Tanumbirini 1 Interpretive Summary

Middle Velkerri Interval

As a part of:
Northern Territory Geological Survey - Australia
McArthur Basin Integrated Petroleum Geochemistry, 2016

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Study Project No. AB-74329

November 17, 2016

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INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Middle Velkerri Formation in the Tanumbirini 1 well located in the Beetaloo Sub-Basin, Northern Territories, Australia. Five (5) core chip samples from this well were analyzed by a variety of geochemical techniques, including total organic carbon (TOC, LECO®) and programmed pyrolysis (SRA). The complete results of these analyses are documented in this report along with an integrated geochemical interpretation that is summarized in the following table.

Well Name	Formation	Main Product	Thermal Maturity	Source Rock Richness	Organic Matter Type	Shale Gas Risk
Tanumbirini 1	Middle Velkerri	Estimated Original ⟶		Excellent (4.20% TOC)	Oil-prone Type II	Low
Measured Currently ⟶		Dry Gas	Dry Gas Window	Very Good (3.13% TOC)	Inert Type IV	

Current TOC averages represent all data available; Original TOC averages are only high graded samples that have PPy data

Table 1. Geochemical Summary

MIDDLE VELKERRI FORMATION

Five samples (5) from the Middle Velkerri Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 0.90 to 4.28 wt.% and averaged 3.13 wt.% (very good). All but one of these samples have TOC contents above the minimum requirement of 1 wt.% for *effective* petroleum source rocks and above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Highest TOC content occurs in the upper half of the designated Middle Velkerri interval, at a depth of 3238.8 m (Fig. 1). In most of the other wells evaluated in this study, it was possible to recognize three distinct cycles of TOC within the Middle Velkerri (Lanigan et al, 1994) that could be associated with the base of transgressive systems tracts (TST) in a series of platform/ramp parasequences (Bohacs et al., 2013). In the Tanumbirini 1 well there appears to be only a single cycle of elevated TOC represented within the ~74 m sampled interval. This could be due to the limited extent of samples available from the Middle Velkerri in this well.

The S1 values of the Middle Velkerri source rock samples average 0.12 mg HC/g rock (3 bbl oil/acre-ft) and S2 values average 0.18 mg HC/g rock (4 bbl oil/acre-ft). The S1 and S2 values indicate very low in-situ hydrocarbon saturation and poor remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Middle Velkerri samples, (S1/TOC) x 100, average 5 (Fig. 1). NOC values of 20 to 50 are typical of low maturity source rocks, whereas values of 50 to 100 indicate possible oil staining or shows in thermally mature, tight petroleum source rocks. NOC > 100 are often associated with conventional oil reservoirs and indicate good prospectivity in unconventional shale oil plays. Very low NOC values < 20 are common in post-mature source rocks that have generated and expelled most of their in-situ hydrocarbon saturation, but can also be found in source rocks with poor original hydrocarbon generation capacity. Jarvie (2012) has utilized a depth comparison of TOC versus programmed pyrolysis S1 yields as a potential indicator of producible hydrocarbon saturation in unconventional source rocks. When the S1 yields (reported as mg HC/g rock) exceed or "cross-over" the measured TOC content (reported as wt.%), this would be interpreted to represent zones with good potential for containing producible hydrocarbon saturation (or zones of possible contamination). In the present study, there is no S1 cross-over TOC in any of the Middle Velkerri samples analyzed (Fig. 1).

