DD90VRB2 Interpretive Summary

Kunja Siltstone – Pear Tree Dolostone Interval

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INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Kunja Siltstone, Amos Knob Formation and Pear Tree Dolostone in the DD90VRB2 (Pear Tree 2) well located in the Birrindudu Basin, Northern Territories, Australia. Eleven (11) 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). In addition, client supplied published geochemical data for 14 samples was also incorporated into the interpretive evaluation. 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***
DD90VRB2	Kunja Siltstone	**Estimated Original ⟶**		Good (1.99% TOC)	Oil-prone Type II	Moderate
Measured Currently ⟶		Oil	Early Oil Window	Good (1.74% TOC)	Mixed Type II/III	
DD90VRB2	Amos Knob	**Estimated Original ⟶**		Fair (0.56% TOC)	Mixed Type II/IV	High
Measured Currently ⟶		Oil	Peak Oil Window	Poor (0.22% TOC)	Inert Type IV	
DD90VRB2	Pear Tree Dolostone	**Estimated Original ⟶**		Good (1.33% TOC)	Oil-prone Type II	High
Measured Currently ⟶		Oil	Peak Oil Window	Fair (0.89% TOC)	Gas Prone Type III	

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

Table 1. Geochemical Summary

KUNJA SILTSTONE

Three samples (3) from the Kunja Siltstone were analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (3 samples) composed of client supplied public data (Fig. 1). TOC contents ranged from 1.52 to 2.08 wt.% and averaged 1.74 wt.% (good). All of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while only one (1) sample has TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. Highest TOC content was found near the base of the designated Kunja Siltstone interval (35.9 m depth) (Fig. 1), although TOC is also elevated in the uppermost sample as well and the middle section appears to have lower organic richness based upon the relatively sparse sampling available (Fig. 1).

The S1 values of the Kunja Siltstone source rock samples average 0.30 mg HC/g rock (6 bbl oil/acre-ft) and the S2 values average 4.77 mg HC/g rock (104 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and fair remaining generative potential (Fig. 1). The normalized oil contents (NOC) in the Kunja Siltstone samples, (S1/TOC) x 100, average 17 (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 most likely related to post-mature source rocks that have likely generated and expelled most of their in-situ hydrocarbon saturation or 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

