BMR Urapunga 3 Interpretive Summary

Middle Velkerri Interval

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

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INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Middle Velkerri Formation in the BMR Urapunga 3 well located in the McArthur Basin, Northern Territories, Australia. Twenty (20) core chip samples from this well were analyzed by a variety of geochemical techniques, including total organic carbon (TOC, LECO®), programmed pyrolysis (SRA) and organic petrology with measured maceral reflectance (R_o). 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 Oil Risk*
BMR Urapunga 3	Middle Velkerri	**Estimated Original ⟶**		Excellent (5.50% TOC)	Oil-prone Type II	Low
Measured Currently ⟶		Oil	Peak Oil Window	Excellent (4.74% TOC)	Mixed Type II/III	

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

Twenty samples (20) from the Middle Velkerri Formation were analyzed for LECO TOC content and programmed pyrolysis (Fig. 1). TOC contents ranged from 2.79 to 7.40 wt.% and averaged 4.74 wt.% (excellent). All of these samples have TOC contents above the minimum requirement of 1 wt.% for *effective* petroleum source rocks and all are also above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. There are three distinct cycles of TOC within this interval with maxima occurring at depths of 40, 75 and 130 m (Fig. 1). These three organic rich intervals have been previously recognized within the Middle Velkerri (Lanigan et al, 1994) and could be associated with the base of transgressive systems tracts (TST) in a series of platform/ramp parasequences (Bohacs et al., 2013). These stepwise changes in TOC and corresponding minimal change in Hydrogen Index values (HI) suggests that production was the major control on organic richness along with auto-dilution by pelagic carbonate (Bohacs et al., 2013).

The S1 values of the Middle Velkerri source rock samples average 2.30 mg HC/g rock (50 bbl oil/acre-ft) and S2 values average 13.00 mg HC/g rock (285 bbl oil/acre-ft). The S1 and S2 values imply very good in-situ hydrocarbon saturation and very good remaining generative potential (Fig. 1). The S1 values should be considered a minimum for in-situ oil saturation since they do not account for potential loss of volatile components during sample collection and analysis. The normalized oil content (NOC) in the Middle Velkerri samples, (S1/TOC) x 100, averages 49 (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. 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, S1 crosses over TOC at two locations within the basal section of the Middle Velkerri Formation, 95.03 and 110.54 m depths (Fig. 1), in the BMR Urapunga 3 well.

Measured Hydrogen Index (HI) values in the Middle Velkerri average 268 mg HC/g TOC, indicating mixed oil/gas-prone Type II/III kerogen quality in these source rocks at present day. Original HI_o of these