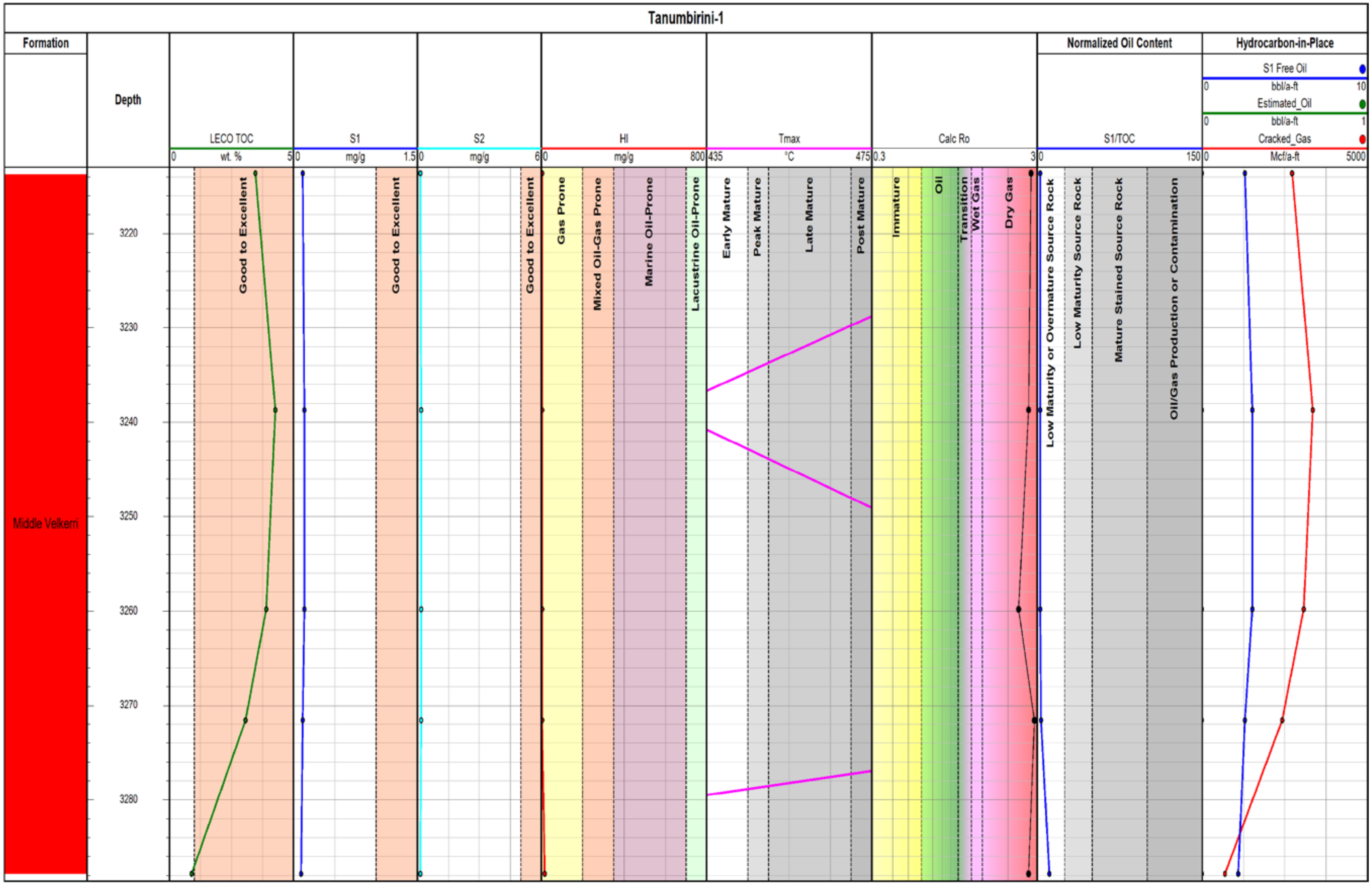

Figure 1. Geochemical depth plots for the Tanumbirini 1 well.

Measured Hydrogen Index (HI) values in the Middle Velkerri average 8 mg HC/g TOC, indicating inert Type IV kerogen quality in these source rocks at present day. Original HI_o of these samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation ratios (TR) based upon HI average 99%, which is consistent with dry gas window thermal maturity. T_{max} values in the Middle Velkerri samples average 546°C on the basis of select samples which were considered valid. T_{max} values > 470°C typically indicate post-mature dry gas window (Type II kerogen). Using these guidelines, the average Middle Velkerri T_{max} values in this well would be interpreted to be in the dry gas window. Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated $R_o = (0.0180)(T_{max}) - 7.16$), the average measured T_{max} value of 546°C is equivalent to a Calc. %R_o value of 2.67%. It is important to note that T_{max} is only a crude measure of thermal maturation (Peters, 1986) and it can be compromised by a variety of pyrolysis artifacts and caveats.

Production Index (PI) values in the Middle Velkerri samples average 0.40. These elevated PI values are more consistent with source rocks in the late oil to condensate window, which typically have PI values between ~0.25 and 0.40. Samples in the dry gas window tend to have very low PI values due to low S1 yields, but this is more problematic since low S2 yields can cause this ratio to be erratic and inaccurate.

Organic petrology was performed on all five samples analyzed from the Middle Velkerri interval. The results from these analyses show distributions that consist of macerals identified as either non-fluorescing alginite or high reflectance solid bitumens (Figs. 2-6). The former population is present in two samples (Figs. 2 & 5) and was recognized based upon morphology that is elongated like a filament and in some cases shows lineation more typical of alginite macerals. In the two Tanumbirini 1 samples where these types of organic macerals were recognized, they are sparse in occurrence (only 6 readings per sample) and have relatively high reflectance values that average between 2.73 and 2.80% R_o. In other wells evaluated in this study, non-fluorescing alginite populations generally give reflectance values that are lower than the co-occurring high reflectance solid bitumens. Often the non-fluorescing alginite is considered the most representative indigenous kerogen population for thermal maturity assessment. However, in the Tanumbirini 1 well this is not the case and the sparse occurrence of the alginite along with the overlap in reflectance readings between this maceral group and the high reflectance solid bitumens suggests that in these samples the non-fluorescing alginite R_o data should be interpreted cautiously.

The high reflectance solid bitumen groups of organic macerals are thought to possibly represent fine grained migrabitumen, although they could also represent preserved original cyanobacterial kerogen that has subsequently undergone thermal conversion to form a dispersed solid bitumen network within these Velkerri Formation source rocks. The mean measured reflectance values for these solid organic macerals average between 2.39% and 2.70% R_o (values very close to the select T_{max} Calc. %R_o range of 2.33% to 2.92%). Published solid bitumen conversions were applied to these reflectance values. The conversion formula published by Landis and Castaño (1995) for bitumen in lenses/layers (Eq. R_o = (Bitumen R_o +0.41)/1.09) resulted in 2.57 to 2.85% Eq. Ro, while the conversion formula published by Jacob (1985) equation (Eq. Ro = (Bitumen Ro $\times$ 0.618) + 0.4) for 'angular-like' pyrobitumen trapped in mineral pore spaces resulted in 1.88 to 2.07% Eq. R_o. The Landis and Castaño (1995) conversion would suggest an elevated late dry gas window thermal maturity, which is more consistent with the limited reflectance measurements taken on non-fluorescing alginite within these samples. However, experience from other wells evaluated as part of this study shows that the Jacob (1985) conversion appears to provide a possible correction back to a more suitable thermal maturity. In these other wells, the high reflectance solid bitumen reflectance readings can be corrected using the Jacob (1985) formula and often these "corrected" values compare favorably to "uncorrected" readings from the co-occurring population of low reflectance solid bitumen within the same sample. Thus, the calculated 1.88 to 2.07% Eq. R_o values from the high reflectance solid bitumens are considered most reliable for the Tanumbirini 1 well thermal maturity assessment and would suggest the Middle Velkerri samples are within the early dry gas window.

