Appendix 7-D. Bitumen reflectance to vitrinite reflectance equivalent values

1.0 BITUMEN REFLECTANCE TO VITRINITE REFLECTANCE EQUIVALENT VALUES

1.1 Introduction to Bitumen Reflectance

Shale productivity depends on a number of reservoir quality factors. Thermal maturity, one parameter by which shale productivity is assessed, has become imperative in determining the products that buried hydrocarbons are capable of generating (i.e., oil, wet gas, dry gas, etc.). Previously, thermal maturity patterns of the Utica and Marcellus shale plays were estimated using conodont alteration index (CAI)-based maps and vitrinite reflectance (Repetski and others, 2008). While vitrinite reflectance has become a common practice by which the thermal maturity of post-Silurian rocks can be measured, the absence of terrestrial plants in pre-Silurian formations requires reflectance measurements of a different solid hydrocarbon. Solid hydrocarbons, such as bitumen, are commonly found in petroleum systems within source rocks, migration pathways, reservoirs and seals (Landis and Castaño, 1994). Solid hydrocarbons have been proven to exhibit a wide range of morphologies and textures (Landis and Castaño, 1994), yet thermal calibrations based on their optical properties have been used to assess thermal maturation of pre-Silurian formations in order to compare thermal maturities with post-Silurian rocks. In this way, reflectance can provide a common parameter by which solid hydrocarbons of all types can be characterized (Landis and Castaño, 1994).

1.2 Definition and Symbology

Landis and Castaño (1994) define solid hydrocarbons as “accumulations which contain a significant solid phase produced from petroleum generation in source rocks” which includes “the residual solid hydrocarbons produced by the cracking of liquids to gas in reservoirs.” Landis and Castaño (1994) further define “solid bitumen” as the portion of the series <0.7% bitumen reflectance (%BRo) and “pyrobitumens” as >0.7 %BRo. Jacob (1989) defines solid oil bitumens (or “migrabitumens”) as macerals that are relatively dispersed in rocks, that are secondary forming, and that take the shape of cavities that they occupy. Organic petrologists (e.g., Camp and others, 2013) refer to the secondary maceral exsudanite as “bitumen”, while organic geochemists refer to “bitumen” as the portion of total organic matter in a rock that is soluble in organic solvents (Riediger, 1993).

For this Study, the term “bitumen” refers to all solid hydrocarbons of organic origin distinguishable by color and texture from background amorphous organic matter and clay minerals. Therefore, regardless of the “type” of bitumen or other categories of solid hydrocarbons, we presume that these macerals are formed by the conversion of kerogen to solid hydrocarbon, have undergone sufficient temperature and pressure changes to act as an indicator for the capability of a reservoir to generate hydrocarbons at multiple maturity levels (Landis and Castaño, 1994) and indicate some kind of hydrocarbon generation and migration to some degree in the Utica petroleum system (Landis and Castaño, 1994). Like the definition, the symbologies for vitrinite and bitumen reflectance vary from study to study. Jacob (1989) uses RV to denote vitrinite reflectance and Rb for bitumen reflectance, while Riediger (1993) uses VRo and BRo. Landis and Castaño (1994) use VRo and SHRo, while Schoenherr (2007) uses VRr and BRr. For this Study, Ro and BRo are used to denote vitrinite and bitumen reflectance in percent (%).

1.3 Optical Forms of Bitumen

Bitumen occurs in multiple optical forms. Landis and Castaño (1994) report three optical forms at all levels of thermal maturation. Homogeneous bitumen represents macerals that exhibit near-uniform reflectance with each other and are difficult to confuse with other organic petrographic constituents (Landis and Castaño, 1994). Homogeneous macerals are also most reliable when making reflectance measurements and for comparison to vitrinite reflectance. Anisotropic or “coked” bitumen consists of an ensemble of reflectance domains with varying degrees of optical extinction (Landis and Castaño, 1994). While the origins of coked hydrocarbons are unknown, they are presumed to have been exposed to relatively high temperatures, much like the coking of coal (Landis and Castaño 1994). Schoenherr (2007) attributes some coking of bitumen to the influence of hydrothermal fluid movement within a reservoir, especially where coked bitumen is found in lower maturity areas (Schoenherr, 2007). “Granular” bitumen is very common and exhibits a spongy or microporous texture with the lowest reflectance among the varieties (Landis and Castaño, 1994). In this Study, the terms “homogeneous” and “coked” bitumen are used, and granular bitumen is referred to as “degraded” bitumen (Table 7D-1). While the reflectance of bitumen is primarily used to determine the maturity regime and hydrocarbon products expected from a reservoir, the optical form can be a good indicator of reservoir quality (Table 7D-1).