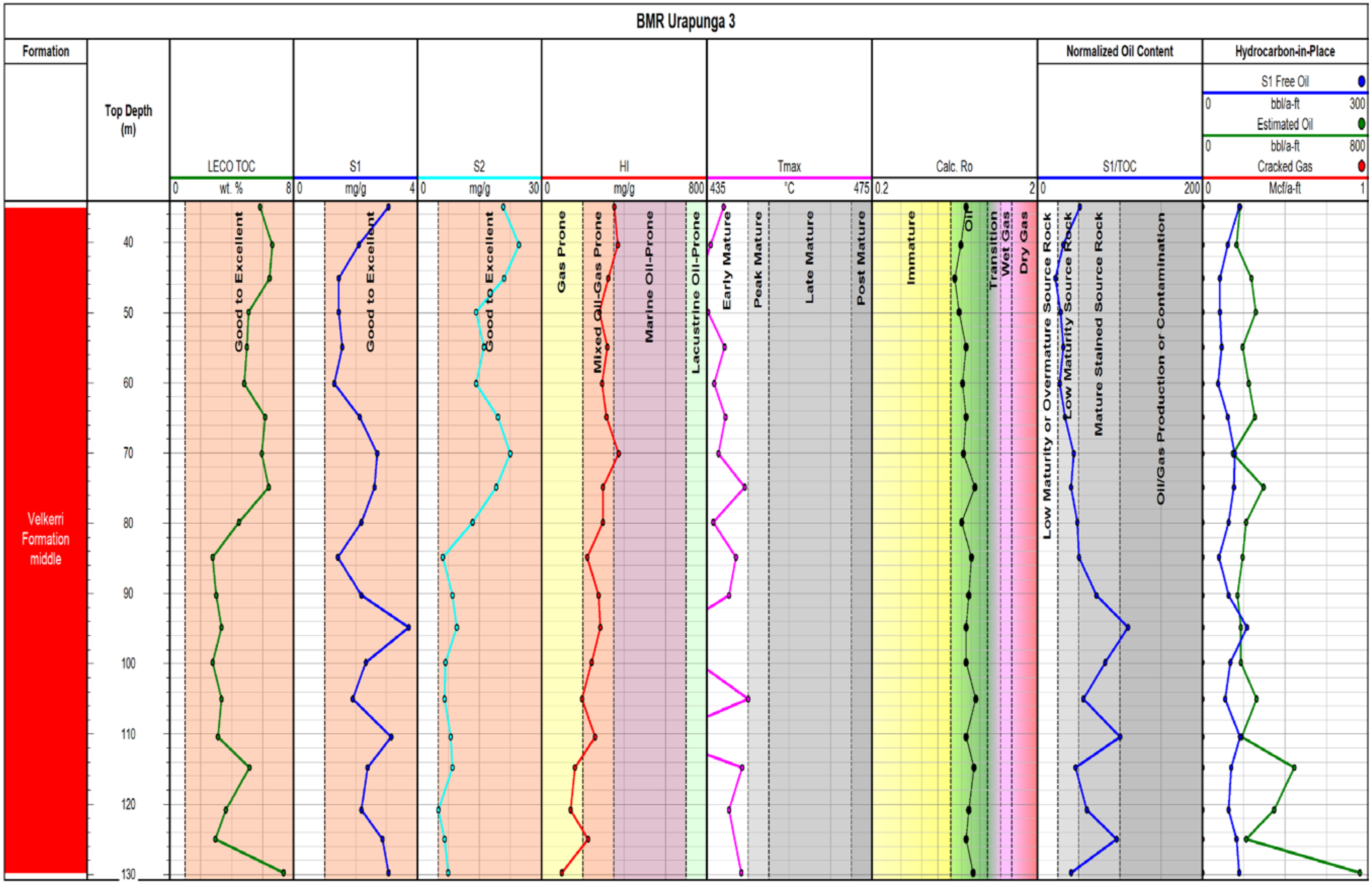

Figure 1. Geochemical depth plots for the BMR Urapunga 3 well.

samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation Ratios (TR) based upon HI average 52%, which is consistent with an early to peak oil window thermal maturity. T_{max} values in the Middle Velkerri samples average 440°C on the basis of select data determined to be reliable. T_{max} between 435 and 445°C typically indicate peak oil window, while values between 425 and 435°C typically indicate early oil window (Type II kerogen). On the basis of these guidelines, the average Middle Velkerri T_{max} values in this well would be interpreted to be in the peak oil 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 440°C is equivalent to a Calc. $\%R_o$ value of 0.75%. 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 these Middle Velkerri samples average 0.18. These moderate PI values are consistent with source rocks in the peak oil window, which typically have PI values between ~0.15 to 0.25. It is noteworthy that samples in the basal section of the Middle Velkerri interval appear to have the most elevated PI values and this is consistent with their elevated NOC, which suggests possible producible in-situ oil saturation within this horizon.

Organic petrology was performed on three (3) samples from the Middle Velkerri interval (85.01, 114.93 and 129.85 m) in the BMR Urapunga 3 well (Figs. 2-4). The results from these analyses show distributions that consist of macerals identified as either non-fluorescing Alginite, low reflecting solid bitumen or high reflectance solid bitumen. The low reflecting solid bitumen population observed in the 85.01 m sample has reflectance values that average 0.78% R_o (Fig. 2) and are considered the most representative indigenous kerogen population for thermal maturity assessment. This group of organic macerals is 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 maturity assessment from this maceral group would be consistent with the peak oil window, which is also supported by the presence of yellow/orange to light brown algal fluorescence colors in this same sample.

The non-fluorescing Alginite maceral group from the two deeper Middle Velkerri samples had average reflectance values that vary from 1.32 to 1.45% R_o, which would suggest a condensate/wet gas thermal maturity. This is judged to be too high in comparison with other geochemical data. The high reflecting solid bitumens tended to have slightly higher reflectance readings in comparison to the Alginite maceral group. The mean measured reflectance value for these solid organic macerals varies from 1.47 to 1.64% R_o. Published solid bitumen conversions were applied to both populations of solid bitumen 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 a 1.09% Eq. R_o when applied to the low reflecting solid bitumens. The conversion formula published by Jacob (1985) equation (Eq. R_o = (Bitumen $R_o \times 0.618$) + 0.4) for 'angular-like' pyrobitumen trapped in mineral pore spaces resulted in values of 1.31 and 1.41% Eq. R_o when applied to the high reflecting solid bitumens. Neither of these conversions result in Eq. R_o values that are consistent with other geochemical maturity data since they would suggest condensate/wet gas maturity. Comparison with other samples examined in the current study suggest that 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 population of low reflectance solid bitumen within the same sample. This does not appear to be the case in readings from the Middle Velkerri in the BRM Urapunga 3 well.

