Beetaloo Sub-Basin Interpretive Summary

Kyalla – Mainoru Interval

As a part of:
Northern Territory Geological Survey - Australia

Submitted to:
Daniel Revie
Northern Territory Geological Survey
Department of Mines and Energy
38 Farrell Crescent
Winnellie, NT 0820 Australia

Prepared By:
Weatherford Laboratories
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Report Contributors:

Tim Ruble (Petroleum Geochemistry)

Elizabeth Roberts (Compiler)

Brian Hankins & Jennifer Yee (Isologica Data Processing)

Elvira Barcelona (Organic Petrology)
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INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Roper Group source rocks (Kyalla, Velkerri, Corcoran and Mainoru Formations) in thirteen (13) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells 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 also incorporated into the interpretive evaluation. The complete results of these analyses are documented in the individual well reports. Formation specific integrated geochemical interpretations and spatial trends are considered within the context of the current document.

GEOCHEMICAL SCREENING

Routine total organic carbon (TOC) was measured using the LECO TOC analyzer and programmed pyrolysis was performed with the Source Rock Analyzer (SRA). All samples were analyzed on an “as-received” basis and were not subject to any additional bulk solvent extraction steps in order to remove potential artifacts associated with in-situ hydrocarbon saturation.

The TOC and programmed pyrolysis data are useful for screening for potential petroleum source rocks (Table 1). The data define the quantity, quality, and thermal maturity of organic matter present in the rocks (Peters, 1986). The data are also useful for recognizing potentially producible oil within the rocks (Jarvie, 2012). We employ the following guidelines from Peters et al. (2005) for the interpretations of geochemical screening data presented in this report:

<table>
<thead>
<tr>
<th>Generative Potential</th>
<th>TOC (weight %)</th>
<th>S1 (mg HC/g rock)</th>
<th>S2 (mg HC/g rock)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Poor</td>
<td>&lt;0.5</td>
<td>&lt;0.5</td>
<td>&lt;2.5</td>
</tr>
<tr>
<td>Fair</td>
<td>0.5 – 1.0</td>
<td>0.5 – 1.0</td>
<td>2.5 – 5.0</td>
</tr>
<tr>
<td>Good</td>
<td>1.0 – 2.0</td>
<td>1.0 – 2.0</td>
<td>5.0 – 10.0</td>
</tr>
<tr>
<td>Very Good</td>
<td>2.0 – 4.0</td>
<td>2.0 – 4.0</td>
<td>10.0 – 20.0</td>
</tr>
<tr>
<td>Excellent</td>
<td>&gt;4.0</td>
<td>&gt;4.0</td>
<td>&gt;20.0</td>
</tr>
</tbody>
</table>

Table 1. Generative Potential (Quantity of organic matter)

Bear in mind that these guidelines are qualitative and empirical. The average TOC of petroleum source rocks worldwide is 1.8 wt. %, of shale source rocks 2.2 wt. %, and of carbonate source rocks 1.9 wt. % (Jones, 1984; Miles, 1989). Petroleum source rocks also need a minimum TOC of about 1.5 – 2.0 wt. % before expulsion can occur during thermal maturation (Pepper, 1991; Lewan, 1994). For these reasons, many petroleum geochemists regard 2.0 wt. % as a minimum TOC value for defining economic source rocks and viable resource play reservoirs, although 1.0 wt % TOC continues to be used as the minimum cut off for an effective source rock (meaning a unit that can both generate and expel hydrocarbons, but which may not be of significant volume to be commercial).

The normalized oil ratio, NOR, is calculated by normalizing the ratio of S1/TOC. This value is also called the Oil Saturation Index (OSI) by Jarvie (2012). Interpretive guidelines for NOR are:

- 0 – 50: oil-lean
- 50 – 100: possible oil staining or show; mature, tight petroleum source rock
- >100: reservoirs or contamination.

These guidelines are for conventional reservoirs, in unconventional reservoirs, Jarvie (2012) considers a NOR value > 100 mg hydrocarbon/g TOC as potentially productive.

Kerogen types are generally grouped into five basic categories (Table 2). Type I and II kerogens generate dominantly oil with minor amounts of primary associated gas. Type II/III is a mixed kerogen type that has
the potential to generate both oil and gas. Type III kerogens mainly generate gas, with only a small amount of typically waxy oil, while Type IV kerogens have little or no remaining potential to generate hydrocarbons.

The type of kerogen present is dependent on the type of primary organic matter and is also an indication of the source rock depositional environment. Well preserved algae typically dominate in Type I kerogen, which usually indicate a lacustrine depositional environment (but are also sometimes found in specific marine settings). Type II kerogen is deposited exclusively in marine conditions and contains dominant amorphous organic matter (AOM) along with cutinites, plant spores, exines and resins. During initial maturation, Type I & II source rocks generate mainly oil and only a limited amount of gas. As maturation proceeds through higher temperatures, secondary cracking in these source rocks cracks the generated oil into gas. Type III organic material is comprised of vitrinite and is typically woody material found in continental rocks deposited in swamps, rivers and deltas, but it can also be found in marine environments where it is washed in from a nearby shelf and often results in mixed Type II/III kerogen. Type IV kerogen contains inertinite, where oxidation of organic material has occurred, either before it is deposited or in situ.

<table>
<thead>
<tr>
<th>Kerogen type</th>
<th>Hydrogen Index (HI) mg HC/g TOC</th>
<th>S2/S3</th>
<th>Main product at peak maturation</th>
</tr>
</thead>
<tbody>
<tr>
<td>I</td>
<td>&gt;600</td>
<td>&gt;15</td>
<td>Oil</td>
</tr>
<tr>
<td>II (II-S)</td>
<td>300 – 600</td>
<td>10 – 15</td>
<td>Oil</td>
</tr>
<tr>
<td>II/III</td>
<td>200 – 300</td>
<td>5 – 10</td>
<td>Mixed oil and gas</td>
</tr>
<tr>
<td>III</td>
<td>50 – 200</td>
<td>1 – 5</td>
<td>Gas</td>
</tr>
<tr>
<td>IV</td>
<td>&lt;50</td>
<td>&lt;1</td>
<td>None</td>
</tr>
</tbody>
</table>

Table 2. Kerogen Type and Expelled Product (Quality of organic matter)

Caution should be exercised when using the pyrolysis kerogen quality parameters. The kerogen type designations are mainly based on optical characteristics defined by organic petrology. The HI and S2/S3 values are laboratory chemical quantities calculated from the TOC and pyrolysis results. A common problem with interpreting kerogen type from the pyrolysis data is that the laboratory results reflect hydrogen content of the organic matter and not necessarily the maceral type. For example, both oxidation and reworking of kerogen, and increasing thermal stress, lower the HI value even if the organic material was deposited as hydrogen-rich Type I or Type II kerogen.

In the current study, the geologic age of these samples (Palaeo- to Mesoproterozoic) limit the types of organic matter that could be found in potential source rocks. Primitive marine cyanobacterial associated with Type I and/or Type II kerogen is likely to be dominant (Summons et al., 1994; Taylor et al., 1994; Law et al., 2010). However, in some instances poorly preserved organic matter with elevated oxygen content (high Oxygen Index and elemental O/C ratios) would suggest the presence of inert Type IV organic material.

<table>
<thead>
<tr>
<th>Maturity</th>
<th>%Rₒ</th>
<th>T_max (°C) Type II Kerogen</th>
<th>T_max (°C) Type I Kerogen</th>
<th>Production Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Immature</td>
<td>&lt; 0.50</td>
<td>&lt;425</td>
<td>&lt;440</td>
<td>&lt;0.10</td>
</tr>
<tr>
<td>Early Oil</td>
<td>0.50 – 0.65</td>
<td>425 – 435</td>
<td>440 – 442</td>
<td>0.10 – 0.15</td>
</tr>
<tr>
<td>Peak Oil</td>
<td>0.65 – 0.90</td>
<td>435 – 445</td>
<td>442 – 446</td>
<td>0.15 – 0.25</td>
</tr>
<tr>
<td>Late Oil</td>
<td>0.90 – 1.1</td>
<td>445 – 450</td>
<td>446 – 450</td>
<td>0.25 – 0.35</td>
</tr>
<tr>
<td>Condensate/Wet Gas</td>
<td>1.1 – 1.4</td>
<td>450 - 470</td>
<td>450 - 470</td>
<td>&gt;0.40</td>
</tr>
<tr>
<td>Dry Gas</td>
<td>&gt;1.4</td>
<td>&gt;470</td>
<td>&gt;470</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 3. Thermal Maturation for Type I and Type II Kerogen

Thermal maturity guidelines based upon organic petrology (measured maceral reflectance %VRₒ) and programmed pyrolysis are shown in Table 3. The T_max values listed above are general with regard to maturity. The maturity scale is kerogen-type-dependent (see Huc, 2013, p. 109 – 110). For example,
some Type I kerogen enters the oil window ~ 440° to 442°C and exits at ~ 446° to 448°C due to the very narrow range of activation energies for this type of organic matter. Terrigenous organic matter dominated by Type III kerogen has a wider range, entering the oil window ~ 430°C to 435°C and exits at ~ 466° to 472°C. Sulfur-rich Type II-S kerogen enters the oil window at ~420°C and exits ~450°C due to the differences in relative bond strength, with S-C bonds being significantly weaker than C-C bonds.
KYALLA PETROLEUM GEOCHEMISTRY

KYALLA INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Kyalla Formation source rocks in nine (9) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells 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 was also incorporated into the interpretive evaluation. The complete results of these analyses are documented in the individual well reports and are summarized in Table 4.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Oil Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Balmain 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Good (1.94% TOC)</td>
<td>Oil-prone Type I/II</td>
<td>Moderate</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Minor Oil Early Oil Window</td>
<td>Good (1.32% TOC)</td>
<td>Oil-prone Type II</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Burdo 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Good (1.09% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Peak Oil Window</td>
<td>Fair (0.85% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Chanin 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Good (1.27% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Late Oil Window</td>
<td>Fair (0.79% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Elliott 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Good (1.46% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Peak Oil Window</td>
<td>Fair (0.87% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Jamison 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Very Good (2.37% TOC)</td>
<td>Oil-prone Type II</td>
<td>Low</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Late Oil Window</td>
<td>Good (1.65% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>McManus 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Fair (0.88% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Minor Oil Early Oil Window</td>
<td>Poor (0.40% TOC)</td>
<td>Mixed Type II/III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Ronald 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Good (1.04% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Peak Oil Window</td>
<td>Fair (0.74% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sever 1</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Fair (0.93% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil Peak Oil Window</td>
<td>Fair (0.72% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>Kyalla</td>
<td>Estimated Original</td>
<td>Very Good (2.10% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate</td>
<td></td>
</tr>
</tbody>
</table>

Table 4. Kyalla Geochemical Summary

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

The Kyalla Formation source rock samples analyzed from the Beetaloo Sub-Basin have good generative potential (Table 4; Fig. 1). Organic richness varies from 0.03 wt.% (poor) to as high as 8.97 wt.% (excellent) TOC, with an average value of 1.15 wt. % TOC (good). The histogram plot of TOC distributions (Fig. 1) illustrate that the dominant population is within the 0.5 to 1.0 wt. % range. Outside of this range there appears to be a general trend of progressive decrease in frequency of samples with increasing TOC content. Almost half of these samples have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks. About 15% of these samples also have TOC content above the minimum requirement of 2 wt.% for economic petroleum source rocks, which is a favorable factor for unconventional resource development.

The distribution of elevated TOC values in the Kyalla Formation is not restricted to a single well within the sample suite evaluated from the Beetaloo Sub-Basin, but the Jamison 1 well does tend to dominate the other wells. Not only does the Jamison 1 well contain the highest recorded TOC content, but it also contains more than 70% of the TOC values > 2 wt.%. This is also illustrated on the base map showing spatial distributions of measured TOC within the Kyalla Formation in the Beetaloo Sub-Basin (Fig. 2). On this map, the average TOC values are shown and the Jamison 1 well located in the central portion of the basin clearly has the highest average TOC (Fig. 2). The Shenandoah 1A and Balmain 1 wells also have relatively high TOC and both of these wells are located very near each other and are also in the central portion of the basin (Fig. 2). In contrast, most of the other wells sampled in this study that are located more along the basin margins tend to have somewhat lower average TOC contents within the Kyalla Formation (Fig. 2). This would suggest that within the Beetaloo Sub-Basin the central region may represent a somewhat different paleo-depositional environment that was more conducive to organic productivity and/or preservation. It is also noteworthy that the Jamison 1 well has the thickest measured Kyalla interval (746 m) of all the wells sampled in the current study. Apparently, mineral dilution has not adversely affected organic matter preservation in the central depocenter. The geographic differences in the abundance of preserved organic matter within the Kyalla source rock interval would clearly benefit from the addition of more wells and further data points, especially within the central depocenter where elevated TOC trends are apparent.
Figure 1. Histogram plot of Total Organic Carbon (TOC) distributions for Kyalla Formation source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.%, while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.
Figure 2. The spatial distribution of organic richness for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average LECO TOC content and are reported as wt.%. 

Pyrolysis S2 yields in the Kyalla Formation samples vary from 0.05–20.12 mg HC/g rock (Fig. 3) and average values within individual wells vary from 0.70–8.29 mg HC/g rock or 15–182 bbl/a-ft. These indicate a poor to good amount of remaining primary hydrocarbon generation potential (both oil and gas), which is consistent with variable levels of primary thermal conversion in the early to late oil window. There are two dominant populations of data for the Kyalla Formation samples that would appear to correspond with two different organic facies within this interval (Fig. 3). Samples from the first population have variable TOC, but generally elevated S2 values and generally plot within the oil-prone Type II kerogen region (Fig. 3). These samples are consistent with well-preserved Type II kerogen (see Langford and Blanc-Valleron, 1990) that has undergone minimal thermal conversion and are best represented by samples from the Balmain 1 and upper portions of the Jamison 1 wells (Fig. 3). The second major grouping of samples represents a more disperse set of data points that extend from inside the organic
lean box to populate the regions associated with gas-prone Type III kerogen and inert Type IV kerogen (Fig. 3). These data also represent samples that are only partially converted due to their moderate thermal maturity (early/late oil), but likely had much more limited original generation potential in comparison to the other group of source rock samples. These samples appear to include the grouping of very elevated TOC values > 4 wt.% in the Jamison 1 well (Fig. 3). Original placement of the first population of samples prior to thermal conversion would be generally within the oil-prone Type II region. The second group of samples is more likely to represent original organic matter that would be a mix of oil-prone Type II and inert Type IV kerogen, although they have been presumed to contain only Type II for purposes of hydrocarbon yield modeling in this study (see individual well reports and hydrocarbon yield calculations for more details). This interpretation may be somewhat optimistic given the geochemical results presented herein.
Figure 3. Total Organic Carbon (TOC) versus Remaining Hydrocarbon Generation Potential (S2) for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Insert plot is expanded view to better illustrate details within this data set. Plot symbology defined in Fig. 4.
The spatial distribution of S2 content for the Kyalla Formation samples shows some significant variations between the wells in this study (which was not apparent in TOC). Geographically, the Balmain 1 well in the central portion of the study area has a much higher S2 content in comparison to nearby Shenandoah 1A well and to all other wells in the study area (Fig. 5). This difference in remaining generation potential is predominantly thought to be a consequence of interpreted thermal maturity, with the Balmain 1 well being in the early oil window and the nearby Shenandoah 1A well interpreted to be in the late oil window. As will be discussed in the following section, this parameter could also be influenced by differences the organofacies represented in the samples analyzed for this investigation. For example, the McManus 1 well is also interpreted to be in the early oil window, but has a much lower S2 content in comparison to the Balmain 1 well (Fig. 5). This well is located more along the basin margin with a relatively lower TOC and likely had less original generation potential in comparison to wells in the central depocenter. Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these S2 variations. In particular, it is noteworthy that the differences in remaining generation potential and interpreted thermal maturity between the Balmain 1 and Shenandoah 1A well are so pronounced despite their close proximity to each other. However, the Kyalla intervals in these two wells are separated by ~600 m depth, with the Balmain 1 being significantly shallower. This would potentially imply the offset is due to a major fault that not only could have resulted in the apparent depth differences, but may have influenced local heat flow and consequently thermal maturity. Again, further geologic integration will be necessary to address these issues.
Figure 5. The spatial distribution of remaining hydrocarbon generation potential (S2) for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S2 content and are reported as mg HC/g rock.

KYALLA KEROGEN TYPE AND EXPELLED PRODUCT

The Kyalla Formation is reported to consist of interbedded grey to black mudstone, silty mudstone, siltstone and fine sandstone (Munson, 2014). The mudstone-rich facies is variably organic rich and has been reported to contain mixtures of Type I and Type II kerogen (Munson, 2014), but the proportions of each type are unclear. The depositional conditions and the geologic age of these samples would be conducive to preservation of source rocks with a dominant cyanobacterial oil-prone kerogen (Type I and Type II) along with possible minor to significant amounts of oxidized Type IV organic material.

The Kyalla source rock samples analyzed in this study were found to compose potentially two distinct lithofacies, although the influence of sample type variability in the geochemical data cannot be
discounted. The most prospective samples appear to be characterized by high S2 and moderately high TOC content, are distinctive in having very high hydrogen index (HI) values ~500–700 mg HC/g TOC (Fig. 6). These samples could represent particularly well preserved oil-prone marine Type I kerogen samples containing filamentous algae and/or cyanobacterial biomass. Organic petrology results are only available from one Kyalla Formation sample (Chanin 1; 1101 m) and they do not appear to document an end-member of this organic facies. The kerogen macerals in this single Kyalla sample are dominated by oil-prone Type II organic matter that consists of variable abundances of lens/layer amorphous organic matter (AOM), inert AOM, minor exsudatinite along with solid bitumens.

The other suite of samples from the Kyalla Formation come from samples that may represent a different type of facies associated with less prospective source rock lithologies. These samples tend to have lower TOC content, but this is not exclusively the case as they also contain a group of samples with the highest TOC content. The more diagnostic feature is that these samples have lower hydrogen index (HI) values <400 mg HC/g TOC and much higher oxygen index (OI) values > 30 mg CO2/g TOC (Fig. 6). These samples likely represent lower quality preserved Type II organic matter that has been partially oxidized prior to preservation. The degree of oxidation would appear to dictate the classification of this material as Type II/III, Type III and/or Type IV in some instances (Fig. 6). Unfortunately, only limited organic petrology results from the current study are available in the Kyalla Formation samples and no results are available from samples that are interpreted to clearly represent this organofacies group.

Measured present day HI values in the Kyalla Formation samples range from 6 to 688 mg HC/g TOC (Fig. 6) and average 80 to 471 mg HC/g TOC in the wells investigated in this region. On a plot of HI versus Oxygen Index (OI) (pseudo van Krevelen diagram), many of the samples plot along the maturation pathway for either Type I or Type II kerogens (Fig. 6). However, as previously noted select samples have much lower relative HI and much higher OI values and plot in other regions of this diagram in zones presently associated with Type II/III, Type III and Type IV kerogen (Fig. 6). Since these Kyalla source rocks are considered early to late mature with regard to oil generation, the kerogen HI values have been reduced from only slightly to significantly as a consequence of thermal maturity; thus, they generally indicate either oil-prone Type I/II kerogen and/or gas-prone Type III to inert Type IV kerogen quality at present day (Fig. 6).

Measured OI values in Kyalla Formation samples varies from 0 to 1003 mg CO2/g TOC and there are many samples with elevated OI in the > 35 range (Fig. 6). Some of these samples would appear to plot in more in the region typically associated with mixed marine/terrigenous Type II/III organic matter, although structured organic matter of this type which is typically associated with terrigenous organic matter was not present during this geologic age. Thus, these samples are more likely to represent a mixture of Type II marine algal and Type IV oxidized inert organic matter. Still other samples appear to represent end-members that may be composed dominantly of Type IV oxidized inert organic matter (Fig. 6). Organic petrology kerogen examination of additional samples to examine the possible presence of oxidized material could help confirm such a depositional interpretation.
Figure 6. Hydrogen Index versus Oxygen Index (pseudo-van Krevelen plot) for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

A plot of measured elemental H/C versus O/C ratios from isolated kerogen (van Krevelen diagram) provides another representation of the kerogen quality in the Kyalla Formation source rock samples (Fig. 7). This plot indicates that the kerogen in select samples is currently in the oil-prone Type I and Type II to gas-prone Type III regions. Thermal maturity effects tend to lower both the H/C and O/C ratios from their original immature positions. In this case these samples are only partially converted and within the early to late oil window, so their original position on the van Krevelen diagram would likely be within the oil-prone Type I or Type II region. These select samples tend to have low O/C ratios and appear to follow the maturation pathway for Type I kerogen (Fig 7). It is likely that these samples represent the more prospective organic facies with dominantly high HI values and none of these samples are from the interpreted facies that likely contains more oxidized organic matter. Future work should try to sample both types of organic facies within the Kyalla for enhanced interpretive capabilities.
Spatial distributions in the HI values were evaluated in the context of previous trends within both TOC and S2 yields (Fig. 8). The Balmain 1 well in the central portion of the study region was found to have a much higher average HI value in comparison to the other wells in this study region (Fig. 8). This matches the trend in S2 yield and is likely to be a consequence of the somewhat lower thermal maturity in this well (early oil) and possibly better representation of the more prospective organofacies that contains better preserved, high HI organic matter (Type I). The McManus 1 well also has a relatively high average HI value that is also likely due to low thermal maturity (early oil) in this well (Fig. 8). Given that the current data set illustrates only average HI values (often representing considerable interval thickness) for multiple lithofacies representing the Kyalla Formation in this study area, the interpretation of spatial variations within these samples is very speculative. It is possible that these trends in HI could simply represent overprinting of thermal maturity variations rather than offering any insights into kerogen type variability. Further integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these HI variations. In particular, it would seem appropriate to more
clearly define specific sub-facies within the Kyalla Formation on the basis of possible lithology variability as well as unique organic geochemical properties.

Figure 8. The spatial distribution of the Hydrogen Index (HI) values for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average HI and are reported as mg HC/g TOC.

**KYALLA THERMAL MATURITY**

The organic-matter in the Kyalla Formation source rocks evaluated in the current investigation appears to have entered into the early to late stage of conventional oil generation window for most wells, although some of the deeper samples in the Shenandoah 1A and Jamison 1 wells may be into the gas window.