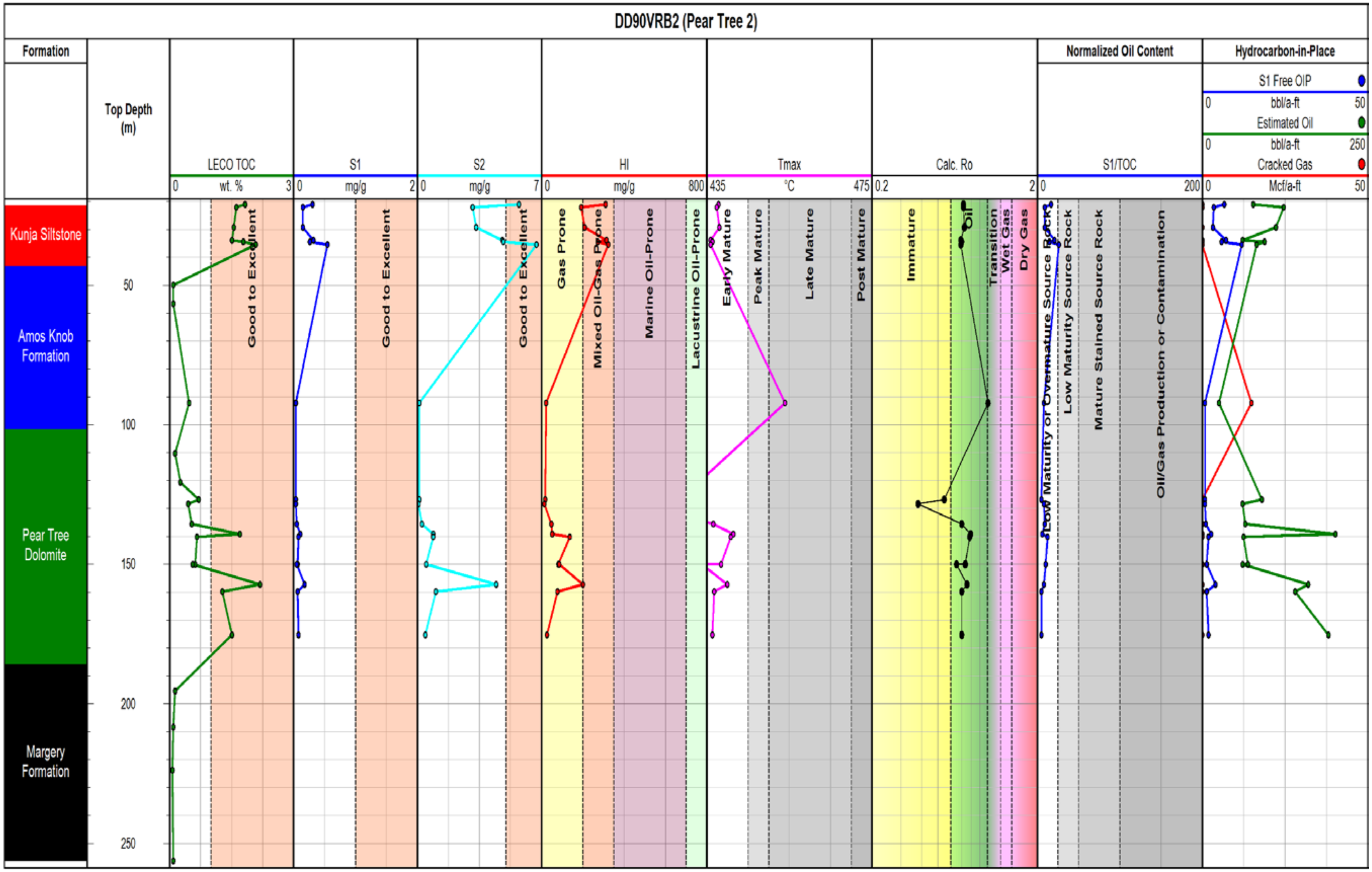

Figure 1. Geochemical depth plots for the DD90VRB2 well.

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 samples analyzed (Fig. 1).

The measured Hydrogen Index (HI) values in the Kunja Siltstone average 272 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 samples are estimated to average 450 mg HC/g rock, which indicate oil-prone Type II kerogen. Transformation Ratios (TR) based upon HI are 51%, which suggest an early oil window thermal maturity. The T_{max} values in the Kunja Siltstone samples average is 437°C. T_{max} between 425 and 435°C typically indicate early oil window, while samples in the peak oil window usually have values between 435 and 445°C (Type II kerogen). On the basis of these guidelines, the average Kunja Siltstone 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 measured T_{max} value of 437°C is equivalent to a Calc. $\%R_o$ value of 0.71%. 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.

The Production Index (PI) values in the Kunja Siltstone samples average 0.06. These low PI values would normally indicate immature source rocks, which typically have PI values < 0.1. Alternatively, the low PI values in these Kunja Siltstone samples are a consequence of low S1 yields and could suggest significant expulsion/migration of hydrocarbons out of these potential source rocks.

The thermal maturity of the Kunja Siltstone source rocks was also evaluated by measured Kübler Index values from XRD, which are based upon illite crystallinity. These values can be used as maturity indicator when samples contain sufficient high quality clays (Abad, 2008). A single sample (34.7 m) from the Kunja Siltstone (avg. 29% clays) has a measured Kübler Index of 0.229, which is equivalent to a measured vitrinite reflectance of > 4% (late stage metagenesis). This interpretation is inconsistent with other geochemical maturity ratios evaluated in this study and suggests the Kübler Index should be used with caution to evaluate thermal maturity in Palaeoproterozoic aged source rocks.

AMOS KNOB

One sample (1) from the Amos Knob Formation was analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (2 samples) composed of client supplied public data (Fig. 1). The Amos Knob Formation in the DD90VRB2 well exhibits poor generative potential for petroleum source rocks based on TOC content values (Fig. 1). TOC content ranges from 0.09 to 0.48 wt.% and averages 0.22 wt.% (poor). None of the samples analyzed exceed the minimum value of 1 wt.% for *effective* petroleum source rocks. The highest relative TOC occurs near the base of the sampled interval (92.24 m), but depth trends in TOC are speculative due to the sparse sampling within this interval (Fig. 1).

The S1 value in the Amos Knob is 0.04 mg HC/g rock (1 bbl oil/acre-ft), indicating very low in-situ hydrocarbon saturation (Fig. 1) and is consistent with the low TOC content of these samples. NOC value of only 8 in the Amos Knob interval is lower in comparison to the overlying Kunja Siltstone. Oil cross over (NOC > 100) was not observed (Fig. 1). The S2 value in the Amos Knob is 0.11 mg HC/g rock (2 bbl oil/acre-ft), indicating poor remaining hydrocarbon generation potential.

The measured HI value in the Amos Knob sample is 23 mg HC/g TOC, which indicate inert Type IV kerogen quality in these source rocks at present day. Estimated original HI_o values in these samples are speculative, but likely average 250 mg HC/g TOC, indicative of a postulated mixed Type II/IV kerogen quality. Transformation Ratios (TR) based upon HI average 93%, which is generally consistent with an elevated gas window thermal maturity. This could suggest that original HI_o estimations are too high.

The organic-matter in the Amos Knob interval in the DD90VRB2 well is thermally mature and is interpreted to be in the peak oil window. The programmed pyrolysis T_{max} value is 454°C (Fig. 1). T_{max} between 445 and 450°C typically indicate late oil window, while samples in the condensate/wet gas window usually have values between 450 and 470°C (Type II kerogen). Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated R_o = (0.0180)(T_{max}) – 7.16), this is equivalent to a Calc. %R_o value of 1.01%. 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 and is especially problematic in samples with low S2 values such as observed in the Amos Knob. Consequently, the interpreted peak oil window maturity for this interval is based more upon determinations in adjacent stratigraphic intervals where data is more reliable.

