# A Methodology for Integrating Unconventional Geologic and Engineering Data into a Geocellular Model

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## ABSTRACT

Unconventional field development and well performance analysis encompass multiple disciplines and large data sets. Even when seismic and other data sets are not available, geologists can build geocellular models to determine factors that improve operational efficiency by incorporating well log, geosteering, stratigraphic, structural, completion, and production data. I present a methodology to integrate these data sets from vertical and horizontal wells in order to build a sequence stratigraphic and structurally-framed geocellular model for an unconventional Marcellus Formation field in the Appalachian basin, USA. The model would benefit from additional data sets in order to perform a rigorous investigation of performance drivers. However, the presented methodology emphasizes the value of constructing geocellular models for fields with sparse data by building a geologically detailed model in a field area without seismic and core data.

I use third-order stratigraphic sequences interpreted from vertical wells and geosteering data to define model layers and then incorporate completion treating pressures and proppant delivered per stage into the model. These data were upscaled, and geostatistically distributed throughout the model in order to visualize completion trends. Based on these results, I conclude that geologic structure and treating pressures coincide, as treating pressures increase with stage proximity to a left-lateral strike slip fault, and completion trends vary among third-order systems

tracts. Mapped completion issues are further emphasized by areas with higher model proppant values, and all treating pressure and proppant realizations for each systems tract have the greatest variance away from data points. Similar models can be built to further understand any global unconventional play, even when data is sparse, and, by doing so, geologists and engineers can: 1) predict completion trends based on geology, 2) optimize efficiency in the planning and operational phases of field development, and 3) foster supportive relationships within integrated subsurface teams.

## INTRODUCTION

The Appalachian basin has a natural gas production history of nearly 140 years, which initially focused on conventional plays, and horizontal drilling was introduced to the basin in 1944 in order to produce oil from the previously depleted Devonian Venango Formation sandstone (Figure 1; Van Tyne, 1983; Overby et al., 1988). Between 2011 and 2016, more than 28 trillion cubic feet (TCF) of natural gas and 102 million barrels (MMBbls) of oil/condensate from the almost 12,000 unconventional wells have been produced from the Appalachian basin, and nearly 85% of these producing wells have been drilled in the Middle Devonian organic-rich shale of the Marcellus Formation (Kallanish Energy, 2017). In the late 2000's, operators began dedicating exploration efforts to the formation, and Engelder and Lash (2008) published that the formation may hold up to 489 trillion cubic feet (TCF) of recoverable hydrocarbon reserves, although the United States Energy Information Administration (U.S. EIA, 2018) has reduced the proven reserves to 77.2 TCF. To date, two geographic regions have the most productive unconventional Marcellus Formation wells: 1) northeast Pennsylvania, and 2) southwest Pennsylvania/northwest West Virginia.

Prior to the recent horizontal drilling activity associated with unconventional wells in the Appalachian basin, Marcellus Formation stratigraphic studies relied on outcrop observations (Hall, 1939; Brett and Baird, 1985; ver Streaten, 1996; Brett et al., 2011). With the recent proliferation of Marcellus Formation subsurface data, outcrop studies have been integrated with well core, geophysical, and geochemical data (i.e., Rickard, 1984; Engelder and Lash, 2008; Lash and Engelder, 2011; Wang and Carr, 2012; Wang and Carr, 2013; Kohl et al., 2014). Geologic observations and advances in horizontal drilling and hydraulic fracturing have improved drilling and completion operational efficiency in the Marcellus play (U.S. Energy Information Agency, 2016). However, uncertainty still remains regarding how various geologic factors affect the development of an unconventional Marcellus Formation field.

In order to understand the drivers that affect well operations, production, and economics, potential factors must be individually considered prior to establishing an integrated, multivariate model that highlights major elements influencing both production and well cost. Unconventional well field development is typically optimized over time to achieve maximum production for minimum cost. Some factors considered during the optimization process are: 1) drilling target, 2) structure found within and surrounding the field, 3) well orientation, 4) up-dip or down-dip well placement, 4) well length, 5) well spacing, 6) well tortuosity, 7) completion design, and 8) facilities. Particular to the Appalachian basin, well units and the individual wellbores within those units are typically oriented perpendicular to the northeast-southwest present day maximum compressive stress direction in order to increase fracturing capacity during completion operations (Engelder et al., 2009). This orientation also allows the induced fractures to exploit pre-existing transverse fractures that are oriented nearly parallel to the present day maximum compressive stress, as described by Engelder et al. (2009; see "*Joints*" section). Well completion operations in the Marcellus Formation vary widely and are continuously optimized, and some completion variables include stage spacing, perforation spacing, proppant type and volume, water volume, and gel use.

The cost associated with operations varies among unconventional plays and operators. The U.S. EIA (2016) estimated that the total capital cost of facilities, drilling, and completion for a single Marcellus horizontal well was $6.1 million in 2015, with completion costs accounting for approximately of 63% of that total. Completion issues, such as 'screen-outs' and 're-perforations' also contribute to increased operational costs. Screen-outs occur when fracturing fluid injection requires pressures in excess of safe operating conditions, which is usually limited by wellbore or wellhead equipment. Often times, a bridge of proppant forms across a perforation, restricting fracture fluid flow and causing a screen-out. Between 2016-2017, a single screen-out may cost an unconventional operator in the United States up to $100,000 if coiled tubing cleanout, flowback, and standby charges are all necessary (Lecampion, et al., 2015). Understanding how completion operations may change throughout an unconventional field can drastically decrease completion costs, as engineers can optimize plans based on observed trends.

Wells may be re-perforated at any point throughout the life of a well, such as when original perforations become clogged, wells are shut-in for a prolonged time period, or if a specific well stage does not accept the scheduled amount of sand and water during fracturing. Re-perforations contribute to increased operational costs, as additional time and supplies are needed for the operation. Specific to this paper, stages were re-perforated during the initial completion operations because they did not accept the scheduled proppant volume. Changes in reservoir composition and stress regime may affect the occurrence of screen-outs and re-perforations. Elevated concentrations of quartz and carbonate minerals increase shale brittleness and thus the reservoir 'fracability' (likeliness to create fracture networks), and clay mineral content generally increases mudrock ductility (Jarvie et al., 2007; Mavko, 2010; Wang and Carr, 2013; Lecampion et al., 2015). Treating pressure, the pressure needed to deliver all scheduled water and proppant volumes to a particular stage, is recorded at the well pad, and pressures are dependent on reservoir rock type and the present day stress field. The delivered proppant at each stage is measured and may vary from the proppant volume scheduled during the planning of completion operations. Studies show that treating pressures are typically higher in more ductile rock types with higher clay content (i.e., Far et al., 2015; Oliver et al., 2016).

These completion parameters (along with numerous other parameters) can be recorded on a two dimensional map of an unconventional field, which provides information regarding overall trends within the field. However, this technique does not consider the well path placement. The stratigraphic variability of the horizontal wellbore placement should affect completion planning, as different sequences and system tracts have inherent lithologic differences. Volumetric geological modeling is a common technique used to spatially visualize, quantify, and predict subsurface geology in petroleum systems (Pyrcz and Deutsch, 2014; Kaufmann and Martin, 2008; Shepard, 2009; Wang and Carr, 2012; Wang and Carr, 2013). Due to small scale heterogeneity in unconventional shale plays, it is necessary to represent both lithologic and structural variations in a three-dimensional model. Cell-based modeling methods are the preferred technique used to extrapolate lithofacies or petrophysical properties to areas with little to no well control when there are gradational relationships among facies (Pyrcz and Deutsch, 2014). Marcellus Formation facies modeling has been completed (Wang and Carr, 2012; Wang and Carr, 2013), and data-driven analytical models have been built to understand completion effectiveness in order to improve production in the Marcellus Formation (i.e., Shelley et al., 2015). These models concluded that geology (depth, thickness, and reservoir quality), well spacing, and completion design all affect well performance. However, there are no publications that report a methodology used to build geocellular models in order to visualize and predict Marcellus Formation operational trends in relation to the geologic structure and stratigraphic well placement.

Difficulties may be encountered when building a volumetric geocellular model for an unconventional field due to relatively close spacing of the horizontal portion of the well-bores. The uncertainty associated with wellbore location, particularly if well head datums were collected with various instruments among well pads, and increasingly inexact well-bore location toward the toes of horizontal wells (the "cone of uncertainty" along the well path) often create problems during model construction. The inherent uncertainty associated with geosteering interpretations also contributes to model inaccuracy. All of these factors must be realized and considered when constructing a geocellular model for an unconventional field. If a predictive model is generated and updated as needed, operation efficiency increases and costs decrease.