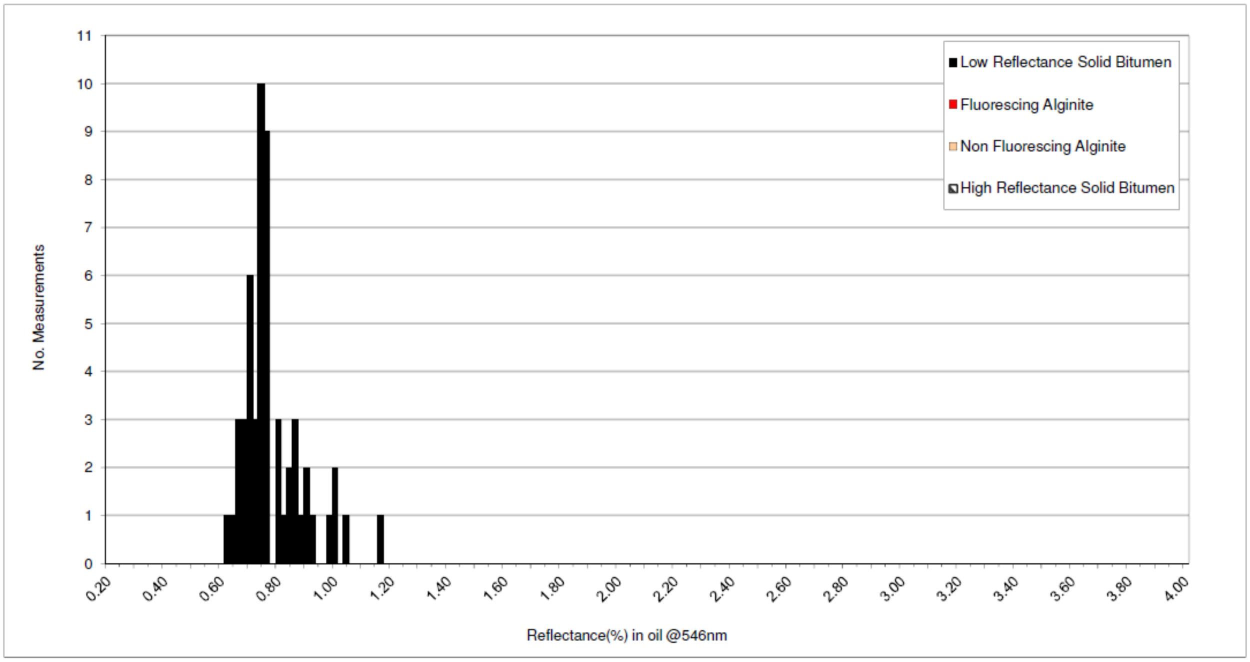

Figure 2. Organic petrology of the Middle Velkerri (85.01 m) in the BMR Urapunga 3 well. Mean maceral reflectance of low reflecting solid bitumen is 0.78% R_o.