Programmed pyrolysis $T_{\text{max}}$ values from samples in which $T_{\text{max}}$ was considered reliable vary from 424° to 530°C (Figs. 9 & 11) and average between 428°C and 456°C for Kyalla source rocks in individual wells.
Measured $T_{\text{max}}$ between 425 and 435°C typically indicate early oil window, while values between 435 and 445°C indicate peak oil window and values between 445 and 450°C indicate late oil window (Type II kerogen). Using the formula published by Jarvie et al. (2007) for Type II kerogen ($\text{Calculated } R_o = (0.0180)(T_{\text{max}}) - 7.16$), the average measured $T_{\text{max}}$ values between 428°C and 456°C are equivalent to Calc. %$R_o$ values of 0.54% and 1.05%.

Figure 9. Hydrogen Index versus $T_{\text{max}}$ for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

The $T_{\text{max}}$ values shown on Fig. 9 illustrate that many of the Kyalla Formation samples are within the early portion of the main oil window and plot within maturity envelopes that are associated with Type I and Type II kerogen. However, there are also a large number of low maturity samples that plot more in the Type II/III and Type III kerogen regions. This interpretation is similar to that obtained from evaluation of geochemical data previously discussed. Both trends show samples that appear to be at more elevated thermal maturity levels with the late oil and into the condensate/wet gas and even dry gas windows (Fig. 9). These elevated values appear to represent primarily samples from the basal portions of the Shenandoah 1A and Jamison 1 wells, but they also include some samples that may contain a higher
abundance of oxidized inert Type IV kerogen that tends to give elevated $T_{\text{max}}$ readings even at moderate maturity levels.

In general, a great deal of caution should be used in the evaluation of $T_{\text{max}}$ data for samples within the early to peak oil window that often contain elevated S1 peaks. Usually, oil-prone source rock samples within the oil window are characterized by a predominant S2 peak and an elevated S1 peak of variable intensity. Depending upon oil characteristics, there can be some carry over from the S1 peak to the S2 peak as evidenced by asymmetry in both peaks. The presence of low temperature S2 shoulders is identified by examination of the pyrograms in some of the Kyalla samples from this study. This suggests that some of what we assume are volatile constituents of the oil or bitumen in the sample are, in fact, not volatilized at 300°C (S1 vaporization temperature), but rather at higher temperatures. Therefore, these components are carried over and included as part of the S2 peak. These could be high-molecular-weight waxes, asphaltenes, and other compounds (note LCM material like walnut hulls can also cause the same effect, but usually have a distinct “shark fin” appearance in the low temperature region). This effect could conceivably lower the measured $T_{\text{max}}$ value during programmed pyrolysis. As a consequence, the interpreted thermal maturity on the basis of $T_{\text{max}}$ should be considered a MINIMUM value due to this uncertainty. The presence of low temperature S2 shoulders in these samples could also cause the measured HI values to be elevated in comparison to their true readings. One method to evaluate this artifact is to solvent extract the samples and re-analyze them by programmed pyrolysis. This would remove any contribution coming from the oil/bitumen and would likely result in somewhat lower HI values, thereby providing a more accurate assessment of true kerogen generation potential and hydrogen content.

Spatial distributions in the $T_{\text{max}}$ derived Calc. $R_o$ values were evaluated in the context of previous trends within other geochemical parameters (Fig. 10). The average Calc. $R_o$ values of the Kyalla wells evaluated from this study region do appear to show some variability as a consequence of thermal maturity (Fig. 10). The Chanin 1 and Jamison 1 wells appear to have the relatively highest thermal maturity, followed by the Shenandoah 1A well. All of these wells are interpreted to be in the late oil window. As noted previously, the Balmain 1 and McManus 1 wells have relatively low Calc. $R_o$ values and both are interpreted to be in the early oil window. The geographic location of the Balmain 1 well within the center of the basin suggests some unusual fault block related explanation for the anomalously low thermal maturity within this well. Most of the wells along the margins of the basin, including the Sever 1 well to the far NW corner of the study area are interpreted to be within the peak oil window and have similar Calc. $R_o$ values (Fig. 10). Homogeneous, oil-prone Type I kerogen tends to have slightly higher activation energies and consequently $T_{\text{max}}$ values should be used with caution to define thermal maturity for these types of samples (see guidelines in Table 3). This could complicate the interpretation of thermal maturity in samples that contain this type of kerogen. Further evaluation of a larger statistical data set with samples from more wells separated by organofacies type and integration with regional geology will be needed to potentially provide further insights into the origin of these Calc. $R_o$ variations.
Figure 10. The spatial distribution of the Calc. R_o values from T_{max} for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average Calc. R_o and are reported as %R_o using the formula of Jarvie et al. (2007) (Calculated R_o = (0.0180)(T_{max}) – 7.16).

Production Index (PI) values in these Kyalla Formation source rock samples vary from 0.03 to 0.67 (Fig. 11) and average from 0.06 to 0.34 for Kyalla source rocks in individual wells. The samples from these wells are interpreted to be within the early to late oil window and tend to have PI values in the range of 0.10 to 0.60, generally plotting in the region associated with extensive generation expulsion (Fig. 11). These elevated PI values are generally consistent with source rocks that are interpreted to be within the main oil window, as shown by the trend envelope (Fig. 11). The trend envelop shown on this plot by a dashed line is based on WFT Labs analysis of over 5000 source rock samples and serves to illustrate the general increase in PI with increasing thermal maturity through the main oil window and its subsequent decrease with increasing oil-to-gas secondary cracking through the condensate/wet gas window. The relatively low PI values in the Sever 1 samples examined in the current study are inconsistent with their interpreted peak oil window thermal maturity and suggest other causes for the relatively low in-situ
hydrocarbon saturation. In this well the Kyalla source rocks are currently buried very shallow (< 330 m) and it would appear likely that any in-situ hydrocarbon saturation has been expelled/lost due to uplift/erosion. Also illustrated on Fig. 11 is a grouping of samples that fall into the area associated with stained or contaminated samples. These tend to have anomalously low $T_{\text{max}}$ values and generally elevated PI that could indicate possible contamination by drilling fluids. The samples with elevated $T_{\text{max}}$ values in the dry gas window also have relatively high PI values that are generally inconsistent with a dry gas thermal maturity level. It is likely that these samples contain a higher abundance of Type IV kerogen that is producing anomalously elevated $T_{\text{max}}$ values, but further investigation will be required to confirm this hypothesis.

Figure 11. Production Index (PI) versus $T_{\text{max}}$ for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Trend envelop shown by dashed line is based on WFT Labs analysis of over 5000 shale samples. Plot symbology defined in Fig. 4.

The average pyrolysis S1 values in the Kyalla Formation source rocks vary from 0.1 to 1.1 mg HC/g rock or 1 to 24 bbl/a-ft. This suggests generally poor to fair in-situ hydrocarbon saturation in these source rock intervals and is generally inconsistent with the elevated TOC and generation potential of these oil-prone
source rocks. These wells are interpreted to be in the early to late oil window and have sufficient thermal maturity to have generated oil. Thus, the low in-situ hydrocarbon saturations are an anomaly with regard to the interpreted thermal maturity. These 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. Regardless, the relatively low in-situ hydrocarbon saturation as determined from the S1 analysis in comparison to quality oil-prone source rocks at peak oil window maturity is a clear risk factor for successful unconventional shale oil development. As noted previously, in the case of the Sever 1 well this may be a consequence of shallow depths of this source rock intervals and uplift/erosion of the geologic section. For other wells within the Beetaloo Sub-basin the low in-situ hydrocarbon saturations may imply loss due to expulsion and migration out of the Kyalla source rocks and into adjacent porous reservoir units.

Estimated kerogen transformation ratios in the Kyalla Formation samples based upon interpreted original and measured present HI vary from 38 to 88% in the wells from this study region. These transformation ratios were calculated using the limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type I and Type II kerogen. These average transformation ratios are below the recommended minimum threshold of 50% for shale oil systems in one of the wells (Balmain 1) and above the recommended minimum of 80% for thermogenic shale gas systems in five of the wells. This is somewhat consistent with the interpreted thermal maturity levels of these wells, although due to lack of kerogen analyses this parameter is poorly constrained. In general some of the elevated TR values that would suggest post-oil window maturity are likely a consequence of over estimation of original HI as note previously during discussion of the two groupings of kerogen organofacies. Spatial distributions in the transformation ratios were evaluated in the context of previous trends within other geochemical parameters (Fig. 12). Geographically, the Balmain 1 and McManus 1 wells clearly have relatively lower transformation ratios and wells like the Shenandoah 1A, Chanin 1 and Jamison 1 located more in the center of the basin tend to have higher transformation ratios (Fig. 12). Further data points and integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these variations in transformation ratios.

The thermal maturity of the Kyalla Formation 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). Samples from select Kyalla source rocks (avg. 45 to 70% clays) have average measured Kübler Index values of 0.175 to 0.296, which is equivalent to a measured vitrinite reflectance of ~2.75% to > 4% (peak to 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 12. The spatial distribution of the Transformation Ratios (TR) for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average TR and are reported as decimal percent conversion using calculated original HIo values based upon measured/interpreted original kerogen distributions.

**Roper Group Thermal Maturity Depth Profiles**

Measured maceral reflectance (\% R_o) analyses were conducted on select samples from eight wells within the Roper Group in the Beetaloo Sub-Basin, including the Kyalla, Upper Velkerri and Middle Velkerri intervals. The results from these analyses (see Fig. 13 and individual well reports) show distributions that consist of macerals identified as either fluorescing alginate, non-fluorescing alginate, low reflectance solid bitumen or high reflectance solid bitumens. The fluorescing alginate populations have mean reflectance of 0.58 to 0.64\% R_o and exhibit orange brown to dark brown fluorescence colors suggesting late oil window thermal maturity (~0.90 to 1.10\% R_o). The low reflectance solid bitumen populations and non-fluorescing alginate have reflectance values that average from 0.48 to 2.18\% R_o and the former are
considered the most representative indigenous kerogen population for thermal maturity assessment (Fig. 13). However, caution should be applied for interpretation of the Jamison 1 Kyalla sample from 1018 m depth that has a measured 0.48% R_o since reflectance in this sample may be “suppressed” due to the high in-situ hydrocarbon saturations (S1 is 3.20 mg HC/g rock). The high reflecting solid bitumen populations, where present, have reflectance values of 0.75 to 2.58% 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 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 0.82 to 1.45% Eq. R_o (Fig. 13). The conversion formula published by Jacob (1985) for ‘angular-like’ pyrobitumen trapped in mineral pore spaces (Eq. R_o = (Bitumen R_o × 0.618) + 0.4) was applied to the high reflecting population and resulted in 0.86 to 1.99% Eq. R_o (Fig. 13). The Landis and Castaño (1995) conversion suggest a condensate/wet to dry gas window thermal maturity for most samples (except shallowest Jamison 1 sample noted previously), which is much higher than predicted by T_max for these wells. The Jacob (1985) conversion also suggests thermal maturity that is generally within the condensate/wet gas to dry gas window, however, for several samples this conversion is closer to actual measured R_o from the low reflectance bitumen population. Comparison with all samples evaluated 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 and non-fluorescing alginite within the same sample. In wells examined from the Beetaloo Sub-Basin, this appears to be only partially valid. In the well containing non-fluorescing alginite this relationship holds and in wells containing low reflectance solid bitumen the Eq. R_o values from the high reflectance bitumen is somewhat higher (Fig. 13). Clearly further study is warranted to better understand these organic petrology results and the proper application of solid bitumen conversions to the multiple populations of organic macerals observed within these Mesoproterozoic samples.

The organic petrology data collected in the current investigation is considered insufficient to fully constrain a thermal maturity depth profile (Fig. 13). The data points available span a considerable depth range from ~335 to 2550 m and would be expected to exhibit a significant maturity trend in a typical heat flow regime. The data shown (with the exception of the shallowest Jamison 1 Kyalla sample noted previously) do appear to span the peak oil window through to the early condensate/wet gas window at a depth of ~1600 m and provide supporting evidence for the interpreted thermal maturity of the Roper Group samples in some wells based upon other geochemical evidence. The Kyalla Formation samples from the wells within this study area span a depth range from ~940 down to ~1600 m depth. The measured maceral R_o data from this region (Fig. 13) show that thermal maturity within this depth interval can range anywhere from peak oil to the late condensate/wet gas window, which is in agreement with the interpreted thermal maturity levels of the Kyalla Formation in wells evaluated in the current study. Below ~1600 m depth maturity readings are less constrained. The single reading from non-fluorescing alginite at 2552 m depth in the Shenandoah 1A well is 2.18% R_o in the Middle Velkerri Formation and supports an interpreted dry gas thermal maturity level for this sample. Clearly, further sampling will be needed to constrain the maturity depth profile for the Beetaloo Sub-basin.

Error bars associated with minimum/maximum reflectance readings show an apparent high degree of anisotropy within several of the low reflecting solid bitumen samples, which is factor that should be considered in future studies where organic petrology results are intended to be used for maturity assessment in Mesoproterozoic samples. Interestingly, the non-fluorescing alginite samples appear to have less anisotropy based upon this limited data set.

The programmed pyrolysis T_max data collected in the current study was also evaluated to see if a consistent depth trend could be established for the Beetaloo Sub-Basin (Fig. 14). Previously in the Beetaloo Sub-basin, such a maturity depth profile constructed from T_max data has been proposed where the top of thermally mature Kyalla and Velkerri occurs at a depth of about 350 m and the top of thermally over-mature Kyalla and Velkerri occurs at a depth of about 1500 m (Law et al., 2010). Thus, the depth range of 350 to 1500 m has been proposed to correspond with the main oil window (“onset of oil
generation” and “oil deadline”), although visualization of plotted $T_{\text{max}}$ data (Law et al., 2010) show an apparent range between ~435 to 465°C that would bracket the peak oil to middle condensate/wet gas widows using the guidelines of the current study (Table 3). The $T_{\text{max}}$ data from the wells sampled in the Beetaloo Sub-Basin (all formations) cover larger depth range from near surface to ~2500 m depth and the do appear to show a similar maturity depth trend within the Roper Group source rocks (Fig. 14).

The $T_{\text{max}}$ values for samples with relatively high S2 yields (> 2 mg HC/g rock) that are interpreted to have high confidence show a range from ~425 to 450°C that would bracket the main oil window generally from surface to ~1500 m depth (Fig. 14). The $T_{\text{max}}$ values in these samples do appear to be generally increasing with depth (Fig. 14), but there are several trends of outlier samples (especially in the shallow region < 500 m depth). Below ~1500 m depth there appears to be a sharp increase in $T_{\text{max}}$ values in the ~450 to 450°C range that would be consistent with the location of the main condensate/wet gas window based upon the guidelines used in the current study. This “kink” in elevated $T_{\text{max}}$ values appears similar to that reported by Law et al. (2010) which corresponds to their “oil deadline” and beginning of the “gas zone”.

Samples that were found to have very low S2 yields (grey symbols on Fig. 14 insert plot) clearly fall off of the proposed thermal maturity depth trend. These include basically all samples > 2000 m depth and several samples with anomalously high $T_{\text{max}}$ values in the shallower horizons (Fig. 14). Some samples in the shallow interval from the surface down to ~500 m depth with relatively high S2 yields show considerable variability in their measured $T_{\text{max}}$ values (Fig. 14) ranging from ~410 to 460°C. The anomalously low readings could be artifacts associated with high in-situ oil saturations, as mentioned previously during the discussion of $T_{\text{max}}$ values. More detailed data parsing using available pyrograms would be required to fully evaluate these readings.
Figure 13. Thermal maturation based on measured maceral reflectance (%Ro) versus depth for the Roper Group source rock samples in the Beetaloo Sub-Basin, Australia. Measured %Ro values for low reflectance solid bitumen are considered most reliable for thermal maturity assessment. Calculated Eq. Ro for high reflectance solid bitumens uses the conversion of Jacob (1985), while Eq. Ro for low reflectance solid bitumen uses the Landis and Castaño (1995) conversion. Error bars shown on low reflectance solid bitumen data points represent the minimum/maximum reflectance readings observed during organic petrology.
Figure 14. Thermal maturation based on programmed pyrolysis $T_{\text{max}}$ versus depth for the Roper Group source rock samples in the Beetaloo Sub-Basin, Australia. Data points colors reflect programmed pyrolysis S2 yields and can be used to distinguish data points with higher confidence levels ($S2 > 2 \text{ mg HC/g rock}$), which are shown on main plot. Insert plot (left) shows all data points. Insert plot (right) shows $T_{\text{max}}$ data plot from Law et al. (2010) with interpreted hydrocarbon generation zones.

**KYALLA ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS**

Petroleum generative capacity depends on the original quantity of organic matter ($\text{TOC}_o$) and the original type of organic matter ($\text{HI}_o$) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by $\text{TOC}_{pd}$ and $\text{HI}_{pd}$ in the Kyalla Formation 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).

$\text{HI}_o$ values can be computed from visual kerogen assessments and assigned kerogen-type $\text{HI}_o$ average values using the following equation (Jarvie et al., 2007):
This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various wells evaluated in the current study are shown in Table 5, along with the resultant average original HIo values calculated using equation (1) above. The kerogen estimations used in this study are generally in agreement with other published sedimentological information regarding Kyalla Formation source rocks, which suggest a dominance of Type I and Type II kerogen in organic-rich mudstone lithologies (Munson, 2014).

<table>
<thead>
<tr>
<th>Well</th>
<th>%Type I</th>
<th>%Type II</th>
<th>%Type III</th>
<th>%Type IV</th>
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<td>0</td>
<td>0</td>
<td>588</td>
</tr>
<tr>
<td>Burdo 1</td>
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<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Chanin 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Elliott 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Jamison 1</td>
<td>5</td>
<td>95</td>
<td>0</td>
<td>0</td>
<td>465</td>
</tr>
<tr>
<td>McManus 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Ronald 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Sever 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
</tbody>
</table>

Table 5. Average Kerogen Estimations for Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia.

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):

$$TR_{III} = 1 - \frac{HI_{pd}[1200 - HI_{o}(1 - PI_{o})]}{HI_{o}[1200 - HI_{pd}(1 - PI_{pd})]}$$

Equation 2

HI_{pd} and PI_{pd} are the measured HI and PI values for the various source rock samples in these wells. The average HI_{pd} and PI_{pd} for the formations evaluated in the current study are shown in Table 6. 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 to 465 mg HC/g TOC (Table 5). 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 varies from 0.38 to 0.88 (Table 6), i.e., on average an estimated 38 to 88% 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):

$$TOC_{o} = \frac{HI_{pd}(\frac{TOC_{pd}}{1 + k})}{HI_{o}(1 - TR_{III})} + \frac{HI_{pd}(\frac{TOC_{pd}}{1 + k})}{HI_{o}(1 - TR_{III})}$$

Equation 3

The data presented in this report are derived from a comprehensive study of the Beetaloo Sub-Basin, which includes the interpretation of kerogen data to infer original kerogen and TOC values. The results provide valuable insights into the thermal history and potential hydrocarbon generation potential of the Kyalla Formation source rocks.
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 for the Kyalla Formation source rock samples before petroleum generation was calculated (Table 6).

The original generation potential $S_{2o}$ can be calculated using the following equation:

$$S_{2o} = \frac{HI \times TOC_o}{100}$$ (4)

For the Kyalla Formation source rocks examined in the various wells in this study, the average $S_{2o}$ values are calculated as mg HC/g rock and also converted to bbl/acre-ft units (multiply $S_{2o}$ by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 6).

Knowing the measured remaining generation potential $S_2$ from programmed pyrolysis and using the calculated original generation potential $S_{2o}$ 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).

Original ($S_{2o}$) – Remaining ($S_2$) = Generated HCs (5)

Using this methodology for the Kyalla Formation source rock samples analyzed in the current study, the estimated generated oil and cracked gas yields are given in Table 6.

<table>
<thead>
<tr>
<th>Well</th>
<th>TOCpd</th>
<th>HIpd</th>
<th>$S_{2pd}$ bbl/a-ft</th>
<th>HIo</th>
<th>TR</th>
<th>TOCo</th>
<th>$S_{2o}$ bbl/a-ft</th>
<th>S1 Free Oil bbl/a-ft</th>
<th>Est. Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
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<td>1.73</td>
<td>471</td>
<td>182</td>
<td>588</td>
<td>0.38</td>
<td>1.94</td>
<td>250</td>
<td>24</td>
<td>69</td>
<td>0</td>
</tr>
<tr>
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<td>115</td>
<td>22</td>
<td>450</td>
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<td>1.09</td>
<td>108</td>
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<td>84</td>
<td>8</td>
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<tr>
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<tr>
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<td>44</td>
<td>450</td>
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<td>1.46</td>
<td>144</td>
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</tr>
<tr>
<td>Jamison 1</td>
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<td>123</td>
<td>49</td>
<td>465</td>
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<td>2.37</td>
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<td>450</td>
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<td>0.88</td>
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<tr>
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<tr>
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<td>0.93</td>
<td>92</td>
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<td>2.10</td>
<td>207</td>
<td>13</td>
<td>170</td>
<td>36</td>
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</tbody>
</table>

Table 6. Hydrocarbon Yields average data for Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia.

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 ($S_1$) 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 Formation source rocks in wells interpreted to be within the peak oil window varies from 66 to 99%, which is consistent with an early oil to dry gas window maturity. This implies that retained oil saturation is elevated in some low maturity wells but in other wells most of the generated hydrocarbons have been expelled from these source rock intervals.
The Kyalla Formation source rock samples in the various wells examined in the current study are interpreted to be in the early to late oil window and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly oil with some associated gas in most wells). 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 7). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original \( S_2^o \) 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 source rock samples in the Beetaloo Sub-Basin, original generation potential \( S_2^o \) averages from 87 to 250 bbl oil/acre-ft (Table 7). These values fall below the other formations on the list of unconventional US Shale plays shown below.