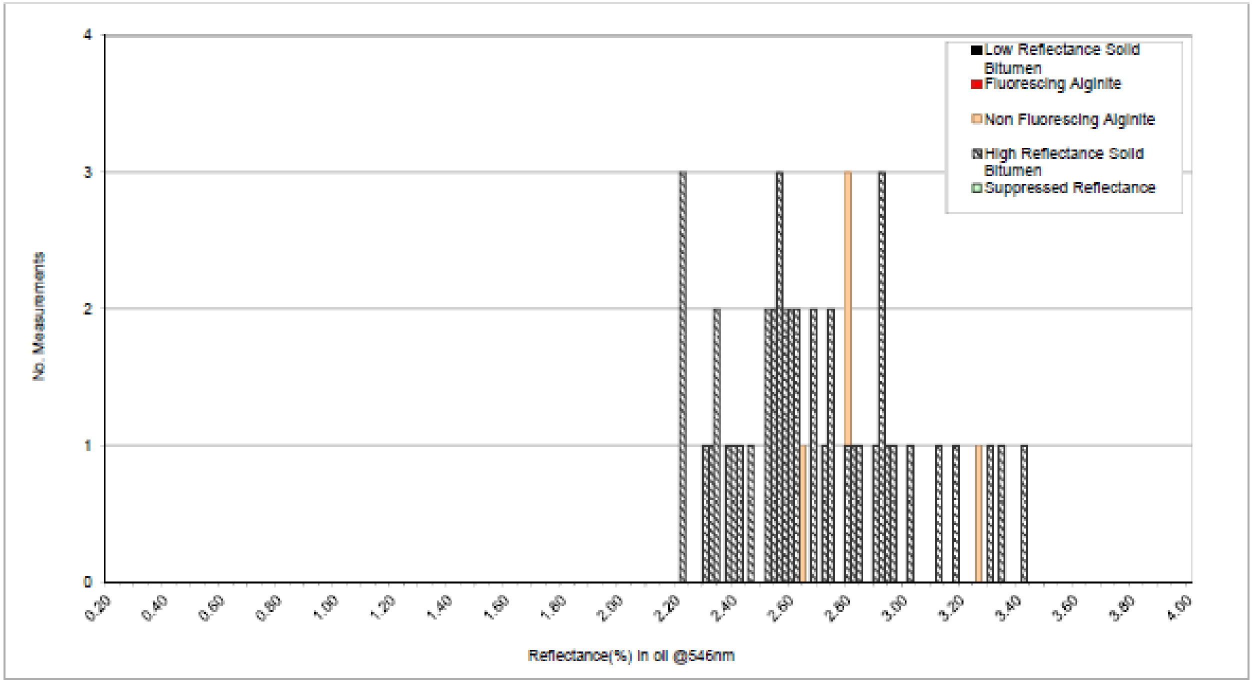

Figure 2. Organic petrology of the Middle Velkerri (3213.7 m) in the Tanumbirini 1 well. Mean maceral reflectance of non-fluorescing Alginite is 2.80% Ro. Mean maceral reflectance of high reflecting solid bitumen is 2.68% Ro, which equates to a calculated Eq. Ro of 2.05% Ro using the conversion of Jacob (1985).