The Production Index (PI) value in the Amos Knob sample is 0.27. These elevated PI values are consistent with source rocks in the peak to late oil window. However, this ratio is considered somewhat unreliable due to the very low yields of both S1 and S2 in this sample.

The thermal maturity of the Amos Knob source rocks was also evaluated by measured Kübler Index values from XRD, which are based upon illite crystallinity. These values can be used as maturity indicator when samples contain sufficient high quality clays (Abad, 2008). A single sample (57.02 m) from the Amos Knob Formation (avg. 58% clays) has a measured Kübler Index of 0.250, which is equivalent to a measured vitrinite reflectance of > 4% (late stage metagenesis). This interpretation is inconsistent with other geochemical maturity ratios evaluated in this study and suggests the Kübler Index should be used with caution to evaluate thermal maturity in Palaeoproterozoic aged source rocks.

PEAR TREE DOLOSTONE

Seven (7) samples from the Pear Tree Dolostone were analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (9 samples) composed of client supplied public data (Fig. 1). TOC contents ranged from 0.08 to 2.19 wt.% and averaged 0.89 wt.% (fair). Four (4) of these samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, while only one (1) sample has TOC content above the minimum requirement of 2 wt.% for *economic* petroleum source rocks. There appears to be at least four distinct cycles of TOC within this interval with maxima occurring at depths of 127, 139, 158 and 176 m (Fig. 1), but the sparse sampling within this interval makes this determination somewhat speculative.

The S1 values in the Pear Tree Dolostone source rock samples average 0.08 mg HC/g rock (2 bbl oil/acre-ft) and S2 values are also low with an average 0.93 mg HC/g rock (20 bbl oil/acre-ft). The S1 and S2 values imply poor in-situ hydrocarbon saturation and poor remaining generative potential (Fig. 1). The normalized oil content (NOC) in the Pear Tree Dolostone samples average only 8 (Fig. 1) and there are no samples exhibiting oil “cross-over”.

Measured Hydrogen Index (HI) values in the Pear Tree Dolostone average 77 mg HC/g TOC, indicating gas-prone Type III kerogen quality in these source rocks at present day (Fig. 1). 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 88%, which is consistent with a late oil to early gas window thermal maturity. T_{max} values in the Pear Tree Dolostone samples average 435°C. T_{max} between 425 and 435°C typically indicate early oil window, while values between 435 and 445°C indicate peak oil window (Type II kerogen). On the basis of these guidelines, the average Pear Tree Dolostone T_{max} values in this well would be interpreted to be at the transition between early to 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 435°C is equivalent to a Calc. %R_o value of 0.68%. 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 Pear Tree Dolostone samples average 0.14. These moderate PI values are consistent with source rocks in the early oil window, which typically have PI values between ~0.10 and 0.15.

Organic petrology was performed on two samples from the Pear Tree Dolostone interval (159.86 & 175.73 m). The results from these analyses (Figs. 2 & 3) show distributions that consist of macerals identified as either fluorescing alginite, low reflectance solid bitumen or high reflectance solid bitumens. The fluorescing alginite population in the 159.86 m sample has a mean reflectance of 0.48% R_o and exhibits light brown to dark brown fluorescence colors suggesting late oil window thermal maturity (~0.90 to 1.10% R_o). The low reflectance solid bitumen population has reflectance values that average 0.92 & 0.95% R_o and are considered the most representative indigenous kerogen population for thermal maturity assessment. The high reflecting solid bitumen population in the 159.86 m sample has a reflectance value of 1.31% R_o. The solid bitumens 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 Pear Tree Dolostone source rocks. 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) was applied to the low reflectance bitumen population and resulted in 1.22-1.24% Eq. R_o. 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 was applied to the high reflecting population and resulted in a 1.21% Eq. R_o. The Landis and Castaño (1995) conversion suggest a condensate/wet gas window thermal maturity, which is much higher than predicted by T_{max} for these samples. The Jacob (1985) conversion also suggests a thermal maturity that is within the early condensate/wet gas window. 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. In this well that does not appear to be valid since the calculated 1.21% Eq. R_o value and the measured 0.92 & 0.95% R_o values would suggest the Mallabah Dolostone samples in this well are within the early wet gas/condensate and peak oil windows respectively.

The thermal maturity of the Pear Tree Dolostone source rocks was also evaluated by measured Kübler Index values from XRD, which are based upon illite crystallinity. These values can be used as maturity indicator when samples contain sufficient high quality clays (Abad, 2008). A single sample (128.36 m) from the Pear Tree Dolostone (avg. 49% clays) has a measured Kübler Index of 0.245, which is equivalent to a measured vitrinite reflectance of > 4% (late stage metagenesis). This interpretation is inconsistent with other geochemical maturity ratios evaluated in this study and suggests the Kübler Index should be used with caution to evaluate thermal maturity in Palaeoproterozoic aged source rocks.