<table>
<thead>
<tr>
<th>Sample Database Averages</th>
<th>( H^o ) m/g TOC</th>
<th>TR</th>
<th>TOC wt%</th>
<th>( S_2^o ) mg/g Rock</th>
<th>Remaining Potential bbl/a-ft</th>
<th>Original Potential bbl/a-ft</th>
<th>Oil Cracked %</th>
<th>( S_1^o ) Free Oil bbl/a-ft</th>
<th>Estimated Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett Shale Ft. Worth Basin</td>
<td>435</td>
<td>0.84</td>
<td>5.38</td>
<td>23.40</td>
<td>94</td>
<td>513</td>
<td>0.40</td>
<td>33</td>
<td>251</td>
<td>1005</td>
</tr>
<tr>
<td>Barnett Shale Delware Basin</td>
<td>435</td>
<td>0.91</td>
<td>5.25</td>
<td>22.84</td>
<td>52</td>
<td>500</td>
<td>0.80</td>
<td>32</td>
<td>90</td>
<td>2149</td>
</tr>
<tr>
<td>Woodford Shale Delware Basin</td>
<td>480</td>
<td>0.89</td>
<td>6.41</td>
<td>30.79</td>
<td>139</td>
<td>674</td>
<td>0.89</td>
<td>46</td>
<td>60</td>
<td>2854</td>
</tr>
<tr>
<td>Haynesville Shale E. Texas Basin</td>
<td>400</td>
<td>0.98</td>
<td>3.93</td>
<td>15.73</td>
<td>7</td>
<td>344</td>
<td>1.00</td>
<td>3</td>
<td>0</td>
<td>2022</td>
</tr>
<tr>
<td>Fayetteville Shale Arkoma Basin</td>
<td>435</td>
<td>0.95</td>
<td>3.34</td>
<td>14.53</td>
<td>15</td>
<td>318</td>
<td>1.00</td>
<td>10</td>
<td>0</td>
<td>1820</td>
</tr>
<tr>
<td>Woodford Shale Arkoma Basin</td>
<td>520</td>
<td>0.87</td>
<td>5.15</td>
<td>26.80</td>
<td>12</td>
<td>587</td>
<td>0.70</td>
<td>87</td>
<td>170</td>
<td>2431</td>
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<tr>
<td>Eagle Ford Shale Gulf Coast Basin</td>
<td>520</td>
<td>0.85</td>
<td>3.19</td>
<td>16.61</td>
<td>61</td>
<td>364</td>
<td>0.47</td>
<td>22</td>
<td>161</td>
<td>848</td>
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<tr>
<td>Marcellus Shale Appalachian Basin</td>
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<td>0.97</td>
<td>6.44</td>
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<tr>
<td>Utica Shale Appalachian Basin</td>
<td>450</td>
<td>0.98</td>
<td>2.74</td>
<td>12.32</td>
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<td>270</td>
<td>1.00</td>
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<td>0</td>
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<td>Barnett Shale Oil</td>
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<td>540</td>
<td>0.00</td>
<td>79</td>
<td>213</td>
<td>0</td>
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<tr>
<td>Barnett Shale Gas</td>
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<td>0.96</td>
<td>5.58</td>
<td>25.13</td>
<td>23</td>
<td>550</td>
<td>0.87</td>
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<td>2751</td>
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<tr>
<td>Balmain 1- Kyalla</td>
<td>588</td>
<td>0.38</td>
<td>1.94</td>
<td>11.43</td>
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<td>250</td>
<td>0.00</td>
<td>24</td>
<td>69</td>
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<td>Burdo 1- Kyalla</td>
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<td>0.82</td>
<td>1.09</td>
<td>4.92</td>
<td>22</td>
<td>108</td>
<td>0.02</td>
<td>5</td>
<td>84</td>
<td>8</td>
</tr>
<tr>
<td>Chanin 1 - Kyalla</td>
<td>450</td>
<td>0.86</td>
<td>1.27</td>
<td>5.74</td>
<td>19</td>
<td>126</td>
<td>0.14</td>
<td>11</td>
<td>93</td>
<td>83</td>
</tr>
<tr>
<td>Elliott 1 - Kyalla</td>
<td>450</td>
<td>0.76</td>
<td>1.46</td>
<td>6.57</td>
<td>44</td>
<td>144</td>
<td>0.00</td>
<td>13</td>
<td>100</td>
<td>5</td>
</tr>
<tr>
<td>Jamison 1 - Kyalla</td>
<td>465</td>
<td>0.82</td>
<td>2.37</td>
<td>11.09</td>
<td>49</td>
<td>243</td>
<td>0.19</td>
<td>16</td>
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<td>277</td>
</tr>
<tr>
<td>McManus 1 - Kyalla</td>
<td>450</td>
<td>0.50</td>
<td>0.88</td>
<td>3.96</td>
<td>48</td>
<td>87</td>
<td>0.00</td>
<td>3</td>
<td>39</td>
<td>0</td>
</tr>
<tr>
<td>Ronald 1 - Kyalla</td>
<td>450</td>
<td>0.74</td>
<td>1.04</td>
<td>4.66</td>
<td>27</td>
<td>102</td>
<td>0.02</td>
<td>9</td>
<td>73</td>
<td>9</td>
</tr>
<tr>
<td>Sever 1 - Kyalla</td>
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<td>0.82</td>
<td>0.93</td>
<td>4.18</td>
<td>15</td>
<td>92</td>
<td>0.00</td>
<td>1</td>
<td>76</td>
<td>0</td>
</tr>
<tr>
<td>Shenandoah 1 - Kyalla</td>
<td>450</td>
<td>0.88</td>
<td>2.10</td>
<td>9.44</td>
<td>31</td>
<td>207</td>
<td>0.04</td>
<td>13</td>
<td>170</td>
<td>36</td>
</tr>
</tbody>
</table>

Table 7. Geochemical Properties and Generation Potential for US Shale plays. Kyalla Formation wells are color coded for possible shale oil (green) and shale gas (red) prospect type.

KYALLA UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Kyalla Formation source rocks in the Beetaloo Sub-Basin have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 15) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for all four diagnostic ratios where available. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas production. Transformation Ratios (TR) were calculated based upon HI, estimates using measured and interpreted fractional composition of kerogen macerals.
The Kyalla Formation source rocks in the Beetaloo Sub-Basin wells are interpreted to represent a moderate to high geochemical risk for in-situ shale oil production with the exception of the Jamison 1 well which is considered a low risk for shale oil. The average measured TOC contents in most wells are below the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Fig. 15). The wells which are above this threshold are the Balmain 1, Jamison 1 and Shenandoah 1A wells. None of these Kyalla Formation wells have average TOC content 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 in these wells is interpreted to be dominantly oil-prone Type II kerogen.

Thermal maturity parameters from programmed pyrolysis place these wells within the early to late oil window. The average $T_{\text{max}}$ values between 428 to 456°C are mostly above recommended minimum value of 435°C for shale oil and below the minimum of 455°C for shale gas (Fig. 15). The exception is the McManus 1 well which falls below the minimum shale oil threshold. For the other wells, this amount of conversion would likely be sufficient to generate/expel moderate amounts of hydrocarbons from this fairly organic lean source facies. Transformation ratios (TR), the least constrained risk parameter, average 38% for the Balmain 1 well interpreted to be in the early oil window and fall below the recommended minimum of 50% for shale oil (Fig. 15). All other wells are at or above the 50% threshold. The TR in several of these wells that are interpreted to be in the peak to late oil window exceeds the recommended minimum 80% threshold for shale gas systems (Fig. 15).

In the Kyalla Formation source intervals, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor to fair (avg. 3 to 24 bbl oil/acre-ft), which is a significant concern regarding risk.
assessment for unconventional oil (Figs. 16 & 17). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Kyalla Formation wells interpreted to be in the oil window at 39 to 170 bbl oil/acre-ft (Figs. 16 & 18). 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. 16). These values are higher compared to the Kyalla Formation due primarily to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC). Furthermore, the in-situ oil saturation is significantly lower and this is the reason the Shenandoah 1A well is considered a moderate risk for commercial shale oil development (despite having all risk parameters above minimum thresholds on Fig. 15). Further investigation is needed to assess the reasons why measured in-situ hydrocarbon saturation is so low within the Kyalla interval. It is likely that any in-situ oil saturation has migrated out of this source facies as a consequence of expulsion and/or geologic processes like uplift/erosion within the basin, especially from intervals that are presently at very shallow burial depths.
Figure 16. Hydrocarbon yield estimates for the Mesoproterozoic Kyalla Formation source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the oil window.

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 Formation source intervals in these wells is in the early to
late oil window and hydrocarbon saturation is likely to vary from heavy and immobile to fairly light and mobile with increased thermal maturity. The presence of heavy oil and solid bitumens 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 Formation 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 17. The spatial distribution of the S1 Free Oil saturation for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S1 of all samples and are reported as bbl oil/acre-ft.

Spatial distributions in the measured in-situ S1 free oil saturations, estimated generated oil yields and estimated cracked gas yields (Figs. 17 through 19) were evaluated in the context of previous trends within other geochemical parameters. As noted previously, measured in-situ S1 oil saturations are generally low.
in the Kyalla Formation wells evaluated in this study area (3 to 24 bbl oil/acre-ft). Geographically, these minor differences in in-situ oil saturation manifest themselves as trend of relatively higher S1 content in the wells located in more central region of the Beetaloo Sub-Basin (Fig. 17). This is especially true for the Balmain 1 well, which is much shallower than adjacent wells and appears to have retained more of its generated hydrocarbon saturation. More well data points will be required to see if this apparent trend is valid. Spatial trends in the estimated generated oil yields show that there is higher estimated oil generated in the Shenandoah 1A and Jamison 1 wells within the central portion of the study area (Fig. 18). This is likely a consequence of both higher TOC content and higher thermal maturity.

**Figure 18. The spatial distribution of the Estimated Generated Oil Yields for the Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average generated oil and are reported as bbl oil/acre-ft.**

Spatial trends in the estimated secondary cracked gas yields show that there is no cracked gas from most of the wells in which the Kyalla Formation was evaluated the current study area (Fig. 19). This is
expected due to the relatively low thermal maturity of these wells (early to peak oil window). The major
exception is the Jamison 1 well that is interpreted to be in the late oil window. In this well there is a
moderate amount of secondary cracked gas generated (estimated 19% oil to gas cracking) and for this
reason the well is tentatively considered a low risk for shale oil development as the low in-situ oil
saturation may have been lost due to volatilization prior to sample analysis. The presence of some
secondary cracked gas along with any associated gas is generally considered favorable for oil mobility in
unconventional shale oil systems.

Figure 19. The spatial distribution of the Estimated Cracked Gas Yields for the Kyalla Formation
source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average
secondary cracked gas of all samples and are reported as Mcf gas/acre-ft.
KYALLA MINERALOGY

KYALLA INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Kyalla Formation source rocks in nine (9) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Select samples from these wells were analyzed by X-ray diffraction (XRD). The purpose of this testing was to document the mineralogy of the samples in order to evaluate potential organofacies variations, to examine reservoir quality and brittleness for fracture development, and to assess possible controls on porosity and permeability.

KYALLA MINERALOGY

XRD data taken from samples in the Kyalla Formation (Table 8; Fig. 20) shows that clays are the most abundant minerals present and total clay content averages 54%. Clay types found are dominated by illite/mica (avg. 35%), chlorite (avg. 8%), kaolinite (avg. 7%), and mixed-layer illite/smectite (avg. 4%). Quartz is the dominant non-clay species, its abundance averages 36%. Classification of these samples by rock type shows that most would be classified as either silica-rich argillaceous mudstones or clay-rich siliceous mudstones, although there is a minor amount of argillaceous-siliceous mudstones.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Clays</th>
<th>Carbonates</th>
<th>Quartz</th>
<th>K-spar</th>
<th>Other</th>
<th>Mixed I/S*</th>
<th>TOC</th>
<th>Brittleness Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Kyalla</td>
<td>54</td>
<td>2</td>
<td>36</td>
<td>6</td>
<td>2</td>
<td>4</td>
<td>1.15</td>
<td>41</td>
</tr>
</tbody>
</table>

*ordered interstratified mixed-layer illite/smectite

Table 8. TOC & X-ray diffraction average data (weight %) for Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia.

The shale samples in the Kyalla Formation source intervals are clay dominated, which is a concern for potential fracture stimulation because this is often a fairly ductile mineral assemblage. However, these samples also contain abundant quartz, which is a relatively brittle mineral and conducive to fracture stimulation. Pyrite is present in minor amounts (avg. 1%) and is associated with kerogen that is also a minor component of the overall mineralogy. The minor contribution of these components is usually positive with regard to fracture stimulation in general for organic-rich shales at elevated thermal maturity.

Another potential risk factor for fracture stimulation is the abundance and type of clays within the Kyalla Formation samples. These source rock samples do contain significant amounts of clays (avg. 54%), and these clays also contain ordered interstratified mixed-layer illite/smectite (avg. 4% and comprising 13% of total clays). In general, successful unconventional shale plays tend to have less than 10% total mixed-layer illite/smectite (R. Bruce, personal communication) and the Kyalla samples analyzed in this study are below this risk threshold. Thus, the abundance of clays in the Kyalla Formation samples would not appear to be a negative risk factor for fracture stimulation; however, further testing to include rock-mechanics measurements is warranted to fully evaluate this parameter.
Figure 20. XRD average mineralogy for Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia. Upper diagram shows relative abundance of clays, carbonates, quartz, pyrite and others. Lower diagram shows clay speciation (percentages shown in pie are renormalized).

Mineralogy data can potentially be utilized to further assess rock mechanical properties, including brittleness. Brittleness Index (BI) values were calculated using equation (6) below. The range of BI values vary from 23–69 and average 41 (Table 8), with higher values supposedly indicating more brittle rock. The highest BI values were found in the samples with the lowest overall clay content. One sample analyzed from the Burdo 1 well had the highest silica content (69%) of all Kyalla samples in this study and it also had the highest brittleness index of 69. Close examination of the data show that both carbonate and quartz have a strong influence on the brittleness calculation. In the most of the Kyalla source rocks, carbonate is generally in very low abundance and the variability in quartz and clays appears to control the Brittleness Index. Recent publications have noted that measured rock mechanical properties were often found to have poor correlations with various formulas for calculating brittleness index values (Yang et al., 2013). Thus, caution should be exercised in using these data for evaluations and any BI values for
previously untested source rocks like the Kyalla Formation should be calibrated against measured rock mechanical data.

$$BI = \frac{1.3(Qtz) + (Kspar) + (Plag) + 1.2(Carb)}{Numerator + 2(Mixed) + 1.5(Chlor + Kaol + Ill) + (Pyr) + (Apa) + (Bar)}$$

Mineralogy data can also be used to compare the Kyalla Formation source rock samples against other US Shale plays. Ternary diagrams of the quartz, carbonate, and clay percentages have been constructed using the individual samples from the various Kyalla Formation wells in the Beetaloo Sub-Basin evaluated in the current study (Fig. 21). In these diagrams, most US Shale plays plot along a continuum between the quartz and carbonate endpoints, which are also the locations of the most brittle rocks (Fig. 21). As clay percentages increase (toward the SE corner of the diagram), the brittleness decreases. As noted previously, the Kyalla samples have generally high clay content (avg. 54%), which may be a risk for fracture stimulation. On the mineralogy ternary diagram (Fig. 21), the Kyalla samples appear to plot along the margins of the envelope representing most US Shale samples, but they do overlap with select samples from a couple of plays (e.g. Ohio Devonian, Lower Huron). The relative brittleness of US Shale samples in this region of the ternary diagram tends to be lower in comparison to other samples that are either more quartz-rich or more carbonate-rich (Fig. 21). However, as noted previously, the total clay content should not be considered the only factor in risk assessment, but rather it is the abundance of mixed-layer illite/smectite clay species that is more likely to be the critical factor. In the Kyalla Formation source rocks, these mixed-layer illite/smectite clay species are in relatively low abundance (avg. 4%). As clearly documented in the mineralogy ternary diagrams, there is considerable variability even within an individual shale play and each shale should be considered based on its own mineralogy and petrophysical attributes. Ultimately, these data need to be calibrated against laboratory measured geomechanical properties for continued improvement in stimulation and completion practices.

Figure 21. XRD mineralogy ternary diagram for Kyalla Formation source rock samples in the Beetaloo Sub-Basin, Australia (left) compared to published data for US Shale plays (right) (Rickman et al., 2008). Sizes of symbols represent the relative brittleness determined by XRD within the published data set, but this is not illustrated in the data from the current study.
### UPPER VELKERRI PETROLEUM GEOCHEMISTRY

#### UPPER VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Upper Velkerri source rocks in five (5) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells 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 was also incorporated into the interpretive evaluation. The complete results of these analyses are documented in the individual well reports and are summarized in Table 9.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Oil/Gas Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Very Good (2.27% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate (Oil)</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td>Minor Oil Early Oil Window</td>
<td>Good (1.02% TOC)</td>
<td>Oil-prone Type II</td>
<td></td>
<td></td>
</tr>
<tr>
<td>McManus 1</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Very Good (2.23% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate (Oil)</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
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<td>Oil Early Oil Window</td>
<td>Good (1.30% TOC)</td>
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<td></td>
<td></td>
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<td>Sever 1</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Very Good (2.88% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate (Oil)</td>
<td></td>
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<td></td>
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<td>Shenandoah 1A</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Fair (0.90% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Gas)</td>
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<td>Measured Currently</td>
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<td>Gas Dry Gas Window</td>
<td>Fair (0.60% TOC)</td>
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<td>Tarlee S3</td>
<td>Upper Velkerri</td>
<td>Estimated Original</td>
<td>Good (1.98% TOC)</td>
<td>Oil-prone Type II</td>
<td>Moderate (Gas)</td>
<td></td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td>Dry Gas Dry Gas Window</td>
<td>Good (1.46% TOC)</td>
<td>Inert Type IV</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

#### Table 9. Upper Velkerri Geochemical Summary

**UPPER VELKERRI GENERATIVE POTENTIAL**

The Upper Velkerri source rock samples analyzed from the Beetaloo Sub-Basin have dominantly good generative potential (Table 9; Fig. 22). Organic richness varies from 0.12 wt.% (poor) to as high as 10.60 wt.% (excellent) TOC, with an average value of 1.27 wt. % TOC (good). The histogram plot of TOC distributions (Fig. 22) illustrate that the dominant population is within the 0.5 to 1.0 wt. % range, although the 0 to 0.5 wt. % range is also elevated. Outside of this range there appears to be a general trend of a rapid progressive decrease in frequency of samples with increasing TOC content. Around one-third of these samples have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks. Only about 18% of these samples have TOC content above the minimum requirement of 2 wt.% for economic petroleum source rocks, which is a potential risk factor for unconventional resource development.

The distribution of elevated TOC values in the Upper Velkerri is not restricted to a single well within the limited sample suite evaluated from the Beetaloo Sub-Basin. In most wells the highest TOC content within the Upper Velkerri tends to occur near the basal contact with the underlying Middle Velkerri, which
generally has much higher organic content. However, the Sever 1 well has its highest values near the middle of the Upper Velkerri interval and these samples constitute all values > 9 wt.% in the TOC histogram plot (Fig. 22). The spatial distributions of measured TOC within the Upper Velkerri do show some variations across the Beetaloo Sub-Basin (Fig. 23). The two wells with the highest average Upper Velkerri TOC (Sever 1 & Tarlee S3) are located in the NW corner of the study area and are outside the main Beetaloo Sub-basin depocenter. The Shenandoah 1A well in the center of the main depocenter has the lowest average TOC, while the Altree 2 and McManus 1 wells located along the basin margins are intermediate in their TOC content. The overall trend appears to be an increase in TOC content moving from SE to NW across the study area (Fig. 23). However, the density of sampling may be affecting the integrity of statistical averages for these TOC values. For example, the elevated Tarlee S3 average TOC value is based upon only one (1) data point. Nevertheless, these apparent spatial trends in TOC could reflect differences in paleo-depositional environment or organic productivity that have imparted geographic variations in the abundance of preserved organic matter within the Upper Velkerri source rock interval. It could also simply reflect sampling bias related to picking the contact with the underlying Middle Velkerri source rock interval. Regardless, caution should be applied to any spatial interpretations since they are based on the distribution of samples from only five wells.

Figure 22. Histogram plot of Total Organic Carbon (TOC) distributions for Upper Velkerri source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.%, while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.
Pyrolysis S2 yields in the Upper Velkerri samples vary from 0.02–21.31 mg HC/g rock (Fig. 24) and average values within individual wells vary from 0.13–7.83 mg HC/g rock or 3–171 bbl/a-ft. These indicate a poor to good amount of remaining primary hydrocarbon generation potential (both oil and gas), which is consistent with marginal organic richness and highly variable levels of primary thermal conversion in the early oil to dry gas windows. There appears to be two populations of data for the Upper Velkerri samples in the Beetaloo Sub-Basin that would likely correspond with different thermal maturity levels and possibly distinct organic facies within this interval (Fig. 24). Samples from the first population have variable TOC, but moderate to elevated S2 values and generally plot within the oil-prone Type II kerogen to mixed oil/gas-prone Type II/III regions (Fig. 24). These samples are consistent with well-preserved Type II to partially oxidized Type II/IV kerogens (see Langford and Blanc-Valleron, 1990) that have undergone minimal thermal conversion and are best represented by samples from the Altree 2 and McManus 1 wells.
(Fig. 24). The second major grouping of samples represents a more disperse set of data points that extend from inside the organic lean box to populate the regions associated with gas-prone Type III kerogen and inert Type IV kerogen (Fig. 24). These data also represent samples that are more fully converted due to their elevated thermal maturity (peak oil to dry gas), but likely had much more limited original generation potential in comparison to the other group of source rock samples. These samples appear to include the grouping of very elevated TOC values > 9 wt.% in the Sever 1 well (Fig. 24). Original placement of the first population of samples prior to thermal conversion would be generally within the oil-prone Type II to mixed Type II/III region. The second group of samples is more likely to represent original organic matter that would be a mix of oil-prone Type II and inert Type IV kerogen, although they have been presumed to contain only Type II for purposes of hydrocarbon yield modeling in this study (see individual well reports and hydrocarbon yield calculations for more details). This interpretation may be somewhat optimistic given the geochemical results presented herein.

Figure 24. Total Organic Carbon (TOC) versus Remaining Hydrocarbon Generation Potential (S2) for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Insert plot is expanded view to better illustrate details within this data set. Plot symbology defined in Fig. 4.
The spatial distribution of S2 content for the Upper Velkerri samples shows significant variations between the wells in this study (Fig. 25). The early oil window maturity wells (Altree 1 & McManus 1) have the highest S2 yields and are located along the margins of the basin. The Sever 1 well in the far NW region of the study area has moderate S2 content in comparison to the other wells (Fig. 24), consistent with its peak oil window interpreted thermal maturity. The dry gas window maturity wells (Tarlee S3 & Shenandoah 1A) have the lowest remaining generation potential as measured by present day S2 yields (Fig. 25). Due to the overwhelming influence of thermal maturity, any facies related differences in original generation potential are lost from the spatial trends observed in this data set. Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these type of S2 variations.
Figure 25. The spatial distribution of remaining hydrocarbon generation potential (S2) for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S2 content and are reported as mg HC/g rock.