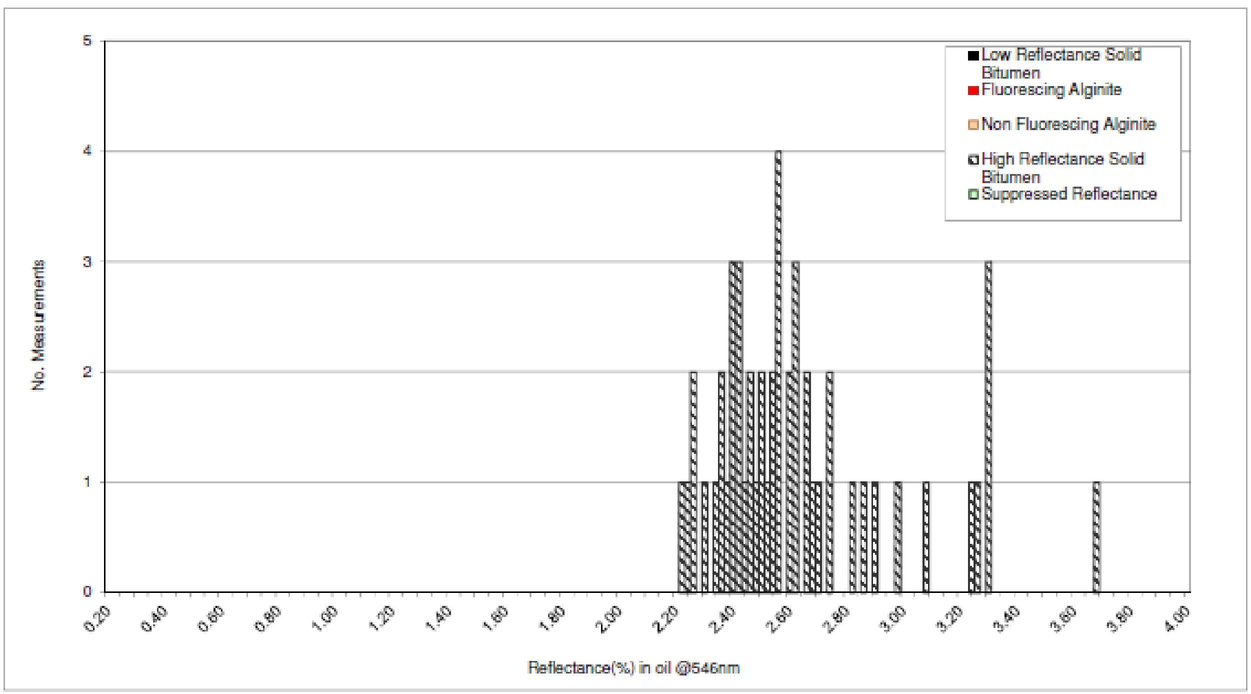

Figure 3. Organic petrology of the Middle Velkerri (3238.78 m) in the Tanumbirini 1 well. Mean maceral reflectance of high reflecting solid bitumen is 2.63% Ro, which equates to a calculated Eq. Ro of 2.03% Ro using the conversion of Jacob (1985).

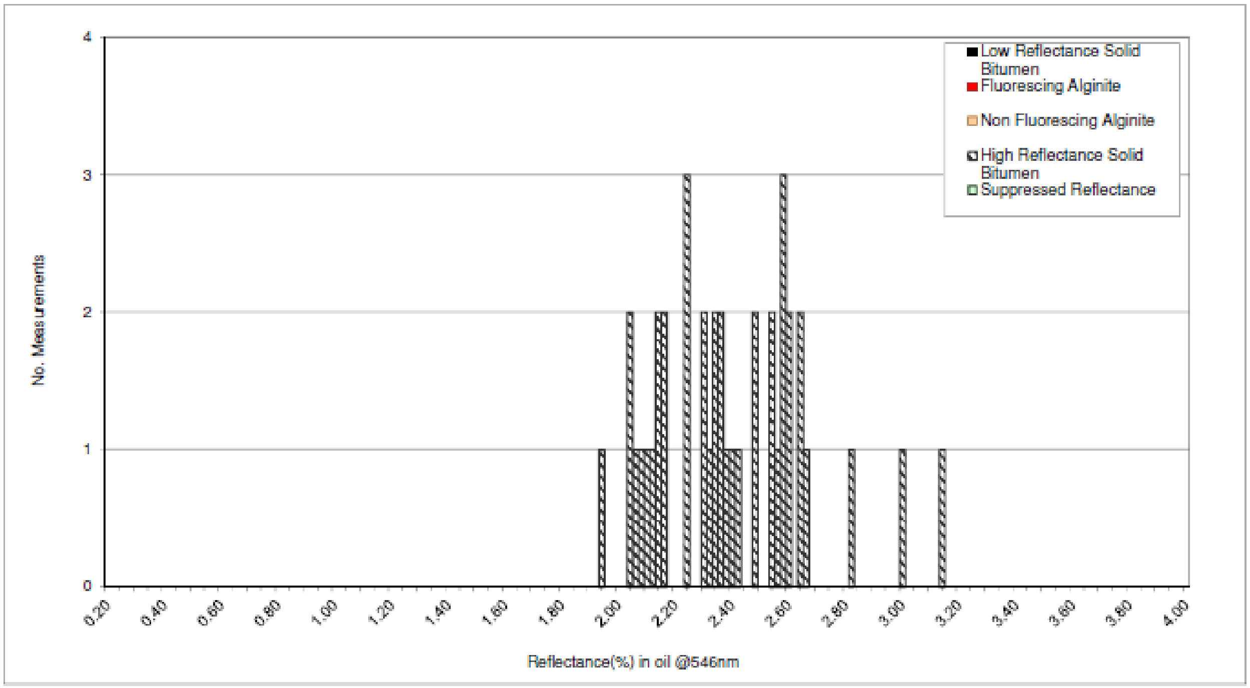

Figure 4. Organic petrology of the Middle Velkerri (3259.8 m) in the Tanumbirini 1 well. Mean maceral reflectance of high reflecting solid bitumen is 2.39% Ro, which equates to a calculated Eq. Ro of 1.88% Ro using the conversion of Jacob (1985).