Table 7D-1. Generalized explanation of bitumen optical forms (as defined for this Study) and subsequent impact on reservoir quality.

Degraded	Low reflectance values Low maturity Poor reservoir quality
Homogeneous	Suitable reservoir quality Reliable for correlation with other indicators of thermal maturity
Coked	High reflectance values Post-mature Poor reservoir quality

1.4 Correlation of Bitumen and Vitrinite Reflectance Values

Many correlations have been made in an attempt to equate bitumen reflectance values (BRo) to vitrinite reflectance values (Ro). However, many of these correlations were developed for post-Silurian formations, for which vitrinite and bitumen reflectance could both be measured in a given sample set. Because each calculation uses a different formation upon which to base values, every correlation varies slightly from one another. To date, a bitumen-to-vitrinite correlation has not been specifically developed for the Utica Shale play. Accordingly, we have used the following three equations to transform this Study’s BRo values to Ro equivalent (Ro eq) values. The end result is a range of maturity rankings and expected hydrocarbon products for the samples we analyzed.

$Ro = 0.618(BRo) + 0.4$ (Jacob, 1989)

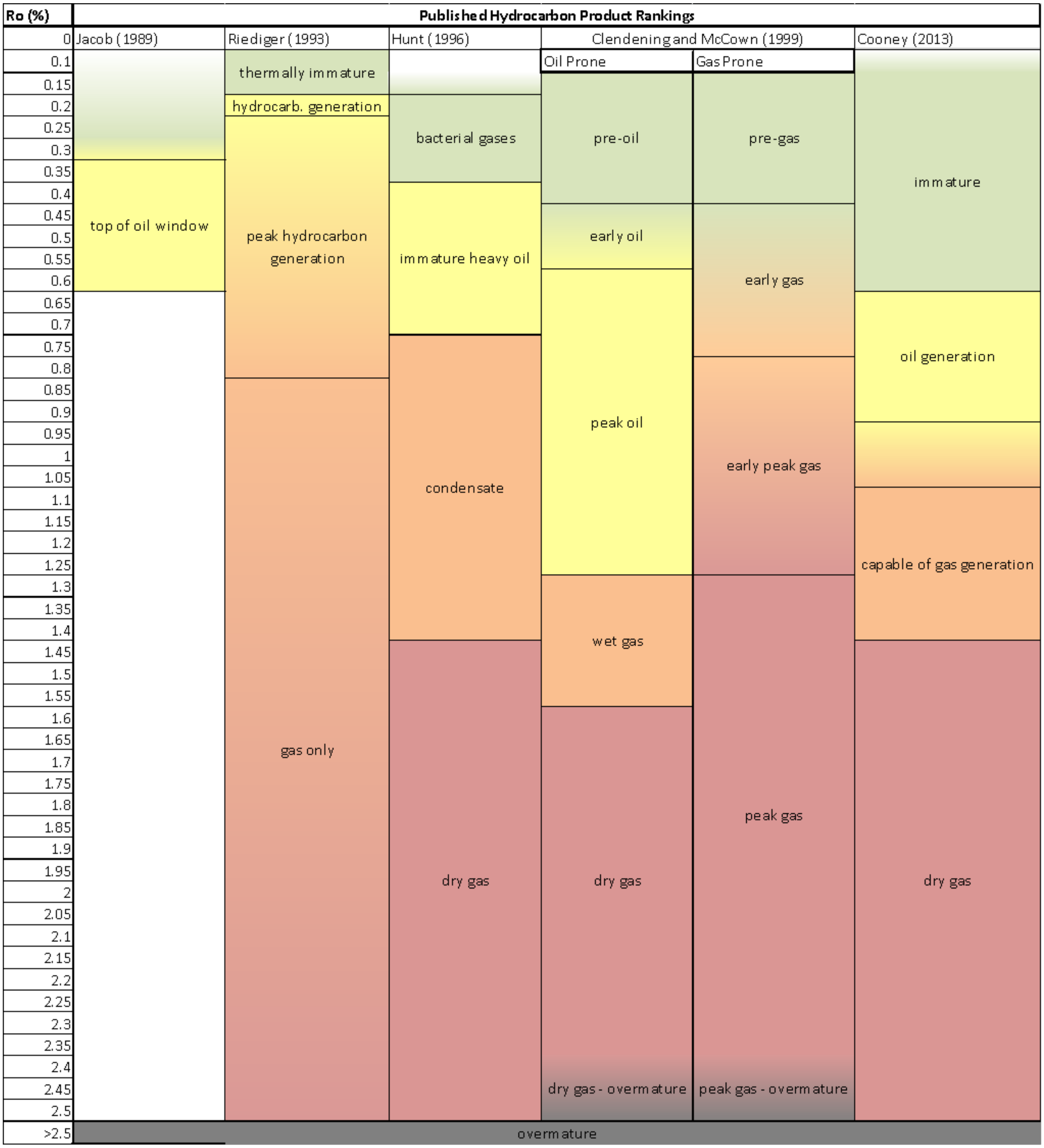
$Ro = (BRo + 0.41) / 1.09^*$ (Landis and Castaño, 1994)