**UPPER VELKERRI KEROGEN TYPE AND EXPPELLED PRODUCT**

The Upper Velkerri is reported to consist of grey mudstone and siltstone with lesser fine sandstone that increases in proportion toward the top of the interval (Munson, 2014). The mudstone-rich facies is generally organic poor, but is inferred to contain similar mixtures of Type I and Type II kerogen as has been reported in the more organic rich Middle Velkerri interval (Munson, 2014). The depositional conditions and the geologic age of these samples would be conducive to preservation of source rocks with a dominant cyanobacterial oil-prone kerogen (Type I and Type II) along with variable and possibly significant amounts of oxidized Type IV organic material.
The Upper Velkerri source rock samples analyzed in this study from the Beetaloo Sub-Basin were found to compose two distinct lithofacies associated with thermal maturity, although the influence of sample type variability and lithofacies in the geochemical data cannot be discounted. The most prospective samples that appear to be characterized by relatively high S2 and moderately high TOC content, are distinctive in having relatively high hydrogen index (HI) values ~200 to 500 mg HC/g TOC (Fig. 26). These samples are relatively low maturity (early oil) and likely represent higher quality oil-prone marine Type II to mixed Type II/III kerogen samples that likely contain preserved lamalginite. Unfortunately, only limited organic petrology results from the current study are available no samples from the Upper Velkerri interval were examined to constrain measured kerogen maceral distributions.

The other major suite of samples that possibly represent a different organofacies within the Upper Velkerri come from wells interpreted to be at elevated maturity levels within the peak oil to dry gas windows. These samples tend to have lower S2 yields but have highly variable TOC (including some very elevated TOC values). Most samples appear to be characterized by generally low hydrogen index (HI) values < 50 mg HC/g TOC (Fig. 26). Many of these samples also have very high oxygen index (OI) values > 20 mg CO2/g TOC (Fig. 26). These samples likely represent lower quality preserved Type II organic matter that has been partially oxidized prior to preservation. The degree of oxidation would appear to dictate the classification of this material as Type II/III, Type III and/or the apparently dominant Type IV kerogen.

Measured present day HI values in the Upper Velkerri samples range from 2 to 461 mg HC/g TOC (Fig. 26) and individual wells average 10 to 337 mg HC/g TOC depending upon thermal maturity. On a plot of HI versus Oxygen Index (OI) (pseudo van Krevelen diagram), most samples from the low maturity wells (Altree 2 & McManus 1) appear to plot along the maturation pathway for Type II kerogens (Fig. 26). However, as previously noted many samples have much lower relative HI and much higher OI values and plot in other regions of this diagram in zones presently associated with Type III and Type IV kerogen (Fig. 26). These values have obviously been reduced as a consequence of high thermal maturity, but they also may represent a distinct organofacies within the Upper Velkerri interval.

Measured OI values in Upper Velkerri samples varies widely from 1 to 347 mg CO2/g TOC and a large number of samples have elevated OI in the > 20 range (Fig. 26). These samples would appear to plot more in the region typically associated with inert Type IV organic matter, although they have been influence by thermal maturity. Thus, these samples are more likely to represent an original mixture of Type II marine algal and Type IV oxidized inert organic matter. Organic petrology kerogen examination of additional samples to examine the possible presence of oxidized material could help confirm such a depositional interpretation.
Figure 26. Hydrogen Index versus Oxygen Index (pseudo-van Krevelen plot) for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

A plot of measured elemental H/C versus O/C ratios from isolated kerogen (van Krevelen diagram) provides another representation of the kerogen quality in the Upper Velkerri source rock samples (Fig. 27). This plot indicates that the kerogen in a single select sample from the Sever 1 well is currently in the gas-prone Type III region. As previously mentioned, thermal maturity effects tend to lower both the H/C and O/C from their original immature position. In this case these samples are partially converted and within the peak oil window, so their original position on the van Krevelen diagram would likely be within the oil-prone Type II region.
Spatial distributions in the HI values were evaluated in the context of previous trends within both TOC and S2 yields. The low maturity Altree 2 and McManus 1 wells located along the northern Beetaloo Sub-Basin margin were found to have higher average HI values in comparison to the other wells (Fig. 28). The Sever 1 well had lower average HI values and the Tarlee S3 and Shenandoah 1A wells that are interpreted to be in the dry gas window had the lowest measured HI values (Fig. 28). In a similar manner to the S2 yields, it is probable that the spatial trends in HI values within these wells simply represent overprinting of thermal maturity variations rather than offering any insights into kerogen type variability. Further integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these HI variations.
Figure 28. The spatial distribution of the Hydrogen Index (HI) values for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average HI and are reported as mg HC/g TOC.

UPPER VELKERRI THERMAL MATURITY

The organic-matter in the Upper Velkerri source rocks evaluated in the current investigation appears to have entered into the early stage of conventional oil generation window for two wells, peak oil for another and into the early dry gas window for the other two wells within this region of study.

Programmed pyrolysis $T_{\text{max}}$ values from samples in which $T_{\text{max}}$ was considered reliable vary from 420° to 488°C (Figs. 29 & 31) and average between 434°C and 488°C for Upper Velkerri source rocks in individual wells (all Shenandoah 1A $T_{\text{max}}$ data in the Upper Velkerri interval was considered unreliable). Measured $T_{\text{max}}$ between 425 and 435°C typically indicate early oil window, while values between 435 and 445°C indicate peak oil window and values > 470°C suggest dry gas window (Type II kerogen). Using the
formula published by Jarvie et al. (2007) for Type II kerogen \( (\text{Calculated } R_o = (0.0180)(T_{\text{max}}) – 7.16) \), the average measured \( T_{\text{max}} \) values between 434°C and 488°C are equivalent to Calc. \%R_o values of 0.65% and 1.62%.

Figure 29. Hydrogen Index versus \( T_{\text{max}} \) for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

The \( T_{\text{max}} \) values shown on Fig. 29 illustrate that the Upper Velkerri samples from the Altree 2 and McManus 1 wells are generally within the early portion of the main oil window and plot within maturity envelopes that are associated with Type II and Type II/III kerogen. A few samples do plot more in the Type IV kerogen region. This interpretation is similar to that obtained from evaluation of geochemical data previously discussed. Samples from the Sever 1 well plot within the main oil window consistent with an interpreted peak oil window maturity and most of these samples plot within maturity envelopes associated with either Type II/III or Type III kerogen. Samples from the Shenandoah 1A well plot in the immature region and are not considered reliable for maturity assessment.

In general, a great deal of caution should be used in the evaluation of \( T_{\text{max}} \) data for samples within the early to peak oil window that often contain elevated S1 peaks. Usually, oil-prone source rock samples
within the oil window are characterized by a predominant S2 peak and an elevated S1 peak of variable intensity. Depending upon oil characteristics, there can be some carry over from the S1 peak to the S2 peak as evidenced by asymmetry in both peaks. The presence of low temperature S2 shoulders is identified by examination of the pyrograms in some of the Upper Velkerri samples from this study. This suggests that some of what we assume are volatile constituents of the oil or bitumen in the sample are, in fact, not volatilized at 300° C (S1 vaporization temperature), but rather at higher temperatures. Therefore, these components are carried over and included as part of the S2 peak. These could be high-molecular-weight waxes, asphaltenes, and other compounds (note LCM material like walnut hulls can also cause the same effect, but usually have a distinct “shark fin” appearance in the low temperature region). This effect could conceivably lower the measured $T_{\text{max}}$ value during programmed pyrolysis. As a consequence, the interpreted thermal maturity on the basis of $T_{\text{max}}$ should be considered a MINIMUM value due to this uncertainty. The presence of low temperature S2 shoulders in these samples could also cause the measured HI values to be elevated in comparison to their true readings. One method to evaluate this artifact is to solvent extract the samples and re-analyze them by programmed pyrolysis. This would remove any contribution coming from the oil/bitumen and would likely result in somewhat lower HI values, thereby providing a more accurate assessment of true kerogen generation potential and hydrogen content.

Spatial distributions in the $T_{\text{max}}$ derived Calc. $R_o$ values were evaluated in the context of previous trends within other geochemical parameters. The average Calc. $R_o$ values of the Upper Velkerri wells evaluated from this study region (Fig. 30) show that the Altree 2 and McManus 1 wells have the lowest thermal maturity which matches trends already noted in S1 and HI. The Shenandoah 1A well in the central portion of the basin has the highest average Calc. $R_o$ value, but this is inferred from adjacent formations since the $T_{\text{max}}$ data from this well was considered unreliable. The Tarlee S3 sample also has elevated Calc. $R_o$ but this is based upon a single sample reading so should be used cautiously for interpretation. Further evaluation of a larger statistical data set with samples from more wells and integration with regional geology will be needed to potentially provide further insights into the origin of these Calc. $R_o$ variations.
Production Index (PI) values in these Upper Velkerri source rock samples vary from 0.04 to 0.77 (Fig. 31) and average from 0.17 to 0.42 for Upper Velkerri source rocks in individual wells. The samples from these wells are interpreted to be within the early to peak oil to dry gas windows and PI values generally plot in the region associated with the early to middle of the oil window (Fig. 31), although there is much scatter within this data set. These PI values are generally consistent with source rocks that are interpreted to be within the early to peak oil window, as shown by the trend envelope (Fig. 31). The trend envelop shown on this plot by a dashed line is based on WFT Labs analysis of over 5000 source rock samples and serves to illustrate the general increase in PI with increasing thermal maturity through the main oil window and its subsequent decrease with increasing oil-to-gas secondary cracking through the condensate/wet gas window. Some Upper Velkerri source rock samples with very elevated PI and low T_max values plot in the region associated with stained or contaminated samples (Fig. 31) and these data should be used...
cautiously for geochemical interpretation (includes all data from Shenandoah 1A well). The single sample from the Tarlee S3 well that has elevated $T_{\text{max}}$ has a fairly high PI value that is somewhat inconsistent with its interpreted dry gas window thermal maturity. Again, this value should be used cautiously for interpretation and more data points from this well are needed to increase confidence.

![Figure 31. Production Index (PI) versus $T_{\text{max}}$ for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Trend envelop shown by dashed line is based on WFT Labs analysis of over 5000 shale samples. Plot symbology defined in Fig. 4.](image)

The average pyrolysis S1 values in the Upper Velkerri source rocks in these wells varies from 0.1 to 1.5 mg HC/g rock or 1 to 34 bbl/a-ft. This suggests poor to good in-situ hydrocarbon saturation in these source rock intervals and is generally consistent with the low to moderate TOC and generation potential of these oil-prone source rocks. These wells are interpreted to be in the early to peak oil to dry gas windows and have sufficient thermal maturity to have generated oil (although in the case of the dry gas wells most of this is presumed to have cracked to secondary gas). Thus, the low in-situ hydrocarbon saturation in the wells within the main oil window is an anomaly with regard to the interpreted thermal maturity. These 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. Regardless, the
relatively low in-situ hydrocarbon saturation as determined from the S1 analysis in comparison to quality oil-prone source rocks at peak oil window maturity is a clear risk factor for successful unconventional shale oil development for wells within the main oil window.

Estimated kerogen transformation ratios in the Upper Velkerri samples based upon interpreted original and measured present HI vary from an average of 46 to 99% in the wells from this study region. These transformation ratios were calculated using the limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type II kerogen. With the exception of the Altree 2 well, these average transformation ratios are above the recommended minimum threshold of 50% for shale oil systems and are the Sever 1, Tarlee S3 and Shenandoah 1A wells are also well above the recommended minimum of 80% for thermogenic shale gas systems. This is generally consistent with the interpreted thermal maturity levels of these wells, although due to lack of kerogen analyses this parameter is poorly constrained. Spatial distributions in the transformation ratios were evaluated in the context of previous trends within other geochemical parameters (Fig. 32). These trends follow the previously established maturity relationships with the Altree 2 and McManus 1 wells located along the margins of the basin having low TR and the other wells having much higher TR values consistent with their interpreted thermal maturity levels.

Measured maceral reflectance (%Ro) analyses were conducted on select samples from two wells within the Upper Velkerri in the Beetaloo Sub-Basin (McManus 1, Sever 1). The results from these analyses (see Fig. 13 and individual well reports) show distributions that consist of macerals identified as either fluorescing alginite, low reflectance solid bitumen or high reflectance solid bitumens. The fluorescing alginite populations have mean reflectance of 0.64% Ro and exhibit orange/brown to dark brown fluorescence colors suggesting peak to late oil window thermal maturity (~0.90 to 1.10% Ro). The low reflectance solid bitumen populations have reflectance values that average 0.83 to 0.98% Ro and are considered the most representative indigenous kerogen population for thermal maturity assessment (Fig. 13). These values are somewhat higher than the interpreted early to peak oil window thermal maturity level of the Upper Velkerri source intervals in these two wells. The single high reflectance solid bitumen measurement in the Sever 1 well gives a 1.19% Eq. Ro using the Jacob (1985) conversion formula and this value is also considered somewhat high for interpreted peak oil thermal maturity level in this well. Clearly further study is warranted to better understand these organic petrology results and the proper application of solid bitumen conversions to the multiple populations of organic macerals observed within these Mesoproterozoic samples.
Figure 32. The spatial distribution of the Transformation Ratios (TR) for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average TR and are reported as decimal percent conversion using calculated original HI_o values based upon measured/interpreted original kerogen distributions.

UPPER VELKERRI 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 Upper Velkerri 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).
HI₀ values can be computed from visual kerogen assessments and assigned kerogen-type HI₀ average values using the following equation (Jarvie et al., 2007):

$$HI₀ = \left( \frac{\% \text{Type I}}{100} \times 750 \right) + \left( \frac{\% \text{Type II}}{100} \times 450 \right) + \left( \frac{\% \text{ Type III}}{100} \times 125 \right) + \left( \frac{\% \text{Type IV}}{100} \times 50 \right)$$  \hspace{1cm} (7)

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various wells evaluated in the current study are shown in Table 10, along with the resultant average original HI₀ values calculated using equation (7) 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).

<table>
<thead>
<tr>
<th>Well</th>
<th>%Type I</th>
<th>%Type II</th>
<th>%Type III</th>
<th>%Type IV</th>
<th>HI₀</th>
</tr>
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<td>13</td>
<td>87</td>
<td>0</td>
<td>0</td>
<td>489</td>
</tr>
<tr>
<td>McManus 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Sever 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
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<tr>
<td>Shenandoah 1A</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Tarlee S3</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
</tbody>
</table>

**Table 10. Average Kerogen Estimations for Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.**

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

$$TR_{HI} = 1 - \frac{HI_{pd}[1200 - HI₀(1 - PI₀)]}{HI₀[1200 - HI_{pd}(1 - PI_{pd})]} \hspace{1cm} (8)$$

$HI_{pd}$ and $PI_{pd}$ are the measured HI and PI values for the various source rock samples in these wells. The average $HI_{pd}$ and $PI_{pd}$ for the formations evaluated in the current study are shown in Table 11. HI₀ and PI₀ 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 HI₀ values of 450 to 489 mg HC/g TOC (Table 10). We assume a PI₀ of 0.02 (see Peters et al., 2005). Using these values in equation 8, the extent of fractional conversion of HI₀ to petroleum varies from 0.46 to 0.99 (Table 11), i.e., on average an estimated 46 to 99% of the petroleum generation process has been completed.

The original TOC₀ in the source rocks before burial and thermal maturation is constrained by mass balance considerations as follows (corrected from Jarvie et al., 2007):

$$TOC₀ = \frac{HI_{pd} \left( \frac{TOC_{pd}}{1 + k} \right)^{83.33}}{HI₀(1 - TR_{HI}) \left( 83.33 - \frac{TOC_{pd}}{1 + k} \right) + HI_{pd} \left( \frac{TOC_{pd}}{1 + k} \right)} \hspace{1cm} (9)$$
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 9, the estimated original TOC\( _o \) for the Upper Velkerri source rock samples before petroleum generation was calculated (Table 11).

The original generation potential \( S_2o \) can be calculated using the following equation:

\[
S_2o = \frac{HIo \times TOC_o}{100}
\]  

For the Upper Velkerri source rocks examined in the various wells in this study, the average \( S_2o \) values are calculated as mg HC/g rock and also converted to bbl/acre-ft units (multiply \( S_2o \) by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 11).

Knowing the measured remaining generation potential \( S2 \) from programmed pyrolysis and using the calculated original generation potential \( S_2o \) 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).

\[
\text{Original (} S_2o \text{)} - \text{Remaining (} S2 \text{)} = \text{Generated HCs}
\]  

Using this methodology for the Upper Velkerri source rock samples analyzed in the current study, the estimated generated oil and cracked gas yields are given in Table 11.

<table>
<thead>
<tr>
<th>Well</th>
<th>TOCpd</th>
<th>HIpd</th>
<th>S2pd bbl/a-ft</th>
<th>HIo</th>
<th>TR</th>
<th>TOCo bbl/a-ft</th>
<th>S2o Free Oil bbl/a-ft</th>
<th>Est. Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
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<td>177</td>
<td>489</td>
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<td>78</td>
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<td>79</td>
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<td>220</td>
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<td>141</td>
</tr>
<tr>
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<td>0.90</td>
<td>89</td>
<td>1</td>
<td>26</td>
</tr>
<tr>
<td>Tarree S3</td>
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<td>0.99</td>
<td>1.98</td>
<td>195</td>
<td>2</td>
<td>30</td>
</tr>
</tbody>
</table>

Table 11. Hydrocarbon Yields average data for Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

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 11). 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 Upper Velkerri source rocks in wells interpreted to be within the early oil window varies from 57 to 80% and the well at peak oil has a 97% value. The low value is consistent with early oil window, but the other elevated values are more consistent with late oil to gas window maturity. This implies that in some wells most of the generated hydrocarbons have been expelled from these source rock intervals.

The Upper Velkerri source rock samples in the various wells examined in the current study are interpreted to be in the early to peak oil to dry gas windows and hydrocarbon yield calculations suggest moderate amounts of generation have occurred (predominantly oil with some associated gas in three wells and dominantly cracked gas in two wells). 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 12). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original \( (S^2_o) \) 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 Upper Velkerri source rock samples in the Beetaloo Sub-Basin, original generation potential \( (S^2_o) \) is variable and averages from 89 to 284 bbl oil/acre-ft (Table 12). These values fall below most of the other formations on the list of unconventional US Shale plays shown below.

<table>
<thead>
<tr>
<th>Sample Name</th>
<th>TOC &gt;1%</th>
<th>Hº</th>
<th>TR</th>
<th>TOCº</th>
<th>S2º</th>
<th>Remaining Potential</th>
<th>Oil Cracked %</th>
<th>S1 Free Oil</th>
<th>Estimated Oil</th>
<th>Cracked Gas</th>
<th>Cracked Free Oil</th>
</tr>
</thead>
<tbody>
<tr>
<td>Barnett Shale Ft. Worth Basin</td>
<td>435</td>
<td>0.84</td>
<td>5.38</td>
<td>23.40</td>
<td>94</td>
<td>513</td>
<td>0.40</td>
<td>33</td>
<td>251</td>
<td>1005</td>
<td></td>
</tr>
<tr>
<td>Barnett Shale Delaware Basin</td>
<td>435</td>
<td>0.91</td>
<td>5.25</td>
<td>22.84</td>
<td>52</td>
<td>500</td>
<td>0.80</td>
<td>32</td>
<td>90</td>
<td>2149</td>
<td></td>
</tr>
<tr>
<td>Woodford Shale Delaware Basin</td>
<td>480</td>
<td>0.89</td>
<td>6.41</td>
<td>30.79</td>
<td>139</td>
<td>674</td>
<td>0.89</td>
<td>46</td>
<td>60</td>
<td>2854</td>
<td></td>
</tr>
<tr>
<td>Haynesville Shale E. Texas Basin</td>
<td>400</td>
<td>0.98</td>
<td>3.93</td>
<td>15.73</td>
<td>7</td>
<td>344</td>
<td>1.00</td>
<td>3</td>
<td>0</td>
<td>2022</td>
<td></td>
</tr>
<tr>
<td>Fayetteville Shale Arkoma Basin</td>
<td>435</td>
<td>0.95</td>
<td>3.34</td>
<td>14.53</td>
<td>15</td>
<td>318</td>
<td>1.00</td>
<td>10</td>
<td>0</td>
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<tr>
<td>Woodford Shale Arkoma Basin</td>
<td>520</td>
<td>0.87</td>
<td>5.15</td>
<td>26.80</td>
<td>12</td>
<td>587</td>
<td>0.70</td>
<td>87</td>
<td>170</td>
<td>2431</td>
<td></td>
</tr>
<tr>
<td>Eagle Ford Shale Gulf Coast Basin</td>
<td>520</td>
<td>0.85</td>
<td>3.19</td>
<td>16.61</td>
<td>61</td>
<td>364</td>
<td>0.47</td>
<td>22</td>
<td>161</td>
<td>848</td>
<td></td>
</tr>
<tr>
<td>Marcellus Shale Appalachian Basin</td>
<td>600</td>
<td>0.97</td>
<td>6.44</td>
<td>38.66</td>
<td>34</td>
<td>847</td>
<td>1.00</td>
<td>24</td>
<td>0</td>
<td>4875</td>
<td></td>
</tr>
<tr>
<td>Utica Shale Appalachian Basin</td>
<td>450</td>
<td>0.98</td>
<td>2.74</td>
<td>12.32</td>
<td>6</td>
<td>270</td>
<td>1.00</td>
<td>12</td>
<td>0</td>
<td>1585</td>
<td></td>
</tr>
<tr>
<td>Barnett Shale Oil</td>
<td>450</td>
<td>0.47</td>
<td>5.47</td>
<td>24.64</td>
<td>326</td>
<td>540</td>
<td>0.00</td>
<td>79</td>
<td>213</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Barnett Shale Gas</td>
<td>450</td>
<td>0.96</td>
<td>5.58</td>
<td>25.13</td>
<td>23</td>
<td>550</td>
<td>0.87</td>
<td>7</td>
<td>68</td>
<td>2751</td>
<td></td>
</tr>
<tr>
<td>Altree 2 - Upper Velkerri</td>
<td>489</td>
<td>0.46</td>
<td>2.27</td>
<td>11.41</td>
<td>171</td>
<td>250</td>
<td>0.00</td>
<td>34</td>
<td>78</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>McManus 1 - Upper Velkerri</td>
<td>450</td>
<td>0.66</td>
<td>2.23</td>
<td>10.03</td>
<td>79</td>
<td>220</td>
<td>0.00</td>
<td>28</td>
<td>141</td>
<td>0</td>
<td></td>
</tr>
<tr>
<td>Sever 1 - Upper Velkerri</td>
<td>450</td>
<td>0.92</td>
<td>2.88</td>
<td>12.97</td>
<td>16</td>
<td>284</td>
<td>0.00</td>
<td>8</td>
<td>267</td>
<td>4</td>
<td></td>
</tr>
<tr>
<td>Shenandoah 1A - Upper Velkerri</td>
<td>450</td>
<td>0.97</td>
<td>0.90</td>
<td>4.06</td>
<td>3</td>
<td>89</td>
<td>0.69</td>
<td>1</td>
<td>26</td>
<td>357</td>
<td></td>
</tr>
<tr>
<td>Tarlee S3 - Upper Velkerri</td>
<td>450</td>
<td>0.99</td>
<td>1.98</td>
<td>8.93</td>
<td>3</td>
<td>195</td>
<td>0.84</td>
<td>2</td>
<td>30</td>
<td>973</td>
<td></td>
</tr>
</tbody>
</table>

Table 12. Geochemical Properties and Generation Potential for US Shale plays. Upper Velkerri wells are color coded for possible shale oil (green) and shale gas (red) prospect type.