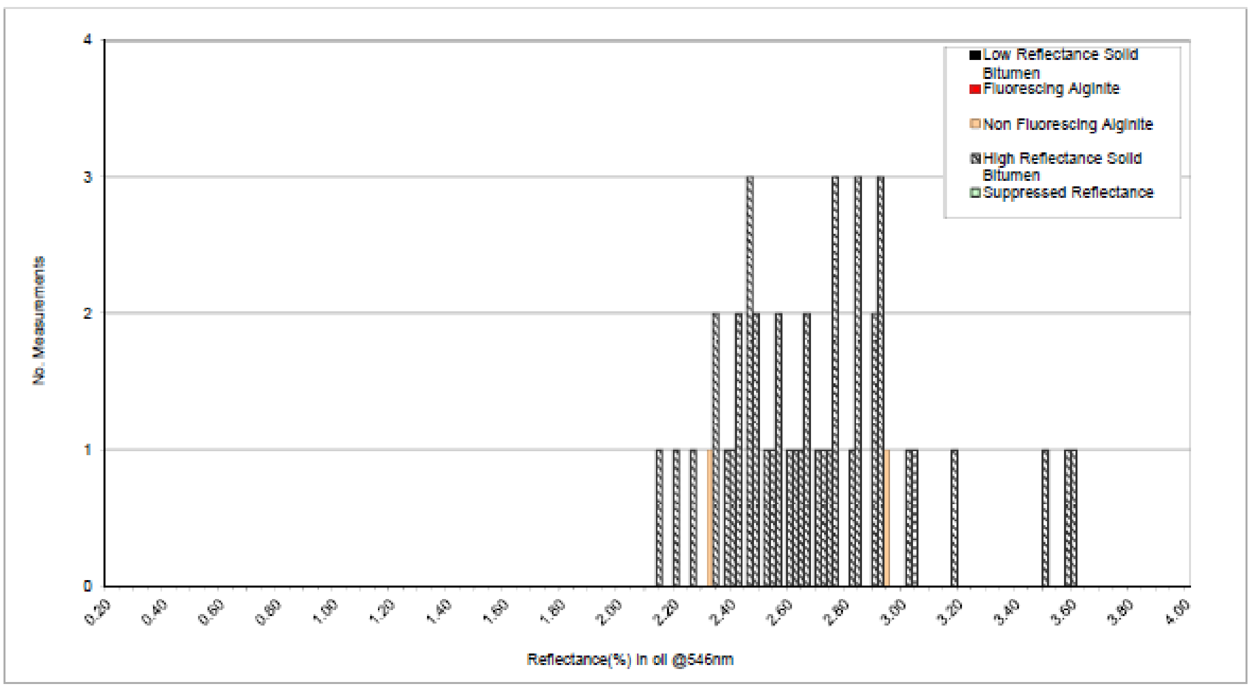

Figure 5. Organic petrology of the Middle Velkerri (3271.6 m) in the Tanumbirini 1 well. Mean maceral reflectance of non-fluorescing Alginite is 2.73% Ro. Mean maceral reflectance of high reflecting solid bitumen is 2.70% Ro, which equates to a calculated Eq. Ro of 2.07% Ro using the conversion of Jacob (1985).

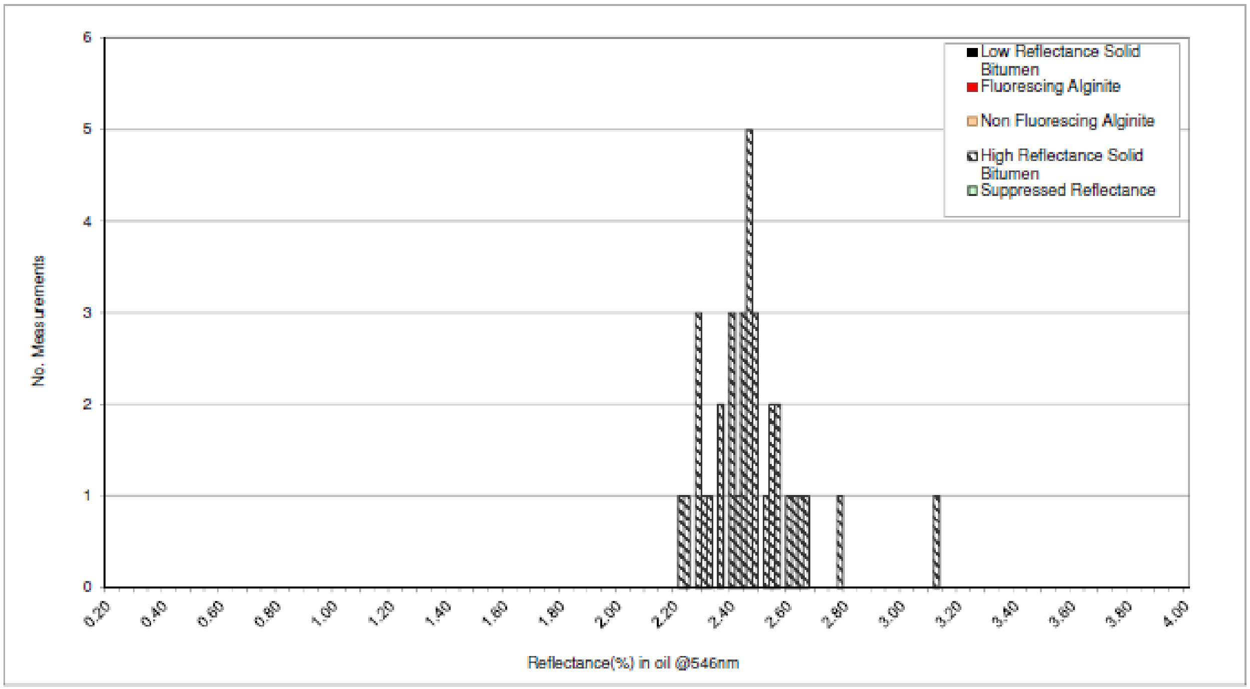

Figure 6. Organic petrology of the Middle Velkerri (3287.85 m) in the Tanumbirini 1 well. Mean maceral reflectance of high reflecting solid bitumen is 2.46% Ro, which equates to a calculated Eq. Ro of 1.92% Ro using the conversion of Jacob (1985).

ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS

Petroleum generative capacity depends on the original quantity of organic matter (TOC_o) and the original type of organic matter (HI_o) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by TOC_{pd} and HI_{pd} in the Middle Velkerri source rock samples examined in this study. We can estimate the extent of the petroleum generation process, the volume of expelled oil and the expulsion efficiency by making some reasonable assumptions based on the core geochemical data and published regional information (Jarvie et al., 2007; Peters et al., 2005).

HI_o values can be computed from visual kerogen assessments and assigned kerogen-type HI_o average values using the following equation (Jarvie et al., 2007):

$$HI_o = \left(\frac{\%\text{Type I}}{100} \times 750\right) + \left(\frac{\%\text{Type II}}{100} \times 450\right) + \left(\frac{\%\text{ Type III}}{100} \times 125\right) + \left(\frac{\%\text{Type IV}}{100} \times 50\right) \qquad (1)$$

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various formations evaluated in the current study are shown in Table 2, along with the resultant average original HI_o values calculated using equation (1) above. The kerogen estimations used in this study are generally in agreement with other published values that suggest Type II to a mixed Type I/II kerogen assemblage (Law et al., 2010; Crick et al., 1988; Taylor et al., 1994).

Formation	%Type I 750 HI_o	%Type II 450 HI_o	%Type III 125 HI_o	%Type IV 50 HI_o	HI_o
Middle Velkerri	0	100	0	0	450

Table 2. Average Kerogen Estimations for Tanumbirini 1 well.

The extent of the petroleum-generation process, or transformation ratio (TR) which is also called fractional conversion, is calculated as follows (Jarvie et al., 2007, p. 497):

$$TR_{HI} = 1 - \frac{HI_{pd}[1200 - HI_o(1 - PI_o)]}{HI_o[1200 - HI_{pd}(1 - PI_{pd})]} \qquad (2)$$

HI_{pd} and PI_{pd} are the measured HI and PI values for the various source rock samples in this well. The average HI_{pd} and PI_{pd} for the formations evaluated in the current study are shown in Table 3. HI_o and PI_o are the original HI and PI values for immature organic matter in the rocks. For this calculation using the assumptions described previously results in an average HI_o value of 450 mg HC/g TOC (Table 2). We assume a PI_o of 0.02 (see Peters et al., 2005). Using these values in equation 2, the extent of fractional conversion of HI_o to petroleum averages 0.99 (Table 3), i.e., on average an estimated 99% of the petroleum generation process has been completed.

The original TOC_o in the source rocks before burial and thermal maturation is constrained by mass balance considerations as follows (corrected from Jarvie et al., 2007):

$$TOC_o = \frac{HI_{pd}\left(\frac{TOC_{pd}}{1+k}\right)(83.33)}{\left[HI_o(1 - TR_{HI})\left(83.33 - \left(\frac{TOC_{pd}}{1+k}\right)\right)\right] + \left[HI_{pd}\left(\frac{TOC_{pd}}{1+k}\right)\right]} \qquad (3)$$

In this equation k is a correction factor based on residual organic carbon being enriched in carbon over original values at high maturity (Jarvie et al., 2007, p. 497). For Type II kerogen the increase in residual carbon C_R at high maturity is assigned a value of 15% (whereas for Type I, it is 50%, and for Type III, it is 0%) and the correction factor k is then $TR_{HI} \times C_R$. The kerogen mix for each individual sample was used in this calculation.

Using equation 3, the average estimated original TOC_o for the Middle Velkerri source rock samples in this well before petroleum generation is 4.20 wt.% (Table 3).

The original generation potential $S2_o$ can be calculated using the following equation:

$$S2_o = \left(\frac{HI_o \times TOC_o}{100}\right) \qquad (4)$$

For the Middle Velkerri source rocks examined in the Tanumbirini 1 well, the average $S2_o$ value is 18.9 mg HC/g rock or approximately 414 bbl/acre-ft (multiply $S2_o$ by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 3).

Knowing the measured remaining generation potential S2 from programmed pyrolysis and using the calculated original generation potential $S2_o$ enables a determination of the amounts of hydrocarbons generated. A VR_o algorithm can then be applied to estimate fractional oil cracking thereby converting yields to estimated oil and cracked gas (reported as Mcf/acre-ft or thousand cubic feet/acre-ft).

$$\text{Original } (S2_o) - \text{Remaining } (S2) = \text{Generated HCs} \quad (5)$$

Using this methodology for the Middle Velkerri samples analyzed in the current study, the generated cracked gas yields average 2459 Mcf/acre-ft and there is nil estimated residual oil due to the estimated 100% oil cracking at this level of thermal maturity.

Formation	TOC_{pd}	HI_{pd}	$S2_{pd}$ bbl/a-ft	HI_o	TR	TOC_o	$S2_o$ bbl/a-ft	S1 Free Oil bbl/a-ft	Est. Oil bbl/a-ft	Cracked Gas Mcf/a-ft
Middle Velkerri	3.13	8	4	450	0.99	4.20	414	3	0	2459

Table 3. Hydrocarbon Yields average data for Tanumbirini 1 well.