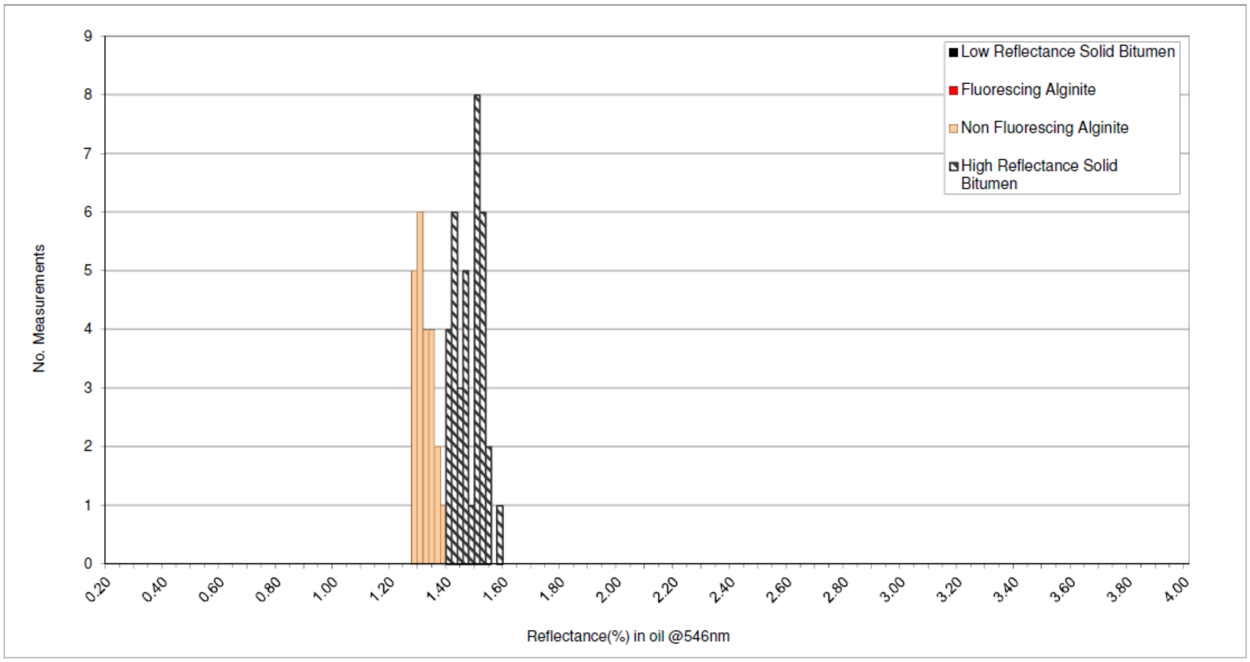

Figure 3. Organic petrology of the Middle Velkerri (114.93 m) in the BMR Urapunga 3 well. Mean maceral reflectance of non-fluorescing Alginite is 1.32% R_o. The high reflecting solid bitumen has mean reflectance of 1.47% R_o, which equates to calculated Eq. R_o of 1.31% R_o using the conversion of Jacob (1985).

