Chanin 1 Interpretive Summary

Kyalla Interval

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

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PETROLEUM GEOCHEMISTRY

INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Kyalla, Formation in the Chanin 1 well located in the Beetaloo Sub-Basin, Northern Territories, Australia. Eight (8) 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 28 samples were 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
Chanin 1	Kyalla	***Estimated Original*** ⟶		*Good (1.27% TOC)*	*Oil-prone Type II*	**High**
Measured Currently ⟶		Oil Wet Gas	Late Oil Window	Fair (0.79% 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

KYALLA

Eight (8) samples from the Kyalla Formation were analyzed for LECO TOC content and programmed pyrolysis, with the remaining data set (28 samples) composed of client supplied public data (Fig. 1). TOC contents ranged from 0.13 to 2.35 wt.% and averaged 0.79 wt.% (fair). Eight (8) samples have TOC content above the minimum requirement of 1 wt.% for *effective* petroleum source rocks, two (2) of these samples have 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 Kyalla interval (1267 m depth) (Fig. 1) and the basal portion of the Kyalla in this well has a much thicker zone of elevated TOC (Fig. 1).

The S1 values of the Kyalla source rock samples average 0.50 mg HC/g rock (11 bbl oil/acre-ft) and the S2 values average 0.85 mg HC/g rock (19 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 contents (NOC) in the Kyalla samples, (S1/TOC) x 100, average 52 (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, there is no S1 cross over TOC in any of the Kyalla samples analyzed (Fig. 1), although the overlying Jamison Sandstone sample has an NOC of 105 consistent with a conventional oil reservoir.