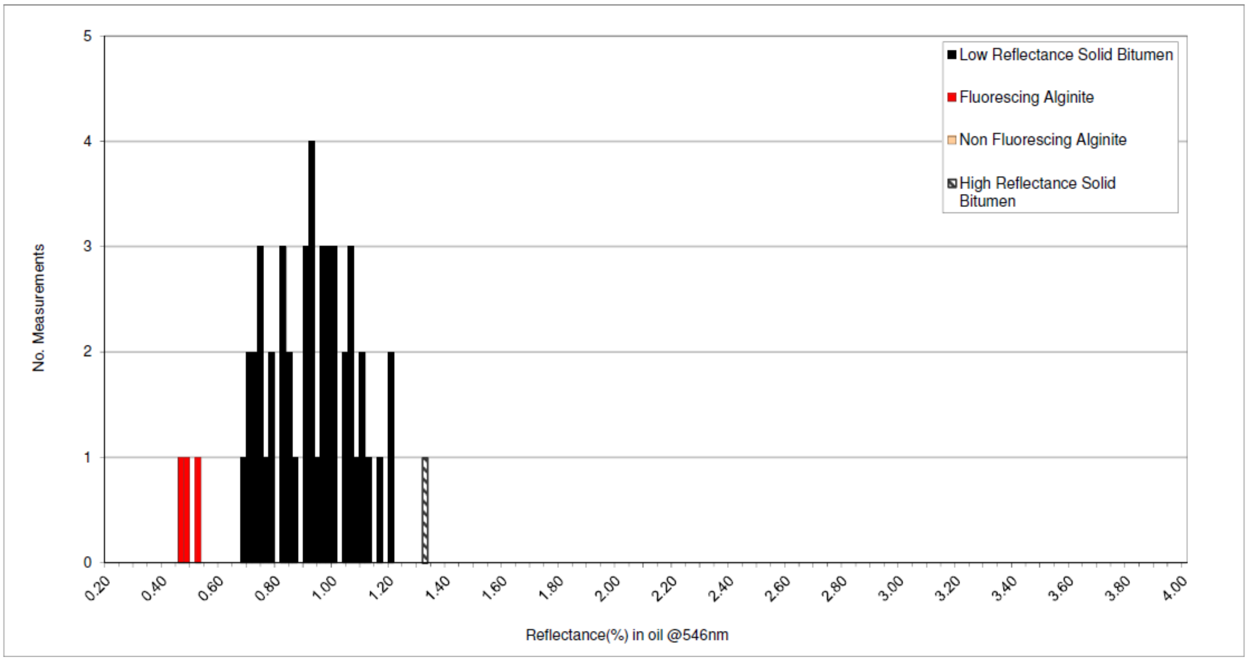

Figure 2. Organic petrology of the Pear Tree Dolostone (159.86 m) in the DD90VRB2 well. Mean maceral reflectance of low reflecting solid bitumen is 0.92% R_o. The high reflecting solid bitumen has mean reflectance of 1.31% R_o, which equates to calculated Eq. R_o of 1.21% R_o using the conversion of Jacob (1985).