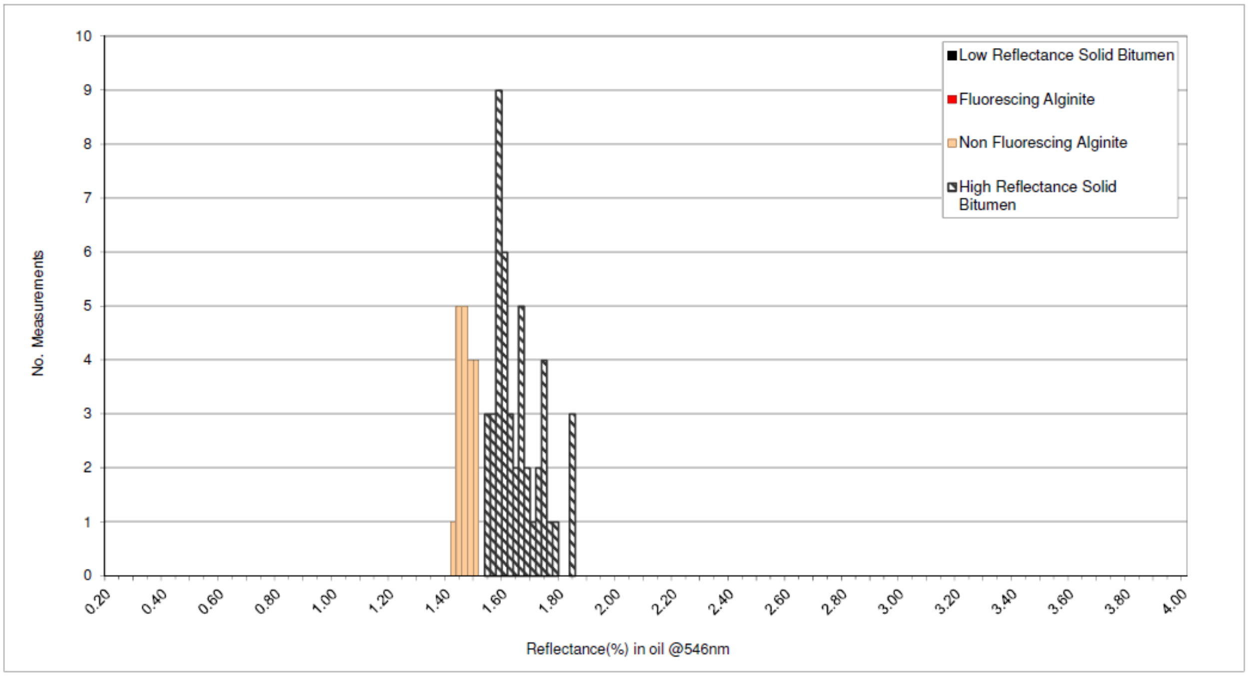

Figure 4. Organic petrology of the Middle Velkerri (129.85 m) in the BMR Urapunga 3 well. Mean maceral reflectance of non-fluorescing Alginite is 1.46% R_o. The high reflecting solid bitumen has mean reflectance of 1.64% R_o, which equates to calculated Eq. R_o of 1.41% R_o using the conversion of Jacob (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 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. For the BMR Urapunga 3 well, the measured kerogen maceral distributions show 100% Type II kerogen for two samples and 12% Type I with 88% Type II for the other sample (dominantly inert AOM with minor lens/layer AOM and lamalginite). 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 BMR Urapunga 3 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):

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

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 is 0.52 (Table 3), i.e., on average an estimated 52% 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):

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

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 source rock samples in this well before petroleum generation is 5.50 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 Velkerri source rocks examined in the BMR Urapunga 3 well, the average $S2_o$ value is 24.8 g HC/g rock or approximately 542 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).

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

Using this methodology for the Middle Velkerri samples analyzed in the current study, the generated oil yields average 258 bbl/acre-ft (Table 3).

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	4.74	268	285	450	0.52	5.50	542	50	258	0

Table 3. Hydrocarbon Yields average data for BMR Urapunga 3 well.

The amount of hydrocarbons (oil + gas) expelled from the rocks can be estimated as the difference between the amount of residual oil measured via programmed pyrolysis (S1) and the amount of estimated generated hydrocarbon yields determined above (equation 5). The expulsion efficiency (ExEf) can then be calculated as a direct proportion of the measured retained oil saturations and the average generated hydrocarbon yields. Thus, the resulting expulsion efficiency for the Middle Velkerri interval in this well is estimated to be 80%.

The Middle Velkerri source rock interval in the BMR Urapunga 3 well is interpreted to be in the peak oil windows and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly oil with some associated gas). From an exploration risk perspective, this is 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 542 bbl oil/acre-ft, which compares favorably to 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	0.52	5.50	24.77	285	542	0.00	50	258	0

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Velkerri Formation source rocks in the BMR Urapunga 3 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 5) 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. 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 gray) 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.