Specific to this study, a geocellular model that incorporates well orientation, stratigraphic placement of the horizontal portion of the wellbore, structural complexity, completion stages, treating pressure, and proppant delivered per stage is presented. Factors that affect completion issues, and thus operating costs and well economics, are addressed. Fifteen-day cumulative production is the only common production interval to all completed wells in the field area, and it must be emphasized that this is too short a period to use to analyze field-wide production trends (see Introduction and Discussion sections). Rather, this production is used as a 'placeholder' in the model, and the 15-day cumulative production should be replaced by 90 or 180-day production when available. By building geocellular models with the methodology presented, geologists and engineers can work together to predict how geology affects completion operations in an unconventional field. This study specifically presents model results for an eight square mile unconventional Marcellus Formation well field in Ritchie County, West Virginia (Figures 2 and 4).

## Geologic Setting

### *Acadian foreland basin*

Deformational loading created by the Middle Devonian collision of micro-continent Avalonia with Laurentia formed the northeast-southwest trending Acadian foreland basin, in which the Marcellus Formation was deposited. The Acadian Mountains bounded the basin to the southeast, and the Findlay/Algonquin Arch constrained the basin to the northwest (Figure 2; Castle, 2001; Ettensohn and Lierman, 2012). During this time, Laurentia was located in a subtropical climate, which promoted the deposition of interbedded carbonates, organic-rich shales, and clastic detritus. The clastic sediment was primarily shed northwestward off of the Acadian highlands into a shallow, restricted, epeiric sea, which was periodically flooded from the southwest by the Rheic Ocean (Mesolella, 1978; Brett and Baird, 1985; Edinger et al., 2002; Ettehnson and Lierman, 2012). Tectonic subsidence and eustatic sea level rise caused sediment deposition within the Acadian basin to generally shift from the shallow, marine shelf carbonates of the Early Devonian to the organic-rich, marine clastics of the Middle and Upper Devonian. (Ettehnson and Lierman, 2012). Throughout the Paleozoic, pre-existing basement-rooted structures in the basin were reactivated in various manners due to changes in stress regime (Gao et al., 2000; Jacobi, 2002; Jacobi and Fountain, 2002; Tamulonis et al., 2014).

### *Marcellus Formation geology*

The geologic nomenclature used in this study is outlined in Figure 1. The Middle Devonian Marcellus Formation is the basal unit of the Hamilton Group and covers most of the Appalachian basin with an average gross thickness of 80 feet (24 meters; Wang and Carr, 2013). Formation thickness is greatest in northeastern Pennsylvania (>350 feet, 107 meters) and thins to the west and north, eventually pinching out in Ohio and New York (Figure 2; Barnoski et al., 2007; Lash and Engelder, 2011; Wang and Carr, 2013). In the northwest West Virginia study area (Figure 2), the Marcellus Formation overlies the limestone and calcareous shale of the Onondaga Formation and underlies the Stafford Member limestone of the Mahantango Formation (Figure 1). Kohl et al. (2014) report that the paleowater depth of the organic-rich portion of the Marcellus to be approximately 330 feet (100 meters), and Brett and Baird (1985) estimate that the Marcellus Formation was deposited over a span of 2 million years.

Marcellus Formation provenance is interpreted to be the Acadian Highlands, which were located to the southeast of the basin. Historically, the shale has been divided into two third-order transgressive-regressive sequences from outcrop and subsurface data: 1) the Onondaga Formation/Union Springs member, and 2) the Cherry Valley/Oatka Creek members. (Figure 3; Lash and Engelder, 2011; Kohl et al., 2014). Kohl et al. (2014) used subsurface data to conclude that the Union Springs member of the Marcellus Formation of New York, Pennsylvania, and eastern Ohio was deposited during transgressive, highstand, and falling-stage systems tracts. Boyce (2010) mapped variations in gross Marcellus Formation subsurface thickness in southeast Pennsylvania and West Virginia and related thickness changes to paleo-topographic features. Lash and Engelder (2011) and Kohl et al. (2014) observed that the two third-order sequence interpretation is not observed in the southeast Pennsylvania and northwest West Virginia portion of the Appalachian basin.

Marcellus Formation petrophysical studies from well log, core and outcrop data establish a well-defined relationship between high gamma-ray values and high total organic carbon (TOC) content determined from geochemical analysis (i.e., Schmoker, 1981; Boyce, 2010; Wang and Carr, 2013; Kohl et al., 2014). TOC values range between 5% to 20% and relative higher values correlate to high gamma-ray "peaks" (Swanson, 1960; Schmoker, 1981; Boyce, 2010; Wang and Carr, 2013; Kohl et al., 2014). Wang and Carr (2013) report that the most abundant minerals in the Marcellus Formation are quartz (average of 35% by volume) and illite (average of 25% by volume), with variable amounts of chlorite, pyrite, calcite, dolomite, plagioclase, K-feldspar, kaolinite, mixed layers of illite/smectite, and apatite. Boyce (2010) states that portions of the Marcellus contain up to 67% quartz by volume. Modeled clay mineralogy from petrophysical studies generally increases upward through the Marcellus Formation, from approximately 5% above the Onondaga Formation top to nearly 50% at the Marcellus Formation top (Wang and Carr, 2013).

Using the Kohl et al. (2014) nomenclature and results, TOC decreases, thorium-bearing clay content increases, and the terrigenous silt fraction also increases in the portion of the formation above the high-gamma/TOC/uranium shale of the Union Springs member. Throughout the Union Springs member, $CaCO_3$ content ranges between 0% and 20% and generally occurs as thin, fossil-rich beds or layers of concretions (Kohl et al., 2014). Blood et al. (2013) demonstrate that the late transgressive to early regressive Marcellus systems tracts become enriched in biogenic silica. The lower portion of the Union Springs member is typically the horizontal drilling target due to its high TOC/low clay/high silica content, as it has superb reservoir quality and a high rate-of-penetration (ROP) during drilling operations. However, the thin $CaCO_3$ rich concretion layers noted by Kohl et al. (2014) drastically slow drilling operations in this portion of the Marcellus.

*Rome trough*

The Rome trough (Figure 2) is a northeast-southwest trending graben in the Appalachian basin that initially formed during Early and Middle Cambrian rifting associated with the opening and spreading of the Iapetus Ocean and has been re-activated numerous times throughout the Paleozoic (Woodward, 1961; Harris, 1978; Shumaker and Wilson, 1996; Gao et al., 2000; Baranoski et al., 2007). Over the past 50 years, geologists have studied the complex structural architecture of the trough in order to understand hydrocarbon generation and entrapment and the tectonic evolution of the Appalachian foreland basin (Woodward, 1961; Dominic et al., 1996; Beardsley, 1997; Ryder et al., 1997). Gao et al. (2000) examined along-axis segmentation and growth history of the Rome trough in the Cambrian through Pennsylvanian and divided the trough into three segments based on subsurface and geophysical data: 1) an eastern Kentucky section, 2) the southern West Virginia section, and 3) the northern West Virginia/Pennsylvania section.

Sub-segments within each of the three segments have varying reactivation histories (Dominic et al., 1996). Subsurface evaluation and mapping suggest that Rome trough faults were less active from the Late Ordovician to Pennsylvanian, and relatively low-relief inversion structures are hypothesized to have formed periodically as the foreland basin developed throughout the Paleozoic (Gao et al., 2000). Gao et al. (2000) also used seismic data to illustrate gross thickness variations in Acadian-aged sediment packages between the southern and northern West Virginia segments. Lash and Engelder (2011) observe local variations in Marcellus Formation transgression/regression cycles in the western, more distal areas of the Appalachian basin within the Rome trough just north of the study area, which may reflect influence of basement structures and northwest-striking cross-structural discontinuities that formed or were reactivated during Acadian plate convergence.

*Joints, Fractures, Stress, and Production*

Engelder et al. (2009) describe two regional joint sets, J1 and J2, which are observed in Middle to Upper Devonian Appalachian basin black shale outcrops and subsurface data (Figure 4). It is hypothesized that both joint sets formed near peak burial depths when natural fractures developed as the thermal maturation of organic matter induced high fluid pressures in the shales. The orientations of both joint sets vary slightly throughout the basin, with the J1 set oriented in a more W-E direction and the J2 set oriented NW-SE (Figure 4). When present together, the older J1 set is crosscut by the younger, more pervasive J2 set.