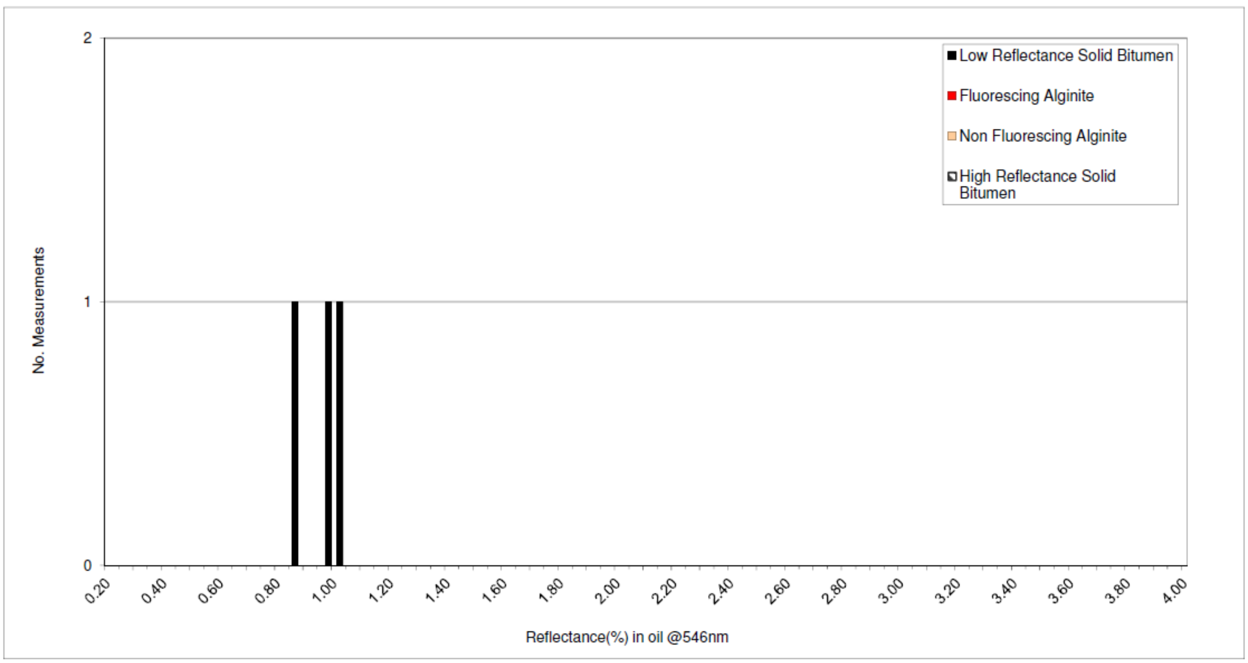

Figure 3. Organic petrology of the Pear Tree Dolostone (175.73 m) in the DD90VRB2 well. Mean maceral reflectance of low reflecting solid bitumen is 0.95% R_o.

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 Mallabah Dolostone source rocks 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. For the DD90VRB2 well, two samples from the Pear Tree Dolostone interval (159.86 & 175.73 m) were examined and the measured kerogen maceral distributions show 100% Type II kerogen (dominantly lens/layer AOM and inert AOM with minor amounts of diffuse AOM). 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 sedimentological information regarding this formation. Stromatolites are common throughout the succession, which was deposited in low- to medium-energy, shallow- to deep-marine conditions (Munson, 2014).

Formation	%Type I 750 HI_o	%Type II 450 HI_o	%Type III 125 HI_o	%Type IV 50 HI_o	HI_o
Kunja Siltstone	0	100	0	0	450
Amos Knob	0	50	0	50	250
Pear Tree Dolostone	0	100	0	0	450

Table 2. Average Kerogen Estimations for DD90VRB2 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 average HI_o values of 450 & 250 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 varies from 0.51 to 0.93 (Table 3), i.e., on average an estimated 51 to 93% 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):

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

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 estimated original TOC_o for the source rock samples in this well before petroleum generation average 1.99 wt.% for the Kunja Siltstone, 0.56 wt. % for the Amos Knob and 1.33 wt. % for the Pear Tree Dolostone (Table 3).

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

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

For the Kunja Siltstone source rocks examined in the DD90VRB2 well, the average $S2_o$ values are 9.0 mg HC/g rock or approximately 196 bbl/acre-ft (multiply $S2_o$ by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999), while the Amos Knob $S2_o$ values are 1.4 mg HC/g rock or 31 bbl/acre-ft and the Pear Tree Dolostone $S2_o$ values are 6.0 mg HC/g rock or 131 bbl/acre-ft (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 Kunja Silstone samples analyzed in the current study, the estimated generated oil yields average 92 bbl/acre-ft, while the Amos Knob has 26 bbl/acre-ft of oil (plus 15 Mcf/acre-ft of cracked gas) and the Pear Tree Dolostone has 110 bbl/acre-ft of oil (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
Kunja Siltstone	1.74	272	104	450	0.51	1.99	196	6	92	0
Amos Knob	0.48	23	2	250	0.93	0.56	31	1	26	15
Pear Tree Dolostone	1.02	77	20	450	0.88	1.33	131	2	110	0

Table 3. Hydrocarbon Yields average data for DD90VRB2 well.

For shale oil systems, 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 these source rock intervals ranges from 93 to 98%, which is more consistent with a source rock in the late oil to early wet gas/condensate window.

The Kunja Siltstone and Pear Tree Dolostone source rock intervals in the DD90VRB2 well are interpreted to be in the oil window and hydrocarbon yield calculations suggest moderate amounts of generation have occurred (predominantly oil with some associated 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 Kunja Siltstone, original generation potential ($S2_o$) averages 196 bbl oil/acre-ft, while the Pear Tree Dolostone is slightly lower at 131 bbl/acre-ft and the Amos Knob is only 31 bbl/acre-ft. All of these values are below 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
Kunja Siltstone	450	0.51	1.99	8.96	104	196	0.00	6	92	0
Amos Knob	250	0.93	0.56	1.40	2	31	0.09	1	26	15
Pear Tree Dolostone	450	0.88	1.33	5.97	20	131	0.00	2	110	0

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Palaeoproterozoic Kunja Siltstone, Amos Knob Formation and Pear Tree Dolostone source rocks in the DD90VRB2 well have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 4) 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 of the diagnostic ratios where available (R_o data is limited). 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.