*For Ro > 4.0

$$Ro = (BRo + 0.2443) / 1.0495 \qquad \text{(Schoenherr, 2007)}$$

Jacob (1989) described a linear relationship between vitrinite and bitumen at concentrations between <0.1% and 3.0%BRo, with a standard deviation of ± 0.06%. Only the lowest reflectance data, however, were used to represent the degree of hydrocarbon maturity. Landis and Castaño (1994) focused on measuring solid hydrocarbons interpreted to being derived locally and measured vitrinite and bitumen on the same rock samples. Landis and Castaño (1994) found that BRo% is not equivalent to Ro% at concentrations less than ~4.0%Ro, but that above 4.0%Ro, the two are, in fact, similar. The correlation by Landis and Castaño (1994) included more data points than that of Jacob (1989), excludes samples where vitrinite is suppressed and only reflects one textural type (homogeneous). Schoenherr (2007) points out that the Jacob (1989) regression only includes BRo values with a maximum of 2.7% and does not apply to BRo values at higher maturities. However, the regression of Landis and Castaño (1994), which applies to higher maturity samples, did not correlate with the Schoenherr (2007) data. In order to combine the best fit regression for all maturities, Schoenherr (2007) combined the Jacob (1989) and Landis and Castaño (1994) regressions. Interestingly, Bertrand (1993) found the linear relationship between bitumen and vitrinite to vary as a function of lithology, with unique regressions needed for each formation.

Once a suitable bitumen-to-vitrinite regression is determined, reflectance values can be correlated with hydrocarbon products (oil, wet gas, dry gas, etc.). Figure 7D-1 illustrates a summary of some Ro and Ro eq correlations with hydrocarbon products in organic petrology literature. The terminology used to describe hydrocarbon products are from each of the listed references. It is obvious that the rankings vary from author to author based on available data, formation(s) studied, and other factors. Even so, these rankings describe general ranges of thermal maturity regimes.



Ro (%)	Published Hydrocarbon Product Rankings					
0	Jacob (1989)	Riediger (1993)	Hunt (1996)	Clendening and McCown (1999)		Cooney (2013)
0.1		thermally immature		Oil Prone	Gas Prone	immature
0.15				pre-oil	pre-gas	
0.2		hydrocarb. generation	bacterial gases			
0.25		peak hydrocarbon generation				
0.3						
0.35	top of oil window					
0.4						
0.45			immature heavy oil			
0.5				early oil	early gas	
0.55						
0.6				peak oil		
0.65						oil generation
0.7						
0.75						
0.8			condensate		early peak gas	
0.85		gas only				
0.9						
0.95						
1						
1.05						
1.1						
1.15						capable of gas generation
1.2						
1.25						
1.3				wet gas	peak gas	
1.35						
1.4						
1.45						
1.5			dry gas			dry gas
1.55						
1.6				dry gas		
1.65						
1.7						
1.75						
1.8						
1.85						
1.9						
1.95						
2						
2.05						
2.1						
2.15						
2.2						
2.25						
2.3						
2.35						
2.4				dry gas - overmature	peak gas - overmature	
2.45						
2.5						
>2.5		overmature				

Figure 7D-1. Hydrocarbon product rankings compiled from literature to illustrate variations in correlating BRo% values to Ro% or Ro eq% values and their corresponding hydrocarbon products.