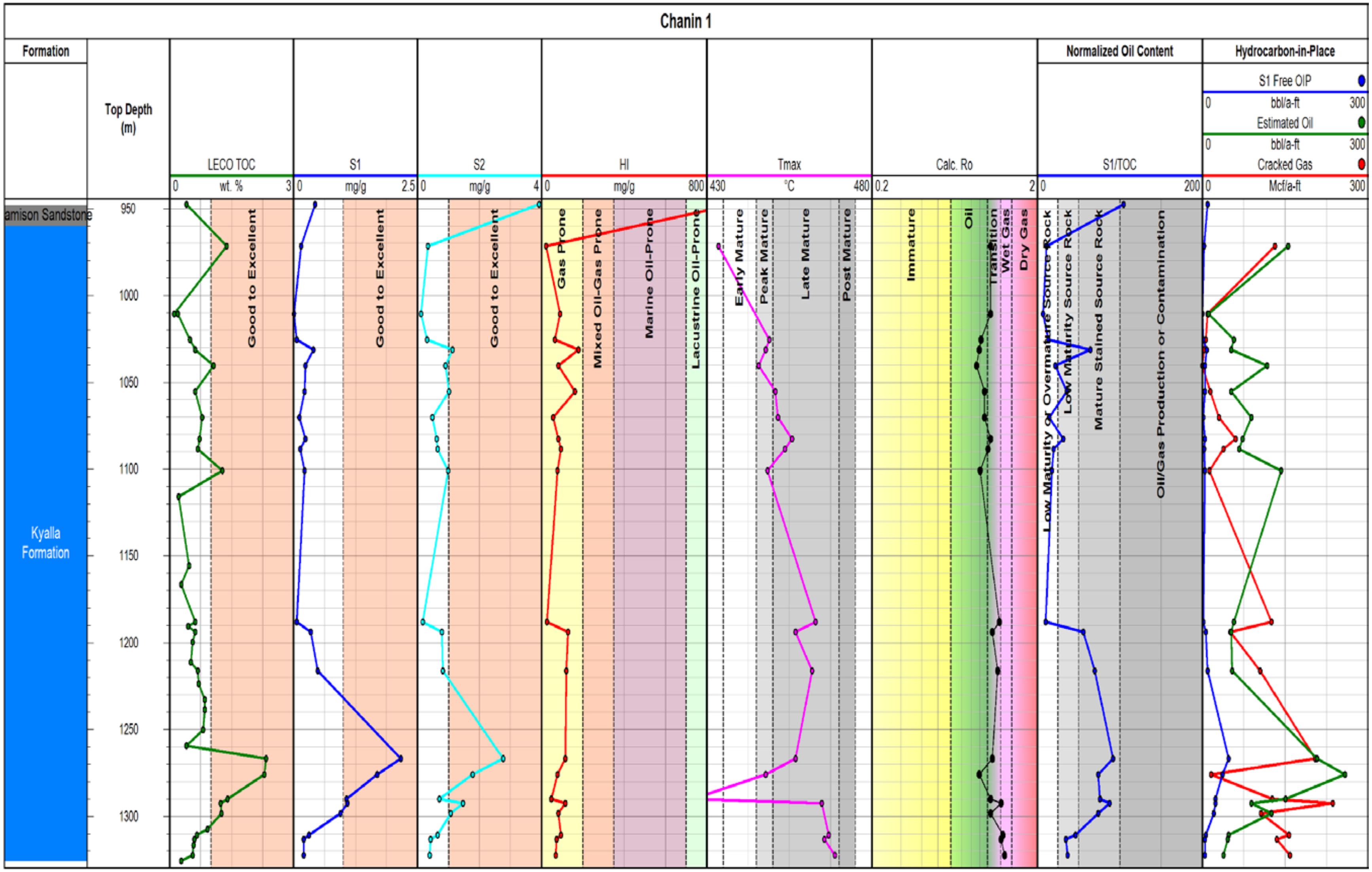

Figure 1. Geochemical depth plots for the Chanin 1 well.

The measured Hydrogen Index (HI) values in the Kyalla average 91 mg HC/g TOC, indicating gas-prone Type 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 average 86%, which suggest late oil window thermal maturity. The T_{max} values in the Kyalla samples average is 456°C. T_{max} between 445 and 450°C typically indicate late oil window, while values between 450 and 470°C typically indicate condensate/wet gas window (Type II kerogen). On the basis of these guidelines, the average Kyalla T_{max} values in this well would be interpreted to be in the early condensate/wet 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 measured T_{max} value of 456°C is equivalent to a Calc. $\%R_o$ value of 1.05%. 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 Kyalla samples average 0.31. These elevated PI values are consistent with source rocks in the late window, which typically have PI values in the range of 0.25 to 0.35, while post-mature samples in the gas window have values > 0.40.

Organic petrology was performed on one sample from the Kyalla interval (1101 m). The results from this analysis show a distribution that consists of macerals identified as either low reflectance solid bitumen or high reflectance solid bitumens (Fig. 2). The low reflectance solid bitumen population has reflectance values that average 1.17% R_o and are considered the most representative indigenous kerogen population for thermal maturity assessment. The high reflecting solid bitumen population has reflectance values that average 1.33% 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 Kyalla Formation 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 a 1.45% 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 1.22% Eq. R_o. The Landis and Castaño (1995) conversion would suggest dry gas thermal maturity and is inconsistent with other geochemical maturity data. However, the Jacob (1985) conversion does appear to provide a possible correction back to a more suitable thermal maturity that is in general agreement with the average value from the population of low reflectance solid bitumens. 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. Thus, the calculated 1.22% Eq. R_o value and the measured 1.17% R_o values would both suggest the Kyalla samples in this well are within the late oil to early wet gas/condensate window.

The thermal maturity of the Kyalla source 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 (1071 m) from the Kyalla Formation (avg. 59% clays) has a measured Kübler Index of 0.238, 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 Mesoproterozoic aged source rocks.