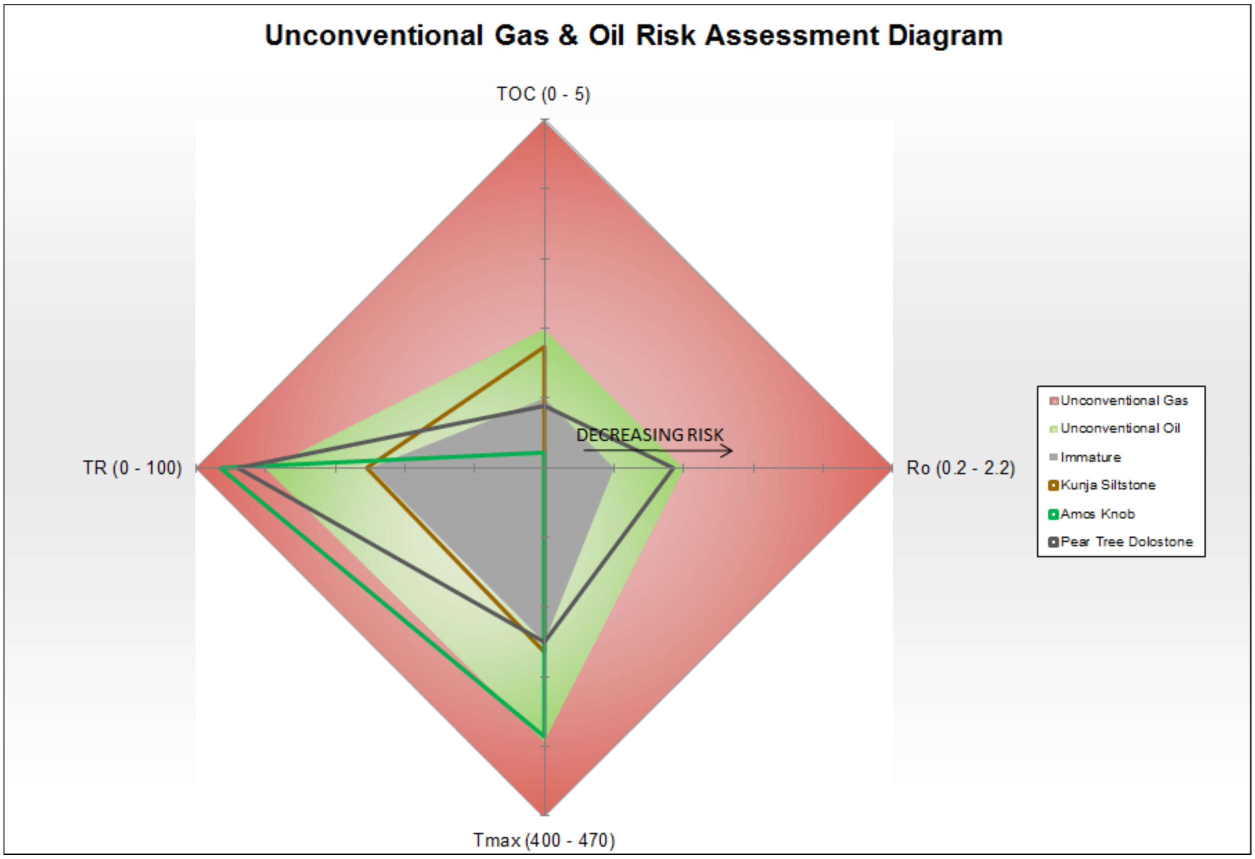

Figure 4. Geochemical Risk Assessment diagram for Palaeoproterozoic Mallabah Dolostone source rocks in the DD90VRB2 well.

The Kunja Siltstone source rock interval in the DD90VRB2 well is interpreted to represent a moderate geochemical risk for in-situ shale oil production. The average measured TOC content of 1.74 wt.% is above the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 4). However, it is below 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 Kunja Siltstone source interval in early oil window. The average Tmax value of 437°C is above recommended minimum value of 435°C for shale oil and well below the minimum of 455°C for shale gas (Fig. 4). This amount of conversion would likely be sufficient to generate/expel moderate amounts of hydrocarbons from this organic rich, oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 51% and fall just above the recommended minimum of 50% for shale oil and far below the 80% threshold for shale gas systems (Fig. 4).

The Amos Knob and Pear Tree Dolostone source rock intervals in the DD90VRB2 well are both interpreted to represent a high geochemical risk for in-situ shale oil production. The average measured TOC contents of 0.22 & 0.89 wt.% are below the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 4), although a few samples in the Pear Tree Dolostone interval do exceed this threshold. Original organic matter type is interpreted to be mixed Type II/IV in the Amos Knob interval, while the Pear Tree Dolostone is predominantly oil-prone Type II marine algal kerogen based upon select measured visual kerogen analysis. Thermal maturity parameters from programmed pyrolysis place both source intervals in main oil window. The average Tmax values of 454 and 435°C are between recommended minimum values of 435°C for shale oil and 455°C for shale gas (Fig. 4). Transformation Ratios (TR), the least constrained risk parameter, average 93 & 88% and fall above the recommended minimum of 50% for shale oil and above the 80% threshold for shale gas systems (Fig. 4). Measured maceral reflectance values in the Pear Tree Dolostone give a mean for low reflectance solid bitumen of 0.94% 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. 4).

