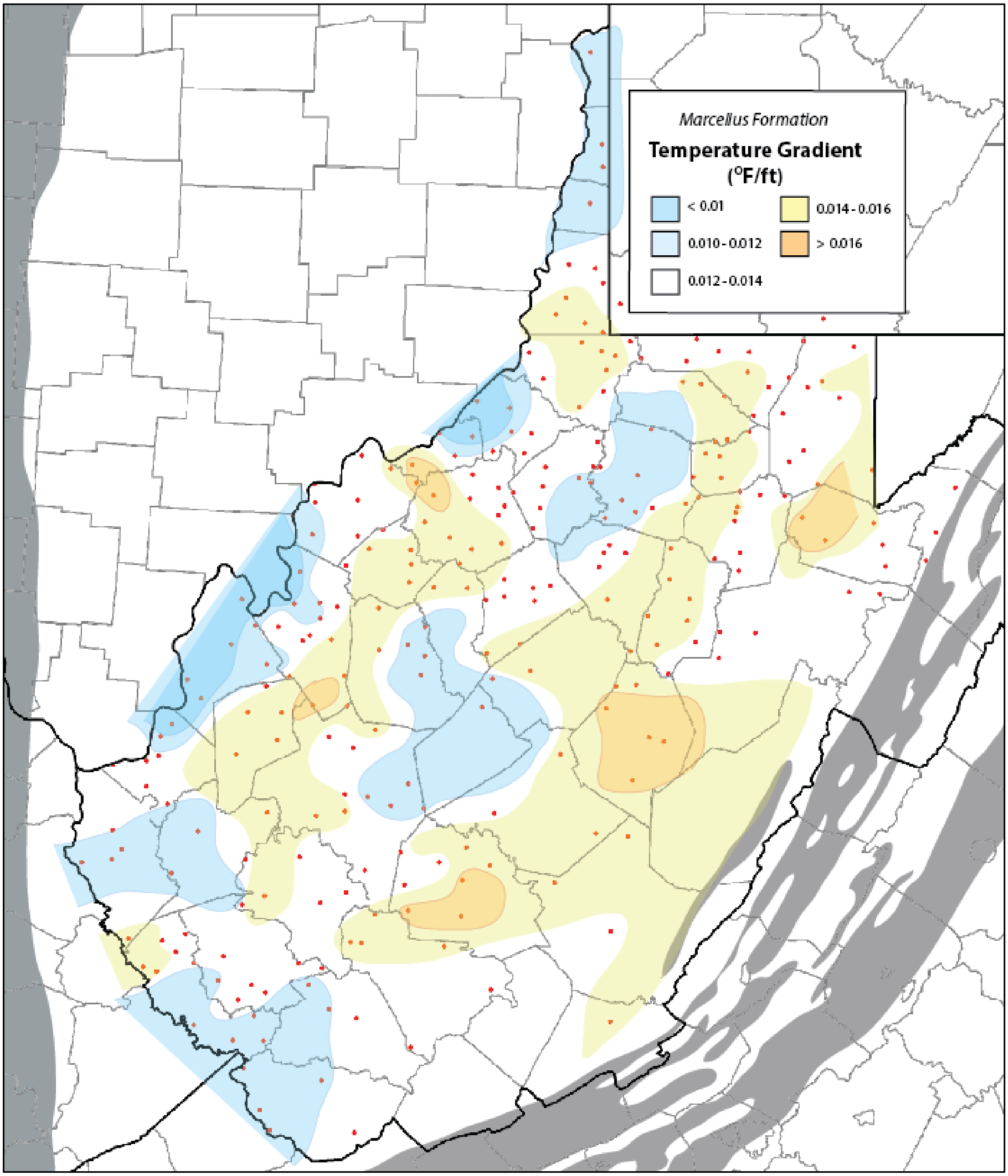


Figure 14. *Temperature gradient map for the Marcellus Formation. Data are interpreted from logs that penetrate the Marcellus.*

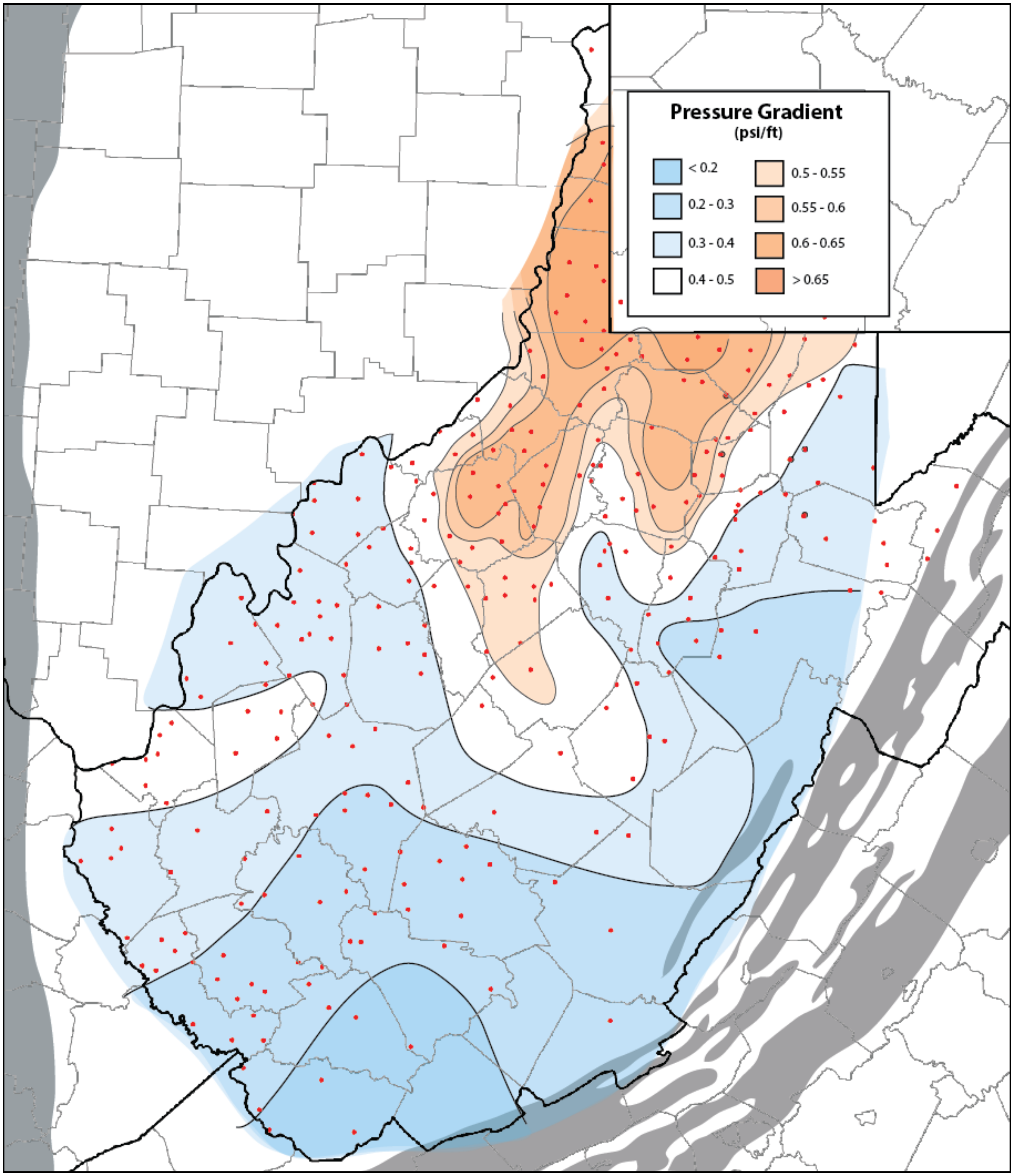


Figure 15. *Pressure gradient map for the Marcellus Play+. Data are specific to Marcellus Play development and as per operator reports filed with the State of West Virginia and as per pressure gradient maps published by Zagorski et al. (2012, 2017).*

Upper Devonian units. A second approach uses the formulations of Passey et al. (1990), which converts resistivity (or other log readings) into estimates of TOC using porosity and a factor to represent LOM. TOC was calculated from both methods and compared to those core-derived TOCs measured at the MSEEL sites. A good correlation was difficult to achieve.

An alternative approach focuses solely on direct correlations between TOC (TOC_{den}) and bulk density (ρb_{log}) as determined through compilation of numerous proprietary core-based TOC measurements within the Marcellus of the central Appalachian basin. Data obtained at the MSEEL sites has allowed the following empirical relationship to be inferred.

8. $\mathbf{TOC_{den}=(\rho b_{log}-C1)/C2}$

with C1 and C2 as proprietary constants. The best match for the Marcellus was obtained by using the proprietary density relationship. It is noted that all of these approaches are likely best suited to evaluation of only the more organic-rich components of the various RUs and may underestimate TOC in bounding units (see Bowker and Grace, 2010). **Figure 16** is the resultant estimated average TOC within the Marcellus Formation.

Results

Based on the methods and assumptions described above, total assessed OGIP density for the MRU exceeds 100 Bcf/mi^2 throughout much of the core play area in northcentral West Virginia (**Figure 17**). The OGIP for the GBRU (**Figure 18**) ranges from < 20 to 80 Bcf/mi^2. Total OGIP for the MRU in West Virginia represented by **Figure 17** is 878 Tcf. Total OGIP for the GBRU in West Virginia represented by **Figure 18** is 115 Tcf. These values are two to three times larger than recent prior estimates (see Discussion). The distribution of that gas by county is provided in **Table 1**. Distribution by lithostratigraphic unit and RU is provided in **Figure 19**.

The dominant source of gas in the MRU is typically the Marcellus Formation. However, in certain regions of the play, particularly in northwestern West Virginia, the Marcellus accounts for less than half of the RU's OGIP total (**Figure 20**), with substantial gas volumes assigned to both the Geneseo and West River shale members of the Genesee Formation. **Figures 21 to 26** present OGIP resource densities determined for the Marcellus, Mahantango, Geneseo-Burket, West River, Middlesex, and Cashaqua lithostratigraphic units.

The primary controls on the OGIP for the MRU appear to be the distribution of overpressure, the distribution of the Tully Limestone, the occurrence and thickness of the Marcellus Formation, and the distribution of gas-filled porosity within other units that are included within the MRU. To the south and west, primary controls are reduced reservoir pressure due both to reduced pressure gradient and reduced reservoir depth. An additional factor is stratigraphic thinning of the gas-bearing intervals. To the east, increasing structural complexity is a primary control. General dilution of Marcellus reservoir quality and overmaturity are possible additional controls to the east.

The distribution of OGIP within the MRU is marked by prominent lineation with a northeast to southwest orientation. This architecture is seen in maps of porosity and TOC as well (**Figure 27**) and is consistent with the orientation and location of known basement faults associated with the Rome Trough (Shumaker, 1996; Zagorski et al., 2017; Boswell, 1988).

The study evaluation produces an OGIP associated with Marcellus Play development in West Virginia that is significantly higher than previous estimates. This is a necessary finding given observations of past and expected well performance exceeding the prior in-place volumes. Therefore, it is suspected that prior OGIP assessments have been highly conservative which is likely a common aspect of OGIP studies and is a likelihood that was predicted by Zagorski

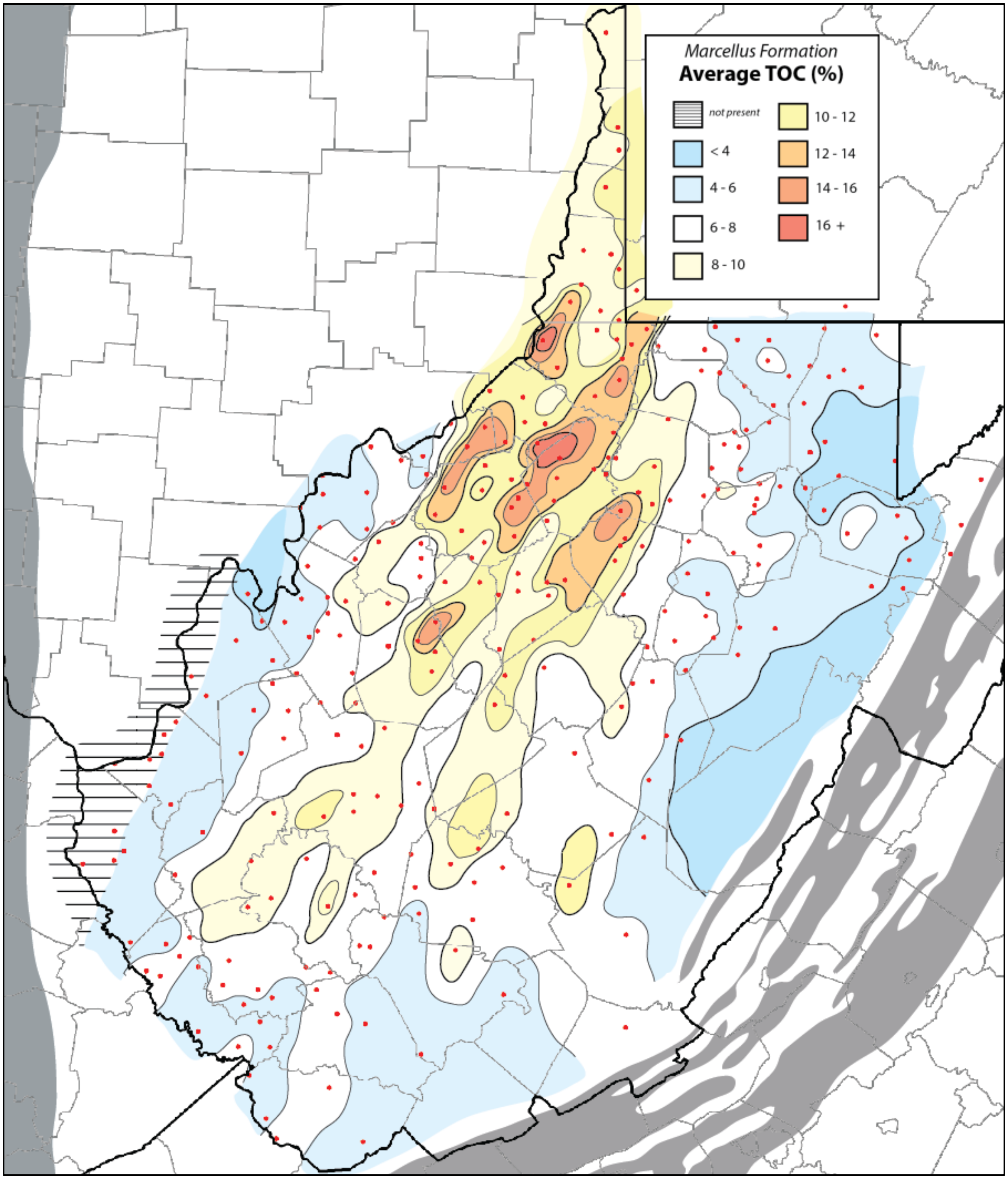


Figure 16. *Average estimated TOC map for the Marcellus Formation. Data are interpreted from well log gamma ray and density response as described in the text.*