It is by coincidence that the J1 joint set orientation is nearly parallel to the maximum contemporary tectonic stress field. Most unconventional Marcellus Formation well units are oriented in a NW-SE manner so the reservoir stimulation efforts can utilize the contemporary tectonic stress field, as well as the pre-existing joint sets, in order to maximize hydraulic fracturing efforts. It is hypothesized that this orientation benefits well planning and hydraulic stimulation efforts in the Marcellus Formation by effectively draining both joint sets, as the horizontal wells crosscut the J1 joints and the planned stimulations crosscut the J2 joints (Engelder et al., 2009). Outcrop observations show that J1 and J2 joints are open at the surface, but core collected from the Eastern Gas Shale Project show that relatively deep wells drilled through the Devonian shales in Pennsylvania and West Virginia have some mineralized veins. Healed joints may cause completion operational issues if they serve as barriers to fluid flow (Engelder et al., 2009).

Seismic waves have been used to determine subsurface fracture orientation and intensity. Particular to the Marcellus, Far and Hardage (2014) studied fractures and stress anisotropy in the Marcellus Formation by using multicomponent seismic data, concluding that PS-waves provide the most precise information regarding the location, orientation, and intensity of natural fractures and stress anisotropy; regional stress is the main cause in velocity anisotropy (interpreted to be variations of joint orientations); and amplitude variations are useful for fracture studies. Inks et al. (2014) analyzed Marcellus fractures using seismic volume azimuthal attributes and concluded that J2 azimuths are dominant in areas with higher estimated ultimate recovery (EUR) wells, which may be attributed to higher gas generation and longer joint length, and areas with lower EUR wells have a more dominate J1 trend or a scattered azimuthal trend.

Elsaig et al. (2017) conducted laboratory experiments on Marcellus Formation core plugs obtained from a study area in north-central West Virginia in order to investigate the impact of stress on porosity and permeability. This investigation found that both permeability and to a lesser extent porosity decrease with the increase of net stress. Schlanser et al. (2016) used a statistical clustering algorithm on twelve Marcellus Formation petrophysical logs to distinguish five shale lithofacies based on mineralogy, organic content, and brittleness. This study concluded that organic richness and the ability to create/maintain a hydraulic fracture, as determined by rock brittleness, are important geologic factors when considering hydrocarbon production potential. In order to assess unconventional production trends on a field-scale, Carpenter (2017) established that 90-day initial gas production is needed to accurately predict of long-term production trends, and Ifejika et al. (2017) state that initial production should exceed 180 days in order to be a reliable indicator of well performance.

*Study area*

The study area is an unconventional Marcellus Formation field in the Rome trough area of Ritchie County, West Virginia (Figures 2 and 4). This field does not have 2D/3D seismic surveys or core and contains 28 numerically-labeled, horizontal wells and two vertical wells (Figure 4). In the study area, the Marcellus Formation is relatively thin (59 to 63 feet thick; 18 to 19 meters) and more lithologically variable compared to wells flanking the Rome trough (i.e., 81 feet/25 meters in the 1 Avanti well, Figures 2 and 3).

The horizontal wells are oriented in a NW-SE direction in order to be parallel to the maximum contemporary tectonic stress, and the horizontal portion of the wellbores were targeted to be drilled in the section of the Marcellus with highest gamma-ray values (Figures 3, 4 and 6). The thickness of the Marcellus Formation increases by four feet (1.2 meters, 7% increase) between the Pen 1 and Hall 2 vertical wells in the field, and 90% of this increase occurs within the upper half of the formation. The Onondaga Formation contour map (constructed from geosteering interpretations; Figure 4) shows that the overall orientation of the field is approximately N10ºE, 0.3ºSE. A small anticline is encountered in the southern wells, and a left-lateral strike-slip fault is mapped (Figure 4). The width of the feature is approximately 1,200 feet (366 m), with 2 to 10 feet (0.6 to 3 meters) of vertical offset. The lateral extent and depth of the feature is unknown, as adjacent subsurface data to the north or south of the study area is not available, and seismic surveys do not exist to provide depth constraints. This strike-slip fault is oriented in a similar fashion to the cross-structural discontinuities described by Lash and Engelder (2011).

Drilling depth of the horizontal wells range from approximately -5,110 subsea feet true vertical depth (SSTVD; 1,560 meters) to -5,260 feet SSTVD (-1,600 meters), and horizontal well lengths range from approximately 5,500 feet (1,680 meters) to 10,970 feet (3,340 meters; Table

1). Average spacing between these horizontal wells is consistently 500 feet (152 meters). A "slick-water plug and perf" completion technique was designed, for which a volume of water and other additives were used to fracture the well after perforation, and proppant was then mixed with the fluid to keep the new fractures from collapsing. To date, only 16 of the 28 wells have been completed and produced for at least 15 days (Table 1; Figure 4).

## METHODOLOGY

A comprehensive workflow was developed that integrates drilling, completion, production, and geologic data into a geocellular model, which is illustrated in Figure 5. Though this specific study is focused on emphasizing the value of constructing geocellular models for a field with sparse data, additional data sets not used available for the field area (i.e., core, seismic, geomechanics, petrophysics) are also represented in the workflow. Prior to drilling, the stratigraphy in the vertical well logs within and surrounding the study area was interpreted. The stratigraphically and structurally-framed geocellular model was updated with data collected during drilling and completion operations. Gamma-ray log API values from the unconventional wells were normalized, upscaled, and geostatistically distributed throughout the model volume with a Gaussian random function simulation. Following drilling activity, a completion schedule was developed, which defined stage length, cluster spacing, water volume, chemical additives, and proppant volume to be delivered per stage, among other parameters, and completion operations began in the easternmost wells and progressed westward. For each well, "toe" (end of well) stages were completed first, and completion activity progressed toward the "heel" (below the curve). During flowback for all completed wells, chokes were increased in 1/64 or 2/64 inch increments from an initial choke range of 14/64 to 15/64 inch to a final choke range of 23/64 to 25/65 inch, and recovered fracture fluid recovered ranged between 21% to 25%. Completion results (actual stage locations, treating pressures, normalized proppant delivered per stage) were immediately incorporated into the geocellular model, and completion issues, such as screen-outs and re-perforations, were mapped at the respective stages. As new data was acquired, it was added to the model and incorporated into the geostatistical distribution (Figure 5). Logistical changes in the completion schedule caused operations to move away from the study area before all of the drilled wells were completed. The completed wells were put on flowback, and normalized 15-day cumulative production results were incorporated into the model.

**Stratigraphic analysis**

Historically, the Marcellus Formation has been broken into two third-order stratigraphic sequences (i.e., Lash and Engelder, 2011; Kohl et al., 2014), but initial analysis of the study area shows that this stratigraphic framework does not extend throughout the Rome trough portion of the Appalachian basin. Vertical well logs in the study area suggest that the Marcellus Formation may have three third-order stratigraphic sequences; Sequence 1 (S1, which includes the Onondaga), Sequence 2 (S2), and Sequence 3 (S3; Figure 3). The wells logs do not have a ‘repeated section’ created by faulting. Each of the three sequences is further divided into lowstand (LST), transgressive (TST), and highstand (HST) systems tracts. It was necessary to differentiate between S1 LST, S2 LST, and S3 LST during operations in order to drill in the pre-defined target by recognizing that similar, low gamma-ray API log values may be associated with any of the three LST’s. Though this is an important observation and work continues to further understand Marcellus Formation Rome trough stratigraphy, the focus of this study is to develop and utilize a geocellular model construction methodology in a field with little data in order to study completion trends in different systems tracts throughout an unconventional field, and the model stratigraphic framework must be initially discussed in order to describe the workflow used to build the model.

The two vertical wells in the study area were normalized to a 0 to 600 gamma-ray API scale, which was comparable to the real-time measuring-while-drilling (MWD) gamma-ray API values recorded by logging tools during drilling operations. The normalized gamma-ray API values reported in this section are from the Hall 2 type log (Figures 3 and 6). S1 LST (gamma-ray < 100 API) occurs in the underlying Onondaga Formation, and S1 TST extends upwards to the base of a maximum flooding surface (MFS1). The base of S2 HST occurs at MFS1, which is picked where the gamma-ray peak is approximately 310 API, and this systems tract extends upward to the lowest gamma-ray values of the entire Marcellus Formation, which are in S2 LST (~130 API). S2 TST extends to the base of MFS2, which is the highest Marcellus gamma-ray API peak (>570 API) in the study area. S2 HST extends upward to S3 LST, which has the second lowest Marcellus gamma-ray values at 150 API, and S3 TST overlies S3 LST. The gamma-ray peak that is approximately 470 API is interpreted to be MFS3 and is at the base of S3 HST, which extends upward to the bottom of the Stafford Limestone (Figure 3).