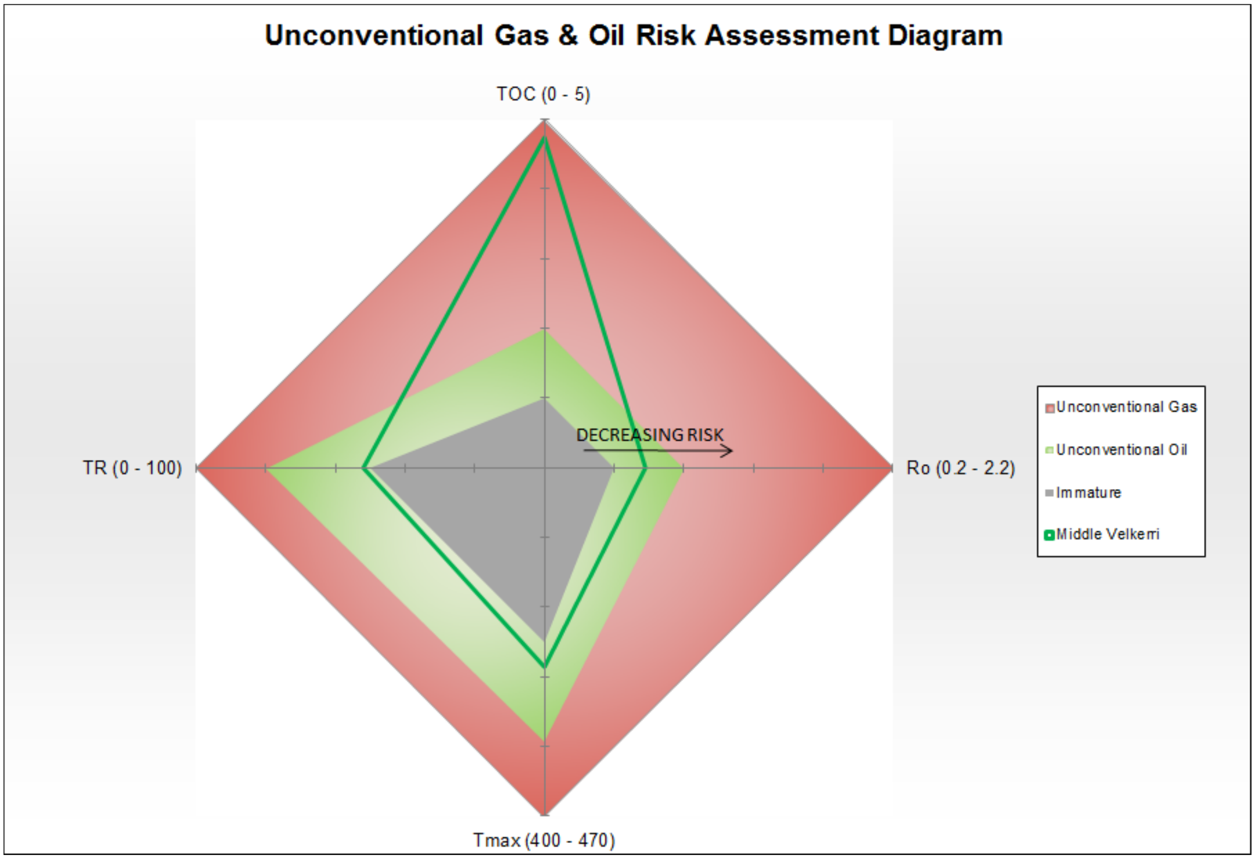

Figure 5. Geochemical Risk Assessment diagram for Mesoproterozoic Velkerri Formation source rocks in the BMR Urapunga 3 well.

The Middle Velkerri source rock interval in the BMR Urapunga 3 well is interpreted to represent a low geochemical risk for in-situ shale oil production. The average TOC content of 4.74 wt.% is above the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 5). 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 based upon measured visual kerogen analysis. Thermal maturity parameters from programmed pyrolysis place the Middle Velkerri source interval in peak oil window. The average Tmax value of 440°C is above the recommended minimum value of 435°C for shale oil, but below the minimum of 455°C for shale gas (Fig. 5). This amount of conversion would likely be sufficient to generate/expel significant amounts of hydrocarbons from this organic-rich, oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 52% and fall above the recommended minimum of 50% for shale oil systems (Fig. 5). Measured maceral reflectance values in the Middle Velkerri give a mean for low reflectance solid bitumen of 0.78% R_o, which is above the recommended minimum threshold of 0.5% R_o for shale oil and below the minimum of 1.0% R_o for shale gas (Fig. 5). On the basis of all of these measured geochemical risk parameters, the Middle Velkerri source interval would be considered a low risk for shale oil and a high risk for shale gas since all of the thermal maturity risk parameters do fall well below recommended minimum thermogenic shale gas thresholds (Fig. 5).

In the Middle Velkerri source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is very good (avg. 50 bbl oil/acre-ft), suggesting low risk for shale oil development (Fig. 6). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Middle Velkerri at 258 bbl oil/acre-ft (Fig.6). As a comparison, a representative example from the core area of Barnett Shale oil production in the Fort Worth Basin has an estimated generated oil yield of 213 bbl/a-ft with a measured in-situ oil saturation of 79 bbl/a-ft (Fig. 6). These values are comparable to the Middle Velkerri and minor differences could be due to differences in retention/expulsion efficiency possibly related to differences in geologic age of these formations.

It is important to note that the quantity of oil generated from a potential source rock is only one geochemical factor to consider in regard to risk assessment. Equally important is the quality of the oil generated, since this factor can be a critical element in assessing the movability and ultimate recovery. The interpreted thermal maturity of the Middle Velkerri source interval in this well is in the peak oil window and hydrocarbon saturation is likely to be fairly light a mobile. However, the presence of heavy oil and/or bitumen could also indicate a source interval with restricted microporosity. Such microporosity is considered necessary for recovery of in-situ oil saturation and can be better assessed using scanning electron microscopy (SEM). Source rock extract fingerprints and bulk fractional compositional analyses from select Velkerri samples would also aid in the determination of the quality of the in-situ hydrocarbon saturation and provide a better assessment of their movability and ultimate recovery potential.