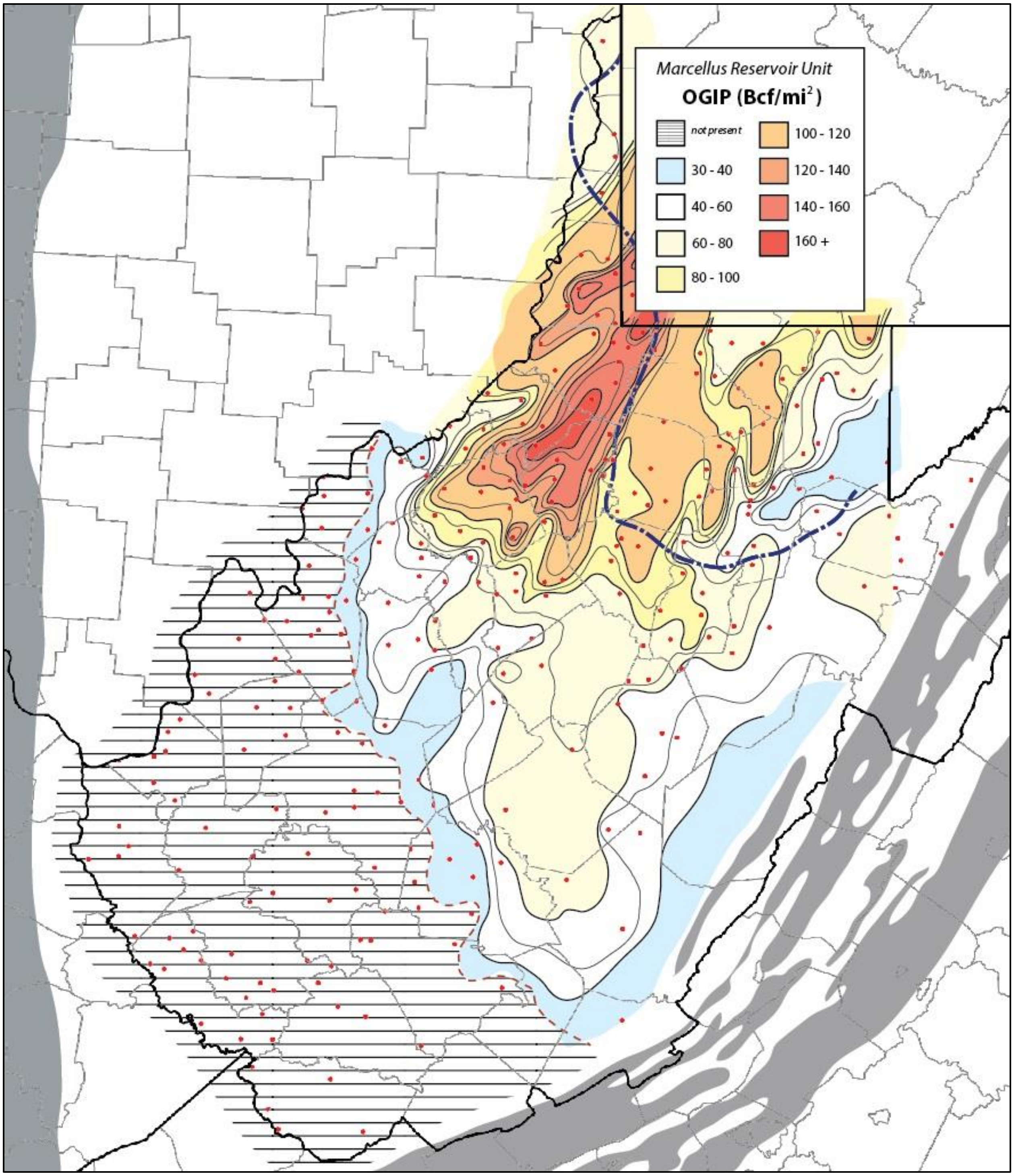


Figure 17. *OGIP map for the MRU. Data are interpreted from logs with some core calibration and with shale-related adjustments. In the hachured area, the Marcellus is present, but contains less than 30 Bcf/mi^2 and is considered part of the RRU.*

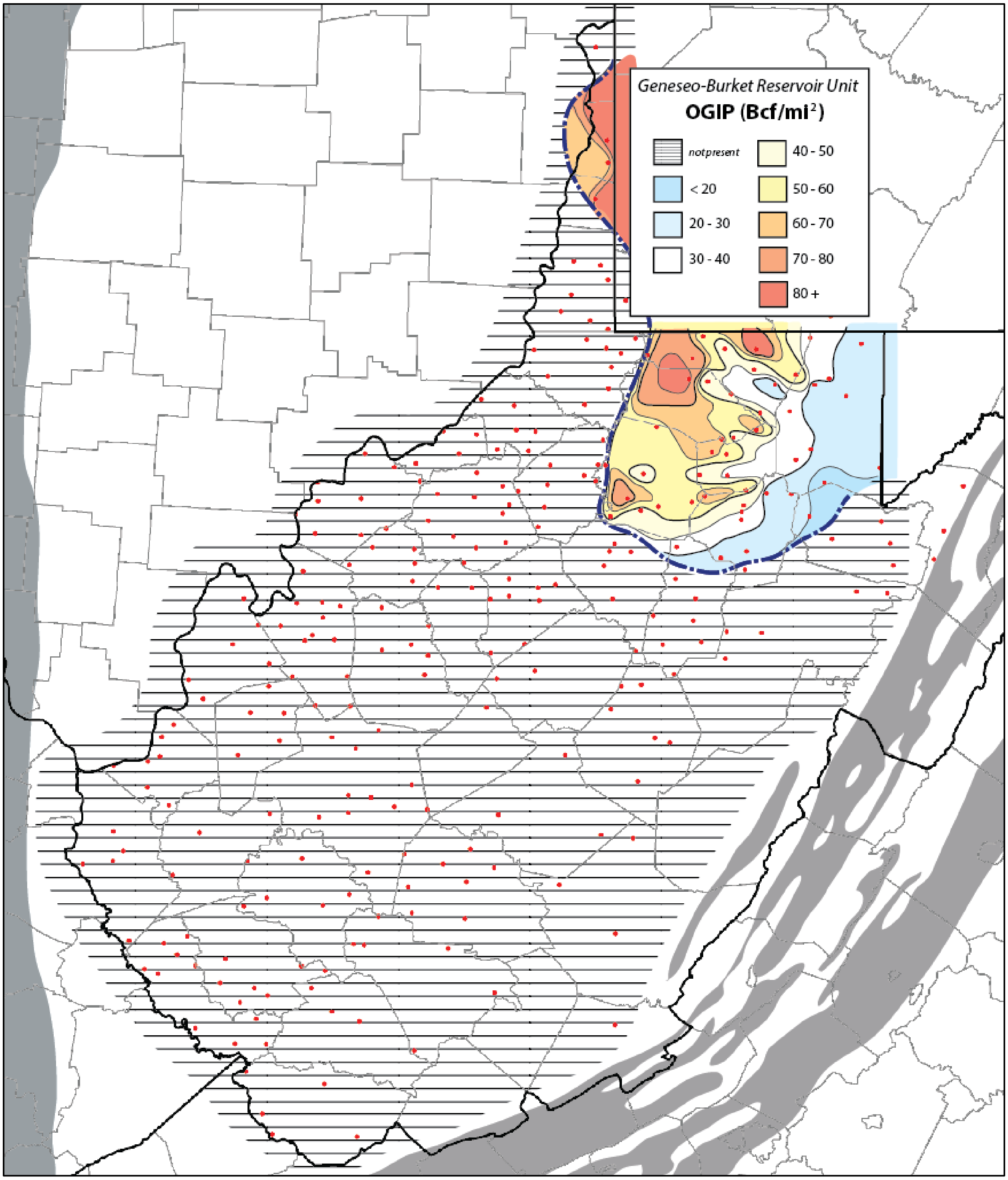


Figure 18. *OGIP map for the GBRU. Data are interpreted from logs with some core calibration and with shale-related adjustments. The dashed blue line indicates the limit of the GBRU.*

Table 1. *First order approximation of rTRR in the MRU in West Virginia by county. The uTRR is based on the TRR map of Boswell et al. (2020); drilled area is based on total lateral lengths of 3,880 Marcellus wells from the Enverus database. The rTRR calculation assumes that existing wells are spread evenly throughout each county, which is not correct, and would be expected to result in a slight overestimation of rTRR in certain counties. To address this problem where it appears to be most severe, the northeastern section of Ritchie County has been segregated.*

County	Area (mi^2)	OGIP (Tcf)	OGIP (Bcf/mi^2)	uTRR (Tcfge)	Drilled (mi^2)	% Drilled	TRR drilled	rTRR (Tcfge)
Wetzel	359	50.3	140	19.4	71.7	20.0	3.9	15.5
Doddridge	320	44.2	138	17.1	106.4	33.2	5.7	11.4
Marshall	307	35.9	117	13.4	91.5	29.8	4.0	9.4
Tyler	258	34.6	134	13.7	89.0	34.5	4.7	9.0
NE Ritchie	200	22.0	110	5.3	57.1	28.5	1.5	3.8
Marion	310	33.2	107	18.0	`11.9	3.8	0.7	17.3
Harrison	416	46.2	111	23.1	56.2	13.5	3.1	20.0
Monongalia	361	36.1	100	18.0	26.9	7.4	1.3	16.7
Taylor	173	17.3	99	8.8	14.5	8.4	0.7	8.1
Ohio	106	9.6	91	1.8	41.0	38.7	0.7	1.1
Lewis	389	35.8	92	13.9	1.3	0.3	0.1	13.8
Gilmer	340	26.9	79	8.7	1.3	0.4	0	8.7
Pleasants	131	9.6	73	2.5	1.9	1.4	0.1	2.4
Upshur	355	26.3	74	7.5	12.4	3.5	0.3	7.2
Brooke	89	6.4	72	1.3	24.6	27.6	0.4	0.9
Barbour	341	21.5	63	11.2	16.0	4.7	0.5	10.7
Preston	648	36.9	57	12.6	2.8	0.4	0.1	12.5
All others	7,544	385.1	51	20.5	10.2	0.0	0.0	20.5
Total	12,577	877.6	69.6	216.8	624.8	6.5	27.8	189.0