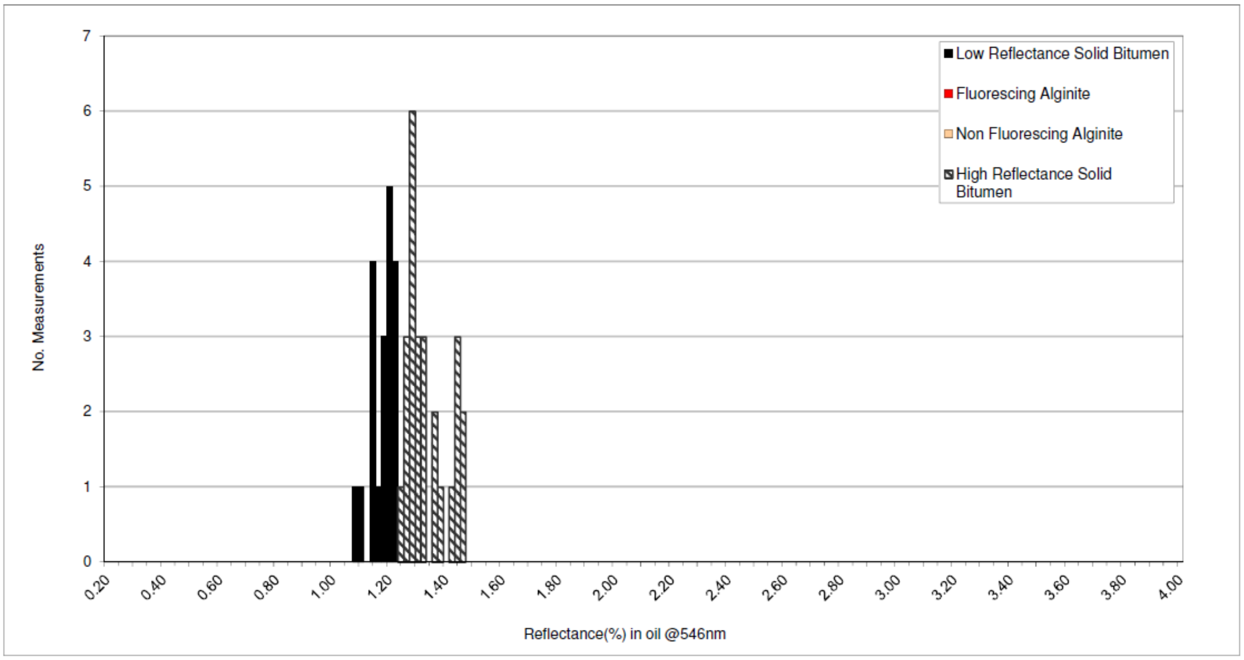

Figure 2. Organic petrology of the Kyalla (939 m) in the Chanin 1 well. Mean maceral reflectance of low reflecting solid bitumen is 1.17% R_o. The high reflecting solid bitumen has mean reflectance of 1.33% R_o, which equates to calculated Eq. R_o of 1.22% R_o using the conversion of Jacob (1985).

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 Kyalla 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 Chanin 1 well, the measured kerogen maceral distributions show 100% Type II kerogen (dominantly inert AOM with minor lens/layer AOM) in the sample from 1101 m depth. 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
Kyalla	0	100	0	0	450

Table 2. Average Kerogen Estimations for Chanin 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):

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

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 values 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 0.86 (Table 3), i.e., on average an estimated 86% 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 estimated original TOC_o for the Kyalla source rock samples in this well before petroleum generation average 1.27 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 Kyalla source rocks examined in the Chanin 1 well, the average $S2_o$ values are 5.7 mg HC/g rock or approximately 126 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 Kyalla samples analyzed in the current study, the estimated generated oil yields average 93 bbl/acre-ft (Table 3). Oil cracking is estimated to have 14% and resulted in 83 Mcf/acre-ft of secondary cracked gas generation.

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
Kyalla	0.96	91	19	450	0.86	1.27	126	11	93	83

Table 3. Hydrocarbon Yields average data for Chanin 1 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 the Kyalla interval is 90%, which is consistent with a source rock in the peak to late oil generation window.

The Kyalla source rock interval in the Chanin 1 well is interpreted to be in the late oil window and hydrocarbon yield calculations suggest minor to moderate amounts of generation have occurred (predominantly oil with minor secondary cracked 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 Kyalla Formation, original generation potential ($S2_o$) averages 126 bbl oil/acre-ft, this is below all of the other formations on the list of unconventional US Shale plays shown below.

Sample Database Averages TOC >1%	HI^o mg/g TOC	TR	TOC^o wt%	$S2^o$ 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
Kyalla	450	0.86	1.27	5.74	19	126	0.14	11	93	83

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

UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Kyalla Formation source rocks in the Chanin 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. 3) 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. 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.