**Drilling target, completion operations and issues, and production**

A ten-foot thick interval that consists of the entire S2 TST thickness and the high gamma-ray API MFS2 (base of S2 HST) was the drilling target for all of the horizontal wells in the study area (Figures 3 and 6). This target interval was picked during the field planning phase due to the superior reservoir quality (up to 19% TOC and low clay content), relatively high drilling speeds noted within this interval in a nearby field (approximately 510-700 feet (155-213 meters)/hour ROP compared to less than 250 feet (76 meters)/hour ROP in S2 LST and S2 HST), and high gamma-ray API signature, making it an obvious target to follow for geosteering interpretations during drilling operations. Real-time vertical geosteering cross sections were continuously generated by correlating MWD gamma-ray data with the vertical Hall 2 type log, and the interpretations were examined and quality control-checked (Figure 6).

Of the 28 drilled horizontal Marcellus Formation wells in the study area, sixteen wells were completed with a total of 544 "slick-water plug and perf" stages (Wells 1-7 and Wells 14-22; Table 1; Figure 4). Initially, the western wells in the field were not completed due to logistical changes in the completion schedule, and they currently have yet to be completed. For the completed wells, normal stage spacing was 150 feet (45 meters) with perf cluster spacing of 50 feet (15 meters), and three wells were completed with a reduced cluster spacing (RCS) of 30 feet (9 meters) and stage spacing of 75 feet (23 meters; Wells 3, 15, and 17; Table 1; Figure 4). Ten of the completed wells were fractured with a proppant schedule of 1,650 lbs/lateral foot (Wells 1, 2, 3, 4, 5, 14, 16, 17, 18, and 20) and six wells were fractured with an 1,800 lbs/lateral foot schedule (Wells 6, 7, 15, 19, 21, 22; Table 1; Figure 4).

The 544 completed stages were mapped along the horizontal portion of the wells, and stages with particular completion issues were highlighted (Figure 4). The completed stages were divided into four groups: 1) stages that had no completion issues, 2) stages that experienced screen-outs, 3) stages that were re-perforated and, after which, accepted more than 95% of the scheduled proppant, and 4) stages that were re-perforated and then accepted less than 95% of the scheduled proppant. The 95% proppant cut-off was subjectively defined by completion engineers, for which re-perforated stages accepting >95% of proppant were categorized as a 'successful re-perforation', and those accepting <95% were classified as an 'unsuccessful re-perforation'. The screen-out and re-perforated stages were assigned as having a "completion issue" (Table 1; Figures 4, 9, and 10).

The locations of completion issue stages were then visually examined to determine if trends existed. This again was a subjective exercise, so a set of criteria was developed to aid with the mapping. A hypothesis that mineralogical variations within the stratigraphy and/or mineralized joint sets may cause completion issues was proposed. After an initial visual inspection, it appeared that some of the completion issues stages had a systematic orientation, and straight lines were drawn to connect stages with either screen-outs or re-perforations (Figure 4). In order to map these lines, problem stages occurred in at least three adjacent wells, and the line connecting the problem stages had an orientation within a 15° range of either the local J1 or J2 orientation reported by Engelder et al. (2009; Figure 4). The stratigraphic positions of problem stages were also recorded.

Of the 16 completed wells, all wells were produced between 15 and 28 days, and as such, 15 days is the only common production period among the 16 completed wells. Fifteen-day cumulative gas production results were normalized to thousands of cubic feet equivalent per lateral foot of the horizontal portion of the well (15-day cumulative production MCFE/foot), which accounts for the range of lateral lengths (Table 1, Figure 4). Unfortunately, this relatively short production time period is not long enough to be used to study production trends (see Introduction and Discussion sections), and when available, longer production time periods will be imported into the model. For each stage, treating pressures and proppant volumes were recorded, and the proppant volumes delivered per stage were normalized to pounds of proppant per lateral stage foot in order to account for various stage lengths (Figures 4, 9, and 10).

**Geocellular model construction**

Seismic and core data are not available at or near the study area, which is often a critical input for geocellular model construction, and the lack of this data made it necessary for the geocellular model to be generated from geosteering interpretations. The 28 horizontal well trajectories (x, y, and z coordinates) and two vertical wells were imported into geocellular modeling software. In order to build a model that incorporates geologic and engineering data, the horizontal well geosteering interpretations for the Tully, Hamilton, Marcellus, and Onondaga Formations, as well as all of the three Marcellus Formation sequence tops and the S2 system tract and drilling target tops, were imported into the software (Figures 5, 6, and 7; Table 2). The above tops from the two vertical wells were also imported. A model boundary was defined around the field, and formation and sequence/system tract top surfaces were generated using the horizontal and vertical well interpretations. Unfortunately, due to operational time constraints, detailed petrophysical analysis was not performed on the vertical wells prior to operations. Geosteering cross sections and model cross sections for each well were compared to ensure that the model depicted the final geosteering interpretation. Figure 4 displays the Onondaga Formation top contour surface generated from the vertical and horizontal data, and Figure 6 illustrates an example of the agreement between the geocellular model surfaces and the horizontal geosteering cross section interpretation.

The Burket, Tully, and Mahantango Formations were each divided into five layers with various thicknesses, and this portion of the model will not be discussed in detail as there is no horizontal completion data from these formations. Table 2 displays the layering used within the Marcellus Formation, which was divided into a total of 57 layers. All of the completed stages are located in S2, so the individual systems tracts/drilling target intervals for this sequence were layered. A geostatistical analysis that determined the average thickness over which the vertical well log data significantly varies was used to quantify the thickness of model layers needed within each Marcellus sequence, the drilling target interval (S2 TST/MFS2), the upper portion of

S2 HST above the target, and S2 LST (Table 2; Figure 7). Within S2, S2 LST was divided into three one-foot-thick (0.3 meters) layers, the target was divided into ten 0.8-foot-thick (0.2 meters) layers, and upper S2 HST above the target was divided into twelve 1.2-feet-thick (0.4 meters) layers. The total model volume was then divided into $2.52 \times 10^7$ three dimensional cells by using the above layer thicknesses and a 50 feet by 50 feet (15 meters by 15 meters) surface area for each cell (Table 2; Figure 7).

Normalized gamma-ray log API data from the Hall 2 and Penn 1 vertical wells and the horizontal wells were arithmetically upscaled to the defined model layers (Figure 7A). For each stage, treating pressures and normalized proppant delivered were also arithmetically upscaled. Spherical, exponential, and Gaussian variograms were created for the gamma, treating pressure, and proppant in order to quantitatively describe geologic/engineering data variation as a function of separation distance between the data points. Due to the relatively small area and lack of well log variability between the two vertical well logs, directional, horizontal exponential variograms with a major range of 50, a minor range of 25, a vertical range of 1, a sill of 1, and a nugget of 0.01 were used. The major direction for these variograms was N45°E (the average regional structural orientation of this portion of the basin; Figures 7C and 8) for the distribution of gamma, treating pressure, and proppant distribution in all Marcellus layers (Figures 5, 7, 8, 9, and 10).

Data from all 544 completed horizontal stages were used for treating pressure distribution. Wells with a 1,650 lbs/foot proppant delivery schedule (Wells 1, 2, 3, 4, 5, 14, 16,17,18, and 20) were used for proppant distribution, and the wells with 1,800 lbs/lateral foot proppant schedule were purposefully excluded from the distribution, as they were initially scheduled to have a higher proppant volume (Table 1; Figure 10). The upscaled data was then distributed throughout all cells in the model volume. Several deterministic and stochastic geostatistical distribution methods were analyzed to simulate the gamma and completion data throughout the model volume, and stochastic Gaussian random function simulations (GRFS) were ultimately used for this case study (Pyrcz and Deutsch, 2014). A total of ten realizations were generated by GRFS for gamma, treating pressure (DTP) and delivered proppant (DNPD) distributions, and the histograms and mapped results from two of these ten realizations (realizations 1 and 10) are shown in Figures 8, 9, and 10. Wells 11, 12, 13, 25, 26, 27, and 28 were not included in the model volume due to the relatively far distance from wells with completion data and lack of data to the west of the strike-slip fault.