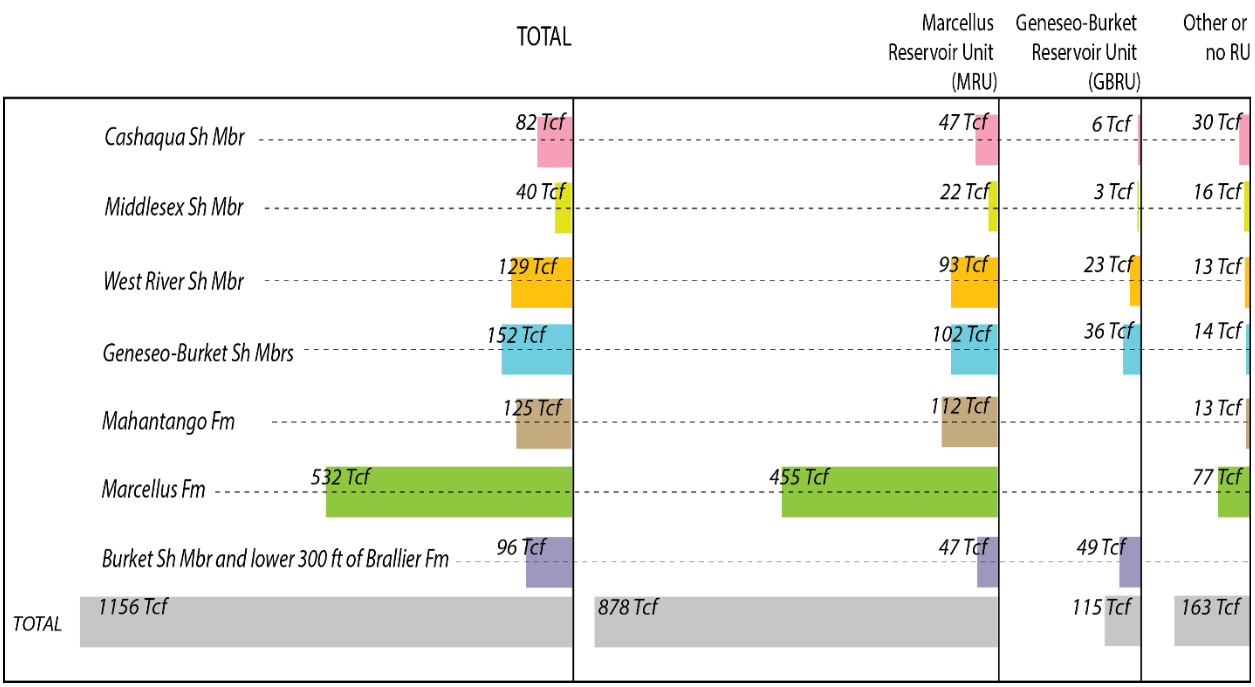


Figure 19. *OGIP resource distribution by lithostratigraphic unit and RU.*

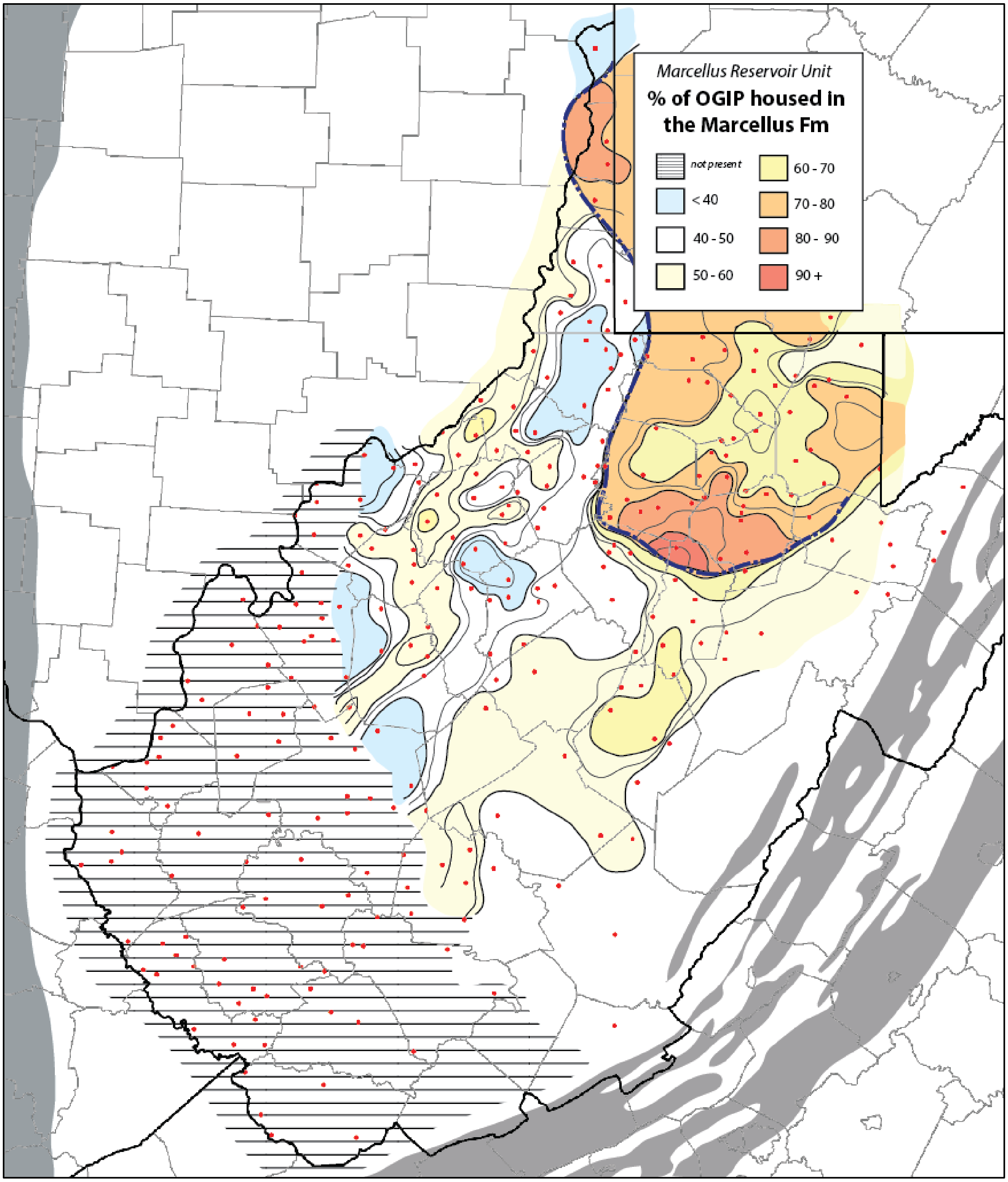


Figure 20. *Map showing share of total MRU OGIP associated with the Marcellus Formation. In northeastern West Virginia, the balance of the OGIP occurs within the Mahantango Formation. Elsewhere (west and south of the dashed blue line), gas that is part of the MRU also occurs in the Genesee and Sonyea formations.*

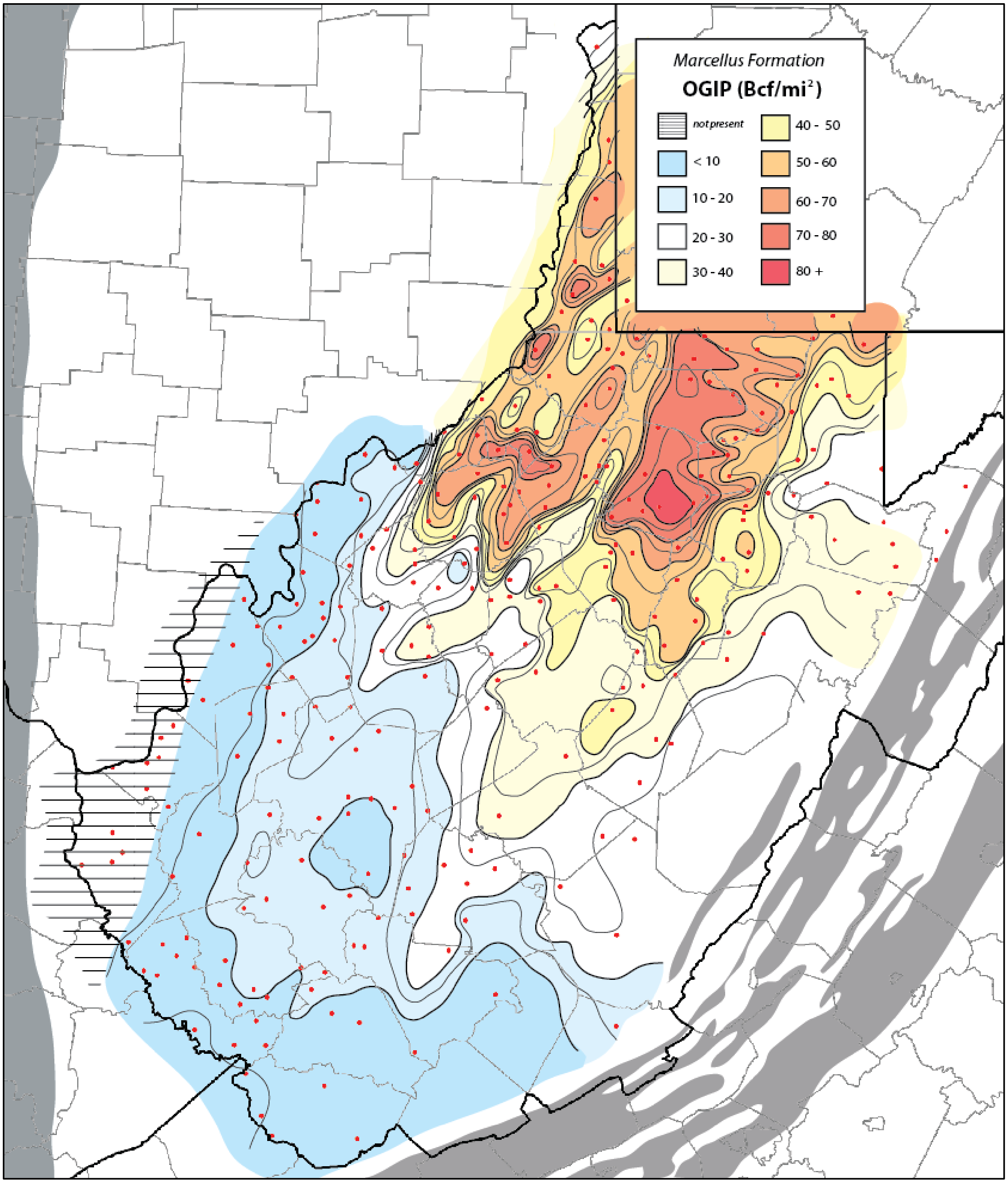


Figure 21. *OGIP map for the Marcellus Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments.*

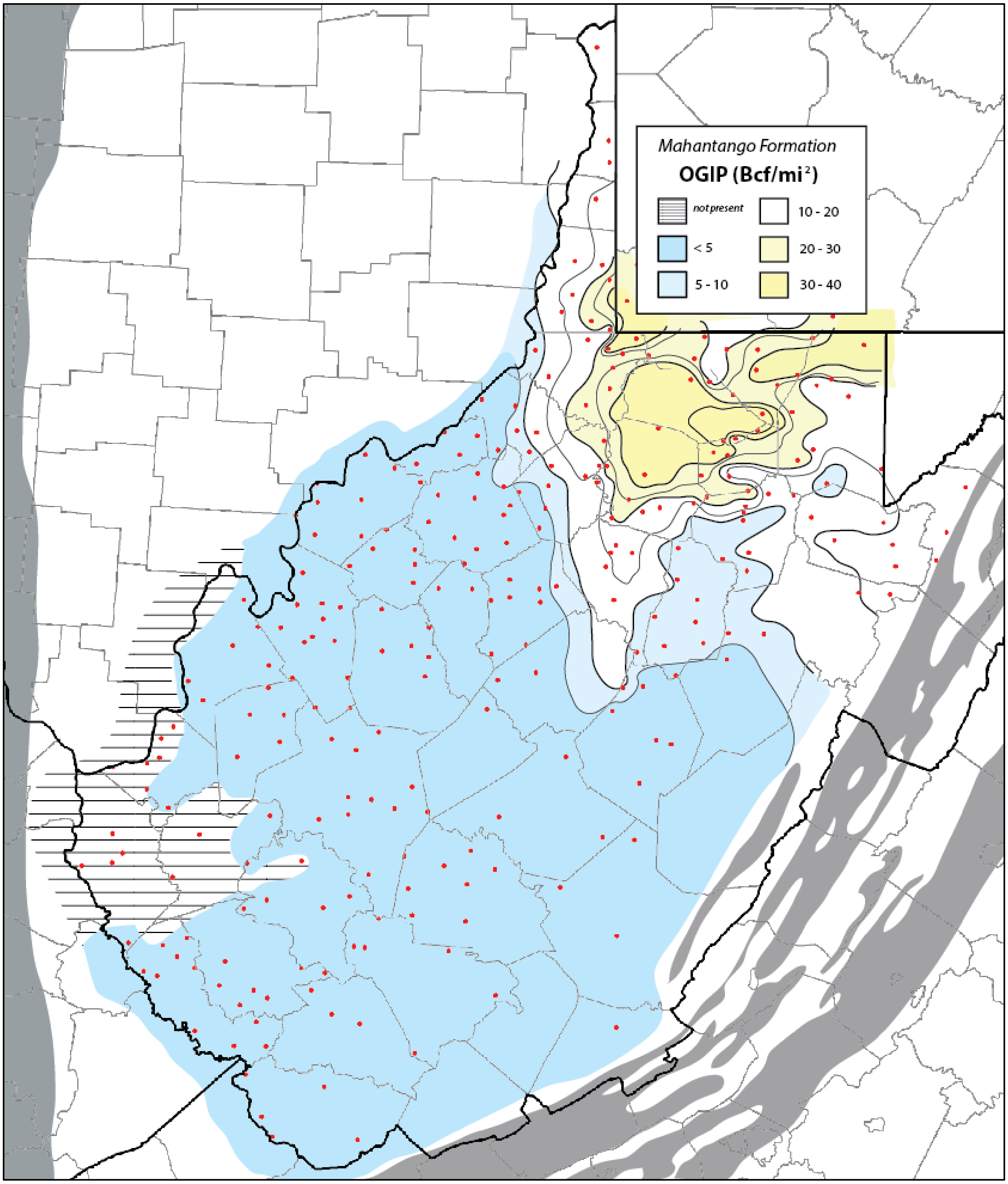


Figure 22. *OGIP map for the Mahantango Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments.*