The Middle Velkerri source rock interval in the Tanumbirini 1 is interpreted to be in the dry gas window and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly dry gas). From an exploration risk perspective, this is generally favorable. However, it is useful to relate these hydrocarbon yields to other productive unconventional US Shale plays (Table 4). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original ($S2_o$) generation potential of the source rocks. These values related to the ultimate volumes of hydrocarbon that could be generated at depth in the basin. For the Middle Velkerri original generation potential ($S2_o$) averages 414 bbl oil/acre-ft, this is comparable to several of the other formations on the list of unconventional US Shale plays shown below.

Sample Database Averages TOC >1%	HI° mg/g TOC	TR	TOC° wt%	S2° mg/g Rock	Remaining Potential bbl/a-ft	Original Potential bbl/a-ft	Oil Cracked %	S1 Free Oil bbl/a-ft	Estimated Oil bbl/a-ft	Cracked Gas Mcf/a-ft
Barnett Shale Ft. Worth Basin	435	0.84	5.38	23.40	94	513	0.40	33	251	1005
Barnett Shale Delaware Basin	435	0.91	5.25	22.84	52	500	0.80	32	90	2149
Woodford Shale Delaware Basin	480	0.89	6.41	30.79	139	674	0.89	46	60	2854
Haynesville Shale E. Texas Basin	400	0.98	3.93	15.73	7	344	1.00	3	0	2022
Fayetteville Shale Arkoma Basin	435	0.95	3.34	14.53	15	318	1.00	10	0	1820
Woodford Shale Arkoma Basin	520	0.87	5.15	26.80	12	587	0.70	87	170	2431
Eagle Ford Shale Gulf Coast Basin	520	0.85	3.19	16.61	61	364	0.47	22	161	848
Marcellus Shale Appalachian Basin	600	0.97	6.44	38.66	34	847	1.00	24	0	4875
Utica Shale Appalachian Basin	450	0.98	2.74	12.32	6	270	1.00	12	0	1585
Barnett Shale Oil	450	0.47	5.47	24.64	326	540	0.00	79	213	0
Barnett Shale Gas	450	0.96	5.58	25.13	23	550	0.87	7	68	2751
Middle Velkerri	450	0.99	4.20	18.89	4	414	1.00	3	0	2459

Table 4. Geochemical Properties and Generation Potential for US Shale plays and current study.

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Middle Velkerri Formation source rocks in the Tanumbirini 1 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 7) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for all four diagnostic ratios where available. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas production. Transformation Ratios (TR) were calculated based upon HI_o estimates using measured and interpreted fractional composition of kerogen macerals.

The Middle Velkerri source rock interval in the Tanumbirini 1 well is interpreted to represent a low geochemical risk for in-situ shale gas production. The measured TOC content averages 3.13 wt.% is above the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 7). It is also above the minimum requirements of 2 wt.% for *economic* petroleum source rocks, which is also the minimum threshold for prospective shale gas. Original organic matter type is interpreted to be predominantly oil-prone Type II marine algal kerogen. Thermal maturity parameters from programmed pyrolysis place the Middle Velkerri source interval in early dry gas window. The average T_{max} value of 546°C is well above the recommended minimum value of 455°C for shale gas (Fig. 7). This amount of conversion would likely be sufficient to generate/expel significant amounts of hydrocarbons from this oil prone source facies. Transformation ratios (TR), the least constrained risk parameter, average 99% and fall well above the recommended minimum of 80% for shale gas systems (Fig. 7). Measured maceral reflectance values give an average calculated Eq. R_o of 1.99% R_o for high reflectance solid bitumens, which is above the recommended minimum of 1.0% for shale gas (Fig. 7). On the basis of all of these measured geochemical risk parameters, the Middle Velkerri source interval would be considered a low risk for shale gas since all values fall above recommended minimum thresholds (Fig. 7).