## RESULTS

### Geocellular model

Careful inspection of the model determined that 100% of the horizontal wellbores are located in the exact stratigraphic position noted in the final geosteering interpretations, and all mapped completed stages are also in the appropriate stratigraphic interval (Figure 6). Histograms for one normalized gamma-ray API distribution simulation and two of the ten treating pressure and proppant realizations (realizations 1 and 10) are displayed in Figures 7C and 8 and show that the distributed values represent the actual data collected from the wellbores and the geologic trend within the Rome trough. These results indicate that the geostatistical methods used to distribute the data throughout the model volume were geologically reasonable, and the model results reflect the actual distribution of data collected from the wells, as well as structure/stratigraphy of the field. However, distributed values outside of the completed well paths (i.e., values at Wells 8-10 and 23-24) are predicted values based on the geostatistical distribution associated with the recorded completion data. As 15-day cumulative production is not an adequate time period to analyze field-wide production trends (Carpenter, 2017; Ifejika et al., 2017), a thorough analysis of the current production results will not be presented in this paper. However, possible factors to be considered when studying longer interval production are addressed in the "Discussion" section.

**Drilling trends and mapped completion issues**

Wells located within the strike-slip fault as delineated by the Onondaga contours (Wells 9, 10, 11, 23, 24, and 25) all had lower ROP's while drilling in the S2 TST/MFS2 target. These wells had an average ROP of 160 feet (49 meters)/hour compared to an average of 540 feet (165 meters)/hour for wells outside of the fault drilled in the target. These ROP's do not include 'sliding' time taken to re-orientate the well in order to keep the drill bit within the geologic target. "Dogleg severity" measures the change in the inclination and/or azimuth of a borehole, is expressed in degrees/100 feet of measured depth, and was recorded during drilling operations. Each well within the strike-slip fault experienced at least five "doglegs" in excess of 6°/100 feet and one dogleg in excess of 10°/100 feet, though the orientation of the doglegs was not consistent. Dogleg severity did not exceed 6°/100 feet in wells outside of the fault zone.

S2 contained 100% of all 544 completed stages, and within S2, 88% (478) completed stages are in the within the S2 TST/MFS2 drilling target, 8% (44 stages) are in the upper portion of S2 HST above the drilling target, and 4% (22 stages) are in S2 LST. Well 4 has the largest number of completed stages (eight) located within the portion of S2 HST above the target, and Wells 6, 14, 17, 18, 20, and 21 do not have any stages in the upper S2 HST (Figure 9). Well 18 has the most stages (three) within S2 LST, and Wells 1, 2, 4, 6, 15, 16, 19, 20, 21 do not have any stage within this systems tract (Figure 9). Of the 544 stages, 476 stages (88%) experienced no completion issue, 30 stages (5%) experienced screen-outs, 21 stages (4%) were re-perforated and after which accepted more than 95% of the scheduled proppant, and 17 stages (3%) accepted less than 95% of the scheduled proppant after being re-perforated.

Visually mapping completion issues approximately parallel to the J2 direction was not possible, as the wellbores were drilled nearly parallel to this orientation. Five completion issue trends, A-E, were mapped and are approximately parallel to the J1 orientation (Figure 4). The northernmost Trend A is mapped in Wells 3, 4, 5, 6, and 7 and has a slightly more W-E oriented than the local J1 orientation mapped by Engelder et al. (2009), varying from the J1 orientation by 10°. Trend A extends farthest to the west compared to the other completion issue trends, and because Well 8 has not been completed, the western extent of this trend is unknown. Trend B occurs in Wells 1, 2, and 3 and has nearly the same orientation as Trend A. The eastern extent of Trend B is unknown due to lack of data east of Well 1. Trend C occurs in Wells 2, 3, 4, 5, and 6, has the same orientation as Trends A and B, and both the western and eastern extents of this completion trend can be defined within the completed horizontal portion of the intersecting wells. Trend D is mapped in up-dip Well 4 and down-dip Wells 19, 20, and 21, and varies from the J1 orientation by 14°, as it is more east-west oriented. The eastern limit of Trend D is not known, as the trend projects into the curved and vertical portions of Wells 3 and 16, and these sections of the wellbores were intentionally not completed. Trend E is the southernmost completion issue trend mapped in Wells 14, 15, 16, 17, and 18 and has the exact orientation as the local J1 joint set. Trend E is mapped in the easternmost down-dip Well 14, so the eastern extent of this trend is unknown. From a stratigraphic perspective, 77% of all screen-outs and re-perforations occurred in the high gamma MFS2 portion of the drilling target, where gamma-ray

API values range between 400-576 API, 15% occur in the relatively lower gamma portion of the drilling target, 4% occur in the upper S2 HST, and 4% occur in S2 LST.

**Distributed treating pressures (DTP)**

Figure 8 shows the variograms used to distribute treating pressures, as well as the histograms comparing the actual treating pressure data and the DTP model values for two of the ten model realizations (realizations 1 and 10). For each of the ten realizations, the actual stage data and model data closely mirror each other, illustrating that the model distribution method represents the data, and the mean, median, and standard deviations for each realization did not vary by more than 1.85%, 1.25% and 1.17%, respectively (Figure 8). Distributed treating pressure (DTP's) model results for realizations 1 and 10 in the upper S2 HST, the drilling target, and S2 LST are displayed in Figure 9. For all ten DTP and DNPD realizations, the greatest variation in model results occurred away from data points in the each of the three model zones presented (i.e., to the north, east, and west of the completed stages in the respective zone).

The upper S2 HST hosts 8% of the completed stages (Figures 9A and 9D). For both realizations 1 and 10, the lowest DTP's in this systems tract occur in the eastern, down-dip wells (Wells 14, 15, 16, 17, and 18), with pressures ranging from 6,020-6,760 psi. Upper S2 HST DTP's steadily increase from the heels to toes in the eastern up-dip well in all realizations (Wells 1-5), but this pattern is not observed in the down-dip wells. Treating pressures consistently increase northwestward throughout the field in all realizations, with the highest treating pressures (up to 8,970 psi) in the four western up-dip wells (4, 5, 6, and 7). In S2 HST, all realizations show that treating pressure distributions vary most significantly to the north of Wells 1, 2 and 3. Realization 1 has a treating pressure high north of Wells 1 and 2, and realization 10 has a high to the north of Well 3 (Figures 9A and 9D).

The drilling target contains 88% of all stages, and thus has the most robust treating pressure and proppant data set (Figures 9B, 9E ,10B, and 10E). Realizations 1 through 10 within the drilling target show that DTP's increase to the northwest portion of the field (up to 9,010 psi; Figures 9B and 9E). The lowest DTP's for all realizations are between 6,030-6,250 psi and located at the heels of the easternmost up-dip and down-dip wells (Wells 1, 2, 14, 15, and 16). DTP's of both the up-dip and down-dip eastern wells generally increase toward the toe, with heel stage DTP's ranging from 6,010-8,010 psi and toe stages ranging from 7,530-8,020 psi. A low DTP area (7,250-7,500 psi) occurs at the heels of the westernmost completed northbound Wells 5, 6, and 7, though the shape of this low is slightly different in all realizations. In general, the ten realizations did not drastically differ aside from the area to the north of the up-dip wells (Figures 9B and 9E).

Only 4% of completed stages are located in S2 LST (Figures 9C and 9F), and the DTP's in all ten realizations in this systems tract do not follow the consistent northwestward/westward increase trend observed in the upper S2 HST and the drilling target realizations. The distributed treating pressures range between 7,230-8,540 psi, except for one stage in the western south-bound Well 22 that has a treating pressure of 8,910 psi. This particular stage is in the very bottom portion of S2 LST, which has the lowest gamma values within S2. The ten model realizations had the most significant variation in this stratigraphic interval, and the DTP patterns to the north and east of the up-dip wells and the relatively high DTP area at Wells 23 and 24 have the most disparity among the realizations (Figures 9C and 9F).

Examining DTP trends for each well in a heel-to-toe fashion suggests that a consistent trend does not occur in the upper S2 HST and S2 LST for all ten realizations (Figures 9A, 9C, 9D, and 9E). In the upper S2 HST, the eastern up-dip Wells 1, 2, 3, 4, and 5 have higher DTP's at the toes, and the western up-dip Wells 6 and 7 have lower DTP's at the toes. Upper S2 HST down-dip Wells 19, 20, 21, and 22 have higher DTP's at the heels; Wells 16, 17, and 18 have slightly higher toe DTP's; and DTP's are fairly consistent throughout Wells 14 and 15 (Figures 9A and 9D). Up-dip drilling target DTP's increase toward the toe in completed Wells 1-7, and down-dip well DTP's (Wells 14-22) increase more gradually toward the toes (Figures 9B and 9E). There is no statistical correlation on a field-level relating heel-to-toe SSTVD elevation changes and drilling target treating pressure variations between the heel and toe stages. As previously mentioned, the S2 LST values are generally lower and more consistent compared to DTP values in S2 HST and the drilling target, and there is not an obvious toe/heel DTP trend in this systems tract, except in down-dip Wells 19-22, which have a gradual increase toward the toes (Figures 9C and 9F).