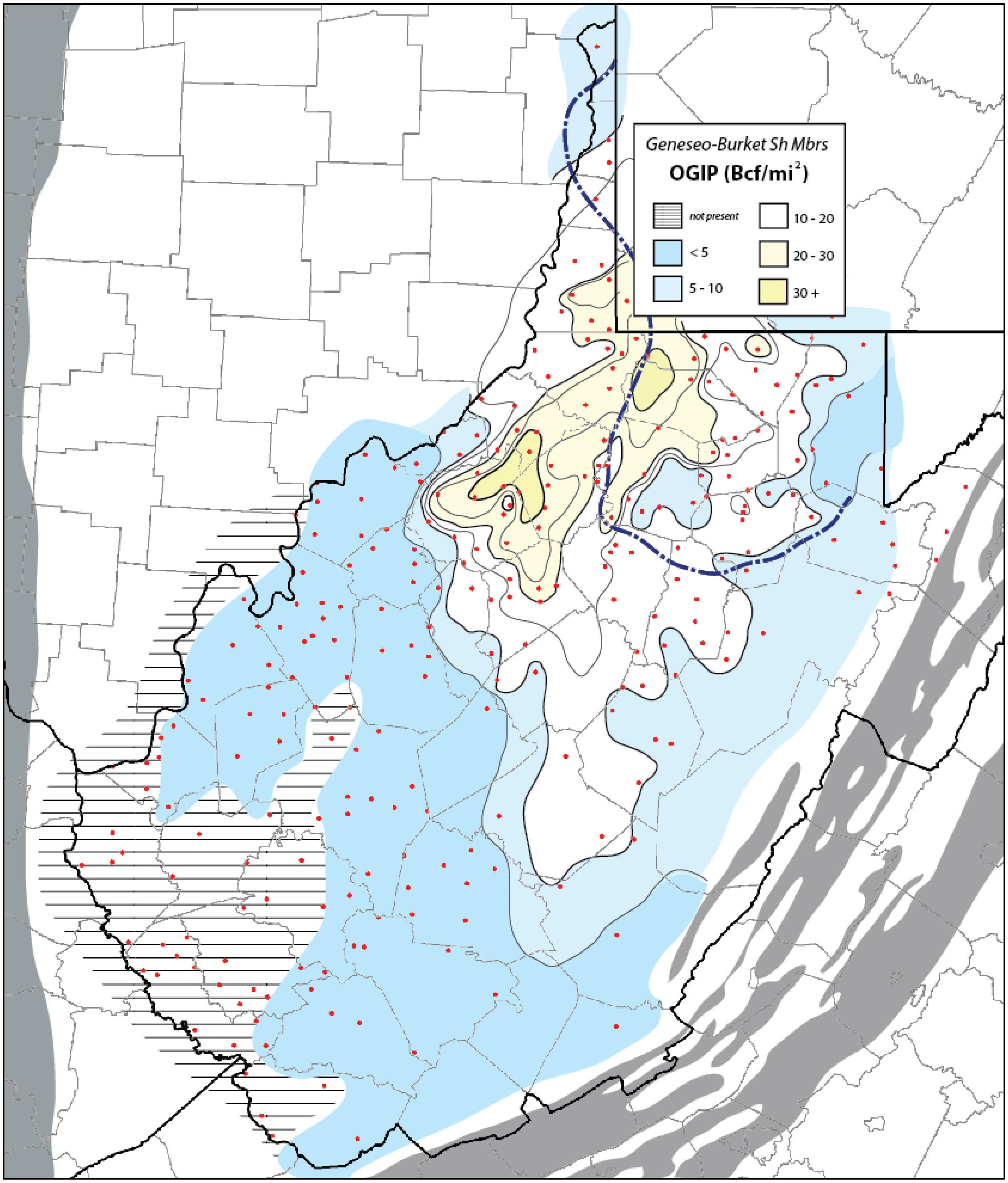


Figure 23. *OGIP map for the Geneseo Shale Member of the Genesee Formation and the equivalent Burket Shale Member of the Harrell Shale. Data are interpreted from logs with some core calibration and with shale-related adjustments. To the east of the blue dashed line, resources are assigned to the GBRU; to the west, they contribute to the MRU.*

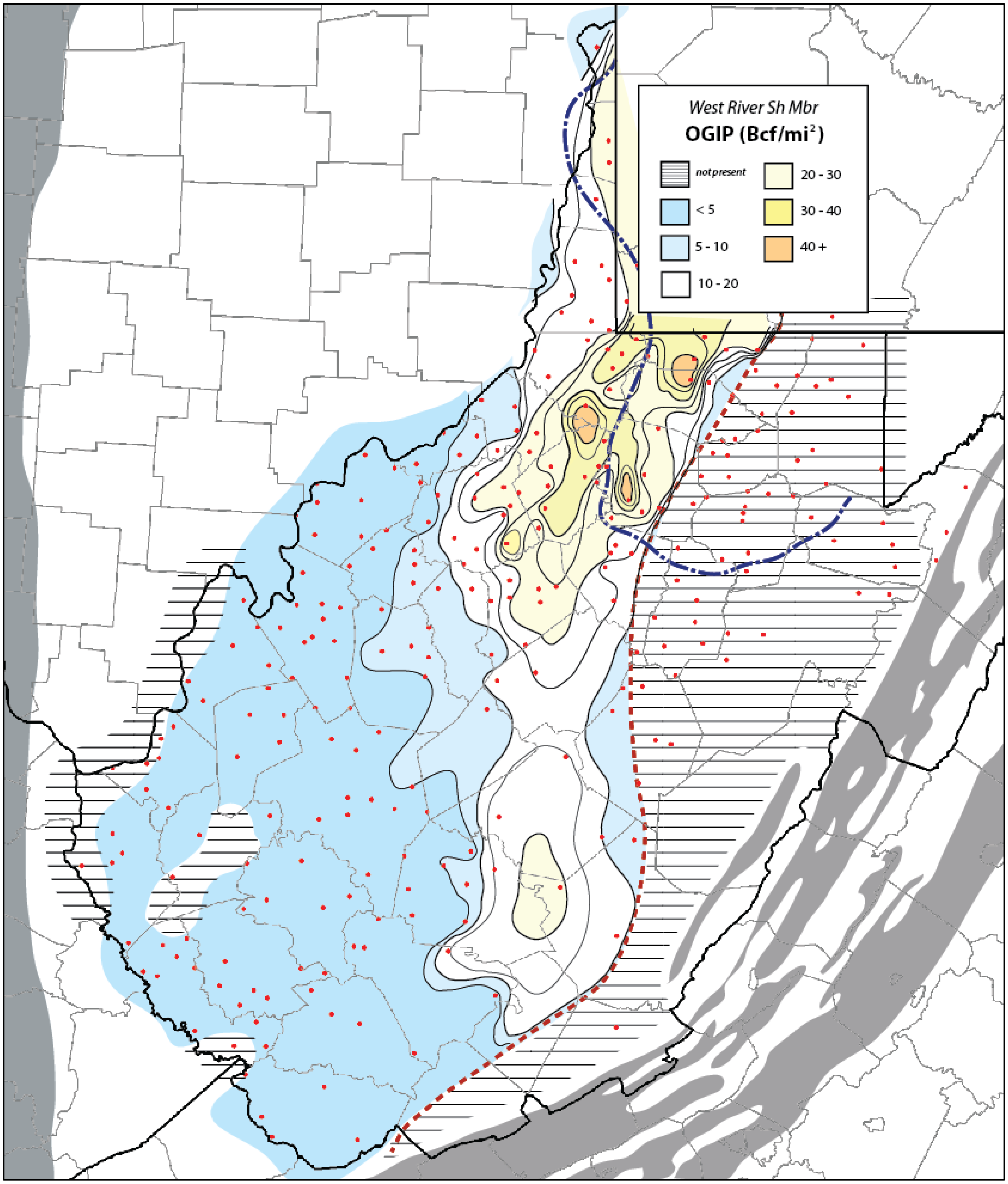


Figure 24. *OGIP map for the West River Shale Member of the Genesee Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments. To the east of the blue dashed line, resources are assigned to the GBRU; to the west, they contribute to the MRU. The red dashed line shows the lateral lithofacies boundary of the West River (Boswell and Pool, 2018).*

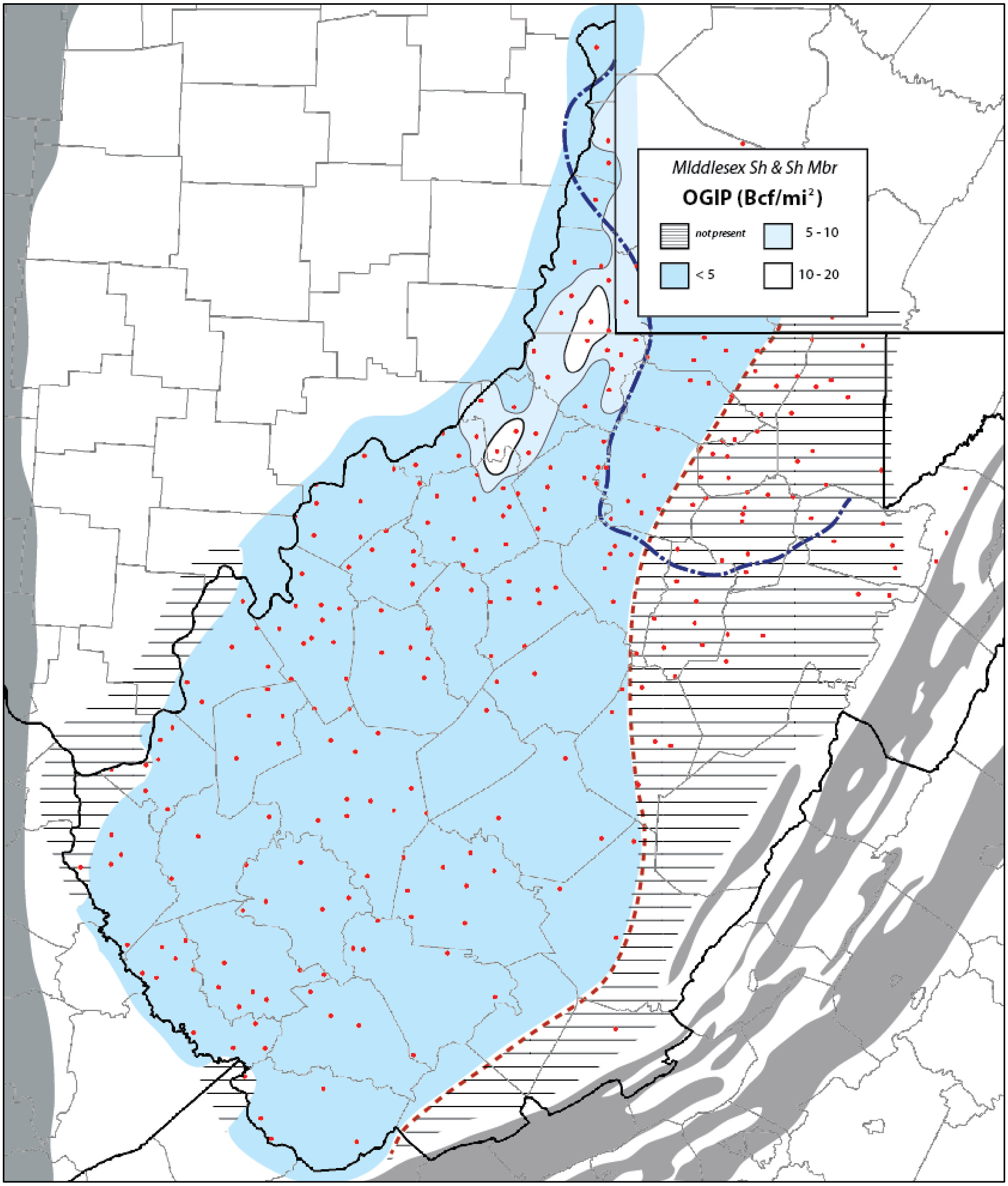


Figure 25. *OGIP map for the Middlesex Shale and Middlesex Shale Member of the Sonyea Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments. To the east of the blue dashed line, resources are assigned to the GBRU; to the west, they contribute to the MRU. The red dashed line shows the lateral lithofacies boundary of the Middlesex (Boswell and Pool, 2018).*