**UPPER VELKERRI UNCONVENTIONAL OIL & GAS RISK ASSESSMENT**

The Mesoproterozoic Upper Velkerri source rocks in the Beetaloo Sub-Basin have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 33) 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. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas production. Transformation Ratios (TR) were calculated based upon HIo estimates using measured and interpreted fractional composition of kerogen macerals.
The Upper Velkerri source rocks in the Beetaloo Sub-Basin wells are interpreted to represent a moderate to high geochemical risk for in-situ shale oil and gas production. The average measured TOC contents of all wells except the Shenandoah 1A are above the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Fig. 33). However, only the Sever 1 well has an average TOC value 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 in these wells is interpreted to be dominantly oil-prone Type II kerogen, although the Altree 2 well is interpreted to have a mix of Type I and Type II kerogen.

Thermal maturity parameters from programmed pyrolysis place two wells within the early oil window, one within the peak oil window and one in the dry gas window (Shenandoah 1A data considered unreliable). The average $T_{\text{max}}$ values of 434 & 435°C for the McManus 1 & Altree 2 wells are at or below the recommended minimum value of 435°C for shale oil, while the 442°C value for the Sever 1 well is above this threshold (Fig. 33). In general, this amount of thermal conversion would likely be sufficient to generate/expel moderate to significant amounts of hydrocarbons from these marginally organic rich source facies. The 488°C value for the Tarlee S3 sample is well above the minimum of 455°C for shale gas (Fig. 33). Transformation ratios (TR), the least constrained risk parameter, average between 46 to 99% in these Upper Velkerri wells. The Altree 2 well is below the recommended minimum of 50% for shale oil, but the McManus 1 well is above this threshold. The other wells have TR values above the 80% threshold for shale gas (Fig. 33).

In the Upper Velkerri source intervals interpreted to be in the oil window, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor to good (avg. 8 to 34 bbl oil/acre-ft), which is a
potential concern regarding risk assessment for unconventional oil (Figs. 34 & 35). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Upper Velkerri wells interpreted to be in the oil window at 78 to 267 bbl oil/acre-ft (Figs. 34 & 36). 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. 34). These values are higher compared to most of the Upper Velkerri wells due primarily to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC). In one of the Upper Velkerri wells (Sever 1) generated oil yields are slightly higher than the Barnett Shale (Fig. 34). However, measured in-situ oil saturation in this well is quite low at only 8 bbl oil/acre-ft, so this is the reason it is considered a moderate risk for shale oil development.

For the Upper Velkerri wells interpreted to be within the dry gas window (Shenandoah 1A & Tarlee S3), measured in-situ oil saturation determined by programmed pyrolysis S1 yields very low (avg. 1 to 2 bbl oil/acre-ft). Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Upper Velkerri intervals in these wells at 26 to 30 bbl oil/acre-ft. and oil cracking is estimated to have been 69 to 84%, resulting in cracked gas yields of 357 to 973 Mcf/acre-ft (Figs. 34 & 37). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/a-ft (Fig. 34). Both the residual oil and cracked gas generated yields for the Barnett Shale are significantly higher compared to the Upper Velkerri in these wells and are primarily due to differences in organic richness (Barnett Shale in gas window has 4.21 wt. % TOC).

![Figure 34. Hydrocarbon yield estimates for the Mesoproterozoic Upper Velkerri source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the oil window.](image)

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 Upper Velkerri source intervals in these wells is in the early to peak oil window and hydrocarbon saturation is likely to vary from heavy and immobile to fairly light and mobile with increased thermal maturity (dry gas wells have only light residual condensate). The presence of heavy oil and solid bitumens 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 Upper 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.
Spatial distributions in the measured in-situ S1 free oil saturations, estimated generated oil yields and estimated cracked gas yields (Figs. 35 through 37) were evaluated in the context of previous trends within other geochemical parameters. As noted previously, measured in-situ S1 oil saturations are generally low in many of the Upper Velkerri wells evaluated in this study area but are elevated in the Altree 2 and McManus 1 wells (34 to 28 bbl oil/acre-ft). Geographically, these differences in in-situ oil saturation manifest themselves as trend of relatively higher S1 content in the low maturity wells located along the northern Beetaloo Sub-Basin margin (Fig. 35). More well data points will be required to see if this apparent trend is valid. Spatial trends in the estimated generated oil yields show that there is higher estimated oil generated in the Sever 1 well within the far NW region of the study area (Fig. 36). This is likely a consequence of both higher TOC content and higher thermal maturity in comparison to the other two wells interpreted to be within the early oil window (Altree 2 & McManus 1). The relatively low oil
saturation in the Sever 1 well compared to its high estimated generated oil yield suggests that oil in this well was potentially lost due to expulsion or possibly gas-flushing from generation in underlying formations.

Figure 36. The spatial distribution of the Estimated Generated Oil Yields for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average generated oil and are reported as bbl oil/acre-ft.

Spatial trends in the estimated secondary cracked gas yields (Fig. 37) closely follow thermal maturity patterns previously established for transformation ratios and Calc. $R_o$. This is expected since the algorithm to estimate oil to gas cracking is based upon the measured % Calc. $R_o$ and/or interpreted Calc. $R_o$ values. Thus, the Shenandoah 1A and Tarlee S3 wells which are interpreted to be in the early dry gas window are the only wells that have significant amounts of estimated cracked gas from the Upper Velkerri interval (oil associated gas is not factored into this determination). The Tarlee S3 cracked gas yield is
higher due to its higher TOC content, but this should be considered somewhat speculative since it is based on only one sample analysis.

Figure 37. The spatial distribution of the Estimated Cracked Gas Yields for the Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average secondary cracked gas of all samples and are reported as Mcf gas/acre-ft.
UPPER VELKERRI MINERALOGY

UPPER VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Upper Velkerri source rocks in five (5) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Select samples from these wells were analyzed by X-ray diffraction (XRD). The purpose of this testing was to document the mineralogy of the samples in order to evaluate potential organofacies variations, to examine reservoir quality and brittleness for fracture development, and to assess possible controls on porosity and permeability.

UPPER VELKERRI MINERALOGY

XRD data taken from samples in the Upper Velkerri (Table 13; Fig. 38) shows that clays are generally the most abundant minerals present and total clay content averages 42%. Clay types found are dominated by illite/mica (avg. 22%), mixed-layer illite/smectite (avg. 11%), chlorite (avg. 7%) and kaolinite (avg. 2%). Quartz is the dominant non-clay species and its abundance averages 43%, which is roughly equivalent to the total abundance of clays. Classification of these samples by rock type shows that most would be classified as either silica-rich argillaceous mudstones or clay-rich siliceous mudstones, although there is one sample from the Sever 1 well that is a clay-rich carbonate mudstone.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Clays</th>
<th>Carbonates</th>
<th>Quartz</th>
<th>K-spar</th>
<th>Other</th>
<th>Mixed I/S*</th>
<th>TOC</th>
<th>Britteness Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Upper Velkerri</td>
<td>42</td>
<td>6</td>
<td>43</td>
<td>2</td>
<td>7</td>
<td>11</td>
<td>1.27</td>
<td>50</td>
</tr>
</tbody>
</table>

*ordered interstratified mixed-layer illite/smectite

Table 13. TOC & X-ray diffraction average data (weight %) for Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

The shale samples in the Upper Velkerri source intervals are clay dominated, which is a concern for potential fracture stimulation because this is often a fairly ductile mineral assemblage. However, these samples also contain abundant quartz, which is a relatively brittle mineral and conducive to fracture stimulation. Pyrite is present in minor amounts (avg. 2%) and is associated with kerogen that is also a minor component of the overall mineralogy. The minor contribution of these components is usually positive with regard to fracture stimulation in general for organic-rich shales at elevated thermal maturity.

Another potential risk factor for fracture stimulation is the abundance and type of clays within the Upper Velkerri samples. These source rock samples do contain significant amounts of clays (avg. 42%), and these clays also contain abundant ordered interstratified mixed-layer illite/smectite (avg. 11% and comprising 25% of total clays). In general, successful unconventional shale plays tend to have less than 10% total mixed-layer illite/smectite (R. Bruce, personal communication) and the Upper Velkerri samples analyzed in this study are above this risk threshold. Thus, the abundance of clays in the Upper Velkerri samples would appear to be a negative risk factor for fracture stimulation; however, further testing to include rock-mechanics measurements is warranted to fully evaluate this parameter.
Mineralogy data can potentially be utilized to further assess rock mechanical properties, including brittleness. Brittleness Index (BI) values were calculated using equation (12) below. The range of BI values vary from 29–82 and average 50 (Table 13), with higher values supposedly indicating more brittle rock. The highest BI values were found in the samples with the lowest overall clay content. One sample analyzed from the Sever 1 well had the highest carbonate content (77%) of all Upper Velkerri samples in this study and it also had the highest BI of 82. Another sample from the Shenandoah 1A well had the highest silica content (73%) of all Upper Velkerri samples in this study and it also had a very high BI of 74. Close examination of the data show that both carbonate and quartz have a strong influence on the brittleness calculation. In the most of the Upper Velkerri source rocks, carbonate is generally in very low abundance and the variability in quartz and clays appears to control the Brittleness Index. Recent publications have noted that measured rock mechanical properties were often found to have poor correlations with various formulas for calculating brittleness index values (Yang et al., 2013). Thus,
caution should be exercised in using these data for evaluations and any BI values for previously untested source rocks like the Upper Velkerri should be calibrated against measured rock mechanical data.

\[
BI = \frac{1.3(\text{Qtz}) + (\text{Kspar}) + (\text{Plag}) + 1.2(\text{Carb})}{\text{Numerator} + 2(\text{Mixed}) + 1.5(\text{Chlor + Kaol + Ill}) + (\text{Pyr}) + (\text{Apa}) + (\text{Bar})}
\] (12)

Mineralogy data can also be used to compare the Upper Velkerri source rock samples against other US Shale plays. Ternary diagrams of the quartz, carbonate, and clay percentages have been constructed using the individual samples from the various Upper Velkerri wells in the Beetaloo Sub-Basin evaluated in the current study (Fig. 39). In these diagrams, most US Shale plays plot along a continuum between the quartz and carbonate endpoints, which are also the locations of the most brittle rocks (Fig. 39). As clay percentages increase (toward the SE corner of the diagram), the brittleness decreases. As noted previously, the Upper Velkerri samples have generally high clay content (avg. 42%), which may be a risk for fracture stimulation. On the mineralogy ternary diagram (Fig. 39), the Upper Velkerri samples appear to plot within the SE corner of the envelope representing most US Shale samples and they do overlap with select samples from a number of plays (e.g. Ohio Devonian, Lower Huron, Second White Specs, Cane Creek, Devonian). The relative brittleness of US Shale samples in this region of the ternary diagram tends to be lower in comparison to other samples that are either more quartz-rich or more carbonate-rich (Fig. 39). However, as noted previously, the total clay content should not be considered the only factor in risk assessment, but rather it is the abundance of mixed-layer illite/smectite clay species that is more likely to be the critical factor. In the Upper Velkerri source rocks, these mixed-layer illite/smectite clay species are also in relatively high abundance (avg. 11%). As clearly documented in the mineralogy ternary diagrams, there is considerable variability even within an individual shale play and each shale should be considered based on its own mineralogy and petrophysical attributes. Ultimately, these data need to be calibrated against laboratory measured geomechanical properties for continued improvement in stimulation and completion practices.

Figure 39. XRD mineralogy ternary diagram for Upper Velkerri source rock samples in the Beetaloo Sub-Basin, Australia (left) compared to published data for US Shale plays (right) (Rickman et al., 2008). Sizes of symbols represent the relative brittleness determined by XRD within the published data set, but this is not illustrated in the data from the current study.
MIDDLE VELKERRI PETROLEUM GEOCHEMISTRY

MIDDLE VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Middle Velkerri source rocks in seven (7) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells 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 was also incorporated into the interpretive evaluation. The complete results of these analyses are documented in the individual well reports and are summarized in Table 14. Formation specific integrated geochemical interpretations and spatial trends are considered within the context of the current document.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Oil/Gas Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Oil</td>
<td>Early Oil Window</td>
<td>Excellent (5.10% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Very Good (3.75% TOC)</td>
<td>Mixed Type II/III</td>
<td></td>
</tr>
<tr>
<td>Broadmere 1</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Oil</td>
<td>Early Oil Window</td>
<td>Very Good (3.36% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Very Good (2.89% TOC)</td>
<td>Oil-prone Type II</td>
<td></td>
</tr>
<tr>
<td>McManus 1</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Oil</td>
<td>Peak Oil Window</td>
<td>Excellent (5.52% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Very Good (3.91% TOC)</td>
<td>Gas Prone Type III</td>
<td></td>
</tr>
<tr>
<td>Sever 1</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Dry Gas</td>
<td>Dry Gas Window</td>
<td>Excellent (4.93% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Very Good (3.79% TOC)</td>
<td>Inert Type IV</td>
<td></td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Gas</td>
<td>Dry Gas Window</td>
<td>Good (1.74% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Good (1.32% TOC)</td>
<td>Inert Type IV</td>
<td></td>
</tr>
<tr>
<td>Tarlee S3</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Dry Gas</td>
<td>Dry Gas Window</td>
<td>Excellent (5.42% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Excellent (4.11% TOC)</td>
<td>Inert Type IV</td>
<td></td>
</tr>
<tr>
<td>Walton 2</td>
<td>Middle Velkerri</td>
<td>Estimated Original</td>
<td>Oil</td>
<td>Early Oil Window</td>
<td>Excellent (7.15% TOC)</td>
<td>Oil-prone Type II</td>
</tr>
<tr>
<td>Measured Currently</td>
<td></td>
<td></td>
<td></td>
<td>Excellent (6.36% TOC)</td>
<td>Oil-prone Type II</td>
<td></td>
</tr>
</tbody>
</table>

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

Table 14. Middle Velkerri Geochemical Summary

MIDDLE VELKERRI GENERATIVE POTENTIAL

The Middle Velkerri source rock samples analyzed from the Beetaloo Sub-Basin have dominantly very good generative potential (Table 14; Fig. 40). Organic richness varies from 0.09 wt.% (poor) to as high as 25.60 wt.% (excellent) TOC, with an average value of 3.96 wt. % TOC (very good). The histogram plot of TOC distributions (Fig. 40) illustrate that the dominant population is within the 2.5 to 3.0 wt. % range.
Outside of this range there appears to be a trend of progressive decrease in frequency of samples with both increasing and decreasing TOC content and the overall pattern is generally bell shaped (Fig. 40). About 90% of these samples have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks. Furthermore, approximately 80% of these samples have TOC content above the minimum requirement of 2 wt.% for economic petroleum source rocks, which is very favorable for unconventional resource development.

Figure 40. Histogram plot of Total Organic Carbon (TOC) distributions for Middle Velkerri source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.%, while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.

The distribution of elevated TOC values in the Middle Velkerri is not entirely restricted to a single well within the sample set evaluated from the Beetaloo Sub-Basin. However, the Sever 1 well is unique in having a couple of samples with very elevated TOC values in excess of 15 wt.%. All wells examined in this study tend to exhibit similar trends with depth in TOC through the Middle Velkerri interval. There appears to be three distinct cycles of elevated TOC within this source interval, although the thicknesses of these zones are variable from well to well. 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 spatial distributions of measured TOC within the Middle Velkerri do show some variations across the Beetaloo Sub-Basin (Fig. 41), however, there is no obvious trend or pattern within the data. For example, the well with the highest average Middle Velkerri TOC (Walton 2) is in relatively close proximity a well with only moderate average TOC (McManus 1). One obvious observation is that the Shenandoah 1A well located in the center of the main Beetaloo Sub-Basin depocenter has relatively low average TOC in
comparison to the other wells. This could possibly indicate a localized zone of low organic productivity and/or preservation or it could be linked to mineral dilution in the marine depocenter. Unlike other formations evaluated in the current study, the Middle Velkerri is densely sampled in all wells and there is unlikely to be any statistical anomalies associated with the sampling process. The moderately high and somewhat random variability in average TOC content within the Middle Velkerri in the Beetaloo Sub-Basin may provide additional insights into depositional conditions that existed during accumulation of this source rock package but will require further study. Variations in the paleo-depositional environment or organic productivity could have imparted geographic variations in the abundance of preserved organic matter within the Middle Velkerri source rock interval as noted in the Shenandoah 1A well. It would be useful to further refine these variations by examining individual sub-units within the Middle Velkerri and to supplement the number of wells sampled in order to better constrain the spatial variability. Further integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these TOC variations.
Figure 41. The spatial distribution of organic richness for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average LECO TOC content and are reported as wt.%. 

Pyrolysis S2 yields in the Middle Velkerri samples vary from 0.02–70.66 mg HC/g rock (Fig. 42) and average values within individual wells vary from 0.15–29.27 mg HC/g rock or 3–641 bbl/a-ft. These indicate a poor to excellent amounts of remaining primary hydrocarbon generation potential (both oil and gas), which is consistent with variable levels of primary thermal conversion in the early oil to dry gas window. There appears to be at least two and possibly three populations of data for the Middle Velkerri samples that would likely correspond with different organic facies within this interval (Fig. 42). One group of samples have variable, but generally elevated TOC and S2 values and plot in the region for oil-prone Type II kerogen (Fig. 42). These samples are from wells interpreted to be within the early oil window and have likely not had TOC and S2 reduced very much as a consequence of thermal maturity. They could represent a population of samples dominated more by well-preserved oil-prone Type II kerogen. Most of the other Middle Velkerri samples have only moderate S2 values and plot below the lower border line that
separates oil-prone Type II kerogen (Fig. 42). These samples are highly variable and plot in regions consistent with Type II/III, Type III and Type IV kerogens (see Langford and Blanc-Valleron, 1990). These data represent samples that are only partially converted due to their moderate thermal maturity (early/peak oil in most wells), but likely had much more limited original generation potential in comparison to other group of Middle Velkerri source rocks. Original placement of these samples prior to thermal conversion is considered to be predominantly within the oil-prone Type II region (see individual well reports and hydrocarbon yield calculations for more details), although this interpretation may be somewhat optimistic given the geochemical results presented herein. The third apparent group of samples have variable, but sometimes very elevated TOC and relatively low S2 values and are significantly altered as a consequence of elevated thermal maturity. These samples plot along the line that separates Type III and Type IV kerogen (Fig. 42) and are more consistent with inert carbonaceous residue typically associated with Type IV kerogen (see Langford and Blanc-Valleron, 1990). These samples have been assumed to contain original oil-prone Type II kerogen for purposes of hydrocarbon yield estimations in this study, however, they could represent oxidized organic matter from a condensed marine geologic section that was initially a mixture of Type II/IV kerogen. Further organic petrology work will be necessary to evaluate these samples in greater detail.
Figure 42. Total Organic Carbon (TOC) versus Remaining Hydrocarbon Generation Potential (S2) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Insert plot is expanded view to better illustrate details within this data set. Plot symbology defined in Fig. 4.

The three wells with relatively high S2 content, Broadmere 1, Altree 2 and Walton 2, are located along the western and northern margins of the main Beetaloo Sub-Basin (Fig. 43) and are all interpreted to be within the early oil window. Geographically, there does appear to be a trend of relatively higher S2 content in wells located along the margins of this study area in the Beetaloo Sub-Basin (Fig. 42). The Shenandoah 1A, Tarlee S3 and Sever 1 wells are all interpreted to be within the dry gas window and not surprisingly they have very low S2 yields (Fig. 43). Thus, spatial trends in S2 appear to reflect thermal maturity variability and may not offer much insight into differences in original generation potential. Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these S2 variations.
Figure 43. The spatial distribution of remaining hydrocarbon generation potential (S2) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S2 content and are reported as mg HC/g rock.

**MIDDLE VELKERRI KEROGEN TYPE AND EXPELLED PRODUCT**

The Middle Velkerri is reported to consist of dark grey to brown-black claystone, mudstone and minor siltstone (Munson, 2014). The claystone facies is generally organic rich and is reported to contain mixtures of Type I and Type II kerogen (Munson, 2014). The depositional conditions and the geologic age of these samples would be conducive to preservation of source rocks with a dominant cyanobacterial oil-prone kerogen (Type I and Type II) along with variable amounts of oxidized Type IV organic material.

The Middle Velkerri source rock samples analyzed in this study were found to compose two to potentially three distinct lithofacies, although the influence of thermal maturity and sample type variability in the geochemical data cannot be discounted. The most prospective samples that appear to be characterized
by relatively high TOC and S2 content, are distinctive in having high hydrogen index (HI) values ~350 to 750 mg HC/g TOC (Fig. 44). These samples come from wells interpreted to be in the early oil window. These samples could represent particularly well preserved oil-prone marine Type I kerogen samples containing filamentous algae and abundant frambooidal pyrite. Organic petrology results from a single sample from the Middle Velkerri tend to document these types of samples. The kerogen macerals are dominated by oil-prone Type I and Type II organic matter that consists of variable abundances of lamalginite, lens/layer amorphous organic matter (AOM) and inert AOM along with solid bitumens.