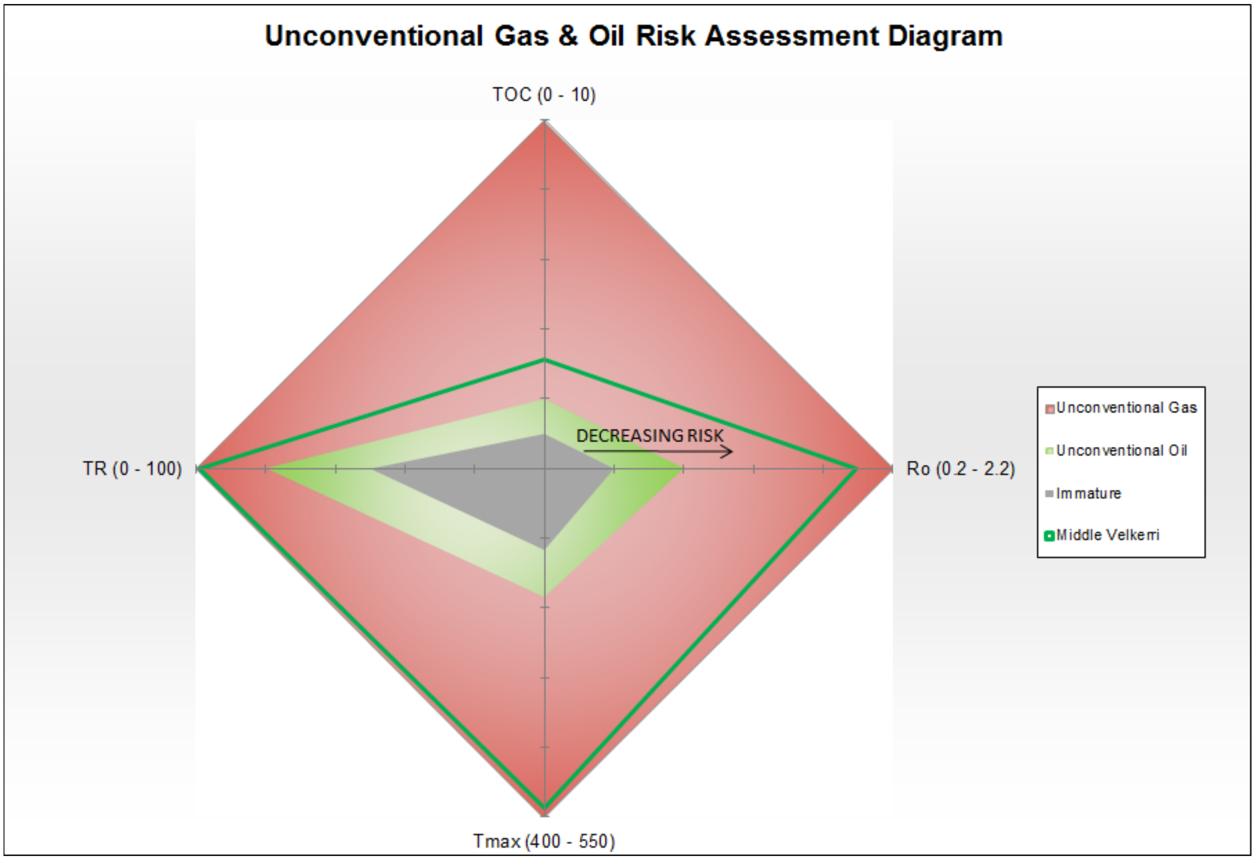

Figure 7. Geochemical Risk Assessment diagram for Mesoproterozoic Velkerri Formation source rocks in the Tanumbirini 1 well.

In the Middle Velkerri source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor (3 bbl oil/acre-ft), which is consistent with the interpreted thermal maturity level of this interval (Fig. 8). Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Middle Velkerri at 0 bbl oil/acre-ft and oil cracking is estimated to have been 100%, resulting in a cracked gas yield of 2459 Mcf/acre-ft (Fig. 8). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/acre-ft. These values are slightly higher compared to the Middle Velkerri and are primarily due to differences in organic richness (Barnett Shale gas example has average of 4.21 wt. % TOC).

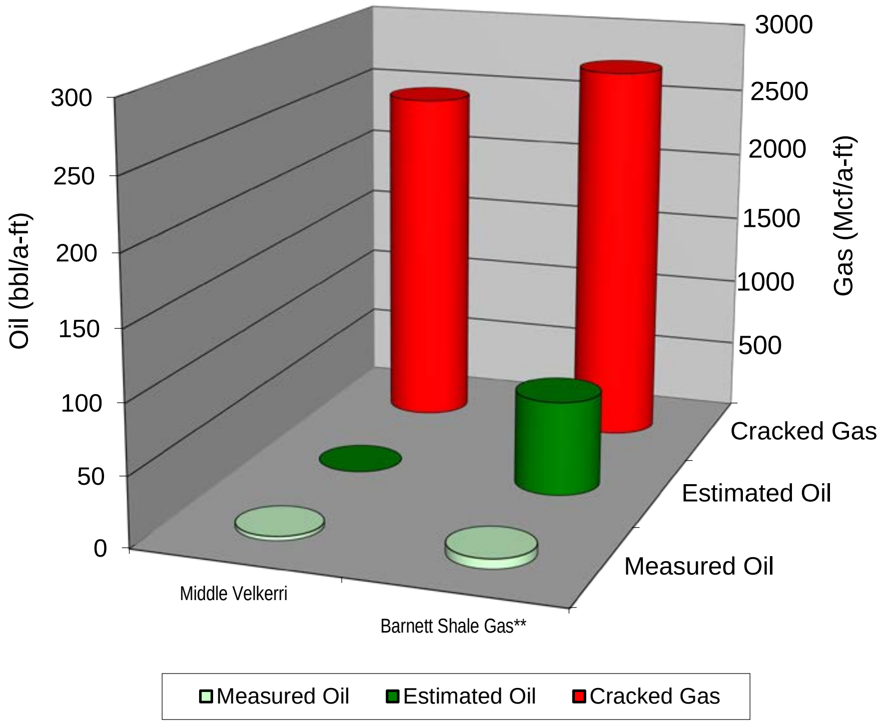

Figure 8. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the Tanumbirini 1 well compared to Barnett Shale in the gas window.

Geochemical Summary

The Upper Velkerri source interval in the Tanumbirini 1 well is interpreted to represent low geochemical risk for unconventional shale gas development. It clearly has elevated organic richness (avg. 3.13 wt.% TOC) and is considered a very good source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that the source interval is in the early dry gas window, 2.67% Calc. R_o & 1.99% Eq. R_o from solid bitumen reflectance. All key risk ratios are above recommended minimum thresholds for shale gas systems. The Middle Velkerri has likely generated significant amounts of secondary cracked gas (avg. 2459 Mcf/acre-ft) and these values are comparable to other systems such as the Barnett Shale in the gas window.

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