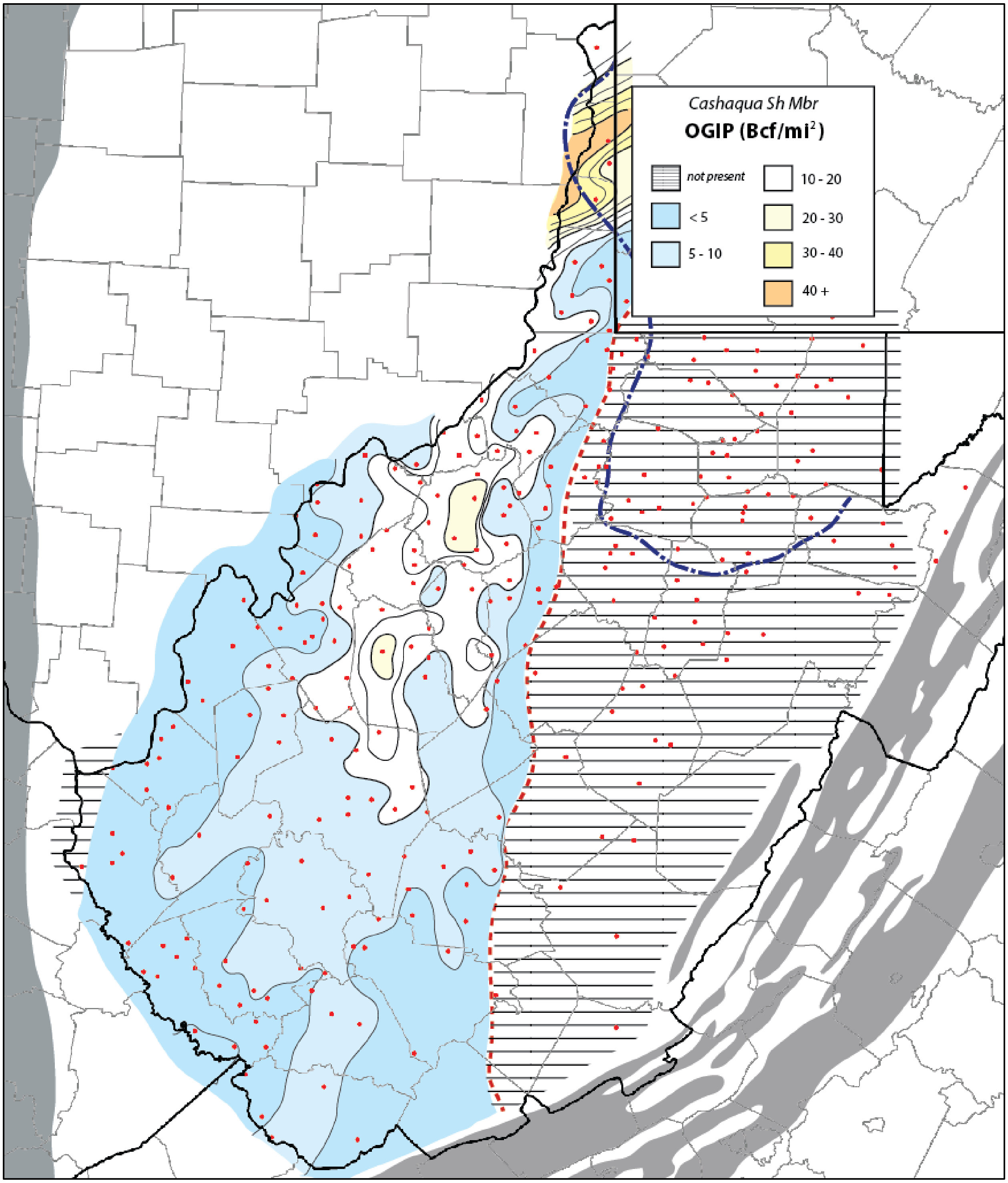


Figure 26. *OGIP map for the Cashaqua Shale Member of the Sonyea Formation. Data are interpreted from logs with some core calibration and with shale-related adjustments. To the east of the blue dashed line, resources are assigned to the GBRU; to the west, they contribute to the MRU. The red dashed line shows the lateral lithofacies boundary of the Cashaqua (Boswell and Pool, 2018).*

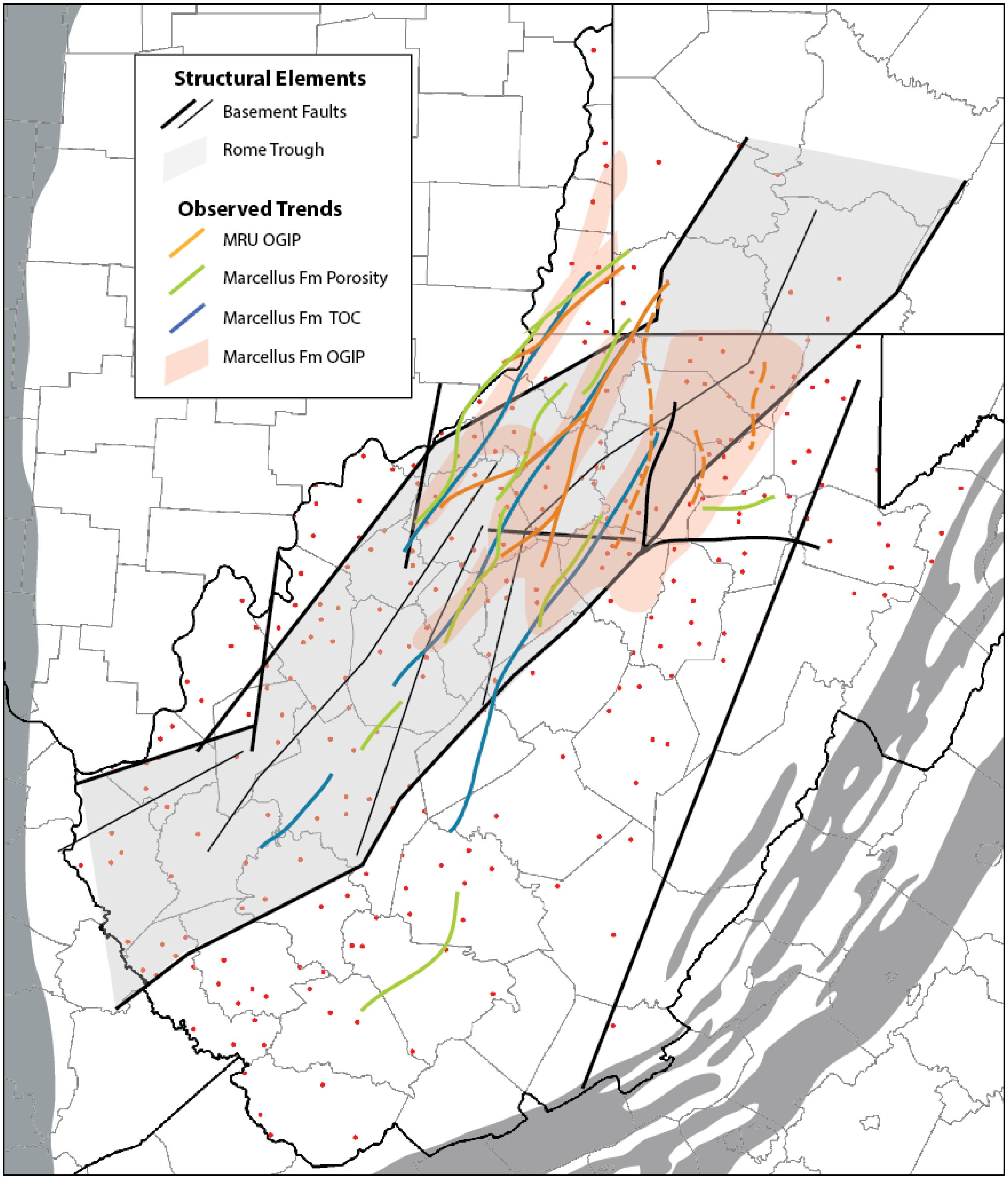


Figure 27. *Map showing relationship between mapped trends within the MRU (various colors) and the locations and trend of basement faults (black lines) associated with the Rome Trough (grey shading). MRU trends are as follows: orange line – Figure 17, green line – Figure 10, blue line – Figure 16, and pink shading – Figure 21. Basement faults are as summarized by Shumaker (1996), Zagorski et al. (2017), and Boswell (1988).*

et al. (2017). Consequently, the study approach was designed to avoid unnecessarily conservative assumptions and underestimation in all parameters relevant to OGIP.

As noted above, the primary consideration added to these calculations (in the effort to produce an OGIP estimate that makes sense in light of demonstrated well productivity) is the transition from a strictly-defined lithostratigraphic unit to a reservoir unit (RU) for assessment—e.g., from the Marcellus Formation to the Marcellus Reservoir Unit (MRU). The following evaluates the sensitivity in OGIP results to various key OGIP parameters.

Sensitivity Analysis

To gauge the sensitivity of the OGIP results with respect to various input parameters, a subset of 27 wells was selected for iterative analysis (**Figures 28 and 29**). Nine wells were located within areas previously assessed to have TRR > 50 Bcf/mi^2 and assigned to the "play core." Nine more are assigned to the "outer core" (TRR between 30 and 50 Bcf/mi^2) and the remaining nine are on the "play margin" (TRR < 30 Bcf/mi^2).

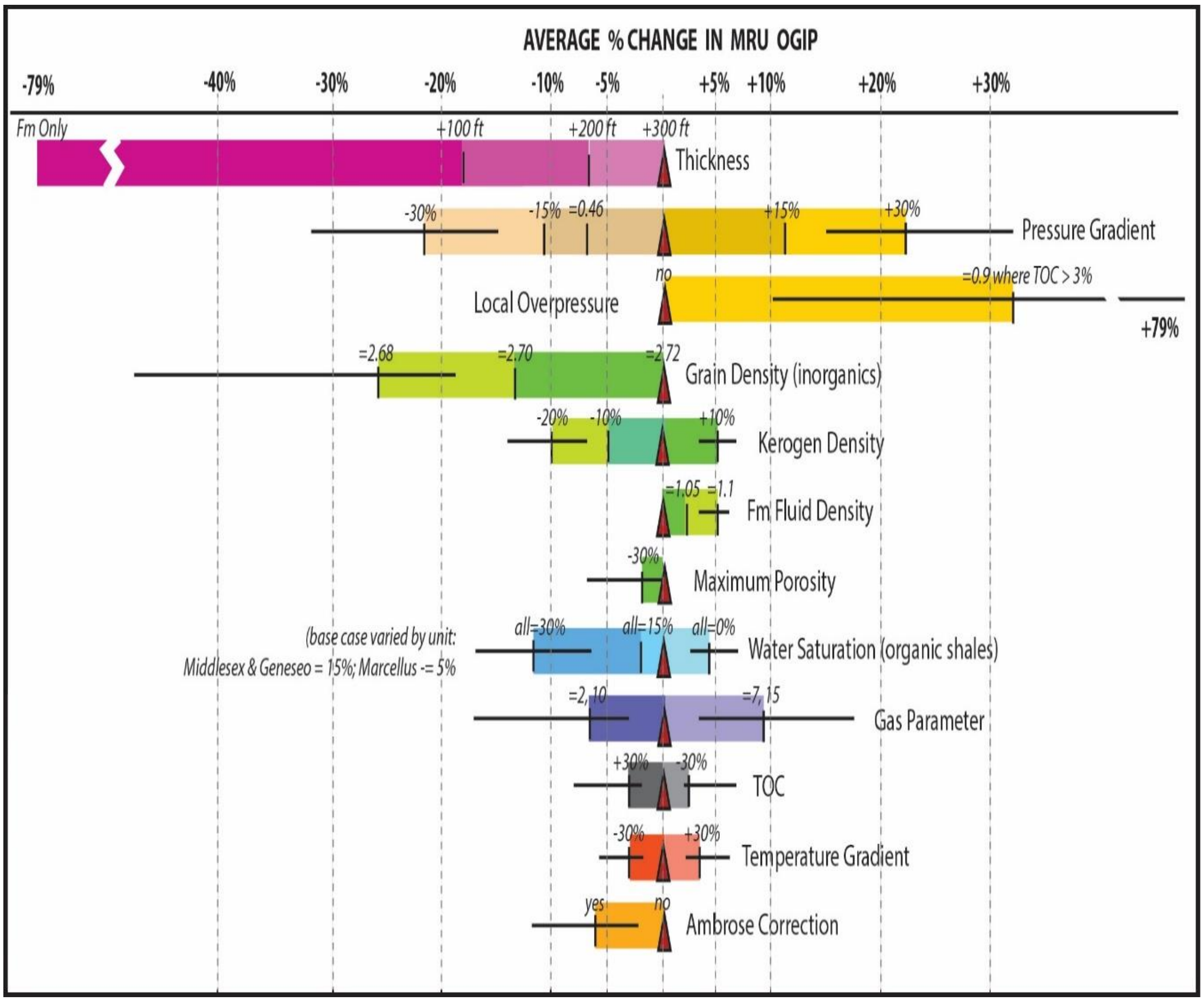


Figure 28. *Impact on average OGIP results for the MRU based on alternative runs for 27 wells shown in Figure 29 as per changes from prior approaches to OGIP calculation. The red triangles mark the revised settings used in this study. The most impactful change on MRU (for this 27 well subset) is the expansion in reservoir thickness (top fuchsia bar). Other key modifications include the grain density assumption and the water saturation assumption. Black bars show range of impact observed for individual wells.*