The other major suite of samples that possibly represent a different organofacies within the Middle Velkerri come from wells also interpreted to be within the early oil window. These samples tend to have lower TOC content and S2 yields. Most samples appear to be characterized by somewhat lower hydrogen index (HI) values ~200 to 600 mg HC/g TOC (Fig. 44). Many of these samples also have high oxygen index (OI) values > 30 mg CO₂/g TOC (Fig. 44). These samples likely represent lower quality preserved Type II organic matter that has been partially oxidized prior to preservation. The degree of oxidation would appear to dictate the classification of this material as Type II, Type II/III, and/or Type III in some instances.

A third group of sample occupy a position associated with inert Type IV kerogen and have very low HI values < 50 mg HC/g TOC (Fig. 44). Many of these samples also have very low OI values and are likely overmature kerogen from wells interpreted to be within the dry gas window. However, there are several samples with elevated OI values that could represent samples with a high abundance of original oxidized organic matter.

Measured present day HI values in the Middle Velkerri samples range from 1 to 730 mg HC/g TOC (Fig. 44) and individual wells average 6 to 418 mg HC/g TOC depending upon thermal maturity. On a plot of HI versus Oxygen Index (OI) (pseudo van Krevelen diagram), most of the samples plot along the maturation pathway for either Type I or Type II kerogens (Fig. 44). There is a trend line of samples with very low OI values that appear to follow the Type I maturation pathway (Fig. 44). The major grouping of samples appears to be within the Type II kerogen envelope and follow that maturation pathway (Fig. 44). The overmature grouping of Type IV kerogen samples is shown along the x-axis of this plot (Fig. 44). Since all of the Middle Velkerri source rocks are considered mature with regard to oil generation, all kerogen HI values have been reduced somewhat as consequence of thermal maturity.

Measured OI values in Middle Velkerri samples varies from 0 to 156 mg CO₂/g TOC and there are many samples with elevated OI in the range of 30 to 60 (Fig. 44). These samples still appear to plot in the region typically associated with marine Type II organic matter, but some samples do appear to be more of a mixed Type II/III kerogen. Structured organic matter of this type which is typically associated with terrigenous organic matter was not present during this geologic age. Thus, these samples are more likely to represent a mixture of Type II marine algal and Type IV oxidized inert organic matter. Organic petrology kerogen examination of additional samples to examine the possible presence of oxidized material (possibly classified as inert AOM) could help confirm such a depositional interpretation.
Figure 44. Hydrogen Index versus Oxygen Index (pseudo-van Krevelen plot) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

A plot of measured elemental H/C versus O/C ratios from isolated kerogen (van Krevelen diagram) provides another representation of the kerogen quality in the Middle Velkerri source rock samples (Fig. 45). This plot indicates that the kerogen in select Middle Velkerri samples currently ranges from inert Type IV to oil-prone Type I. As previously mentioned, thermal maturity effects tend to lower both the H/C and O/C from their original immature position. In this case these samples are partially converted and within the early oil to dry gas windows, so their original position on the van Krevelen diagram would likely be within the oil-prone Type I/II region. The trendline of the various Middle Velkerri samples shown on this diagram appears to closely follow the maturation pathway that would be expected for a mixed oil-prone Type I/II kerogen suite (Fig. 45), although the elevated O/C ratio for the sample with elevated H/C is more in line with a Type II kerogen rather than a Type I.
Figure 45. Elemental Hydrogen/Carbon versus Oxygen/Carbon ratios from isolated kerogen (van Krevelen plot) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

Spatial distributions in the HI values were evaluated in the context of previous trends within both TOC and S2 yields (Fig. 46) and the trends in S2 closely match HI in general. The wells with relatively low HI values due to elevated thermal maturity are clearly distinguished on this map. The three wells with relatively high HI content are located in the eastern and northern regions of the Beetaloo Sub-Basin margins (Fig. 46). Geographically, there does appear to be a trend of relatively higher HI content in wells located along the margins of this study area in the Beetaloo Sub-Basin (Fig. 46), but within these wells there is more random variability in HI. Thus, spatial trends in HI appear to reflect thermal maturity variability as the dominant controlling factor, but differences in organic kerogen type may also be present within this data. This was also observed in the spatial map of S2 yields. Further integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these HI variations and it would potentially be useful to further sub-divide the Middle Velkerri into distinct organofacies based upon the TOC depth trends observed in the current study.
Figure 46. The spatial distribution of the Hydrogen Index (HI) values for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average HI and are reported as mg HC/g TOC.

MIDDLE VELKERRI THERMAL MATURITY

The organic-matter in the Middle Velkerri source rocks evaluated in the current investigation appears to have entered into the early to peak stage of conventional oil generation window for most wells and into the early dry gas window for three of these wells.

Programmed pyrolysis $T_{\text{max}}$ values from samples in which $T_{\text{max}}$ was considered reliable vary from ~409˚ to 570˚C (Figs. 47 & 49) and average between 433˚C and 530˚C for Middle Velkerri source rocks in individual wells (note high maturity Shenandoah 1A well had no reliable $T_{\text{max}}$ readings in the Middle Velkerri interval). Measured $T_{\text{max}}$ between 425 and 435˚C typically indicate early oil window, while values between 435 and 445˚C indicate peak oil window and values > 470˚C are typical of the dry gas window.
(Type II kerogen). Using the formula published by Jarvie et al. (2007) for Type II kerogen (\(\text{Calculated } R_o = (0.0180)(T_{\text{max}}) - 7.16\)), the average measured \(T_{\text{max}}\) values between 433°C and 530°C are equivalent to Calc. %\(R_o\) values of 0.63% and 2.38%.

**Figure 47. Hydrogen Index versus \(T_{\text{max}}\) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.**

The \(T_{\text{max}}\) values shown on Fig. 47 illustrate that most of the Middle Velkerri samples bracket the immature to early oil window and plot within maturity envelopes that are associated with Type I, Type II and Type II/III kerogen. These include samples from the Altree 2, Broadmere 1 and Walton 2 wells that are interpreted to be in the early oil window. Samples from the McManus 1 well typically plot within the main oil window envelope and appear to span the entire range from early to late oil window (Fig. 47). These samples fall into the maturity envelopes associated with Type II and Type II/III kerogen. Select samples from the Tarlee S3 well plot into the dry gas window, consistent with its interpreted thermal maturity (note some samples plot are outside the range of Fig. 47). However, most samples from the Sever 1 and Shenandoah 1A wells which are interpreted to be in the dry gas window have low \(T_{\text{max}}\) values and are not considered reliable for thermal maturity assessment (Fig. 47). Additional support for interpreted thermal
maturity in the Middle Velkerri source rocks comes from aromatic biomarker ratios examined using core slice experiments (Flannery and George, 2014). In the Walton 2, well these biomarkers give a range of calculated reflectance values from 0.48 to 0.70% Ro, supporting an early oil window maturity (Flannery and George, 2014). In the McManus 1 well, the calculated reflectance values from these biomarkers range from 0.86 to 1.03% Ro, supporting a peak oil window maturity (Flannery and George, 2014).

In general, a great deal of caution should be used in the evaluation of Tmax data for samples within the early to peak oil window that often contain elevated S1 peaks. Usually, oil-prone source rock samples within the oil window are characterized by a predominant S2 peak and an elevated S1 peak of variable intensity. Depending upon oil characteristics, there can be some carry over from the S1 peak to the S2 peak as evidenced by asymmetry in both peaks. The presence of low temperature S2 shoulders is identified by examination of the pyrograms in some of the Middle Velkerri samples from this study. This suggests that some of what we assume are volatile constituents of the oil or bitumen in the sample are, in fact, not volatilized at 300°C (S1 vaporization temperature), but rather at higher temperatures. Therefore, these components are carried over and included as part of the S2 peak. These could be high-molecular-weight waxes, asphaltenes, and other compounds (note LCM material like walnut hulls can also cause the same effect, but usually have a distinct “shark fin” appearance in the low temperature region). This effect could conceivably lower the measured Tmax value during programmed pyrolysis. As a consequence, the interpreted thermal maturity on the basis of Tmax should be considered a MINIMUM value due to this uncertainty. The presence of low temperature S2 shoulders in these samples could also cause the measured HI values to be elevated in comparison to their true readings. One method to evaluate this artifact is to solvent extract the samples and re-analyze them by programmed pyrolysis. This would remove any contribution coming from the oil/bitumen and would likely result in somewhat lower HI values, thereby providing a more accurate assessment of true kerogen generation potential and hydrogen content. Samples from the Shenandoah 1A well that is interpreted to be within the early dry gas window typically had very low Tmax values (many < 425°C) and were considered unreliable for thermal maturity assessment due to very low S2 yields. This also affected select data from the Sever 1 and Tarlee S3 wells which are also interpreted to be in the dry gas window.

Spatial distributions in the Tmax derived Calc. Ro values were evaluated in the context of previous trends within other geochemical parameters. The average Calc. Ro values of the Middle Velkerri wells evaluated from this study region show considerable variability as a consequence of thermal maturity (Fig. 48). The Tarlee S3 well in the NW portion of the study area has the highest average Calc. Ro value, followed by the Shenandoah 1A well in the center of the study area (Calc. Ro value in this well represents actual measured maceral reflectance reading from a single sample in this interval) and the Sever 1 well also located in the far NW corner of the study area (Fig. 48). All of these wells are estimated to be in the dry gas window. All of the other Middle Velkerri wells are interpreted to be within the early oil window to early portion of the peak oil window. These wells are located along the main Beetaloo Sub- Basin margin and the spatial trend documents the lower maturity to the north and east as you move up and out of the main depocenter (Fig. 48). Further evaluation of a larger statistical data set with samples from more wells and integration with regional geology will be needed to validate and potentially provide further insights into the origin of these Calc. Ro variations.
Production Index (PI) values in these Middle Velkerri source rock samples vary from 0.03 to 0.64 (Fig. 49) and average between 0.13 to 0.50 for Middle Velkerri source rocks in individual wells. The samples from wells interpreted to be in the early oil window have variable but sometimes very low PI values in the 0.05 to 0.40 range (Fig. 49). Many of these samples fall within the zone designated for low level conversion or plot into the lower left corner of the main oil window region (Fig. 49). However, there are also many samples that plot outside of this region and these may represent more porous lithologies that have been saturated with expellable hydrocarbon saturation (some of these samples plot in the stained or contaminated area). The samples from the well interpreted to be within the peak oil window tend to have PI values in the 0.20 to 0.50 range and generally plot in the region associated with intensive generation and expulsion (Fig. 49). These elevated PI values are consistent with source rocks that are interpreted to within the main oil widow, as shown by the trend envelope (Fig. 49). The trend envelop shown on this plot...
by a dashed line is based on WFT Labs analysis of over 5000 source rock samples and serves to illustrate the general increase in PI with increasing thermal maturity through the main oil window and its subsequent decrease with increasing oil-to-gas secondary cracking through the condensate/wet gas window. The high PI values in many of the Middle Velkerri samples examined in the current study are consistent with their interpreted thermal maturity and suggest high in-situ hydrocarbon saturations, which is a positive indicator for shale oil development. Samples from the wells interpreted to be within the dry gas window generally plot in the region for stained or contaminated samples and have anomalously low $T_{\text{max}}$ values along with anomalously high PI (Fig. 49). Select samples from the Tarlee S3 plot in the dry gas region but also have anomalously high PI values (Fig. 49) which may indicate some OBM contamination or minor residual condensate saturation.

Figure 49. Production Index (PI) versus $T_{\text{max}}$ for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Trend envelop shown by dashed line is based on WFT Labs analysis of over 5000 shale samples. Plot symbology defined in Fig. 4.

The average pyrolysis S1 values in the Middle Velkerri source rocks vary from 0.1 to 2.9 mg HC/g rock or 2 to 64 bbl/a-ft. This suggests poor to very good in-situ hydrocarbon saturation in these source rock...
intervals and is generally consistent with the elevated TOC and generation potential of these oil-prone source rocks. Some of these wells are interpreted to be in the early to peak oil generation window and the other wells are in the dry gas window. All wells have sufficient thermal maturity to have generated oil (or in the case of the dry gas wells, minor retained residual oil from oil to gas cracking) and thus the variable but in some cases quite elevated in-situ hydrocarbon saturations are consistent with regard to the interpreted thermal maturity. These 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.

Estimated kerogen transformation ratios in the Middle Velkerri samples based upon interpreted original and measured present HI vary from 39 to 52% in the wells interpreted to be in the early oil window, 80% in the peak oil window well and 97 to 99% in the gas window wells. These transformation ratios were calculated using the limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type I and Type II kerogen. These average transformation ratios are near or below the recommended minimum threshold of 50% for shale oil systems for the early oil window wells. However, the other wells are all above the recommended minimum of 80% for thermogenic shale gas systems. This is generally consistent with the interpreted thermal maturity levels of these wells. Spatial distributions in the transformation ratios were evaluated in the context of previous trends within other geochemical parameters (Fig. 50).

The three wells interpreted to be within the dry gas window all have elevated TR values (Fig. 50). These include both of the wells in the far NW region of the study area and the Shenandoah 1A well in the central depocenter of the main Beetaloo Sub-Basin (Fig. 50). Depth of burial is a factor in the maturity of these Middle Velkerri samples (e.g. Shenandoah 1A well is > 2500 m depth), but it is apparently not the only influence controlling maturity and there may indeed be spatial trend of more elevated thermal maturity in the far NW corner of the study area that is outside of the main Beetaloo Sub-Basin depocenter.

Geographically, in addition to the high TR values in the dry gas wells, there also appears to be a trend of relatively lower transformation ratios in wells located in more northern and eastern regions of the Beetaloo Sub-Basin, which are more along the basin margins (Fig. 50). However, the restricted number of wells available in this study area greatly limits determination of spatial trends and the subtle variations observed should be considered somewhat speculative. The influence of localized heating by igneous intrusions and depth variability due to faulting may play a significant role in the thermal maturity of the Middle Velkerri within individual wells. For example, the Walton 2 well is early oil maturity at a depth range of ~250 to 550 m depth but the nearby McManus 1 well is peak oil window at a depth range of ~1200 to 1550 m depth (see well proximity on Fig. 50). Clearly some geologic faulting or other feature is responsible for the ~1000 m offset in depth of the Middle Velkerri in these two wells. Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these variations in transformation ratios.
Figure 50. The spatial distribution of the Transformation Ratios (TR) for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average TR and are reported as decimal percent conversion using calculated original \( R_o \) values based upon measured/interpreted original kerogen distributions.

Measured maceral reflectance (\( R_o \)) analyses were conducted on select samples from three wells within the Middle Velkerri in the Beetaloo Sub-Basin (McManus 1, Shenandoah 1A, Tarlee S3). The results from these analyses (see Fig. 13 and individual well reports) show distributions that consist of macerals identified as either non-fluorescing alginite, low reflectance solid bitumen or high reflectance solid bitumens. The low reflectance solid bitumen populations in the McManus 1 well have reflectance values that average 0.90\% \( R_o \) and are considered the most representative indigenous kerogen population for thermal maturity assessment (Fig. 13). These values support the interpreted peak oil widow maturity level of the Middle Velkerri in this well. The non-fluorescing alginite populations in the Shenandoah 1A well have reflectance values that average 2.18\% \( R_o \) and appear consistent with regard to the interpreted dry gas thermal maturity level in these well. Likewise, the single high reflectance solid bitumen measurement
in the Tarlee S3 well gives a 1.81% Eq. Ro using the Jacob (1985) conversion formula and this value also supports the interpreted dry gas thermal maturity level in this well. While the results from the Middle Velkerri interval maceral reflectance appear to be consistent with interpreted thermal maturity, further study is warranted to better understand these organic petrology results and the proper application of solid bitumen conversions to the multiple populations of organic macerals observed within these Mesoproterozoic samples.

The thermal maturity of the Middle Velkerri 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). Samples from select Middle Velkerri source rocks from wells that are all in the dry gas window (avg. 30 to 64% clays) have average measured Kübler Index values of 0.210 to 0.326, which is equivalent to a measured vitrinite reflectance of ~3% (mid stage metagenesis) to >4% (late stage metagenesis). In general these maturity interpretations are inconsistent with other geochemical maturity ratios evaluated in this study and suggest the Kübler Index should be used with caution to evaluate thermal maturity in Mesoproterozoic aged source rocks.

**MIDDLE VELKERRI ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS**

Petroleum generative capacity depends on the original quantity of organic matter (TOC₀) and the original type of organic matter (HI₀) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by TOC_pd and HI_pd in the Middle Velkerri source 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).

HI₀ values can be computed from visual kerogen assessments and assigned kerogen-type HI₀ average values using the following equation (Jarvie et al., 2007):

\[
HI_0 = \left( \frac{\% \text{Type I}}{100} \times 750 \right) + \left( \frac{\% \text{Type II}}{100} \times 450 \right) + \left( \frac{\% \text{Type III}}{100} \times 125 \right) + \left( \frac{\% \text{Type IV}}{100} \times 50 \right)
\]  
(13)

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various wells evaluated in the current study are shown in Table 15, along with the resultant average original HI₀ values calculated using equation (13) 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).

<table>
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<th>%Type I 750 HÌ₀</th>
<th>%Type II 450 HÌ₀</th>
<th>%Type III 125 HÌ₀</th>
<th>%Type IV 50 HÌ₀</th>
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<td>450</td>
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</tbody>
</table>
Table 15. Average Kerogen Estimations for Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

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):

\[
TR_{III} = 1 - \frac{HI_{pd}[1200 - HI_o(1 - PI_o)]}{HI_o[1200 - HI_{pd}(1 - PI_{pd})]}
\]  

(14)

HI\textsubscript{pd} and PI\textsubscript{pd} are the measured HI and PI values for the various source rock samples in these wells. The average HI\textsubscript{pd} and PI\textsubscript{pd} for the formations evaluated in the current study are shown in Table 16. HI\textsubscript{o} and PI\textsubscript{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\textsubscript{o} values of 450 to 550 mg HC/g TOC (Table 15). We assume a PI\textsubscript{o} of 0.02 (see Peters et al., 2005). Using these values in equation 14, the extent of fractional conversion of HI\textsubscript{p} to petroleum varies from 0.39 to 0.99 (Table 16), i.e., on average an estimated 39 to 99% of the petroleum generation process has been completed.

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

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

(15)

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 CR 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\textsubscript{III} \times CR. The kerogen mix for each individual sample was used in this calculation.

Using equation 15, the estimated original TOC\textsubscript{o} for the Middle Velkerri source rock samples before petroleum generation was calculated (Table 16).

The original generation potential S2\textsubscript{o} can be calculated using the following equation:

\[
S2_o = \left( \frac{HI_o \times TOC_o}{100} \right)
\]  

(16)

For the Middle Velkerri source rocks examined in the various wells in this study, the average S2\textsubscript{o} values are calculated as mg HC/g rock and also converted to bbl/acre-ft units (multiply S2\textsubscript{o} by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 16).

Knowing the measured remaining generation potential S2 from programmed pyrolysis and using the calculated original generation potential S2\textsubscript{o} enables a determination of the amounts of hydrocarbons generated. A VR\textsubscript{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).

\[
\text{Original (S2\textsubscript{o})} - \text{Remaining (S2)} = \text{Generated HC}s
\]  

(17)
Using this methodology for the Middle Velkerri source rock samples analyzed in the current study, the estimated generated oil and cracked gas yields are given in Table 16.

<table>
<thead>
<tr>
<th>Well</th>
<th>TOCpd</th>
<th>HIp</th>
<th>S2pd bbl/a-ft</th>
<th>HIo</th>
<th>TR</th>
<th>TOCo</th>
<th>S2o bbl/a-ft</th>
<th>S1 Free Oil bbl/a-ft</th>
<th>Est. Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>4.41</td>
<td>274</td>
<td>283</td>
<td>456</td>
<td>0.52</td>
<td>5.10</td>
<td>510</td>
<td>54</td>
<td>227</td>
<td>0</td>
</tr>
<tr>
<td>Broadmere 1</td>
<td>2.94</td>
<td>332</td>
<td>210</td>
<td>478</td>
<td>0.43</td>
<td>3.36</td>
<td>347</td>
<td>29</td>
<td>136</td>
<td>0</td>
</tr>
<tr>
<td>McManus 1</td>
<td>4.34</td>
<td>129</td>
<td>110</td>
<td>450</td>
<td>0.80</td>
<td>5.52</td>
<td>544</td>
<td>46</td>
<td>417</td>
<td>102</td>
</tr>
<tr>
<td>Sever 1</td>
<td>3.79</td>
<td>22</td>
<td>8</td>
<td>450</td>
<td>0.97</td>
<td>4.93</td>
<td>485</td>
<td>5</td>
<td>15</td>
<td>2771</td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>1.29</td>
<td>21</td>
<td>6</td>
<td>450</td>
<td>0.97</td>
<td>1.74</td>
<td>171</td>
<td>2</td>
<td>0</td>
<td>993</td>
</tr>
<tr>
<td>Tarlee S3</td>
<td>4.11</td>
<td>6</td>
<td>3</td>
<td>450</td>
<td>0.99</td>
<td>5.42</td>
<td>534</td>
<td>3</td>
<td>2</td>
<td>3174</td>
</tr>
<tr>
<td>Walton 2</td>
<td>6.48</td>
<td>418</td>
<td>641</td>
<td>550</td>
<td>0.39</td>
<td>7.15</td>
<td>898</td>
<td>64</td>
<td>257</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 16. Hydrocarbon Yields average data for Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

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 17). 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 source rocks in wells interpreted to be within the oil window varies from 75 to 89%, which is more consistent with late oil to early wet gas/condensate maturity. The three dry gas wells all have much higher expulsion efficiency of 99%, which is consistent with their interpreted maturity levels.

