Wednesday, January 27, 2021

Virtual Meeting via Zoom

12:00 –1:00 p.m.

HGS Members $10 Non-Members $25 Students $5

https://www.hgs.org/civicrm/event/info?id=2261

Registered Attendees: A confirmation email will be sent upon registration with meeting links.

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Randy Blood

DRB Geological Consulting

Giving 110%: Field and Laboratory Observations of the Marcellus Shale and Associated Strata Which May Explain Well Production in Excess of Gas-In-Place

The highly productive nature of the Marcellus Shale has led to an interesting observation where individual well EUR often exceeds the calculated Gas-In-Place (GIP). An explanation for this paradox may be found in one, or both, of two broad categories: 1) Our understanding of gas storage in the Marcellus Shale is lacking and this results in volumetric petrophysical models underpredicting GIP, or 2) our assumptions about drainage volume of a well are incorrect and they are drawing hydrocarbon from a larger source area than we expect.

To address GIP, the talk focuses on three aspects of the volumetric model: 1) implementing the Ambrose-Hartman correction to the free gas calculation, 2) modifying the water saturation to reflect anthropogenic sources of water in core, and 3) implementing a dynamic pore pressure gradient. Pressurized rotary sidewall cores were collected from the Marcellus Shale in a well drilled under slightly overbalanced conditions to minimize gas escape. After measuring total gas evacuated from the cores, total uptake experiments were conducted to determine the storage capacity of the samples at varying pressures. Isotopic analysis of core, drilling, and produced water was used to determine the source of these waters. Finally, field analysis of the occurrence of natural hydraulic fractures compared to total organic carbon (TOC) was used to estimate the variation of overpressure development at the bed scale. Total uptake experiments confirm the necessity of the Ambrose-Hartman correction to the free GIP component to accurately quantify GIP. Isotopic analysis of core, drilling, and produced water indicate that the majority of water encountered in the Marcellus Shale results from the drilling and completion process with minimal evidence of mobile in situ water. The increased density of natural hydraulic fractures (NHFs) associated with increasing TOC reveals a strong relationship between overpressure development in beds and TOC content, suggesting the need to treat pore pressure as a dynamic value. When these three aspects are considered, GIP values can increase by 25%.

To address drainage volume, it is worth noting that there are multiple organic-rich units overlying the Marcellus Shale that may contribute to production. Field studies indicate the presence of discrete channel-fill black shales that occur within the overlying grey-shale dominated successions of the Hamilton Group. These features are characterized by black shale facies which are feet to tens of feet in thickness and miles to tens of miles in width. Channel bases are erosional discontinuities marked by pyrite-bearing phosphatic lags. Detailed analyses of well logs indicate such features of the same scale are found in the subsurface. Moreover, common to these deposits is the presence of what we interpret to be gas chimneys: narrow zones of heavily fractured rock 10s to 100s of feet wide, and 100s of feet tall. These fractures consist of closely spaced Mode 1 natural hydraulic fractures that are 10s to 100s of feet tall. The gas chimneys occur at or near the top of black shale dominated strata and continue upward into overlying organic-lean grey to silty shale-dominated strata. Such gas chimneys may connect Marcellus Shale strata to overlying black shale reservoirs in the Hamilton Group or Geneseo Shale. ■

Biographical Sketch

Randy (David) Blood is a geologist and petrophysicist based in the greater Pittsburgh area working on various aspects of Paleozoic strata in the Appalachian Basin. His current interests include evaluating sedimentary features within mudstones and how they affect hydrocarbon transport, drilling and completions, and the distribution and accumulation of critical minerals and rare earth elements. Before starting DRB Geological Consulting, he worked for EQT Production and Chesapeake Energy evaluating their unconventional assets, defining horizontal landing zones, and using inorganic geochemistry data to model facies, estimate rock mechanics, and help solve wellbore stability issues. He also has experience evaluating unconventional assets and sedimentary successions in basins across the United States and abroad.