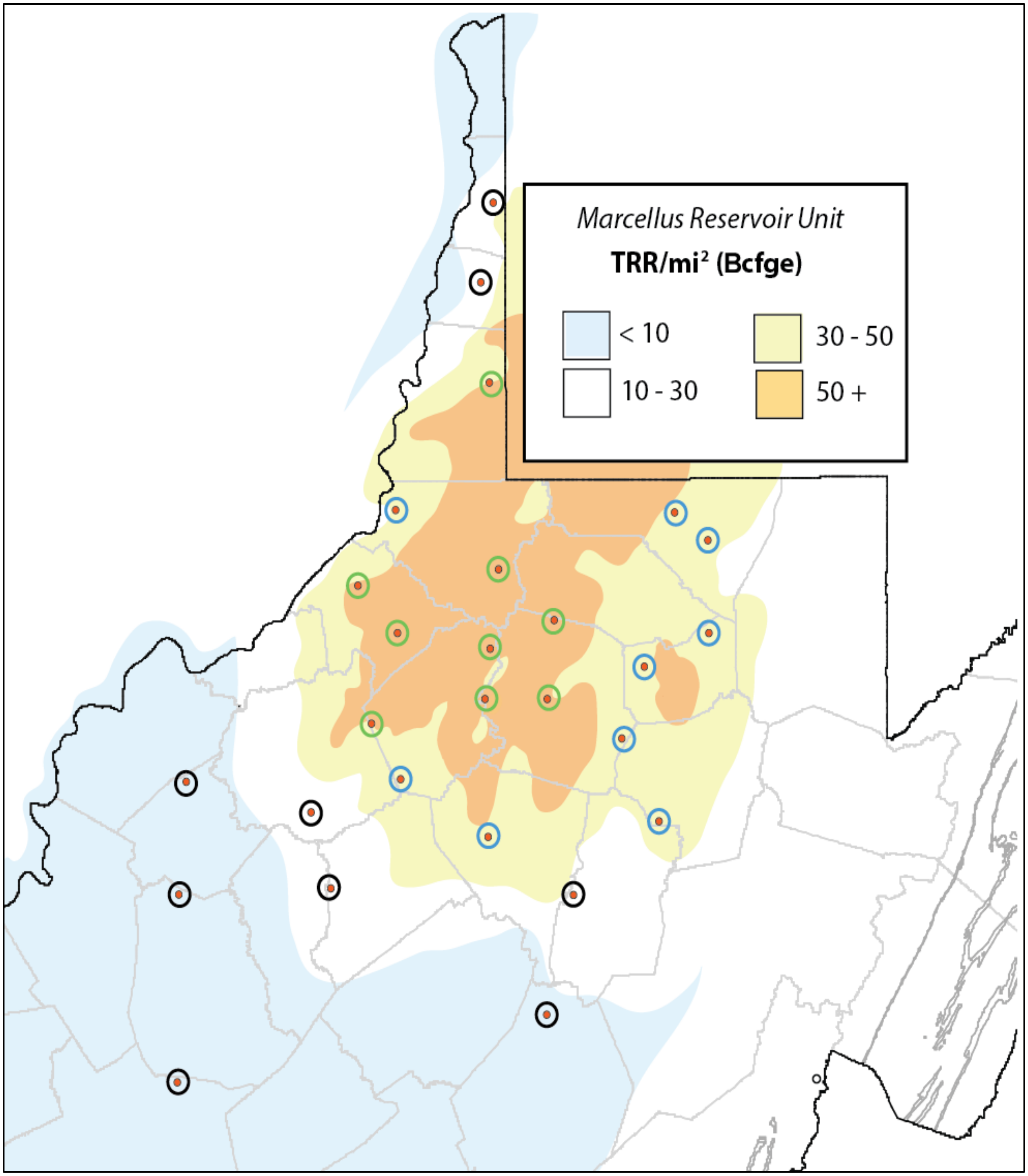


Figure 29. *Well distribution map showing the 27 wells used for sensitivity analysis. The sensitivity analysis examines the gas-in-place calculation plotted against trends in EUR for Marcellus Play wells (Boswell et al., 2020). Green circles are "core area" wells, blue are "outer-core" wells, and black are "play margin" wells (as referenced in Figure 30 and Table 2).*

Thickness: In the sensitivity analysis base case, reservoir thickness was set as the thickness of the Marcellus Formation plus 300 ft. Restriction of thickness to only the Marcellus (the "traditional" approach) reduces OGIP by an average of 41 Bcf/mi^2 for all 27 wells (43% of MRU OGIP). For the 9 core area wells, the average impact is 60 Bcf/mi^2 (49% of MRU OGIP). Alternatively, limiting reservoir thickness to Marcellus plus 200 ft reduces average OGIP by only 6% (or 6 Bcf/mi^2 for all wells and 11 Bcf/mi^2 for the core area wells) (**Figure 28**). Reducing the total MRU thickness by 200 ft reduces average OGIP by 18% (or 18 Bcf/mi^2 for all wells and 32 Bcf/mi^2 for the core area wells). On average, 57% of the MRU OGIP is within the Marcellus Formation and 82% is within the Marcellus Formation or within 100 ft of the top of the Marcellus Formation. Therefore, it is concluded that limiting reservoir volume to only the thickness of the Marcellus Formation renders it very difficult to generate OGIP values that exceed the expected well recovery, particularly in those areas of most active drilling where progressive thinning of the Mahantango and loss to the Tully bring gas-bearing strata of the Genesee Formation and younger units within close stratigraphic proximity to the Marcellus.

Pressure Gradient: The base case pressure gradient for each well is set through reference to the regional pressure gradient map (**Figure 15**). Altering the gradient by 15% typically resulted in a change in OGIP of 11%—this result was noted for both increases and decreases in gradient and becomes larger with greater base case pressure. Similarly, a 30% change in gradient produced an average 22% increase in OGIP. In an effort to reconcile OGIP with projected higher EURs for a well in southwestern Pennsylvania, Blood et al. (2020a, b) have proposed that organic-rich units may be locally highly overpressured. To mimic this concept, an additional test was conducted whereby pressure was set using a gradient of 0.9 psi/ft for those intervals of the Marcellus or Geneseo-Burket where TOC > 3%. For wells in the play core area which are moderately over-pressured in the base case (P_{grad} > 0.6 psi/ft), the increase in OGIP was still large—on average a little over 30%. Where base case pressure was lower, the impact was as much as 79%.

Porosity: Seven sensitivity cases relate directly to the porosity calculation. Two alternative cases were conducted using values of 2.68 and 2.70 g/cc for ρ_m. The results indicate that each 0.01 g/cc change from the base case value of 2.72 (prior to normalization and incorporation of the correction for kerogen content and density) resulted in an average reduction of 6 to 7% in total OGIP.

Two cases were run related to kerogen density. On average, a 10% increase in ρ_k produced a 5% in OGIP while a 10% decrease reduced OGIP by 5%.

Two cases were also conducted using alternative values for formation fluid density. Those results indicate that a 10% increase in ρ_f (from 1.0 to 1.1 g/cc; see Kekacs et al., 2015) produced a 4 to 5% average increase in OGIP.

One final case was set relative to the "maximum porosity" assumption. While many wells have a few thin zones of excessively low density, this parameter only significantly impacts those few wells that were included in the study despite evidence that some substantial portion of the density data is compromised. Of the 27 wells, 23 showed < 3% change in OGIP when the maximum porosity assigned to the intervals of missing density data was reduced by 30%.

Several additional sensitivities relate less directly to porosity. To assess the impact of the double counting of porosity in the adsorbed and free gas calculation, a separate case employs the correction described by Ambrose et al. (2012) using a gas density of 0.34 g/cc and an assumed Langmuir pressure of 550 psi. The correction reduced total free gas values within the organic-rich shales by 10 to 15%, and overall OGIP values for the MRU by roughly 5 to 10%. This correction is not included in the base case.

Two cases also tested scenarios in which the TOC, as calculated by the density relationship (eq. 8), was increased or decreased by 30%. This change tended to have a minor impact on total gas volumes. At any particular fixed bulk density, increasing TOC increased adsorbed gas volumes but decreased free gas volumes somewhat more due to the impact on the porosity calculation. Therefore, a TOC increase (at a given bulk density) resulted in a slight OGIP decrease. The reverse effect was noted when TOC was decreased.

***Water Saturation*:** Three alternative cases were set for S_w. For the base case, the values are 35% for the non-organic-dominated units (Mahantango, West River, and Cashaqua), 15% for the Middlesex and Geneseo-Burket, and 5% for the Marcellus. In one sensitivity case, all organic-rich units were set to S_w=30% with the non-organic units remaining at 35%. In this case, total OGIP decreased by an average of 12%. In a second case, all the organic-rich units were set at S_w=15%; the average OGIP reduction relative to the base case was -4%. In the last case, all organic-rich units were set to S_w=0%, which resulted in an average OGIP increase of 4%.

***Reservoir Temperature, Gas Parameter, Gas Compressibility*:** Two alternative cases were set that adjusted the well-specific temperature gradient (from **Figure 14**) by +30% and -30%. In all wells, the corresponding change was from 1 to 4% of OGIP, with increasing temperature reducing OGIP and decreasing temperature increasing OGIP. A final sensitivity tested the implications of changes to the gas parameter which converts absorbed gas volumes to gas content in Scf/ton. In the base case, this value is set at 5 for the non-organic-rich units, at 10 for the Geneseo-Burket, and at 12 for the Marcellus. Changing these values to 2, 10, and 10 respectively reduced OGIP by an average of 7%. Setting the gas parameter to 7, 15, and 15 increased total OGIP by an average of 9%.

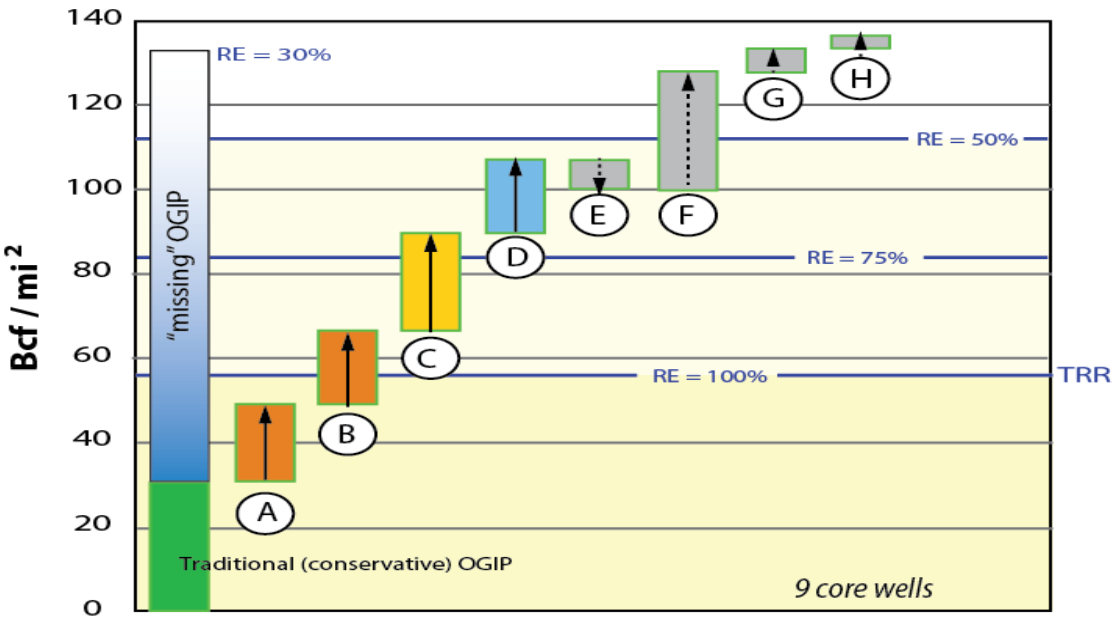
No adjustments were made to Z-factor given the negligible impact on this parameter assessed for small pores (Tran and Sakhaee-Pour, 2019) and the lack of information on likely pore size distributions within the various units in the MRU.

***Discussion*:** The sensitivity analysis indicates that OGIP is responsive to changes in several parameters that are, generally, poorly known: pressure, reservoir volume, porosity, and water saturation. The application of conservative assumptions for any one of these parameters will limit the OGIP estimate on the order of 10 to 20% or more. Setting all of these parameters conservatively will clearly restrict OGIP volumes significantly.

The context for this reappraisal of in-place resources is the recent recognition that predicted ultimate recovery of many wells in West Virginia are already exceeding the volumes thought to exist in place (Boswell et al., 2020). As a result, modifications to prior OGIP estimation procedures were implemented to capture the “missing” gas.

The volume of potential “missing” gas depends on what recovery efficiency is expected or assumed. Given the challenges in shale gas development, including the common observation that a large share of fracture clusters within stages are not productive (e.g., Anifowoshe et al., 2016), a very high RE would seem highly unlikely. However, if a total RE as high as 50% is deemed reasonable, then the volume of “missing” gas is almost 80 Bcf/mi^2 within the play core; ~50 Bcf/mi^2 in the outer core.

Figure 30 shows that, for wells in the play core or outer core, the traditional OGIP method falls short of the average estimated TRR and well short of the volume needed to generate an RE of 50%. (There is no reliable estimate of TRR for the play margin.) While quite large, these incremental volumes of “missing” gas were accounted for (as related to the case of the Marcellus Play in West Virginia) by modifications to the assumptions (these modifications were applied to all 270 wells in the study) as illustrated including: 1) expanding reservoir volume to include 300 ft of non-Marcellus section, 2) setting initial matrix density to 2.72 g/cc instead of 2.68, 3) setting S_w to low values for the Marcellus (5%) and Geneseo-Burket (15%) as opposed to ~30%+ which is commonly derived from resistivity-based formulas, and 4) by deferring the Ambrose correction (due to uncertainty related to details for pore size distributions).