The Middle Velkerri source rock samples in the various wells examined in the current study are interpreted to be in the early to peak oil window to early dry gas window and hydrocarbon yield calculations suggest significant amounts of generation have occurred (predominantly oil with some associated gas in most wells and cracked gas with minor residual oil in other wells). 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 17). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original (S2o) 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 source rock samples, original generation potential (S2o) averages from 171 to 898 bbl oil/acre-ft (Table 17). With the exception of the Shenandoah 1A well, all other wells are > 340 bbl oil/acre-ft and generally fall within the range of the other formations on the list of unconventional US Shale plays shown below. The original generation potential of the most prospective Middle Velkerri well (Walton 2) actually exceeds the average values for all of the other unconventional US Shale plays (Table 17). This suggests that the Middle Velkerri source interval in the Beetaloo Sub-Basin, especially along the northern margin of the basin has good prospectivity from a geochemical hydrocarbon generation perspective. As will be noted in following sections, this is only one component of unconventional risk assessment and other factors such as present day in-situ hydrocarbon saturations and source rock mineralogy must also be considered during evaluation.
Table 17. Geochemical Properties and Generation Potential for US Shale plays. Middle Velkerri wells are color coded for possible shale oil (green) and shale gas (red) prospect type.

### MIDDLE VELKERRI UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Middle Velkerri source rocks in the Beetaloo Sub-Basin have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 51) 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. Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas production. Transformation Ratios (TR) were calculated based upon HI, estimates using measured and interpreted fractional composition of kerogen macerals.
The Middle Velkerri source rocks in all of the Beetaloo Sub-Basin wells are interpreted to represent a low to moderate geochemical risk for in-situ shale oil/gas production in most wells, although the Shenandoah 1A is considered a high risk for shale gas. The average measured TOC contents of all wells are above the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Fig. 51). Average TOC values in most of these wells are also above the minimum requirements of 2 wt.% for economic petroleum source rocks, which is also the minimum threshold for prospective shale gas. The only exception is the Shenandoah 1A well that has an average 1.32 wt. % TOC and is below the recommended minimum shale gas threshold (hence the reason this well is considered high risk). Original organic matter type in these source rock intervals is interpreted to be predominantly oil-prone Type I/II kerogen.

Thermal maturity parameters from programmed pyrolysis place several of these wells within the early to peak oil window, while others are interpreted to be in the dry gas window. The average $T_{\text{max}}$ values between 433 to 444°C for wells within the early to peak oil window are generally above recommended minimum value of 435°C for shale oil (Fig. 51), although the Walton 2 well is slightly below this threshold. This amount of conversion would likely be sufficient to generate/expel significant amounts of hydrocarbons from this organic rich source facies. The average $T_{\text{max}}$ values of 499 & 530°C for two of the wells within the gas window are far above the minimum of 455°C for shale gas (Fig. 51), although no reliable $T_{\text{max}}$ values were available from the Shenandoah 1A well. Transformation ratios (TR), the least constrained risk parameter, average between 39 to 80% for wells interpreted to be in the oil window and two wells (Broadmere 1 & Walton 2) fall below recommended minimum of 50% for shale oil (Fig. 51). For this reason, these two wells are considered a moderate risk for shale oil development. The three wells interpreted to be in the dry gas window have transformation ratios of 97 to 99% and are well above the
80% threshold for shale gas systems (Fig. 51). Measured maceral reflectance values were only available for three of these wells and the value of 0.90% \( R_o \) for low reflectance solid bitumens in the McManus 1 well are above the recommended minimum threshold of 0.6% \( R_o \) for shale oil systems and below the minimum threshold of 1.0% \( R_o \) for shale gas systems (Fig. 51). Measured and Eq. \( R_o \) values for the dry gas wells are 1.81 & 2.18% \( R_o \) and are well above the minimum threshold for shale gas.

For the Middle Velkerri source intervals interpreted to be in the oil window, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is good to very good (avg. 29 to 64 bbl oil/acre-ft), which is a positive factor regarding risk assessment for unconventional oil (Figs. 52 & 53). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Middle Velkerri wells interpreted to be in the oil window at 136 to 417 bbl oil/acre-ft (Figs. 52 & 54). 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. 52). With the exception of the Broadmere 1 well, these values are comparable to most of the Middle Velkerri wells in the Beetaloo Sub-Basin, and some Middle Velkerri wells actually exceed the Barnett Shale in terms of estimated generated oil yields (Fig. 52). However, the in-situ oil saturation is generally somewhat lower in the Middle Velkerri and this could be a consequence of the geologic age of these samples.

For the three Middle Velkerri well interpreted to be within the early dry gas window, the measured in-situ oil saturation determined by programmed pyrolysis S1 yields is low (avg. 2 to 5 bbl oil/acre-ft) as expected for this level of thermal conversion. Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Middle Velkerri interval in these wells at 0 to 15 bbl oil/acre-ft, and oil cracking is estimated to have been 95 to 100%, resulting in cracked gas yields of 993 to 3174 Mcf/acre-ft (Figs. 52 & 55). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/a-ft (Fig. 50). The Sever 1 and Tarlee S3 wells both have cracked gas yields that exceed the Barnett Shale and these two wells are both considered low risk for shale gas. As noted previously, the Shenandoah 1A well has relatively low TOC and the 993 Mcf/acre-ft cracked gas yield in this well if less than half of the Barnett Shale, confirming the high risk for shale gas development in this well.
Figure 52. Hydrocarbon yield estimates for the Mesoproterozoic Middle Velkerri source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the oil and gas window.

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 intervals in some of these wells is in the early oil window and hydrocarbon saturation is likely to be heavy and immobile. Other wells within the
peak oil window likely have fairly light and mobile in-situ oil saturation. However, the presence of solid bitumen as determined from organic petrology analyses 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 Middle 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 53. The spatial distribution of the S1 Free Oil saturation for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S1 and are reported as bbl oil/acre-ft.

Spatial distributions in the measured in-situ S1 free oil saturations, estimated generated oil yields and estimated cracked gas yields (Figs. 53 through 55) were evaluated in the context of previous trends within other geochemical parameters. As noted previously, measured in-situ S1 oil saturations are generally
good in most of the Middle Velkerri wells evaluated in this study which are interpreted to be within the main oil window (29 to 64 bbl oil/acre-ft). Geographically, there does appear to be a trend of relatively lower S1 content in Broadmere 1 well located in eastern region of this study area (Fig. 53) when compared to the three wells in the north central margins of the Beetaloo Sub-Basin. The Walton 2 well has the highest S1 free oil saturation and it also has the highest TOC content. In general, S1 saturation correlates favorably with TOC in the wells that are interpreted to be within the oil window. As expected, very low S1 values were found in the three wells interpreted to be in the dry gas window (Fig. 53). Spatial trends in the estimated generated oil yields appear to be more of a reflection of thermal maturity, with the highest values found in the McManus 1 well that is within the peak oil window and lower values for the three wells interpreted to be in the early oil window (Fig. 54). All of the dry gas wells have very low estimated oil yields due to extensive (95 to 100%) oil to gas cracking.
Figure 54. The spatial distribution of the Estimated Generated Oil Yields for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average generated oil and are reported as bbl oil/acre-ft.

Spatial trends in the estimated secondary cracked gas yields (Fig. 55) closely follow thermal maturity patterns previously established for transformation ratios and Calc. $R_o$. This is expected since the algorithm to estimate oil to gas cracking is based upon the measured % Calc. $R_o$, and/or interpreted Calc. $R_o$ values. Thus, the Sever 1, Shenandoah 1A and Tarlee S3 wells which are interpreted to be in the dry gas window are the only wells that have significant amounts of estimated cracked gas from the Middle Velkerri interval (oil associated gas is not factored into this determination). The Tarlee S3 cracked gas yield is higher due to its higher TOC content and the other two wells follow this trend with the Shenandoah 1A well having the lowest cracked gas yield and lowest average TOC content (the reason this well is considered high risk for unconventional shale gas).
Figure 55. The spatial distribution of the Estimated Cracked Gas Yields for the Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average secondary cracked gas and are reported as Mcf gas/acre-ft.
MIDDLE VELKERRI MINERALOGY

MIDDLE VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Middle Velkerri source rocks in seven (7) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Select samples from these wells were analyzed by X-ray diffraction (XRD). The purpose of this testing was to document the mineralogy of the samples in order to evaluate potential organofacies variations, to examine reservoir quality and brittleness for fracture development, and to assess possible controls on porosity and permeability.

MIDDLE VELKERRI MINERALOGY

XRD data taken from samples in the Middle Velkerri (Table 18; Fig. 56) shows that clays are some of the most abundant minerals present and total clay content averages 37%. Clay types found are dominated by illite/mica (avg. 17%), mixed-layer illite/smectite (avg. 15%), chlorite (avg. 5%), and kaolinite (avg. 1%). Quartz is the dominant non-clay species and its abundance averages 46%, making it the most abundant mineral species present. Classification of these samples by rock type shows that most would be classified as clay-rich siliceous mudstones, although there are a few samples of silica-rich argillaceous mudstones, argillaceous-siliceous mudstones, mixed carbonate mudstones and carbonate dominated lithologies.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Clays</th>
<th>Carbonates</th>
<th>Quartz</th>
<th>K-spar</th>
<th>Other</th>
<th>Mixed I/S*</th>
<th>TOC</th>
<th>Brittleness Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Middle Velkerri</td>
<td>37</td>
<td>3</td>
<td>46</td>
<td>2</td>
<td>12</td>
<td>15</td>
<td>3.96</td>
<td>52</td>
</tr>
</tbody>
</table>

*ordered interstratified mixed-layer illite/smectite

Table 18. TOC & X-ray diffraction average data (weight %) for Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

The shale samples in the Middle Velkerri source intervals have abundant clays, which is a concern for potential fracture stimulation because this is often a fairly ductile mineral assemblage. However, these samples also contain dominantly quartz, which is a relatively brittle mineral and conducive to fracture stimulation. Pyrite is present in minor amounts (avg. 3%) and is associated with kerogen that is also a minor component of the overall mineralogy. The moderate contribution of these components is usually positive with regard to fracture stimulation in general for organic-rich shales at elevated thermal maturity.

Another potential risk factor for fracture stimulation is the abundance and type of clays within the Middle Velkerri samples. These source rock samples do contain moderate amounts of clays (avg. 37%), and these clays also contain abundant ordered interstratified mixed-layer illite/smectite (avg. 15% and comprising 39% of total clays). In general, successful unconventional shale plays tend to have less than 10% total mixed-layer illite/smectite (R. Bruce, personal communication) and the Middle Velkerri samples analyzed in this study are well above this risk threshold. Thus, the abundance and type of clays in the Middle Velkerri samples would appear to be a negative risk factor for fracture stimulation; however, further testing to include rock-mechanics measurements is warranted to fully evaluate this parameter.
Mineralogy data can potentially be utilized to further assess rock mechanical properties, including brittleness. Britteness Index (BI) values were calculated using equation (18) below. The range of BI values vary from 24–76 and average 52 (Table 18), with higher values supposedly indicating more brittle rock. The highest BI values were found in the samples with the lowest overall clay content. A sample analyzed from the Altree 2 well had the highest carbonate content (67%) of all Middle Velkerri samples in this study and it also had the highest BI of 76. A sample from the Sever 1 well had the second highest BI of 75 and it was found to have very high silica content (60%). Close examination of the data show that both carbonate and quartz have a strong influence on the brittleness calculation. In the Middle Velkerri source rocks, carbonate is generally in very low abundance and the variability in quartz and clays appears to control the Brittleness Index. Recent publications have noted that measured rock mechanical properties were often found to have poor correlations with various formulas for calculating brittleness index values (Yang et al., 2013). Thus, caution should be exercised in using these data for evaluations.
and any BI values for previously untested source rocks like the Middle Velkerri should be calibrated against measured rock mechanical data.

\[
BI = \frac{1.3(Qtz) + (Kspar) + (Plag) + 1.2(Carb)}{Numerator + 2(Mixed) + 1.5(Clor + Kaol + Ill) + (Pyr) + (Apa) + (Bar)}
\]  

(18)

Mineralogy data can also be used to compare the Middle Velkerri source rock samples against other US Shale plays. Ternary diagrams of the quartz, carbonate, and clay percentages have been constructed using the individual samples from the various Middle Velkerri wells evaluated in the current study (Fig. 57). In these diagrams, most US Shale plays plot along a continuum between the quartz and carbonate endpoints, which are also the locations of the most brittle rocks (Fig. 57). As clay percentages increase (toward the SE corner of the diagram), the brittleness decreases. As noted previously, the Middle Velkerri samples have generally elevated silica (avg. 46%) and moderate clay content (avg. 37%), which may be a risk for fracture stimulation. On the mineralogy ternary diagram (Fig. 57), the Middle Velkerri samples appear to plot well within the NE portion of the envelope representing most US Shale samples, although some samples with elevated carbonate content are in the SE portion of the ternary diagram. These Middle Velkerri samples generally overlap with a number of unconventional shale plays (e.g. Ohio Devonian, Haynesville, Lower Huron, Devonian, Second White Specs, Woodford, Cane Creek) and the few carbonate rich samples overlap with other US plays (e.g. Niobrara). The relative brittleness of US Shale samples in these regions of the ternary diagram tends to be high since they are generally more quartz-rich or more carbonate-rich (Fig. 57). However, as noted previously, the total clay content should not be considered the only factor in risk assessment, but rather it is the abundance of mixed-layer illite/smectite clay species that is more likely to be the critical factor. In the Middle Velkerri source rocks, these mixed-layer illite/smectite clay species are also in relatively high abundance (avg. 15%). As clearly documented in the mineralogy ternary diagrams, there is considerable variability even within an individual shale play and each shale should be considered based on its own mineralogy and petrophysical attributes. Ultimately, these data need to be calibrated against laboratory measured geomechanical properties for continued improvement in stimulation and completion practices.

Figure 57. XRD mineralogy ternary diagram for Middle Velkerri source rock samples in the Beetaloo Sub-Basin, Australia (left) compared to published data for US Shale plays (right) (Rickman et al., 2008). Sizes of symbols represent the relative brittleness determined by XRD within the published data set, but this is not illustrated in the data from the current study.
LOWER VELKERRI PETROLEUM GEOCHEMISTRY

LOWER VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Lower Velkerri source rocks in six (6) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells 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.). In addition, client supplied published geochemical data was also incorporated into the interpretive evaluation. The complete results of these analyses are documented in the individual well reports and are summarized in Table 19. Formation specific integrated geochemical interpretations and spatial trends are considered within the context of the current document.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Oil/Gas Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>Lower Velkerri</td>
<td>Estimated Original</td>
<td>Very Good</td>
<td>(2.20% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Oil)</td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Light Oil</td>
<td>Wet Gas</td>
<td>Fair (0.56% TOC)</td>
<td>Gas Prone Type III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Broadmere 1</td>
<td>Lower Velkerri</td>
<td>Estimated Original</td>
<td>Fair</td>
<td>(0.88% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Oil)</td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Minor Oil</td>
<td>Late Oil</td>
<td>Fair (0.57% TOC)</td>
<td>Gas-Prone Type III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sever 1</td>
<td>Lower Velkerri</td>
<td>Estimated Original</td>
<td>Good</td>
<td>(1.74% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Gas)</td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Dry Gas</td>
<td>Dry Gas</td>
<td>Fair (0.80% TOC)</td>
<td>Gas-prone Type III</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>Lower Velkerri</td>
<td>Estimated Original</td>
<td>Good</td>
<td>(1.34% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Gas)</td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Gas</td>
<td>Dry Gas</td>
<td>Fair (0.96% TOC)</td>
<td>Inert Type IV</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Walton 2</td>
<td>Lower Velkerri</td>
<td>Estimated Original</td>
<td>Good</td>
<td>(1.19% TOC)</td>
<td>Oil-prone Type II</td>
<td>High (Oil)</td>
</tr>
<tr>
<td>Measured Currently</td>
<td>Oil</td>
<td>Early Oil</td>
<td>Fair (0.90% TOC)</td>
<td>Gas-Prone Type III</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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

Table 19. Lower Velkerri Geochemical Summary

LOWER VELKERRI GENERATIVE POTENTIAL

The Lower Velkerri source rock samples analyzed from the Beetaloo Sub-Basin have fair generative potential (Table 19; Fig. 58). Organic richness varies from 0.02 wt.% (poor) to as high as 4.62 wt.% (excellent) TOC, with an average value of 0.70 wt. % TOC (fair). The histogram plot of TOC distributions (Fig. 58) illustrate that the dominant population is within the 0 to 0.5 wt. % range. Outside of this range there appears to be a trend of progressive decrease in frequency of samples with increasing TOC content. Slightly less than one-quarter of these samples have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks. Furthermore, only about 10% of these samples have TOC content above the minimum requirement of 2 wt.% for economic petroleum source rocks, which is a potential risk factor for unconventional resource development.
Figure 58. Histogram plot of Total Organic Carbon (TOC) distributions for Lower Velkerri source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.% , while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.

The distribution of elevated Lower Velkerri TOC values in most of these Beetaloo Sub-Basin wells is noted to be restricted predominantly to a relatively thin zone that often occurs near the middle or base of the designated interval. The only well that has a wider distribution of elevated TOC values is the Shenandoah 1A well, where there are two separate zones with elevated TOC located near the top and base of the section. This is also illustrated on the base map showing spatial distributions of measured Lower Velkerri TOC within the Beetaloo Sub-Basin (Fig. 59). On this map, the average TOC values are shown and the Shenandoah 1A well has somewhat higher organic richness (avg. 0.96 wt. %) in comparison to all other wells in this region. Spatial trends within the TOC should be interpreted with caution due to the relatively narrow zone of elevated TOC.
Figure 59. The spatial distribution of organic richness for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average LECO TOC content and are reported as wt. %.

The spatial distributions of measured TOC within the Lower Velkerri do show some variations across the Beetaloo Sub-Basin (Fig. 59), however, there is no obvious trend or pattern within the data. For example, the well with the lowest average Middle Velkerri TOC (McManus 1) is in close proximity to a well with relatively high average TOC (Walton 2). However, the density of sampling may be affecting the integrity of statistical averages for these TOC values. For example, the McManus 1 well that has the lowest average TOC value of this group is based upon only six (6) data points and is one the wells in this study in which only select LECO TOC results were available. Sorting out any potential differences in paleo-depositional environment or organic productivity that have imparted geographic variations in the abundance of preserved organic matter within the Lower Velkerri source rock interval will require further investigation. It would be preferable if samples from the Lower Velkerri were separated into distinct organofacies for this purpose. Some of the issues related to evaluating average TOC trends within this interval could also
simply reflect sampling bias related to picking the contact with the overlying Middle Velkerri source rock interval that is much more organic rich. Regardless, caution should be applied to any TOC spatial interpretations since they are based on the distribution of samples from only seven wells.

Figure 60. Total Organic Carbon (TOC) versus Remaining Hydrocarbon Generation Potential (S2) for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

Pyrolysis S2 yields in the Lower Velkerri samples vary from 0.01–8.96 mg HC/g rock (Fig. 60) and average values within individual wells vary from 0.09–1.51 mg HC/g rock or 2–33 bbl/a-ft. These indicate a poor amount of remaining primary hydrocarbon generation potential (both oil and gas), which is consistent with generally lean organic richness and different levels of primary thermal conversion in the early/peak oil to condensate/wet gas and dry gas windows. There are potentially three dominant populations of data for the Lower Velkerri samples that likely correspond with different organofacies that are also affected by different levels of thermal alteration (Fig. 60). Three samples with moderate to lean TOC content have relatively high S2 yields and plot in the region associated with oil-prone Type II kerogen (Fig. 60). These samples could represent the only true examples of well-preserved Type II kerogen within the Lower Velkerri interval (see Langford and Blanc-Valleron, 1990).
The second and main group of Lower Velkerri samples appears to have elevated TOC and tend to have relatively elevated S2 values and they generally plot within the mixed oil/gas-prone Type II/III and gas-prone Type III regions (Fig. 60). These samples likely represent a slightly less prospective organic facies and probably represent oil-prone Type II kerogen with a mix of inert Type IV kerogen that has been altered to variable degrees by thermal maturity. Some high thermal maturity samples in this group (gas window) currently plot more toward the inert Type IV region due to lower S2 as a consequence of thermal maturity (Fig. 60).

The third major grouping of samples represents wells that are interpreted to be at high levels of thermal maturity and form a cluster of data points extend along the x-axis and populate the region associated with inert Type IV kerogen (Fig. 60). These data represent samples that are highly converted due to their thermal maturity (condensate/wet gas to dry gas). Assessment of this group of samples is difficult due to their thermal maturity. Original placement of these samples prior to thermal conversion is considered to be predominantly within the oil-prone Type II region (see individual well reports and hydrocarbon yield calculations for more details), although this interpretation may be somewhat optimistic given the geochemical results presented herein.

The Altree 2 well has the highest measured S2 content (Fig. 61) but its relatively high remaining generation potential is apparently not a consequence of low thermal maturity (interpreted to be within the condensate/wet gas). The nearby Walton 2 well also has relatively high S2 content, but this is somewhat expected since this well is interpreted to be within the early oil window (Fig. 61). Geographically, wells located along more of the basin margins tend to have higher S2 content compared to wells like the Shenandoah 1A, which is basin center and dry gas thermal maturity (Fig. 61). The Sever 1 well is also high maturity (dry gas window) and it too has very low S2 yields (Fig. 61). Thus, spatial trends in S2 in these wells likely reflect thermal maturity variability more so than differences in original generation potential. Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these S2 variations.
Figure 61. The spatial distribution of remaining hydrocarbon generation potential (S2) for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S2 content and are reported as mg HC/g rock.

LOWER VELKERRI KEROGEN TYPE AND EXPELLED PRODUCT

The Lower Velkerri is reported to consist of gray-blue claystone to silty mudstone with thin sandstone intervals that are increasingly common towards the base (Munson, 2014). The claystone facies generally organic poor, but is inferred to contain similar mixtures of Type I and Type II kerogen as has been reported in the more organic rich Middle Velkerri interval (Munson, 2014). The depositional conditions and the geologic age of these samples would be conducive to preservation of source rocks with a dominant cyanobacterial oil-prone kerogen (Type I and Type II) along with variable and possibly significant amounts of oxidized Type IV organic material.
The Lower Velkerri source rock samples analyzed in this study were found to compose two to potentially three distinct lithofacies, although the influence of sample type variability in the geochemical data cannot be discounted. The most prospective samples appear to be characterized by relatively S2 content and are distinctive in having relatively high hydrogen index (HI) values maximum of 571 mg HC/g TOC (Fig. 62). These samples could represent higher quality oil-prone marine Type I or Type II kerogen samples containing preserved lamalginite. Unfortunately, only limited organic petrology results from the current study are available no samples from the Lower Velkerri interval were examined which might constrain measured kerogen maceral distributions.