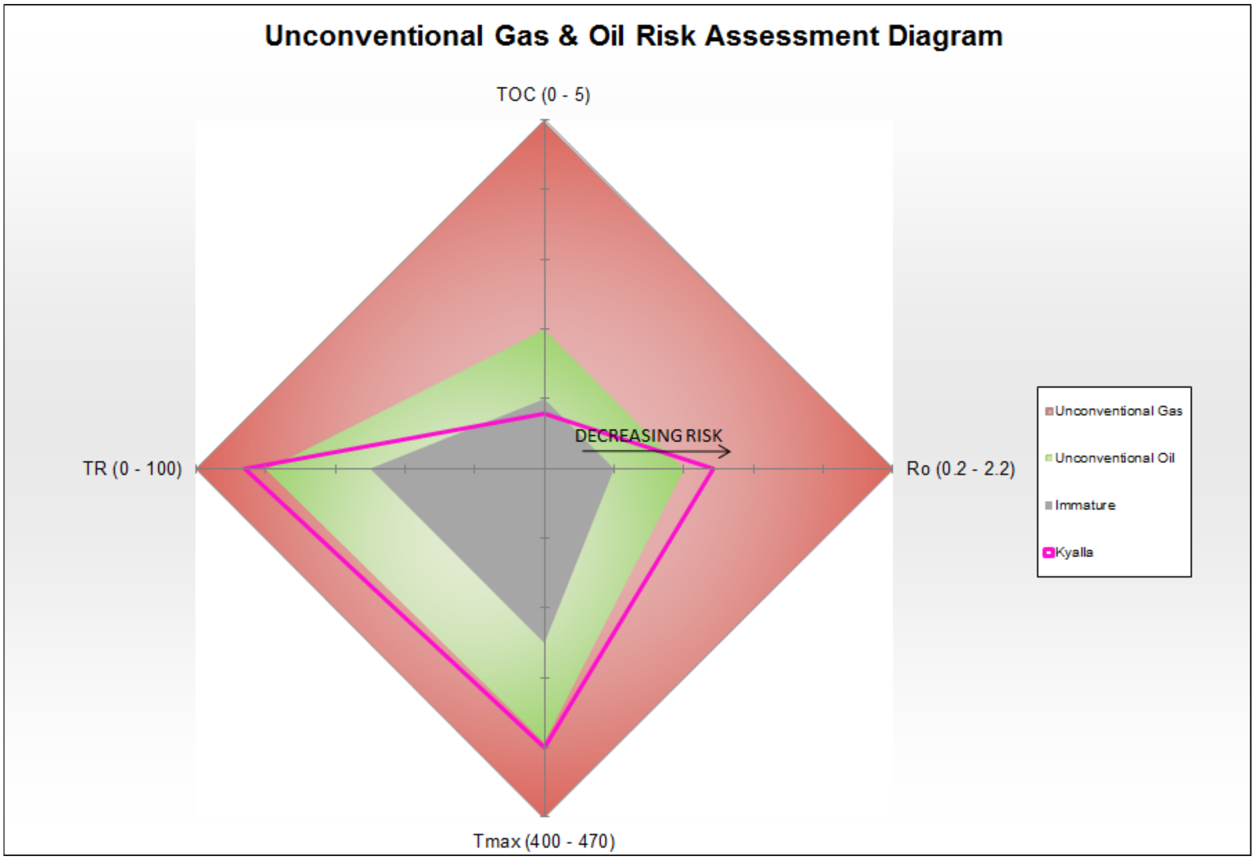

Figure 3. Geochemical Risk Assessment diagram for Mesoproterozoic Kyalla Formation source rocks in the Chanin 1 well.

The Kyalla source rock interval in the Chanin 1 well is interpreted to represent a high geochemical risk for in-situ shale oil production. The average measured TOC content of 0.79 wt.% is below the generally accepted minimum value of 1% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion (Fig. 3). Some samples do exceed this threshold, predominantly in the basal portion of the Kyalla interval, and this zone could represent a somewhat lower risk target. However, the overall average organic richness is considered marginal and thus the designation of high risk. All but two of these samples are 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 based upon measured visual kerogen analysis. Thermal maturity parameters from programmed pyrolysis generally place the Kyalla source interval in late oil to early wet gas/condensate window. The average Tmax value of 456°C is above recommended minimum value of 435°C for shale oil and just above the minimum of 455°C for shale gas (Fig. 3). This amount of conversion would likely be sufficient to generate/expel moderate amounts of hydrocarbons from this oil prone source facies. Transformation Ratios (TR), the least constrained risk parameter, average 86% and fall above the recommended minimum of 50% for shale oil and just above the 80% threshold for shale gas systems (Fig. 3). Measured maceral reflectance values in the Kyalla give a mean for low reflectance solid bitumen of 1.17% R_o, which is above the recommended minimum threshold of 0.5% R_o for shale oil and above the minimum of 1.0% R_o for shale gas (Fig. 3).