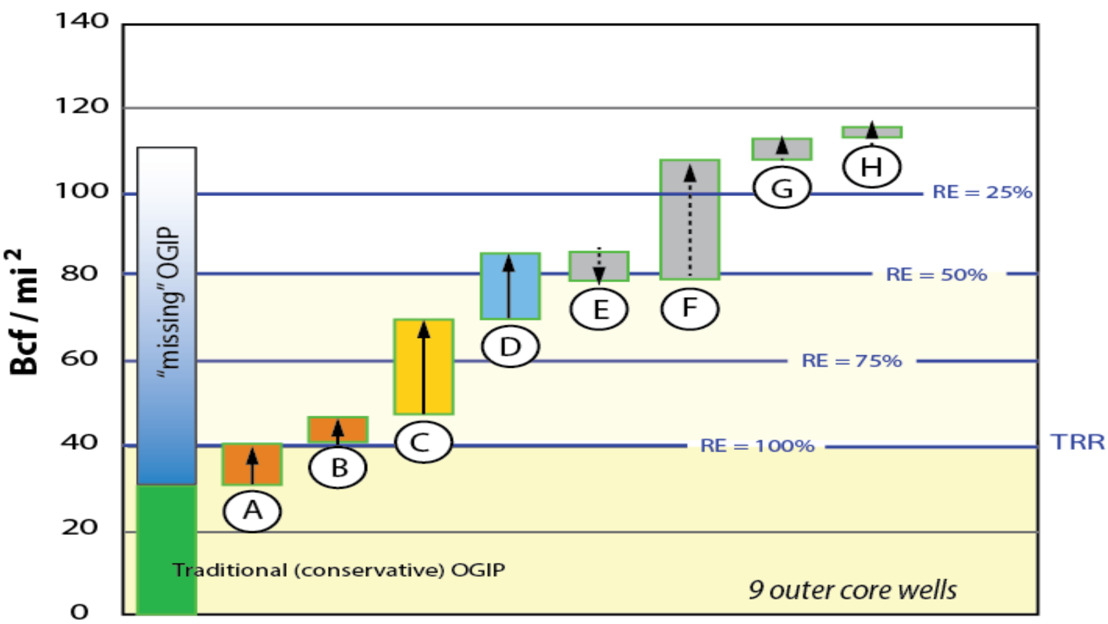


Figure 30. *Schematic diagram illustrating OGIP calculation sensitivities. Green bar illustrates average OGIP/mi^2 achieved with traditional parameter settings. "Missing" OGIP denotes gas volumes needed to achieve select RE. Letters A to H refer to select modifications that are available to reconcile OGIP with interpreted recoverable volumes in West Virginia Marcellus development, as follows: A) expand reservoir thickness by 100 ft; B) expand reservoir thickness by 300 ft (where no frac barrier); C) set density of inorganic matrix components to 2.72 g/cc; D) set water saturation to 5% in Marcellus Formation, 15% in Geneseo-Burket, and 35% in all other units; E) employ Ambrose correction; F) employ local high overpressure where TOC > 3% (per Blood et al., 2020b); G) set fluid density to 1.1 g/cc; H) reduce water saturation in Marcellus and Geneseo-Burket to 0%. The data are shown relative to 9 wells from the area of most intensive recent Marcellus development ("core" wells—top panel) and 9 additional wells from surrounding areas ("outer core"—lower panel). Note the primary distinction between the two areas is the larger impact of expanding reservoir thickness in the core area. Orange, yellow, and blue bars indicate adjustments included in the present OGIP calculations. Optional modifications (shown in grey boxes) have been proposed by Blood et al. (2020b) but are not implemented in this study.*

Table 2 shows additional data for the 27 wells used for the sensitivity analysis.

Blood et al. (2020b) recently report a similar disconnect between recoverable resources and in-place estimates for a development in eastern Greene County, PA. However, in that area, gas in formations immediately above the Marcellus is limited to perhaps 10 Bcf/mi^2 or less based on extrapolation of data for northern Monongalia County. As such, those authors provided new interpretations of locally highly-elevated over-pressures as a means to capture the "missing" gas.

Further Examinations and Discussions

Recovery Efficiency Assessment

Given new estimates of OGIP and TRR that have been broadly calibrated and that are referenced to the same body of rock, it is possible to map RE (the ratio of TRR to OGIP at various specific locations) to observe areal changes within the play. The TRR used is the "ultimate TRR" (uTRR—including both historical and future production), as opposed to the "remaining TRR" (rTRR—only related to as yet-undrilled locations) as is commonly reported in various assessments. **Figure 31** indicates that expected RE for recent or future developments in the core of the play ranges from 40 to 60%. Along the margins of the play, likely RE is less than 30%. Of note is that the greatest RE is not within the area of greatest recent activity (Doddridge, Tyler, Wetzel, and Ritchie counties), but in northeastern West Virginia (Monongalia, Marion, Harrison, Tyler, and Barbour counties). In this area, RE is likely greater due to the presence of thick Tully Limestone, which limits the thickness of the MRU (**Figure 32**) and likely more effectively focuses well stimulation. To the west, the removal of the Tully frac barrier allows greater recovery, but from a much greater in-place resource, resulting in reduced RE.

Remaining Resources

Data published by Boswell et al. (2020) suggest that uTRR for the Marcellus Play in West Virginia is ~216.8 Tcfge (**Table** 1). To determine the rTRR for West Virginia, recoverable resources associated with previously drilled wells need to be identified and removed. As an initial estimate, data from Enverus indicate that the Marcellus Play in West Virginia has produced a cumulative 9.96 Tcfge through mid-2020, with an additional 18.04 Tcfge remaining-to-be-produced in existing wells. Subtracting that total of 28 Tcfge from the uTRR estimate indicates that rTRR for the Marcellus RU in West Virginia is on the order of ~188.8 Tcfge. As an additional check, Enverus data also was used to determine total area drilled in each county (**Table 1**) as the product of total lateral length and a typical well spacing of 800 ft. Assuming constant resource density throughout each county allowed rTRR to be roughly estimated for each county, the total rTRR by this approach is ~189 Tcfge.

The ~189 Tcfge of rTRR for West Virginia indicates volumes that could be developed if every remaining undrilled location is drilled and every well completed successfully such that it produces volumes typical of recent wells drilled in its vicinity, and the well is allowed to produce for a full lifetime of 50 years. This West Virginia-specific value of ~189 Tcfge significantly exceeds the 94 Tcfg mean estimate (equating to 6.8 Bcf/mi^2) for the entire Appalachian basin (**see Figure 33**) reported by Higley et al. (2019). Additional basinwide estimates include: EIA (2020) has assessed 311 Tcf (equating to 11.8 Bcf/mi^2), and Ikonnikova et al. (2018) reports 560 Tcf (equivalent to 13.1 Bcf/mi^2).

uTRR from the Boswell et al. (2020) study and rTRR from this study suggest that by mid-2020, Marcellus development has drilled 3% of the available area in West Virginia and has extracted 12% of the total TRR. In the seven counties that have been the primary drilling targets in recent years (Ohio, Tyler, Doddridge, Marshall, Brooke, Wetzel, and northeastern Ritchie), 51 Tcf or 70% of the total available resource remains to be drilled.

It should be noted that rTRR should not be construed as reserves or as commercially viable

Table 2. *Estimated RE percentage differences for 27 wells given changes to OGIP parameters. TRR is the assessed technically recoverable resource at the well location (per Boswell et al., 2020). Column **A** refers to the most conservative OGIP approach. **B** defers the Ambrose correction. **C** expands reservoir thickness to include strata within 100 ft of the top of the Marcellus; **D** expands that thickness to include up to 300 ft above the Marcellus (excluding the Rhinestreet) where no thick Tully exists. **E** increases porosity by setting increasing ρ_m from 2.68 to 2.72 g/cc. **F** increases gas volume by reducing S_w in the Geneseo-Burket from 0.35 to 0.15 and in the Marcellus Formation from 0.35 to 0.05; **G** reduces S_w in those units to 0.00. **H** increases porosity by increasing ρ_f from 1.0 to 1.1. **I** increases gas volumes through additional strata-bound overpressure (based on 0.9 psi/ft gradient for layers where TOC > 3%). Wells are sorted by TRR into "play core" (TRR > 50 Bcf/mi^2), "outer core" (TRR from 30 – 50 Bcf/mi^2) and "play margin." Note that all these adjustments are required to reduce RE to ~40% for the "play core" or ~30% for the "outer core." Adjustments through case **F** are included in the base case values reported here and are sufficient to reduce RE to values that are generally less than 60%.*

Calculated RE at increasing OGIP for 27 Selected Wells											
PLAY CORE		**TRR** (Bcfge/mi2)	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**
county	*permit*										
TYLER	2004	65	242%	194%	95%	80%	63%	53%	51%	49%	43%
HARRISON	4176	62	165%	121%	84%	83%	67%	56%	55%	52%	42%
TYLER	2033	59	240%	193%	127%	115%	93%	78%	75%	71%	56%
DODDRIDGE	5866	57	175%	141%	101%	61%	47%	41%	40%	38%	31%
WETZEL	2775	56	179%	135%	101%	57%	42%	37%	35%	34%	28%
HARRISON	5227	55	140%	110%	79%	78%	61%	52%	51%	48%	36%
DODDRIDGE	5638	54	246%	198%	162%	96%	67%	59%	56%	54%	38%
DODDRIDGE	2909	51	137%	109%	63%	54%	42%	35%	33%	32%	28%
MARSHALL	1224	50	212%	167%	144%	88%	61%	52%	50%	47%	42%
OUTER CORE											
MONONGALIA	1812	45	174%	128%	108%	108%	72%	59%	57%	54%	44%
DODDRIDGE	5644	45	206%	167%	91%	78%	56%	47%	45%	43%	34%
TAYLOR	646	45	124%	101%	80%	74%	52%	44%	43%	41%	31%
LEWIS	3703	42	167%	137%	98%	75%	57%	50%	48%	46%	33%
HARRISON	5142	38	94%	76%	72%	72%	52%	41%	40%	38%	27%
MONONGALIA	1705	38	115%	91%	66%	62%	45%	38%	37%	35%	28%
TAYLOR	576	35	102%	84%	61%	54%	39%	33%	32%	31%	22%
BARBOUR	2982	35	110%	97%	86%	84%	65%	53%	52%	50%	29%
WETZEL	644	34	74%	58%	43%	38%	30%	25%	24%	24%	18%
PLAY MARGIN											
UPSHUR	3846	25	76%	67%	52%	38%	30%	26%	26%	25%	13%
OHIO	64	20	59%	47%	40%	40%	30%	25%	24%	23%	19%
RITCHIE	9286	20	129%	106%	48%	35%	24%	22%	21%	20%	18%
GILMER	4332	18	94%	75%	44%	40%	30%	26%	25%	23%	19%
BROOKE	106	15	49%	21%	18%	18%	14%	11%	11%	10%	8%
WEBSTER	90	8	44%	31%	21%	19%	13%	11%	11%	10%	9%
WIRT	1136	7	56%	48%	29%	25%	19%	17%	16%	16%	12%
ROANE	3197	5	41%	35%	22%	17%	13%	12%	12%	11%	8%
KANAWHA	6011	4	46%	41%	19%	14%	10%	9%	9%	9%	7%

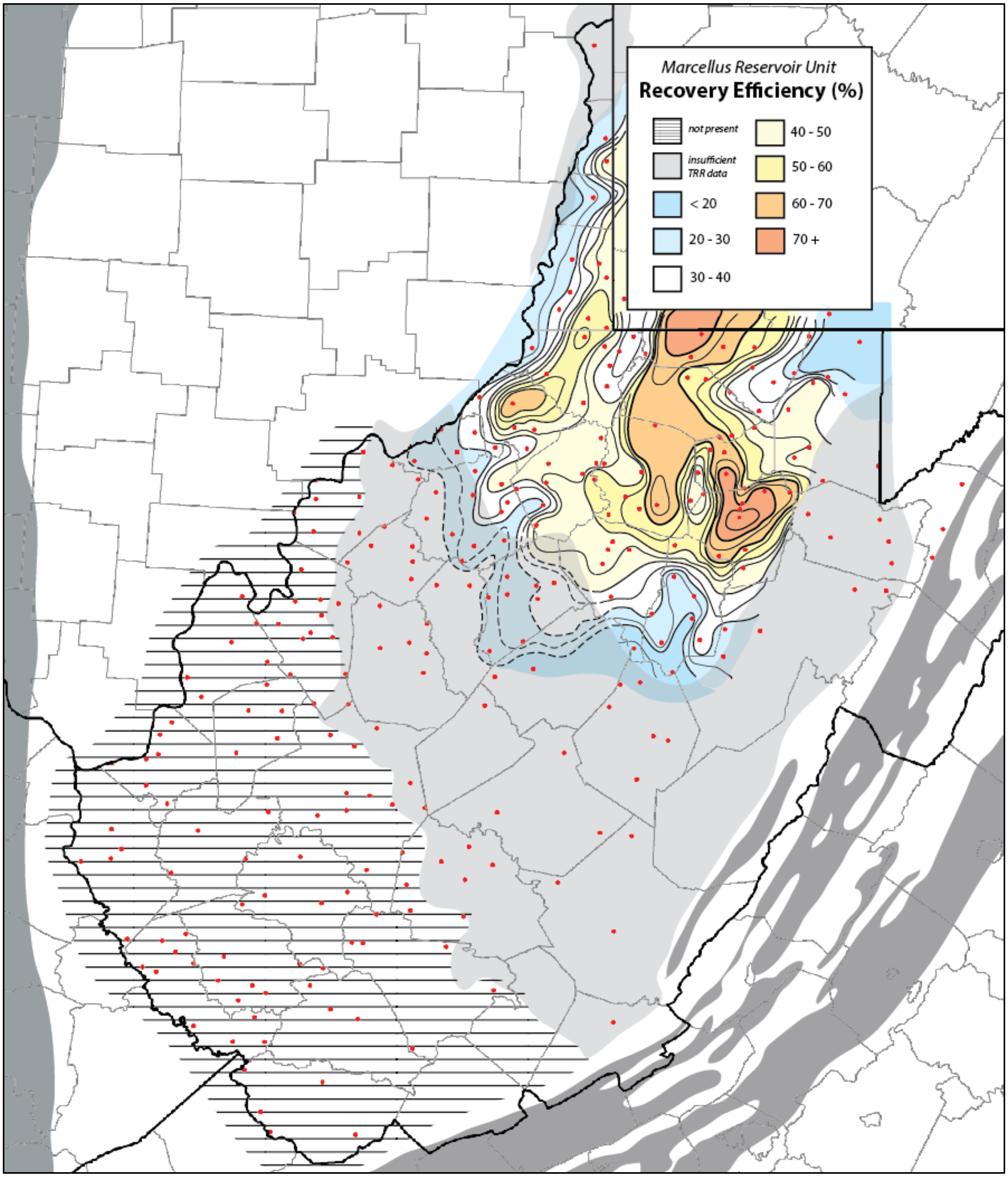


Figure 31. *Estimated ultimate RE map for the MRU. The map indicates the percentage of OGIP within the MRU that is technically recoverable given modern well production performance at any location. Grey area lacks any reliable production data upon which to base recoverable resources; therefore, RE cannot be estimated (at present).*