**Distributed normalized proppant delivered (DNPD)**

Figure 8 shows the variograms used and realization 1 and 10 histogram results for DNPD, and Figure 10 displays DNPD maps for realizations 1 and 10 for the upper S2 HST, the drilling target, and S2 LST (not including the 1,800 lb/ft schedule wells). The mean, median, and standard deviations for each realization did not vary by more than 1.91%, 1.19% and 2.02%, respectively (Figure 8). The upper S2 HST, the drilling target, and S2 LST correspondingly contain 8% (28 stages), 88% (317 stages), and 4% (15 stages) of the 1,650 lbs/ft completed stages (360 total stages). A comparison of all DNPD realizations (realizations 1 and 10 shown in Figure 10) show a similar result to that observed in the treating pressure realizations. For all stratigraphic intervals, patterns to the north of the up-dip wells and the west of Wells 5 and 20 vary the most among realizations, with the S2 LST patterns show the greatest disparity (Figures 10A-F). The upper S2 HST (Figures 10A and 10D) and the drilling target (Figures 10B an 10E) have similar DNPD trends, gradually increasing from the heels to the toes in both the up-dip and down-dip wells, although the upper S2 HST DNPD values are generally lower and less variable than the drilling target. For all ten realizations, the upper S2 HST heel DNPD values range between 1,350 to 1,650 lbs/ft, the up-dip toes do not exceed 2,210 lbs/ft, and the down-dip toes do not exceed 1,610 lbs/ft (Figures 10A and 10D). DNPD values at the heels of the drilling target up-dip wells range between 1,410-1,560 psi/ft, the toes of the up-dip wells increase to 2,440 lbs/ft, and the toes of the down-dip wells have DNPD values up to 2,200 lbs/ft. The red bullseye in the middle of the drilling target up-dip wells (2,490 lbs/ft) is located where stages within adjacent Wells 3, 4, and 5 were re-perforated, with Well 4 having three adjacent re-perforated stages (Figures 10B and 10E). S2 LST has the opposite trend, with DNPD values generally increasing from the toes of the up-dip wells (1,360 to 2,010 lbs/ft) to the toes of the down-dip wells (1,410 to 2,560 lbs/ft; Figures 10C and 10F).

## DISCUSSION

### Geocellular model

A primary goal of this study is to emphasize that precise geologic models can be built for fields with sparse data. However, additional data sets, such as seismic, core, stress, strength, pore pressure, ROP, and 90/180 day production, can be integrated into this model workflow in order to provide valuable information regarding the relationships among robust geology, production, drilling, and completion data sets (Figure 5). It is critically important for the horizontal well paths and completion stages to be in the correct model layer in order for gamma and completion data to be correctly distributed throughout the model, and the model geologic structure must be 'real' and not a misinterpretation of well logs or geosteering data. This agreement, as displayed in Figure 6, is imperative when building a predictive model (Figures 9 and 10). Numerous geostatistical techniques were explored in this study, and it must be acknowledged that though the structural and stratigraphic framework used for the geologic model construction remains constant, the variograms are just one possible input into the GRFS, and each GRFS distribution iteration is a single realization used to fill the model volume. Other distribution techniques, such as kriging, will produce different results. The GRFS simulation creates the most geologically reasonable results for a gradational shale reservoir with fine-scale heterogeneity (i.e., the distributed data histograms match histograms of the actual data; Figures 7, 8, 9, and 10) and the model data typically show a gradational variation rather than abrupt or isolated patterns when constrained by data. The spatial correlation represented by the variograms, the agreement of gamma log and completion data upscaling, the histograms comparing actual data and distributed data (Figures 7C and 8), and the similar mean/median/standard deviation values from all ten treating pressure and proppant realizations provide evidence that the well data match the distributed model data. A total of ten GRFS simulation results were generated, which represent ten possible distributions for the field, and only two realization maps for both DTP and DNPD are shown in Figures 9 and 10. Based on the precise model construction and gradational pattern of the distributed data, it is concluded that the DTP and DNPD model results can be used to characterize changes in completion variables throughout the field and among the stratigraphic model layers when constrained by data, but both DTP and DPND realizations show the greatest variation to the north and west of the field where the model cells are relatively far from actual data points (Figures 9 and 10).

**Stratigraphic analysis**

The Marcellus Formation stratigraphy recorded in the Hall 2 and Pen 1 wells is thinner and more variable than that observed in the 1 Avanti well to the east of the Rome trough (Figures

2 and 3). Only these three vertical wells were examined for this study, and the observation cannot be extended beyond the wells in Figure 3. Due to the location of the study area in the Rome trough, it is possible that Middle Devonian trough reactivation and/or remnant subsidence may have allowed for a more complete depositional record to develop in portions of the trough, while low-relief inversion structures may have created sediment-starved areas. Additional well logs near the study area are currently being studied to provide further insight regarding the trough stratigraphy. However, stratigraphic analysis is not the focus of this study, and speculation as to the cause of distinct stratigraphic signature will not be discussed further than it provided a model stratigraphic framework that is different than that reported by Lash and Engelder (2011) and Kohl et al. (2014).

**Drilling, production, and mapped completion issue trends**

The relatively low ROP's and high angled doglegs recorded in wells located within the strike-slip fault (Wells 9, 10, 11, 23, 24, and 25) suggest that the fault affects the local stress field. The geologic drilling target was the same for all wells, and the MWD gamma data closely match the type log, so it is interpreted that Marcellus S2 lithology is relatively laterally continuous throughout the field. Based on this interpretation and successfully drilling in the target interval, the drilling difficulty experienced throughout the entire length of wells within the fault cannot be attributed to lithologic variations. The lack of seismic data did not allow geologists to identify the structure existence until drilling was completed.

Numerous geologic and engineering factors may affect well production, and 15-day cumulative production is too short a period to analyze for production trends, as 90 or 180-day production is needed to predict field-wide patterns (Carpenter, 2017; Ifejika et al., 2017). Unfortunately, 15-day cumulative production is the only production time period common among all wells, and a longer production interval of at least 90 days should replace the reported production in order to make more robust conclusions regarding field wide production trends. Factors to consider when analyzing normalized 90-day (or longer) production on a field scale are: 1) reservoir quality, thickness, and pressure, 2) stratigraphic target interval, 3) percentage of wellbore within the target, 4) up-dip or down-dip well placement, 5) geologic structure of the field, 6) fracture orientation and intensity, 7) completion schedule, and 8) number of completion issues per well.

It is important to emphasis that mapping the completion issues was an extremely subjective exercise, and additional data, such as three dimensional seismic surveys, core, and image logs, would add significant insight regarding the fracture nature (i.e., open or closed) and fracture network trends and intensity (Wilson et al., 2015). Well proximity to the strike-slip fault does not affect the number of completion issues per well. Factors such as insufficient induced fracture growth, near wellbore fracture plane tortuosity, or fluid leak-off from an induced fracture into the natural fracture system may also cause completion issues (Tamagawa and Watanabe, 2016).

If the completion issues do indeed coincide with the J1 orientation, a possible cause for screen-outs and re-perforations is that the J1 joints are healed in the subsurface. Engelder et al. (2009) observed healed joints in foreland-located cores where the Marcellus Formation is relatively deep (i.e., depths greater than 7,000 feet/2,134 meters, which is approximately 1,000 feet/305 meters deeper than Marcellus measured depths in this study). Veins can form fluid flow barriers, which in turn may cause screen-outs or re-perforations. However, the completion issue trends are not as pervasive as the J1 joint set described by Engelder et al. (2009), and there is no evidence that the J1 joint set is actually found in the subsurface of this field, as core was not collected. The localized completion issue trends do not coincide with DTP patterns, but Trends A, B, and C are mapped where DNPD is relatively high (Figures10B and 10E). This is expected, as Trends A, B, and C are a combination of screen-out and re-perforated stages, which typically use more fluid/proppant to ultimately fracture the stage.

It must be noted that completion issues may be related to mineralogical changes within the individual systems tracts. Geologic layers with mineralogical variability too thin (< 0.5 feet/0.15 meters thick) to be detected by the logging tool resolution may cause operational issues. Often times screen-outs occur in intervals with increased clay content, which are more ductile and less 'fracable' than the more brittle quartz or carbonate rich zones (Lecampion et al., 2015). For the drilling target, 77% of all screen-outs and re-perforations occurred where the gamma values are highest, ranging between 400-576 API, which is not a zone with high clay content (Wang and Carr, 2013; Kohl et al., 2014), so mineralogical variability is not an obvious cause for completion issues.