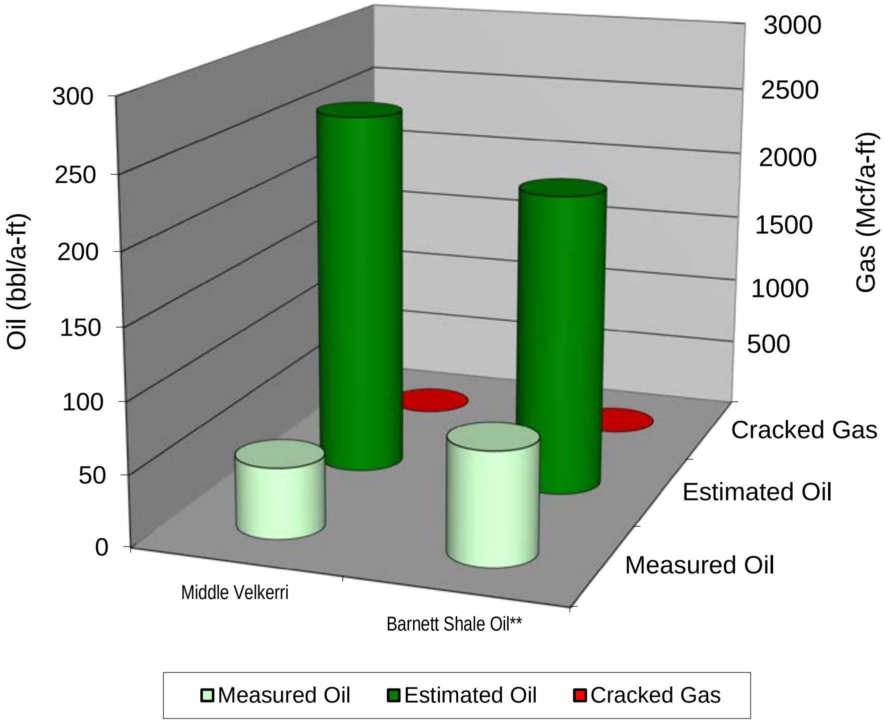

Figure 6. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the BMR Urapunga 3 well compared to Barnett Shale in the oil window.

GEOCHEMICAL SUMMARY

The Middle Velkerri source interval in the BMR Urapunga 3 well is interpreted to represent low geochemical risk for unconventional shale oil development. It clearly has elevated organic richness (avg. 4.74 wt.% TOC) and is considered an excellent source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that the source interval is in the peak oil window, 0.75% Calc. R_o and 0.78% Eq. R_o from solid bitumen reflectance. All key thermal maturity risk ratios are above recommended minimum thresholds for shale oil systems. The Middle Velkerri has likely generated significant amounts of oil (avg. 258 bbl oil/acre-ft) and comparison to other systems such as the Barnett Shale show in-situ oil saturations are slightly lower but generally comparable for the Middle Velkerri. Risk criteria like the S1 versus TOC show oil cross-over for two samples in the middle of this unit. Further evaluation of in-situ oil characteristics would be required to fully evaluate potential oil mobility and recovery risk.