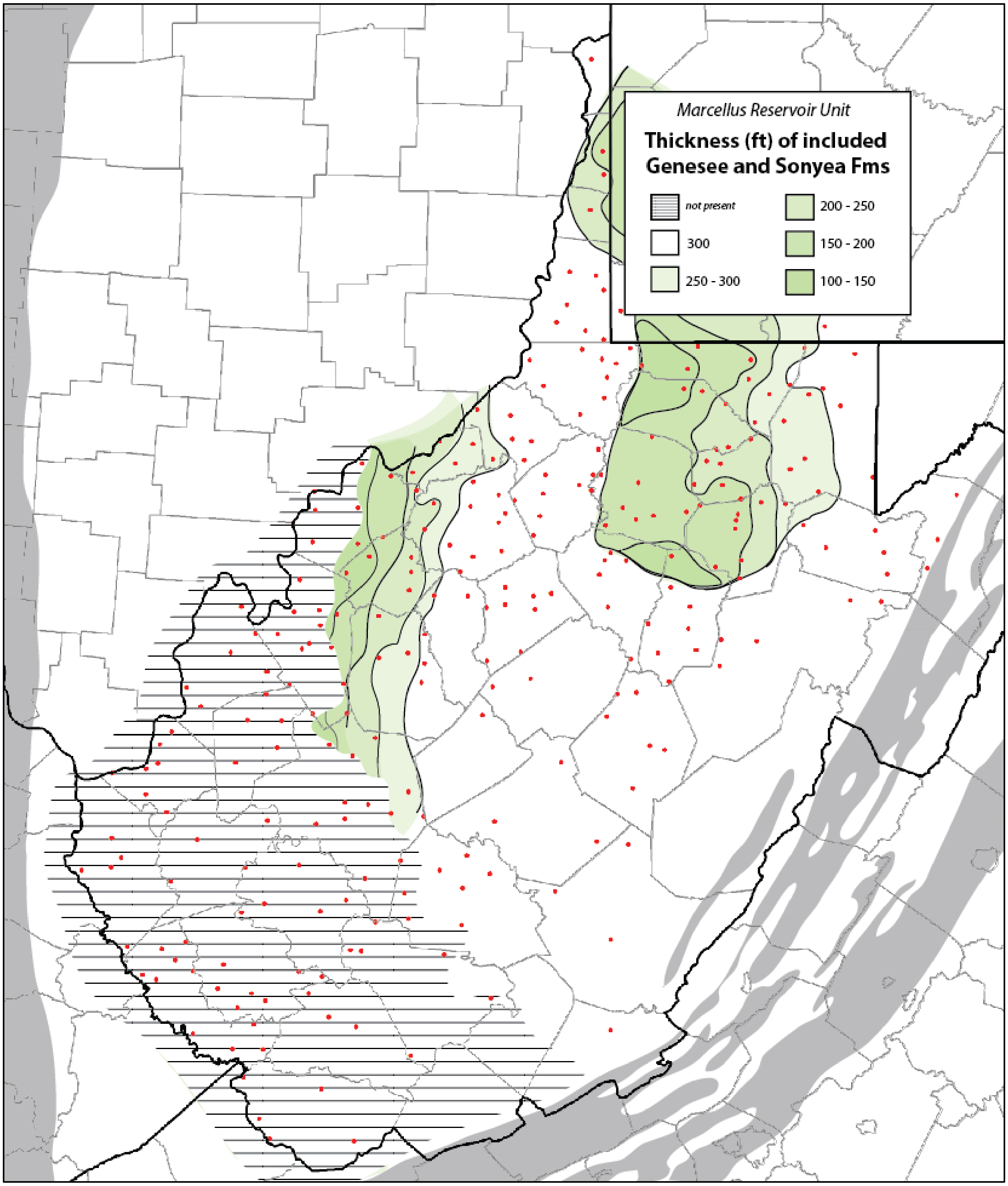


Figure 32. *Thickness map of the MRU. Thickness has been set at 300 ft or the vertical separation between the top of the Marcellus Formation and 1) the base of Tully Limestone (in northeastern West Virginia where the Tully is deemed a likely frac barrier) or 2) the base of the Rhinestreet Shale Member of the West Falls Formation (in southwestern West Virginia).*

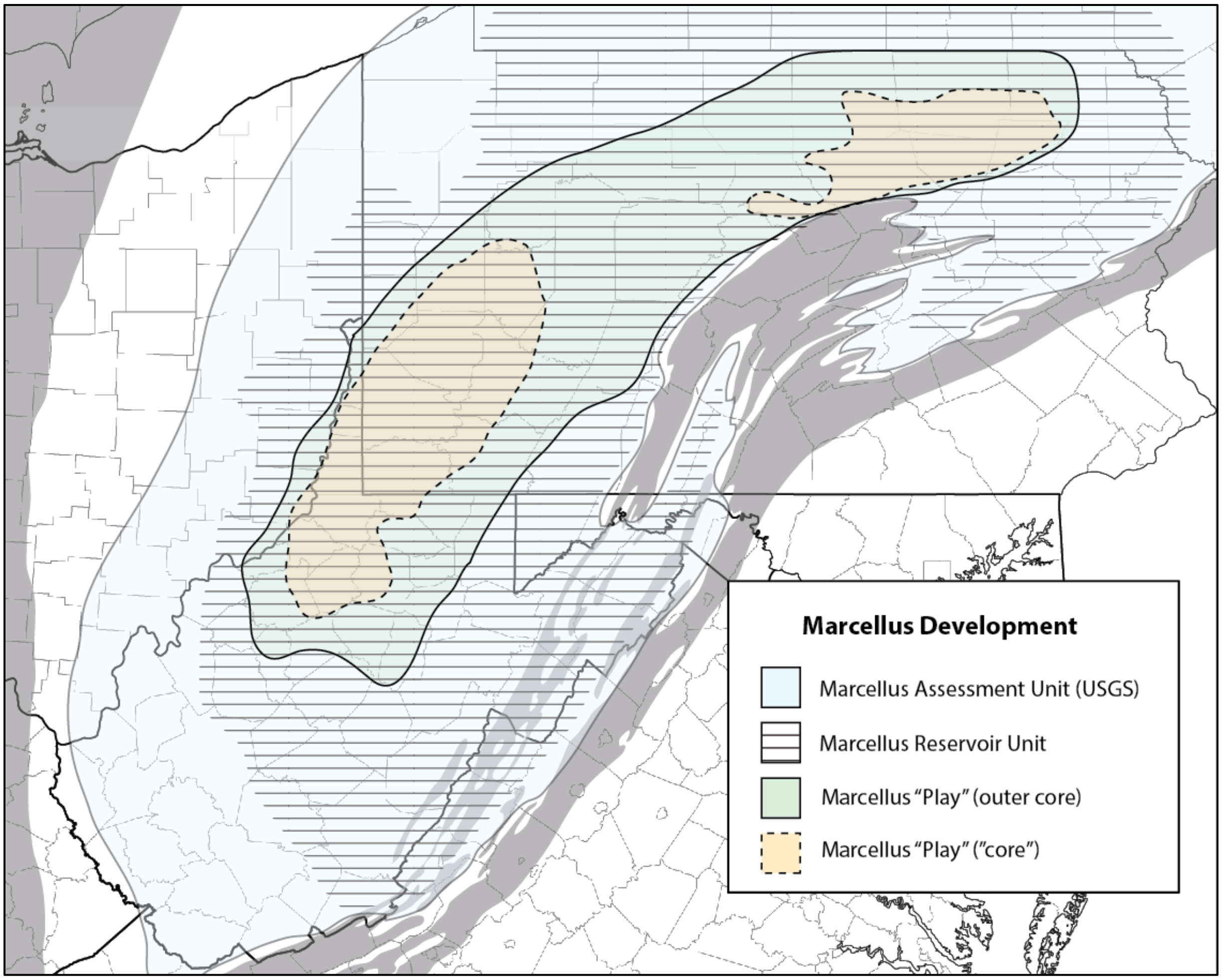


Figure 33. *Map of various depictions of the Marcellus "Play" in the Appalachian basin. Blue denotes the entirety of the Marcellus Assessment Unit as per the USGS (Higley et al., 2019). Green and brown show the area of higher potential related to reservoir quality and pressure. The area of the MRU in West Virginia is shown by the lined pattern.*

resources. At any point in time, the share of the rTRR that is commercially viable varies, and in conditions of low gas prices, the economically-recoverable share of the TRR could be quite low.

Study Summary

An initial estimate of RE associated with Marcellus development, utilizing assessments of uTRR (Boswell et al., 2020), provided a first-order check on existing OGIP assessments. If the EURs utilized in that study are reasonable, then many wells in West Virginia appear certain to ultimately produce substantially more gas than was thought to exist in place. Therefore, methods used to produce prior OGIP estimates were re-examined. In general, it is found that OGIP assessment, which by default deals with very large and somewhat abstract values, is commonly approached in a conservative manner, which when compounded with porosity, saturation, and pressure calculations, have likely tended to substantially undervalue the in-place resource.

Perhaps the most likely driver for artificially low OGIP in the case of the Marcellus Play in West Virginia, is the restriction of reservoir volume to the lithostratigraphic boundaries of the Marcellus Formation. While it is customary for in-place assessments to be conducted for a given lithostratigraphic unit only; to be aligned with well production, the reservoir volume should include all volumes that may ultimately be within the full drainage area of the well. Deciphering this volume is complex; however, microseismic data consistently indicate that stimulation is routinely pervasive within 300 ft vertical distance from Marcellus horizontal wellbores. Most notably in northcentral and western West Virginia, stratigraphic thinning of the Mahantango and Tully formations brings gas-bearing units of the Genesee and younger formations into close stratigraphic association with the Marcellus Formation with no intervening frac barrier. Expanding reservoir thickness from the Marcellus lithostratigraphic unit to a larger Marcellus Reservoir Unit (MRU) is a key element in reconciling conflicting OGIP and recoverable assessments. Sensitivities on 27 wells indicated that 82% of this incremental gas is within 200 ft of the top of the Marcellus Formation.

In addition to revising reservoir thickness, relatively aggressive settings are used for the calculation of porosity (setting initial, non-organic grain density at 2.72 g/cc) and water saturation (=5% within the Marcellus Formation). Full sensitivity analysis of OGIP results to the various assumptions used in the OGIP calculation are provided.

The report calculates OGIP using more than 270 wells in West Virginia for units ranging from the Middle Devonian Marcellus Formation through the Upper Devonian Sonyea Formation. The analysis sums the OGIP for all units together comprising the MRU determined at any location to be potentially accessed by standard well stimulations landed in the Marcellus Formation. OGIP is also estimated for the Geneseo-Burket Reservoir Unit (GBRU). The GBRU is yet to be developed in West Virginia but subject to drilling in much of Pennsylvania—those wells in West Virginia that have been landed in the Geneseo or Middlesex have generally been located where those units are assigned to the MRU (e.g. Wetzel County). The results provide a first assessment of the Geneseo-Burket resources and a substantial increase in OGIP from prior assessments associated with Marcellus development. Overall, an original gas-in-place for the MRU is estimated at 878 Tcf and for the GBRU at 115 Tcf for the State of West Virginia.

OGIP density in the play core area ranges from 100 to 150 Bcf/mi^2 in the MRU and 50 to 80 Bcf/mi^2 in the GBRU. Per lithostratigraphic unit, typical ranges of OGIP density are as follows:

1) Marcellus, 60 to 80 Bcf/mi^2;
2) Mahantango, 10 to 40 Bcf/mi^2;
3) Geneseo-Burket, 10 to 30 Bcf/mi^2;
4) West River, 10 to 40 Bcf/mi^2;
5) Middlesex, 0 to 15 Bcf/mi^2; and
6) Cashaqua, 0 to 5 Bcf/mi^2.

Based on previously reported data on well recovery, it is estimated that the uTRR for the MRU is ~217 Tcfge with rTRR of ~189 Tcfge. Due to lack of production data, no estimates of TRR are available for the GBRU.

Comparison between the newly-revised OGIP and rTRR values indicate reasonable values for recovery efficiency throughout the play core generally ranging from 40% to 60% with play margins from 20% to 40%.

Acknowledgements

The authors thank all of our colleagues at WVGES for their contributions and support, both direct and indirect, to this study. In particular, we acknowledge Jessica Moore, Timothy Vance, Philip Dinterman, Gary Daft, Eric Lewis, Samantha McCreery, Sarah Gooding, Richard Binns, Mary Behling (retired), and B. Mitchel Blake (retired) for their review of the paper, providing supporting materials, cataloging work, and/or general project support. We also thank IHS Markit for providing access to their digital geophysical well logs. Moreover, we recognize the DOE-sponsored EGSP and MSEEL projects from which essential materials were obtained. Furthermore, we appreciate all comments and suggestions related to an earlier version of this study that was presented at AAPG and AGS. In addition, the authors are truly grateful for peer reviews by Ashley Douds (Core2Core Geologic) and Troy Cook (EIA) whose comments and suggestions were extremely helpful.

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