**Distributed treating pressures (DTP)**

The unequal distribution of completed stages throughout the S2 systems tracts displays the successful geosteering in the S2 TST/MFS2 drilling target, which has 88% of all completed stages. However, this accomplishment does not offer a robust completion data set for the upper S2 HST and S2 LST (Figures 9A, 9C, 9D, 9F, 10A, 10C, 10D, and 10F). Despite the unequal distribution, treating pressure trend interpretations in the upper S2 HST and S2 LST, which have 44 (8%) and 22 (4%) stages respectively, will be discussed. Though all ten realization histograms show that the model distribution represents the recorded data (realizations 1 and 10 shown in Figure 8), DTP model patterns for the three stratigraphic intervals vary most significantly away from data points (i.e, to the north and west in of the completed wells), and the S2 LST distribution patterns had the most disparity, as this systems tract contains only 4% of the completed stages. The difference in S2 LST DTP patterns to the north of the up-dip wells, to the east of Well 1, and to the west of Well 7 statistically represents DTP variations in the recorded data, but model patterns differ as they are relatively far from data points and not constrained by data outside of the field.

For all realizations, both the drilling target and the upper S2 HST DTP's primarily show a distinct and consistent field-wide westward/northwestward increase throughout the completed wells (Figures 9A, 9B, 9D, and 9E), which is likely a direct reflection of the stage proximity to the eastern margin of the strike-slip fault. A hypothesis for this trend is that the stress regime and J1/J2 orientations change within and around the strike-slip fault. This in turn causes the well orientation near and within the fault to be non-orthogonal to the local maximum stress direction, and thus initiating higher treating pressures. Natural permeability may also decrease around the fault as stress increases (Elsaig et al., 2017), which could cause higher treating pressures in that area.

In all realizations, S2 LST does not have a northwestward DTP increase throughout the field (Figures 9C and 9F). This systems tract has the lowest number of completed stages, so the different trend may be partially attributed to lack of data. Well 22 has a completed stage with a relatively high treating pressure in S2 LST, and the stratigraphy in which this stage is located has the lowest gamma values for the entire Marcellus Formation in this study area. Aside from the area surrounding the stage in Well 22, S2 LST DTP's are more constant throughout the model volume. S2 LST has a lower, less variable gamma ray signature and higher density values compared to S2 TST and the upper S2 HST, suggesting that S2 LST has higher carbonate content that causes the rock to be more brittle and fracture with lower treating pressures (Schlanser et al., 2016; Wang and Carr, 2012).

Typically, treating pressures are higher at well toes compared to heels due to the friction created by lowering completion equipment to the end of the wellbore (Lecampion et al., 2015). Realizations 1 through 10 for the upper S2 HST and S2 LST wells do not show a consistent heel-to-toe DTP increase, which may be due to lack of data points and/or the fault affect 'smearing' an underlying heel-to-toe trend (Figures 9A, 9C, 9D, and 9F). The robust drilling target data show a consistent heel-to-toe DTP increase in all of the up-dip wells for all realizations, but only half of the down-dip wells have this pattern (Wells 14, 15, 16 and 17; Figures 9B and 9E). Throughout the field, Wells 18, 19, 20, 21, and 22 have the smallest SSTVD elevation differences between the heels and toes for each well (less than 15 feet/4.5 meters compared to 25 to 80 feet/8 to 24 meters; Figure 4) and do not have the consistent heel-to-toe DTP increase, suggesting that friction has less of an effect on treating pressures for wells that do not have significant elevation changes along the wellbore.

These DTP results indicate that the stratigraphic position of the wellbore, stage location along the wellbore, and proximity to the strike-slip fault may all affect treating pressures needed to fracture the reservoir rock. It is possible that the northwestward increase in DTP's in the upper S2 HST and the drilling target would continue throughout the strike-slip fault and then gradually decrease with distance east of the fault. Faults, fracture intensity associated with fault zones and associated natural permeability, and the variable mineral composition of the Marcellus S2 systems tracts should all be considered when designing well placement and hydraulic fracture stimulations.

**Distributed Normalized Proppant Delivered (DNPD)**

Similar to the treating pressure realizations, all ten DNPD realization histograms show that the model distribution represents the recorded data (realizations 1 and 10 shown in Figures 8D, 8E, and 8F). The DNPD model patterns for the three stratigraphic intervals vary most significantly away from data points (i.e., to the north and west in of the completed wells; Figure 10). The S2 LST distribution patterns again had the most variation, as this systems tract contains only 4% of the 1,650 lbs/ft completed stages (Figures 10C and 10F). The model area with variations in S2 LST DNPD realization patterns is similar to that observed with the DTP realizations (Figures 9C, 9F, 10C, and 10F). For all realizations in the three stratigraphic intervals, model patterns in areas to the north of the up-dip wells, to the east of Well 1, and to the west of Well 7 differ as they are relatively far from data points and not constrained by data, but the areas statistically represent DNPD variations in the recorded data (Figures 10C and 10F).

The DNPD trends show that the localized proppant highs are not affected by proximity to the strike-slip fault in all realizations for each stratigraphic interval (realizations 1 and 10 shown in Figure 10). This suggests that if, in fact, there are fracture swarms within or around the fault, induced fractures created by completion operations are not accessing these swarms. The stratigraphic interval in which the stage is located influences proppant delivered, as both the upper S2 HST and the drilling target have the highest DNPD values at the toes of up-dip wells (Figures 10A, 10B, 0D, and 10E), and DNPD increases southward in S2 LST (Figures 10C and 10F). However, all realizations resulted in a high DNPD in S2 LST at down-dip Wells 19, 20, 21, and 22 that is not constrained by a data point, which may highlight a problem with the data distribution method.

Typically, in horizontal wells, proppant delivered is higher at the well heels than at the toes due to the increased friction with distance traveled causing less proppant placement

(Lecampion et al., 2015). The upper S2 HST and drilling target show the opposite trend (Figures 10A, 10B, 10D, and 10E), which may be attributed to increased fracturing by the higher treating pressures at the well toes allowing for more proppant to be placed at the toe stages. Three areas with relatively high DNPD in the drilling target up-dip wells coincide with completion Trends A, B, and C, and this is an expected result, as stages that experience screen-outs may ultimately use more fluid/proppant volumes for stimulation. Also, if less than 95% of the scheduled proppant was delivered to a re-perforated stage, the undelivered proppant volume is sometimes scheduled to be an additional volume delivered to the subsequent stage completed (added to the planned 1,650 or 1,800 lb/ft schedule). Unfortunately, completion operation field notes detailing this possible proppant volume addition are not available.

**Future Work**

The methodology presented in this study provides valuable insight regarding how to construct an integrated sequence stratigraphic and structurally-framed geocellular model for an unconventional field that lacks seismic and core data. As previously noted, the 15-day cumulative production values are not long enough to rigorously study field production and should be replaced with longer values when available. Additional work must be completed to obtain a more holistic understanding of how the study area geology affects drilling and completion operations.  Blind model testing would eliminate bias experienced by a geologist involved in the exploration, planning, operations, and model construction, and when available, completion data from Wells 8, 9, 10, 23, or 24 it can be used to blind test the model. Other future work could include: collecting/interpreting a 3D seismic survey, core, image logs, and reservoir pressures; petrophysical and geomechanical analysis; and fracture modeling in order to better understand fault extent and joint patterns.

# CONCLUSIONS

- Geocellular models can be constructed for unconventional well fields and used to integrate stratigraphy, structure, production, and completion data even when seismic surveys and core are not available. It is essential that the entire length of the horizontal portion of the wellbore is placed in the correct stratigraphic layer for valid model results. This can be a challenging task due to the stratigraphic variability and structural complexity of unconventional fields, and geosteering interpretations must be used to construct the model.
- The U.S. EIA (2016) reports that approximately of 63% of total unconventional Marcellus well costs are attributed to completion operations, and understanding and predicting completion trends throughout a field can potentially increase operational efficiency, and, in turn, decrease total field development costs. Geostatistical methods can be used to visualize and distribute completion data throughout a volumetric geologic model by implementing similar techniques used in petrophysical and facies distribution. By integrating geology, production, and completion data into a single volumetric geocellular model, production and operational trends can be observed and related to stratigraphy and structure. These models can also be used to predict completion trends during well operations and provide recommendations during field development, which in turn increases operational efficiency and decreases well cost.
- Specific to this study, a workflow was developed to incorporate geologic and completion data from an unconventional Marcellus Formation field in West Virginia. Completion re-perforations and screen-outs have a similar orientation to the J1 joint set, which, if mineralized, could create a fluid flow barrier during completion operations, but core was

not collected from this field to determine if systematic joint sets exist in the subsurface. Numerous realizations show that treating pressure distribution trends vary among stratigraphic sequences, and realization results vary most significantly further from data points. Both the Marcellus upper S2 HST and S2 TST/MFS2 drilling target DTP's generally increase westward as structural complexity increases (i.e., proximity to the strike-slip fault). DNPD trends highlight several of the mapped completion issues in all realizations. Screen-out/re-perforation issues and DNPD are not affected by proximity to the strike-slip fault.