In the Kyalla source interval, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is generally poor (avg. 11 bbl oil/acre-ft), which is a significant concern regarding risk assessment for unconventional oil (Fig. 4). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Kyalla at 93 bbl oil/acre-ft, along with minor amounts of secondary cracked gas (83 Mcf/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.4). These values are significantly higher compared to the Kyalla, primarily due to differences in organic richness (Barnett Shale oil example has 4.70 wt. % TOC).

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 Kyalla source interval in this well is in the late oil window and hydrocarbon saturation is likely to be fairly light and mobile. However, the presence of solid 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 Kyalla 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.

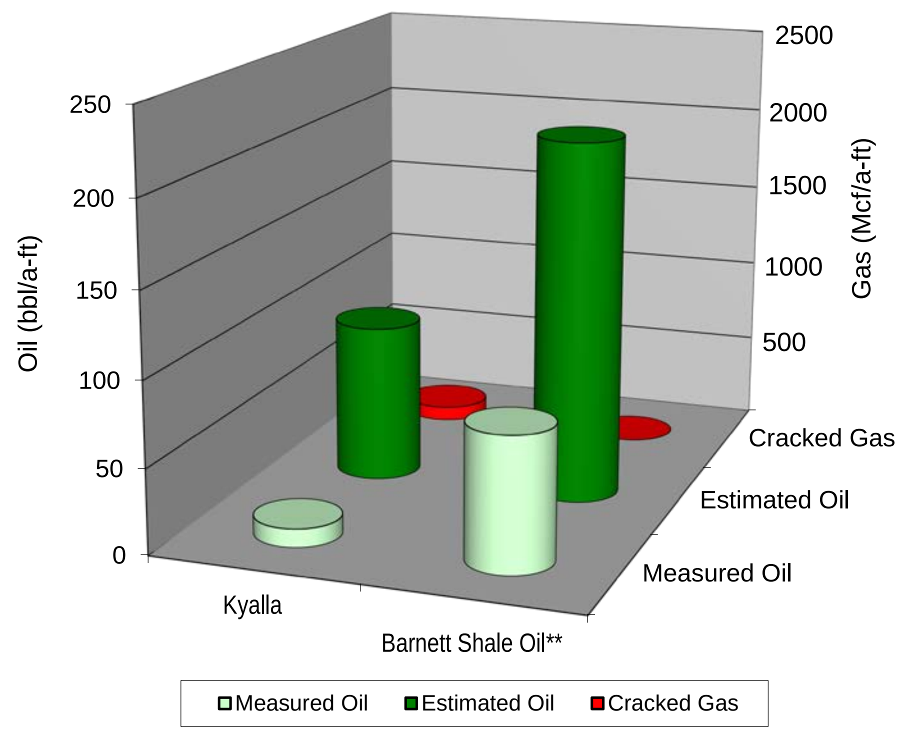

Figure 4. Hydrocarbon yield estimates for the Mesoproterozoic source rocks in the Chanin 1 well compared to Barnett Shale in the oil window.

GEOCHEMICAL SUMMARY

The Kyalla source interval in the Chanin 1 well is interpreted to represent high geochemical risk for unconventional shale oil development. The average measured TOC content of 0.79 wt.% is below the generally accepted minimum value of 1% TOC for unconventional shale oil, although the basal section of this source rock interval does have relatively higher TOC values. The Kyalla source rock contains dominantly oil-prone Type II kerogen based upon visual kerogen analysis. Thermal maturity parameters indicate that this source interval is in the late oil to early wet gas/condensate window, 1.05% Calc. R_o and 1.17% Eq. R_o from solid bitumen reflectance. All key thermal maturity risk ratios are above recommended minimum thresholds for shale oil systems and just above the minimums for shale gas. While the Kyalla has likely generated minor to moderate amounts of oil and secondary cracked gas (avg. 93 bbl oil/acre-ft; 83 Mcf gas/acre-ft), comparison to other systems such as the Barnett Shale show in-situ oil saturations are much lower for the Kyalla. Risk criteria like the S1 versus TOC show no oil cross-over for any of the samples within this unit, also supporting a high risk assessment. Further evaluation of in-situ oil characteristics would be required to fully evaluate potential oil mobility and recovery risk.