Appendix I

Hydrocarbon Yield Calculation
Shelf Group
BMR Urapunga 3

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

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BMR Urapunga 3

Hydrocarbon Yield Calculation

																S2 (meas)	S2 (orig)				
Sample	**Top Depth**	**TOC***	**HI***	**S1***	**S2***	**Calc.Ro**	**PI***	**%Type IV 50 HI°**	**% Type III 125 HI°**	**%Type II 450 HI°**	**%Type I 750 HI°**	**HI°**	**TR**	**TOC°**	**S2°**	**Remaining Potential**	**Original Potential**	**Oil Cracked**	**S1 Free Oil**	**Estimated Oil**	**Cracked Gas**
BMR Urapunga 3	**(m)**	**wt%**	**mg/g TOC**	**mg/g Rock**	**mg/g Rock**	**%**						**mg/g TOC**		**wt%**	**mg/g Rock**	**bbl/a-ft**	**bbl/a-ft**	**%**	**bbl/a-ft**	**bbl/a-ft**	**Mcf/a-ft**
UR15DJR130	35	5.88	354	3.08	20.81	**0.75**	0.13	0	0	100	0	450	0.33	6.51	29.27	456	641	0.00	67	185	0
UR15DJR131	40	6.66	371	2.13	24.71	**0.69**	0.08	0	0	100	0	450	0.27	7.17	32.25	541	706	0.00	47	165	0
UR15DJR132	45	6.46	327	1.46	21.13	**0.64**	0.06	0	0	100	0	450	0.38	7.10	31.97	463	700	0.00	32	237	0
UR15DJR133	50	5.11	281	1.47	14.37	**0.68**	0.09	0	0	100	0	450	0.50	5.84	26.27	315	575	0.00	32	261	0
UR15DJR134	55	4.99	323	1.59	16.11	**0.75**	0.09	0	0	100	0	450	0.40	5.56	25.02	353	548	0.00	35	195	0
UR15DJR135	60	4.82	297	1.32	14.30	**0.71**	0.08	0	0	100	0	450	0.46	5.45	24.52	313	537	0.00	29	224	0
UR15DJR136	65	6.20	315	2.14	19.55	**0.75**	0.10	0	0	100	0	450	0.42	6.94	31.22	428	684	0.00	47	256	0
UR15DJR137	70	5.98	376	2.70	22.46	**0.72**	0.11	0	0	100	0	450	0.27	6.49	29.20	492	639	0.00	59	148	0
UR15DJR138	75	6.41	298	2.63	19.08	**0.84**	0.12	0	0	100	0	450	0.46	7.28	32.78	418	718	0.00	58	300	0
UR15DJR139	80	4.49	298	2.20	13.40	**0.70**	0.14	0	0	100	0	450	0.47	5.15	23.19	293	508	0.00	48	214	0
UR15DJR140	85	2.79	225	1.43	6.27	**0.80**	0.19	**0**	**0**	**100**	**0**	450	0.63	3.38	15.22	137	333	0.00	31	196	0
UR15DJR141	90	3.05	280	2.21	8.53	**0.77**	0.21	0	0	100	0	450	0.52	3.61	16.25	187	356	0.00	48	169	0
UR15DJR142	95	3.37	288	3.73	9.70	0.75	0.28	0	0	100	0	450	0.51	4.04	18.20	212	399	0.00	82	186	0
UR15DJR143	100	2.82	246	2.34	6.95	0.75	0.25	0	0	100	0	450	0.59	3.43	15.44	152	338	0.00	51	186	0
UR15DJR144	105	3.38	196	1.91	6.64	**0.85**	0.22	0	0	100	0	450	0.68	4.17	18.78	145	411	0.00	42	266	0
UR15DJR145	111	3.13	263	3.16	8.22	0.75	0.28	0	0	100	0	450	0.56	3.80	17.10	180	374	0.00	69	194	0
UR15DJR146	115	5.16	164	2.41	8.46	**0.83**	0.22	**0**	**0**	**100**	**0**	450	0.74	6.41	28.86	185	632	0.00	53	447	0
UR15DJR147	121	3.67	141	2.21	5.17	**0.77**	0.30	0	0	100	0	450	0.78	4.68	21.07	113	461	0.00	48	348	0
UR15DJR148	125	2.96	226	2.87	6.70	0.75	0.30	0	0	100	0	450	0.63	3.67	16.49	147	361	0.00	63	214	0
UR15DJR149	130	7.40	101	3.09	7.47	**0.82**	0.29	**0**	**0**	**100**	**0**	450	0.85	9.40	42.30	164	926	0.00	68	763	0
Middle Velkerri (Avg)		**4.74**	**268**	**2.30**	**13.00**	**0.75**	**0.18**	**0**	**0**	**100**	**0**	**450**	**0.52**	**5.50**	**24.77**	**285**	**542**	**0.00**	**50**	**258**	**0**
Barnett Shale Oil**		4.70	300	3.60	14.90	0.86	0.20	0	0	100	0	450	0.47	5.47	24.64	326	540	0.00	79	213	0
Barnett Shale**		4.21	26	0.33	1.07	1.66	0.24	0	0	100	0	450	0.96	5.58	25.13	23	550	0.87	7	68	2751

Notes: Calc.Ro values in **bold** are calculated from measured Tmax. Calc.Ro values in red font are intrepreted from other geochemical maturity data because Tmax was considered unreliable. All other Calc.Ro values are formation specific averages because Tmax was considered unreliable.

Kerogen Type in **bold** have visual kerogen data for estimates TR = Transformation Ratio (fractional conversion) (Original Potential - Remaining Potential) = (Estimated Oil + Cracked Gas)

Estimated Oil and Cracked Gas yield data assume complete conversion and no expulsion of hydrocarbon products and the proportion between each is based on empirical Ro calculated % cracking.

Yields do not represent recoverable products and are intended primarily for comparison purposes, yield calculations based on carbon mass balance are likely to be overestimations. **Estimated parameters for productive Barnett Shale in the Ft. Worth Basin

Hydrocarbon yield calculations and formulas are fully documented in the appendix section of Jarvie et al. (2007)