In all of the source intervals examined in the DD90VRB2 well, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor (avg. 1 to 6 bbl oil/acre-ft), which is a significant concern regarding risk assessment for unconventional oil (Fig. 5). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Kunja Siltstone at 92 bbl oil/acre-ft, while the Amos Knob has 26 bbl oil/acre-ft and the Pear Tree Dolostone 110 bb oill/acre-ft. 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. 5). These values are much higher compared to the formations examined from this well primarily due to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC). While the generated oil yields of the Kunja Siltstone and Pear Tree Dolostone are about half as much as the Barnett Shale, the in-situ oil saturations are significantly lower. This is the reason the Kunja Siltstone is considered a moderate risk for commercial shale oil development, despite having all relevant parameters of the risk assessment diagram (Fig. 4) within the low risk area. Further investigation is needed to assess the reasons why measured in-situ hydrocarbon saturation is so low within the Kunja Siltstone and Pear Tree Dolostone intervals. It is likely that any in-situ oil saturation has migrated out of these source facies (est. 93 to 98% expulsion) as a consequence of uplift/erosion within the basin, since the depth of these sampled intervals in the DD90VRB2 well is only ~21−175 m deep.

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 Kunja Siltstone source interval is early oil window and in-situ oil saturation is likely to be relatively heavy and immobile. The Pear Tree Dolostone source interval in this well is in the peak oil window and hydrocarbon saturation is likely to be fairly light and mobile. However, the presence of solid bitumen noted during organic petrology 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 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.

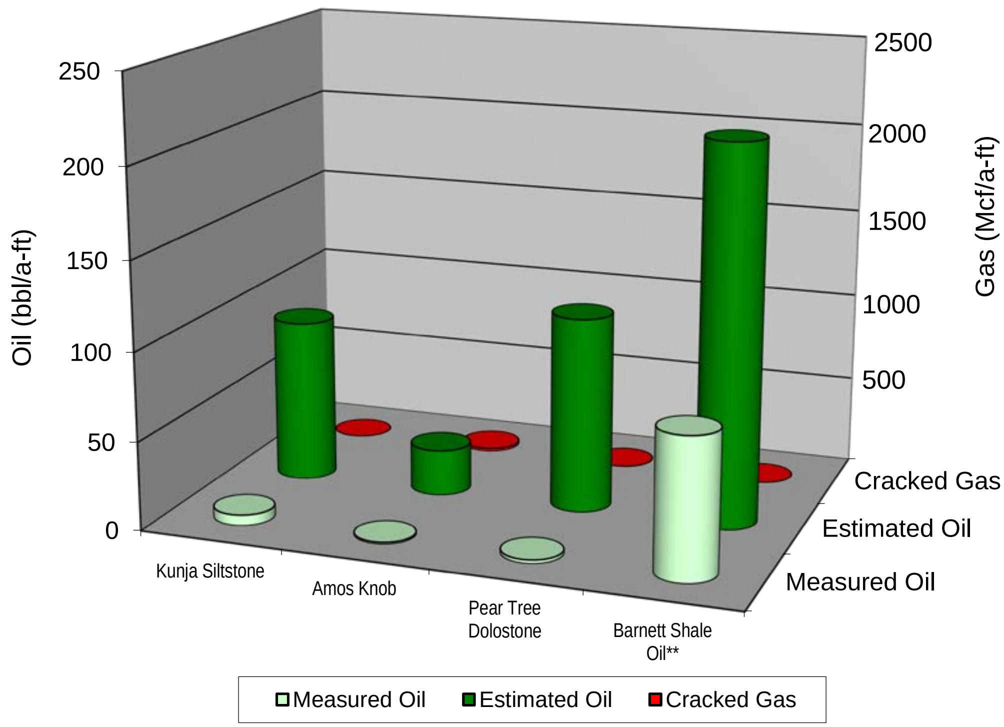

Figure 5. Hydrocarbon yield estimates for the Palaeoproterozoic source rocks in the DD90VRB2 well compared to Barnett Shale in the oil window.

GEOCHEMICAL SUMMARY

The Kunja Siltstone source interval in the DD90VRB2 well is interpreted to represent moderate geochemical risk for unconventional shale oil development. It clearly has elevated organic richness (avg. 1.74 wt.% TOC) and is considered an good source rock with dominantly oil-prone Type II kerogen. Thermal maturity parameters indicate that this source interval is in the early oil window, 0.71% Calc. R_o with a Transformation Ratio of 51%. Although all key risk ratios are above recommended minimum thresholds for shale oil systems, the measured in-situ oil saturations are low (avg. 6 bbl oil/acre-ft). The Kunja Siltstone has likely generated moderate amounts of oil (avg. 92 bbl oil /acre-ft), but it appears likely that most of this oil has been expelled from the source rock interval. Risk criteria like the S1 versus TOC show no oil cross-over for any of the samples in this interval confirming the elevated risk assessment. Further evaluation of in-situ oil characteristics would be required to fully evaluate potential oil mobility and recovery risk.

The Amos Knob Formation in the DD90VRB2 well is interpreted to represent a high geochemical risk for unconventional shale oil development. It has poor organic richness (avg. 0.22 wt. % TOC) and original organic matter type is thought to be mixed Type II/IV with only limited hydrocarbon generation potential despite being presently within the main oil generation window. In-situ oil saturations are low (1 bbl oil/acre-ft) and estimated hydrocarbon generation is also low (26 bbl oil/acre-ft; 15 Mcf gas/acre-ft).