- Though this study is specific to predicting and optimizing operations in an unconventional Marcellus Formation field in the Appalachian basin, a similar methodology may be applied to any global unconventional field, particularly when data is sparse.

## ACKNOWLEDGEMENTS

The author would like to thank Noble Energy for the use of data, and Lindell Bridges, Thomas Schickel, and Sean Wainwright for enlightening conversations.

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differentiate the carbonate-rich, low gamma intervals (Onondaga, S2 LST, and S3 LST) during drilling operations, as well as to emphasize the differences in gamma signature between the study area and the locations outside of the Rome trough. The horizontal drilling target is highlighted in gray.

Figure 4. Map of the study area with 28 unconventional Marcellus wells that were primarily drilled in S2 TST/MFS2 target interval. The ten foot contour intervals are the underlying Onondaga Formation top surface in feet sub-sea true vertical depth (SSTVD). Dashed red arrows demark the left-lateral strike-slip fault boundary. Marcellus Formation thickness increases by four feet in the direction of the purple arrow between the Pen 1 and Hall 2 vertical wells, with 90% of this thickness gain occurring in Sequence 1. The blue numbers at the well toes are the well numbers referred to in the text (Table 1). The boxes along well paths represent completion stages (green box – successful completion with no difficulty; blue box – screen-out stage; orange box – re-perforated stage that took less than 95% of scheduled sand during fracturing; peach box – re-perforated well stage that took greater than 95% of scheduled sand during fracturing). Reduced cluster spaced wells are denoted with "RCS" at the well toe, and wells fractured with 1,800 lbs of proppant/lateral foot (rather than the 1,650 lbs/lateral foot that were used for all other stages; Table 1) are denoted with "1800" at the well toe. Five completion problem "trends" are marked by the pink lines and labeled A-E, and the colored circles at the toes of the completed horizontal wells represent normalized 15-day cumulative hydrocarbon production in thousands of cubic feet equivalent per horizontal foot (MCFE/FT), which serve as a placeholder until longer production intervals are available. The circle in the upper right corner displays the J1 and J2 joint sets Engelder et al. (2009) mapped near the study area.

Figure 5. Illustration of workflow used to construct a geocellular model that integrates engineering and geologic data. Measuring-while-drilling data is abbreviated to “MWD”, and reservoir pressure is abbreviated to “RP”. Production data is not distributed throughout the model. Rather, it is observed on a field scale, and trends are compared to stratigraphic, structure, drilling, completion, and geomechanical trends reflected in the model.

Figure 6. Cross sections displaying the agreement between the A) geosteering interpretation generated from the Hall2 type log and the real-time MWD gamma data (MWD GR API), and the B) geocellular model structure. For both graphs, the vertical axis is true vertical depth (TVD), and the horizontal axis is measured depth (MD). Formation/sequence/systems tracts are listed on the right side, the well path is represented by the black dashed line, and the drilling target (S2 TST/MFS 2) is gray. The dashed line on the right of Figure 6A is the Hall 2 type log normalized gamma-ray API values (GRNorm API), and the sequence and systems tract abbreviations used in both cross sections are listed in Figure 6B.

Figure 7. A) Normalized gamma-ray API log (GrNorm API), density (RHOB), neutron porosity (PHI), and upscaled normalized gamma data (GrNorm Upscaled API) for the Hall 2 type log. B) Three dimensional view of the study area horizontal wells over the Onondaga Formation surface top in sub-sea feet true vertical depth (SSTVD). The red cylinders along the horizontal portion of the well represent completion stages. C) Three dimensional view of the volumetric geocellular gamma model for the study area. The histogram shows the agreement between distributed model data and gamma-ray well log data, and the exponential variogram is displayed on the bottom. The arrows from 7A to 7C show the portion of the model that is the focus of this study (top of Onondaga to top of S2 HST), as all completion stages are located within this stratigraphy.

Figure 8. Geocellular model histograms for realization 1 (REAL 1) and realization 10 (REAL 10) and exponential variograms for the A) upper HST treating pressures, B) drilling target S2 TST/MFS2 treating pressures, C) S2 LST treating pressures, D) upper HST normalized proppant, E) drilling target S2 TST/MFS2 normalized proppant, and F) S2 LST normalized proppant. For all variograms, the nugget is 0.01, and the sill is 1.

Figure 9. . Realization 1 maps (REAL 1; A, B, and C) and Realization 10 maps (REAL 10; D, E, and F) of distributed treating pressures in psi for the portion of S2 HST above the drilling target (A, D), the S2 TST/MFS2 drilling target (B, E), and S2 LST (C, F). County boundaries are denoted with the blue line, and the eastern extent of the strike-slip fault is marked with the dashed black line. The area associated with the western, uncompleted Wells 11-13 and 25-28 was clipped from the model due to lack of nearby data. Stages highlighted with purple circles in A, C, D, and F mark stages that were completed in the upper S2 HST and S2 LST systems tracts (8% and 4% of all stages, respectively). Stages without purple circles in A, C, D, and F were completed in the drilling target (87% of all stages). Stages with no completion issues are colored green, re-perforations are colored peach and orange, and screen-outs are colored blue (Figure 4). For both REAL 1 and REAL 10, the lower treating pressures in the upper S2 HST (A, D) range between 6,020 to 6,760 psi and occur in the eastern-most down-dip wells. Treating pressures consistently increase eastward, with the highest treating pressures (approximately 8,970 psi) occurring in the four western-most, north-bound wells. The drilling target has the most robust treating pressure and proppant data set (B and E). Within the target for REAL 1 and REAL 10, treating pressures generally increase to the northwest portion of the field (up to 9,010 psi). Only 4% of completed stages are located in S2 LST (C and F), and both REAL 1 and REAL 10 show that these treating pressures do not follow the consistent westward increase pattern that is

observed in the upper S2 HST and the drilling target. Treating pressures range approximately between 7,230 to 8,540 psi in S2 LST REAL 1 and REAL 10, except for one stage in the western-most south-bound well, which has a 8,910 psi treating pressure. This particular stage is in the very bottom portion of S2 LST, which has the lowest gamma values within S2.

Figure 10. Realization 1 maps (REAL 1; A, B, and C) and Realization 10 maps (REAL 10; D, E, and F) of distributed normalized proppant delivered (DNPD) in pounds per lateral foot for the upper S2 HST (A, D), the S2 TST/MFS2 drilling target (B, E), and S2 LST (C, F). Wells with an 1,800 lbs/foot schedule were not included in the data distribution due to the higher scheduled proppant delivery, and the stages of these wells are not mapped in this figure. Well numbers are the purple number and the well toes, and wells with reduced cluster spacing and/or 1,800 lbs of proppant/lateral foot are denoted with "RCS and "1800", respectively. Stages in S2 HST and S2 LST are highlighted with purple circles in A, C, D, and F, respectively. Stages without purple circles are in the drilling target (B and E). Stages with no completion issues are colored green, re-perforations are colored peach and orange, and screen-outs are colored blue (see Figure 4). In S2 HST, DNPD REAL 1 and 10 (A and D), heel values range between 1,350 to 1,650 lbs/ft, the up-dip toe values increase to 2,210 lbs/ft, and the down-dip toe values do not exceed 1,610 lbs/ft. REAL 1 and 10 for the drilling target DNPD (B and E), show that the heels of the up-dip wells range between 1,410 to 1,560 psi/ft, the toes of the up-dip wells increase to 2,440 lbs/ft, and the toes of the down-dip wells do not exceed 2,200 lbs/ft. The red bullseye (up to 2,530 lbs/ft) in the middle of the drilling target up-dip wells (B and E) is located where four adjacent stages were re-perforated and coincides with completion issue Trend C. S2 LST REAL 1 and 10 (C and F) have the opposite trend, with DNPD values generally increase from the toes of the up-dip wells (1,360 to 2,010 lbs/ft) to the toes of the southern wells (1,410 to 2,560 lbs/ft). The greatest variation

between REAL 1 and 10 occurs in model areas away from data points (i.e., north of the up-dip wells and south of the down-dip wells) for each of the three model layers, and the realizations for the drilling target (B and E) show the least amount of model variation, as this model layer has the most data points.

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