1.5 Calculated Ro eq% Results

The following table displays the range of calculated mean Ro eq% results for the six Pennsylvania wells evaluated by this Study based on the three correlation calculations described above. These ranges serve to estimate the thermal maturity regime for each of the wells.

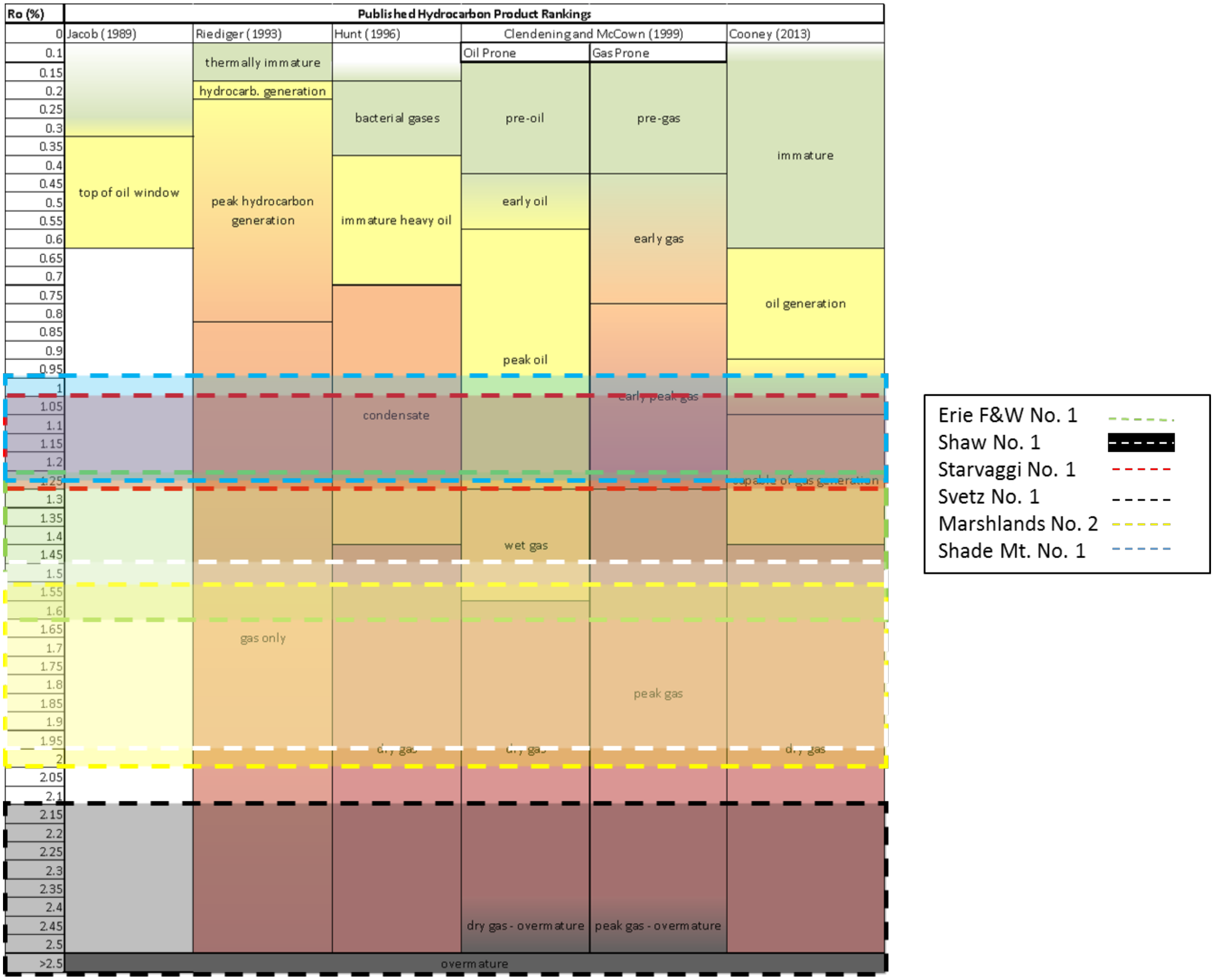


Figure 7D-2. Range of calculated mean Ro eq% values and corresponding thermal maturity regimes for Pennsylvania samples.

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