The Pear Tree Dolostone interval in the DD90VRB2 well is also considered a high geochemical risk due primarily to its low organic richness (avg. 0.89 wt. % TOC). This interval has more oil-prone Type II kerogen and is also within the main oil window, 0.68% Calc. R_o and 0.94% measured R_o with a Transformation Ratio of 88%. The Pear Tree Dolostone has likely generated moderate amounts of oil (avg. 110 bbl oil/acre-ft), but like the other source intervals examined from this well measured in-situ oil saturations are very low (2 bbl oil/acre-ft) and most of the generated oil has likely been expelled.

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Appendix I

Hydrocarbon Yield Calculation
Limbunya Group
DD90VRB2

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

Weatherford®
LABORATORIES

DD90VRB2

Hydrocarbon Yield Calculation

																S2 (meas)	S2 (orig)				
Sample	Top Depth	TOC*	HI*	S1*	S2*	Calc.Ro	PI*	%Type IV 50 HIº	% Type III 125 HIº	%Type II 450 HIº	%Type I 750 HIº	HIº	TR	TOCº	S2º	Remaining Potential	Original Potential	Oil Cracked	S1 Free Oil	Estimated Oil	Cracked Gas
DD90VRB2	(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
5967	21	1.84	311	0.31	5.73	**0.72**	0.05	0	0	100	0	450	0.42	2.05	9.25	125	203	0.00	7	77	0
WH14DJR023	22	1.62	194	0.16	3.15	***0.72***	0.05	0	0	100	0	450	0.68	1.95	8.80	69	193	0.00	4	124	0
WH14DJR022	30	1.56	212	0.15	3.31	***0.73***	0.04	0	0	100	0	450	0.64	1.86	8.37	72	183	0.00	3	111	0
5968	34	1.52	316	0.33	4.81	***0.69***	0.06	0	0	100	0	450	0.41	1.70	7.65	105	168	0.00	7	62	0
WH14DJR021	35	1.79	273	0.27	4.88	***0.70***	0.05	0	0	100	0	450	0.51	2.05	9.24	107	202	0.00	6	95	0
5969	36	2.08	323	0.55	6.72	***0.69***	0.08	0	0	100	0	450	0.40	2.32	10.45	147	229	0.00	12	82	0
Kunja Siltstone (Avg)		**1.74**	**272**	**0.30**	**4.77**	**0.71**	**0.06**	**0**	**0**	**100**	**0**	**450**	**0.51**	**1.99**	**8.96**	**104**	**196**	**0.00**	**6**	**92**	**0**
WH14DJR018	92	0.48	23	0.04	0.11	**1.01**	0.27	50	0	50	0	250	0.93	0.56	1.40	2	31	0.09	1	26	15
Amos Knob (Avg)		**0.48**	**23**	**0.04**	**0.11**	**1.01**	**0.27**	**50**	**0**	**50**	**0**	**250**	**0.93**	**0.56**	**1.40**	**2**	**31**	**0.09**	**1**	**26**	**15**
WH14DJR013	127	0.70	20	0.04	0.14	0.73	0.22	0	0	100	0	450	0.97	0.95	4.29	3	94	0.00	1	91	0
WH14DJR014	128	0.47	17	0.04	0.08	0.73	0.33	0	0	100	0	450	0.98	0.64	2.87	2	63	0.00	1	61	0
WH14DJR012	136	0.54	50	0.05	0.27	**0.70**	0.16	0	0	100	0	450	0.93	0.72	3.22	6	71	0.00	1	65	0
WH14DJR011	139	1.70	54	0.12	0.91	**0.79**	0.12	0	0	100	0	450	0.92	2.25	10.11	20	221	0.00	3	202	0
5970	140	0.67	139	0.09	0.93	**0.78**	0.09	0	0	100	0	450	0.78	0.85	3.81	20	83	0.00	2	63	0
WH14DJR010	150	0.62	82	0.07	0.51	**0.74**	0.12	0	0	100	0	450	0.88	0.81	3.65	11	80	0.00	2	69	0
5971	150	0.56	89	0.06	0.50	**0.65**	0.11	0	0	100	0	450	0.87	0.73	3.28	11	72	0.00	1	61	0
5972	158	2.19	203	0.18	4.45	**0.76**	0.04	**0**	**0**	**100**	**0**	450	0.66	2.62	11.78	97	258	0.00	4	161	0
WH14DJR009	160	1.28	81	0.07	1.04	**0.70**	0.06	0	0	100	0	450	0.88	1.66	7.49	23	164	0.00	2	141	0
WH14DJR008	176	1.52	30	0.09	0.45	**0.70**	0.17	**0**	**0**	**100**	**0**	450	0.96	2.04	9.18	10	201	0.00	2	191	0
Pear Tree Dolomite (Avg)		**1.02**	**77**	**0.08**	**0.93**	**0.73**	**0.14**	**0**	**0**	**100**	**0**	**450**	**0.88**	**1.33**	**5.97**	**20**	**131**	**0.00**	**2**	**110**	**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)