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Appendix I

Hydrocarbon Yield Calculation
Beetaloo Sub-Basin Group
Chanin 1

McArthur Basin Integrated Petroleum Geochemistry, 2016

Northern Territory Geological Survey - Australia

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Chanin 1

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**
Chanin 1	**(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**
TN14DJR051	972	1.40	26	0.16	0.36	1.05	0.31	0	0	100	0	450	0.96	1.89	8.50	8	186	0.12	4	156	133
2956450	1011	0.13	92	0.01	0.12	1.05	0.08	0	0	100	0	450	0.86	0.17	0.76	3	17	0.12	0	12	10
TN14DJR052	1026	0.50	65	0.07	0.32	**0.92**	0.18	0	0	100	0	450	0.90	0.66	2.96	7	65	0.02	2	57	7
2956451	1032	0.63	183	0.41	1.15	**0.90**	0.26	0	0	100	0	450	0.71	0.80	3.59	25	79	0.01	9	53	3
TN14DJR053	1041	1.07	85	0.24	0.91	**0.86**	0.21	0	0	100	0	450	0.87	1.40	6.32	20	138	0.00	5	118	0
2956477	1056	0.63	165	0.23	1.04	**0.96**	0.18	0	0	100	0	450	0.74	0.79	3.57	23	78	0.04	5	53	15
TN14DJR055	1071	0.80	60	0.12	0.48	**0.97**	0.20	0	0	100	0	450	0.91	1.06	4.77	11	105	0.05	3	89	30
2956452	1083	0.74	84	0.24	0.62	**1.05**	0.28	0	0	100	0	450	0.88	0.98	4.40	14	96	0.12	5	73	61
TN14DJR056	1089	0.70	96	0.14	0.67	**1.01**	0.17	0	0	100	0	450	0.86	0.91	4.09	15	90	0.09	3	68	39
TN14DJR057	1101	1.29	78	0.23	1.00	**0.91**	0.19	**0**	**0**	**100**	**0**	450	0.89	1.69	7.62	22	167	0.02	5	143	13
TN14DJR058	1188	0.63	29	0.07	0.18	**1.18**	0.28	0	0	100	0	450	0.96	0.85	3.81	4	83	0.27	2	58	126
2956474	1194	0.62	129	0.35	0.80	**1.07**	0.30	0	0	100	0	450	0.80	0.81	3.63	18	80	0.14	8	53	52
2956455	1217	0.70	120	0.49	0.84	**1.16**	0.37	0	0	100	0	450	0.82	0.92	4.14	18	91	0.24	11	55	105
2956456	1267	2.35	118	2.18	2.78	**1.07**	0.44	0	0	100	0	450	0.82	3.09	13.89	61	304	0.14	48	209	205
	1276	2.30	78	1.70	1.80	**0.90**	0.49	0	0	100	0	450	0.89	3.06	13.78	39	302	0.01	37	260	17
	1290	1.41	52	1.08	0.73	1.05	0.60	0	0	100	0	450	0.93	1.91	8.58	16	188	0.12	24	151	128
2956457	1293	1.24	119	1.09	1.48	**1.21**	0.42	0	0	100	0	450	0.82	1.63	7.36	32	161	0.31	24	89	238
	1299	1.27	84	0.95	1.07	1.05	0.47	0	0	100	0	450	0.88	1.70	7.63	23	167	0.12	21	126	107
2956458	1311	0.68	96	0.32	0.65	**1.25**	0.33	0	0	100	0	450	0.86	0.90	4.04	14	89	0.36	7	48	158
TN14DJR060	1314	0.60	73	0.21	0.44	**1.22**	0.32	0	0	100	0	450	0.89	0.80	3.60	10	79	0.32	5	47	135
2956475	1323	0.57	72	0.21	0.41	**1.28**	0.34	0	0	100	0	450	0.89	0.76	3.42	9	75	0.40	5	39	160
Kyalla (Avg)		**0.96**	**91**	**0.50**	**0.85**	**1.05**	**0.31**	**0**	**0**	**100**	**0**	**450**	**0.86**	**1.27**	**5.74**	**19**	**126**	**0.14**	**11**	**93**	**83**
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)