The second major suite of samples that possibly represent a different organofacies within the Lower Velkerri come from wells interpreted to be at a variety of thermal maturity levels. These samples tend to have lower TOC content and S2 yields. Most samples appear to be characterized by generally low hydrogen index (HI) values ~50 to 250 mg HC/g TOC (Fig. 62). Many of these samples also have high oxygen index (OI) values > 20 mg CO2/g TOC (Fig. 62). These samples likely represent lower quality preserved Type II organic matter that has been partially oxidized prior to preservation. The degree of oxidation would appear to dictate the classification of this material as Type II/III, Type III and/or Type IV in some instances.

The third group of samples appears to represent high maturity samples with dominantly inert Type IV kerogen within the Lower Velkerri (Fig. 62). These samples tend to have variable TOC content and very low S2 yields. All samples appear to be characterized by very low hydrogen index (HI) values < 50 mg HC/g TOC (Fig. 62). Some of these samples also have high oxygen index (OI) values 20-40 mg CO2/g TOC (Fig. 62).

Measured present day HI values in the Lower Velkerri samples range from 1 to 571 mg HC/g TOC (Fig. 62) and individual wells average 9 to 141 mg HC/g TOC depending upon thermal maturity. On a plot of HI versus Oxygen Index (OI) (pseudo van Krevelen diagram), a few samples appear to plot along the maturation pathway for Type I kerogens (Fig. 62). However, as previously noted most samples have much lower relative HI and much higher OI values and plot in other regions of this diagram in zones presently associated with Type II/III, Type III and Type IV kerogen (Fig. 62). Since these Lower Velkerri source rocks are considered early to post mature with regard to oil generation, the kerogen HI values have been reduced variably as a consequence of thermal maturity; thus, they indicate primarily gas-prone Type III and inert Type IV kerogen quality at present day (Fig. 62).

Measured OI values in Lower Velkerri samples varies widely from 1 to 264 mg CO2/g TOC and a large number of samples have elevated OI in the > 20 range (Fig. 62). These samples would appear to plot more in the region typically associated with gas-prone Type III organic matter, although structured organic matter of this type which is typically associated with terrigenous organic matter was not present during this geologic age. Thus, these samples are more likely to represent a mixture of Type II marine algal and Type IV oxidized inert organic matter. Organic petrology kerogen examination of additional samples to examine the possible presence of oxidized material could help confirm such a depositional interpretation.
Spatial distributions in the HI values were evaluated in the context of previous trends within both TOC and S2 yields (Fig. 63). The two wells with relatively low HI values due to elevated thermal maturity in the dry gas window are clearly distinguished on this map (Shenandoah 1A & Sever 1). The three wells with relatively high HI content are located in the eastern and northern regions of the Beetaloo Sub-Basin margins (Fig. 63). The HI in these wells closely follows maturity from the Walton 2 well that is in the early oil window and has the highest HI, to the Broadmere 1 in the late oil which has lower HI and the Altree 2 in the condensate/wet gas that has even lower HI. Geographically, there does appear to be a trend of relatively higher HI content in Lower Velkerri wells located along the margins of this study area in the Beetaloo Sub-Basin (Fig. 63), but within these wells there is more random variability in HI. Thus, spatial trends in HI appear to reflect thermal maturity variability as the dominant controlling factor, but differences in organic kerogen type may also be present within this data. Further integration of the geochemical data with regional geology will be needed to potentially provide further insights into the origin of these HI variations and it would potentially be useful to further sub-divide the Lower Velkerri into distinct organofacies based upon the TOC depth trends and possible kerogen facies observed in the current study.

Figure 62. Hydrogen Index versus Oxygen Index (pseudo-van Krevelen plot) for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.
The organic-matter in the Lower Velkerri source rocks evaluated in the current investigation appears to have entered into the early through late stage of conventional oil generation window for two wells and into the early condensate/wet gas window and early dry gas window for the other wells.

Programmed pyrolysis $T_{\text{max}}$ values from samples in which $T_{\text{max}}$ was considered reliable vary from ~425˚ to 568˚C (Figs. 64 & 66) and average between 424˚C and 556˚C for Lower Velkerri source rocks in individual wells. Measured $T_{\text{max}}$ between 425 and 435˚C typically indicate early oil window, while values between 435 and 445˚C indicate peak oil window and values > 470˚C are typical of the dry gas window (Type II kerogen). Using the formula published by Jarvie et al. (2007) for Type II kerogen ($\text{Calculated } R_o =$
(0.0180)\(T_{\text{max}}\) – 7.16, the average measured \(T_{\text{max}}\) values between 424°C and 556°C are equivalent to Calc. %\(R_o\) values of 0.47% and 2.84%. It is noteworthy that a very large number of samples (~40%) from the Lower Velkerri interval have \(T_{\text{max}}\) values < 420°C and were considered unreliable for thermal maturity assessment purposes. These samples may represent source rocks with possible contamination issues (see Fig. 66) or samples that simply have very low S2 peaks giving anomalous \(T_{\text{max}}\) readings.

Figure 64. Hydrogen Index versus \(T_{\text{max}}\) for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

The \(T_{\text{max}}\) values shown on Fig. 64 illustrate that the Lower Velkerri samples have a wide range of thermal maturity from early oil window up into the dry gas window and plot within maturity envelopes that are associated with Type II, Type II/III and Type III kerogen. Most samples are within the oil-prone Type II and mixed Type II/III envelopes, which is a similar interpretation to that obtained from evaluation of geochemical data previously discussed. There are several samples with elevated \(T_{\text{max}}\) values in the dry gas window that appear to have anomalously high HI values (Fig. 64). These same samples also have anomalously elevated PI values (Fig. 66) and likely represent OBM contamination since they are from the Walton 2 well that is interpreted to be within the early oil window on the basis of select \(T_{\text{max}}\) data from samples with much lower values.
In general, a great deal of caution should be used in the evaluation of $T_{\text{max}}$ data for samples within the early to peak oil window that often contain elevated S1 peaks. Usually, oil-prone source rock samples within the oil window are characterized by a predominant S2 peak and an elevated S1 peak of variable intensity. Depending upon oil characteristics, there can be some carry over from the S1 peak to the S2 peak as evidenced by asymmetry in both peaks. The presence of low temperature S2 shoulders is identified by examination of the pyrograms in some of the Lower Velkerri samples from this study. This suggests that some of what we assume are volatile constituents of the oil or bitumen in the sample are, in fact, not volatilized at 300°C (S1 vaporization temperature), but rather at higher temperatures. Therefore, these components are carried over and included as part of the S2 peak. These could be high-molecular-weight waxes, asphaltenes, and other compounds (note LCM material like walnut hulls can also cause the same effect, but usually have a distinct “shark fin” appearance in the low temperature region). This effect could conceivably lower the measured $T_{\text{max}}$ value during programmed pyrolysis. As a consequence, the interpreted thermal maturity on the basis of $T_{\text{max}}$ should usually be considered a MINIMUM value due to this uncertainty. The presence of low temperature S2 shoulders in these samples could also cause the measured HI values to be elevated in comparison to their true readings. One method to evaluate this artifact is to solvent extract the samples and re-analyze them by programmed pyrolysis. This would remove any contribution coming from the oil/bitumen and would likely result in somewhat lower HI values, thereby providing a more accurate assessment of true kerogen generation potential and hydrogen content. In the anomalous $T_{\text{max}}$ from the Walton 2 well, the $T_{\text{max}}$ values are actually much higher than the interpreted early oil window maturity and these likely represent some unusual OBM artifact.

Spatial distributions in the $T_{\text{max}}$ derived Calc. $R_o$ values were evaluated in the context of previous trends within other geochemical parameters (Fig. 65). The Calc. $R_o$ values follow the maturity trends previously discussed for HI values. The Walton 2 well has the lowest Calc. $R_o$ value (based on select data) and is in the early oil window, followed by the Broadmere 1 and Altree 2 wells that have relatively higher Calc. $R_o$ values (Fig. 65). The two wells with the highest Calc. $R_o$ values are the Shenandoah 1A and Sever 1 wells that are interpreted to be within the dry gas window (Fig. 64). The lower maturity wells on the basis of Calc. $R_o$ values tend to be along the main Beetaloo Sub-Basin margin and the higher maturity wells are either in the main depocenter (Shenandoah 1A) or in the far NW corner of the study area (Fig. 65). Further integration of the geochemical data with regional geology and additional well data points will be needed to potentially provide further insights into the origin of these Calc. $R_o$ variations.
Figure 65. The spatial distribution of the Calc. $R_o$ values from $T_{\text{max}}$ for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average Calc. $R_o$ and are reported as $\% R_o$ using the formula of Jarvie et al. (2007) ($\text{Calculated } R_o = (0.0180)(T_{\text{max}}) - 7.16$).

Production Index (PI) values in these Lower Velkerri source rock samples vary widely from 0.02 to 0.96 (Fig. 66) and average between 0.30 to 0.36 for Lower Velkerri source rocks in individual wells. The samples from wells interpreted to be within the late oil to condensate/wet gas window tend to have PI values in the 0.05 to 0.60 range and generally plot in the region associated with intensive generation expulsion (Fig. 66). However, there are also many samples that plot in the stained/contaminated regions and high level conversion zones (Fig. 66), some of which are from wells interpreted to be within the gas window and others from the Walton 2 well interpreted to be in the early oil window. In general, these samples should be used cautiously for geochemical maturity interpretation. The trend envelop shown on this plot by a dashed line is based on WFT Labs analysis of over 5000 source rock samples and serves to illustrate the general increase in PI with increasing thermal maturity through the main oil window and its subsequent decrease with increasing oil-to-gas secondary cracking through the condensate/wet gas window.
window. The relatively high PI values in most of the Lower Velkerri samples examined in the current study are somewhat consistent with the interpreted thermal maturity for wells in the late oil to wet gas window and suggest generally high in-situ hydrocarbon saturations. This result is somewhat inconsistent with the generally low measured S1 in-situ hydrocarbon saturation, which suggests that many of these samples may be affected by expelled/migrated oil and/or contamination issues. The elevated PI values for samples in the early oil and dry gas window are clearly anomalous and suggest possible contamination.

Figure 66. Production Index (PI) versus T_max for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Trend envelop shown by dashed line is based on WFT Labs analysis of over 5000 shale samples. Plot symbology defined in Fig. 4.

The average pyrolysis S1 values in the Lower Velkerri source rocks vary from 0.1 to 0.7 mg HC/g rock or 1 to 15 bbl/a-ft. This suggests poor to fair in-situ hydrocarbon saturation in these source rock intervals and is generally consistent with the moderate TOC and generation potential of these source rocks. These wells are interpreted to range from early oil to dry gas window thermal maturity. All wells have sufficient thermal maturity to have generated oil and thus the low in-situ hydrocarbon saturations are somewhat of an anomaly with regard to the interpreted thermal maturity (except in the case of dry gas wells with high oil to gas cracking). These 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. Regardless, the relatively low in-situ hydrocarbon saturation as determined from the S1 analysis in comparison to quality oil-prone source rocks at peak oil window maturity is a clear risk factor for successful unconventional shale oil development. It is also considered a risk factor for shale gas development in the well interpreted to be in the wet gas window, since potential expulsion/loss of expected light oil/condensate in-situ saturation would imply a likely loss of in-situ gas content as well.

Estimated kerogen transformation ratios in the Lower Velkerri samples based upon interpreted original and measured present HI vary from 79 to 99% in these wells. These transformation ratios were calculated using the limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type II kerogen. As noted previously, this may be somewhat of an overestimation on the basis of organofacies designations determined in this study. These average transformation ratios are well above the recommended minimum threshold of 50% for shale oil systems and, except for the Walton 2 well, also above the recommended minimum of 80% for thermogenic shale gas systems. This is somewhat inconsistent with the interpreted thermal maturity levels of these wells that span the range between the early oil window to dry gas window. Spatial distributions in the transformation ratios were evaluated in the context of previous trends within other geochemical parameters (Fig. 67). Geographically, the trends are similar to that observed in the Calc. R$_0$ values but with a much smaller dynamic range (Fig. 67). Most of the wells that are interpreted to be within the oil window do show slightly lower TR values and gas window wells show somewhat higher TR values (Fig. 67). The probable causes of these anomalously high TR values is related to the assigned original Type II kerogen and future studies that incorporate more detailed organic petrology data with detailed kerogen analyses will be needed to potentially provide further insights into the origin of these variations.
Figure 67. The spatial distribution of the Transformation Ratios (TR) for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average TR and are reported as decimal percent conversion using calculated original $H_{lo}$ values based upon measured/interpreted original kerogen distributions.

The thermal maturity of the Lower Velkerri 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 from the Lower Velkerri (60% clays) has a measured Kübler Index of 0.277, 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.
LOWER VELKERRI ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS

Petroleum generative capacity depends on the original quantity of organic matter (TOC₀) and the original type of organic matter (HI₀) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by TOCpd and HIpd in the Lower Velkerri 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).

HI₀ values can be computed from visual kerogen assessments and assigned kerogen-type HI₀ average values using the following equation (Jarvie et al., 2007):

$$HI₀ = \left(\frac{\% Type \ I}{100} \times 750\right) + \left(\frac{\% Type \ II}{100} \times 450\right) + \left(\frac{\% Type \ III}{100} \times 125\right) + \left(\frac{\% Type \ IV}{100} \times 50\right)$$  \hspace{1cm} (19)

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various wells evaluated in the current study are shown in Table 20, along with the resultant average original HI₀ values calculated using equation (19) 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).

<table>
<thead>
<tr>
<th>Well</th>
<th>%Type I 750 HI₀</th>
<th>%Type II 450 HI₀</th>
<th>%Type III 125 HI₀</th>
<th>%Type IV 50 HI₀</th>
<th>HI₀</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Broadmere 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Sever 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
<tr>
<td>Walton 2</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
</tbody>
</table>

Table 20. Average Kerogen Estimations for Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

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):

$$TR_{III} = 1 - \frac{HI_{pd}[1200 - HI₀(1 - PI₀)]}{HI₀[1200 - HI_{pd}(1 - PI_{pd})]}$$  \hspace{1cm} (20)

HI₀ and PI₀ are the original HI and PI values for the various source rock samples in these wells. The average HI₀ and PI₀ for the formations evaluated in the current study are shown in Table 21. HI₀ and PI₀ 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 HI₀ values of 450 mg HC/g TOC (Table 20). We assume a PI₀ of 0.02 (see Peters et al., 2005). Using these values in equation 20, the extent of fractional conversion of HI₀ to petroleum varies from 0.79 to 0.99 (Table 21), i.e., on average an estimated 79 to 99% of the petroleum generation process has been completed.

The original TOC₀ in the source rocks before burial and thermal maturation is constrained by mass balance considerations as follows (corrected from Jarvie et al., 2007):
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 21, the estimated original \( TOC_o \) for the Lower Velkerri source rock samples before petroleum generation was calculated (Table 21).

The original generation potential \( S2_o \) can be calculated using the following equation:

\[
S2_o = \left( \frac{HI_o \times TOC_o}{100} \right)
\]  
(22)

For the Lower Velkerri source rocks examined in the various wells in this study, the average \( S2_o \) values are calculated as mg HC/g rock and also converted to bbl/acre-ft units (multiply \( S2_o \) by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 21).

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).

Original (\( S2_o \)) − Remaining (\( S2 \)) = Generated HCs

Using this methodology for the Lower Velkerri source rock samples analyzed in the current study, the estimated generated oil and cracked gas yields are given in Table 21.

<table>
<thead>
<tr>
<th>Well</th>
<th>TOCpd bbl/a-ft</th>
<th>HIp pd</th>
<th>S2pd bbl/a-ft</th>
<th>HIo</th>
<th>TR</th>
<th>TOCo</th>
<th>S2o bbl/a-ft</th>
<th>S1 Free Oil bbl/a-ft</th>
<th>Est. Oil bbl/a-ft</th>
<th>Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Altree 2</td>
<td>1.68</td>
<td>72</td>
<td>33</td>
<td>450</td>
<td>0.89</td>
<td>2.20</td>
<td>216</td>
<td>15</td>
<td>135</td>
<td>290</td>
</tr>
<tr>
<td>Broadmere 1</td>
<td>0.70</td>
<td>106</td>
<td>22</td>
<td>450</td>
<td>0.83</td>
<td>0.88</td>
<td>87</td>
<td>5</td>
<td>59</td>
<td>39</td>
</tr>
<tr>
<td>Sever 1</td>
<td>1.29</td>
<td>55</td>
<td>5</td>
<td>450</td>
<td>0.90</td>
<td>1.74</td>
<td>171</td>
<td>2</td>
<td>1</td>
<td>995</td>
</tr>
<tr>
<td>Shenandoah 1A</td>
<td>0.99</td>
<td>9</td>
<td>2</td>
<td>450</td>
<td>0.99</td>
<td>1.34</td>
<td>132</td>
<td>1</td>
<td>0</td>
<td>783</td>
</tr>
<tr>
<td>Walton 2</td>
<td>0.91</td>
<td>141</td>
<td>25</td>
<td>450</td>
<td>0.79</td>
<td>1.19</td>
<td>120</td>
<td>12</td>
<td>95</td>
<td>0</td>
</tr>
</tbody>
</table>

Table 21. Hydrocarbon Yields average data for Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

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 23). 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 Lower Velkerri source rocks in wells interpreted to be within the oil window varies from 88 to 93%, which is more consistent with a late oil to early wet gas/condensate maturity. This implies that most of the generated
hydrocarbons have been expelled from these source rock intervals, possibly into interbedded porous non-
source rock intervals within the Lower Velkerri.

The Lower Velkerri source rock samples in the various wells examined in the current study are interpreted
to be in the early oil window to early dry gas window and hydrocarbon yield calculations suggest
moderate amounts of generation have occurred (predominantly oil with some associated gas in most
wells and cracked gas with minor residual oil other wells). 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 22). 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 Lower Velkerri source rock samples, original generation potential (S2_o) averages from 87 to 216 bbl
oil/acre-ft (Table 22) and fall well below the other formations on the list of unconventional US Shale plays
shown below.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Database Averages</th>
<th>HIº</th>
<th>TR</th>
<th>TOCº</th>
<th>S2º</th>
<th>Remaining Potential</th>
<th>Original Cracked %</th>
<th>Oil</th>
<th>S1</th>
<th>Estimated Oil</th>
<th>Cracked Gas</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>m/g TOC wt%</td>
<td>m/g Rock bbl/a-ft</td>
<td>% bbl/a-ft</td>
<td>bbl/a-ft</td>
<td>Mcf/a-ft</td>
<td>bbl/a-ft</td>
<td>bbl/a-ft</td>
<td>bbl/a-ft</td>
<td>Mcf/a-ft</td>
<td></td>
</tr>
<tr>
<td>Barnett Shale Ft. Worth Basin</td>
<td>435</td>
<td>0.84</td>
<td>5.38</td>
<td>23.40</td>
<td>94</td>
<td>513</td>
<td>0.40</td>
<td>33</td>
<td>251</td>
<td>1005</td>
<td></td>
</tr>
<tr>
<td>Barnett Shale Delaw are Basin</td>
<td>435</td>
<td>0.91</td>
<td>5.25</td>
<td>22.84</td>
<td>52</td>
<td>500</td>
<td>0.80</td>
<td>32</td>
<td>90</td>
<td>2149</td>
<td></td>
</tr>
<tr>
<td>Woodford Shale Delaw are Basin</td>
<td>480</td>
<td>0.89</td>
<td>6.41</td>
<td>30.79</td>
<td>139</td>
<td>674</td>
<td>0.89</td>
<td>46</td>
<td>60</td>
<td>2854</td>
<td></td>
</tr>
<tr>
<td>Hayneville Shale E. Texas Basin</td>
<td>400</td>
<td>0.98</td>
<td>3.93</td>
<td>15.73</td>
<td>7</td>
<td>344</td>
<td>1.00</td>
<td>3</td>
<td>0</td>
<td>2022</td>
<td></td>
</tr>
<tr>
<td>Fayetteville Shale Arkoma Basin</td>
<td>435</td>
<td>0.95</td>
<td>3.34</td>
<td>14.53</td>
<td>15</td>
<td>318</td>
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<tr>
<td>Woodford Shale Arkoma Basin</td>
<td>520</td>
<td>0.87</td>
<td>5.15</td>
<td>26.80</td>
<td>12</td>
<td>587</td>
<td>0.70</td>
<td>87</td>
<td>170</td>
<td>2431</td>
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<tr>
<td>Eagle Ford Shale Gulf Coast Basin</td>
<td>520</td>
<td>0.85</td>
<td>3.19</td>
<td>16.61</td>
<td>61</td>
<td>364</td>
<td>0.47</td>
<td>22</td>
<td>161</td>
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<tr>
<td>Marcellus Shale Appalachian Basin</td>
<td>600</td>
<td>0.97</td>
<td>6.44</td>
<td>38.66</td>
<td>34</td>
<td>847</td>
<td>1.00</td>
<td>24</td>
<td>0</td>
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<td></td>
</tr>
<tr>
<td>Utica Shale Appalachian Basin</td>
<td>450</td>
<td>0.98</td>
<td>2.74</td>
<td>12.32</td>
<td>6</td>
<td>270</td>
<td>1.00</td>
<td>12</td>
<td>0</td>
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<tr>
<td>Barnett Shale Oil</td>
<td>450</td>
<td>0.47</td>
<td>5.47</td>
<td>24.64</td>
<td>326</td>
<td>540</td>
<td>0.00</td>
<td>79</td>
<td>213</td>
<td>0</td>
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<td>Barnett Shale Gas</td>
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<td>5.58</td>
<td>25.13</td>
<td>23</td>
<td>550</td>
<td>0.87</td>
<td>7</td>
<td>68</td>
<td>2751</td>
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</tr>
<tr>
<td>Altree 2 - Low er Velkerri</td>
<td>450</td>
<td>0.89</td>
<td>2.20</td>
<td>9.88</td>
<td>33</td>
<td>216</td>
<td>0.32</td>
<td>15</td>
<td>135</td>
<td>290</td>
<td></td>
</tr>
<tr>
<td>Broadmere 1 - Low er Velkerri</td>
<td>450</td>
<td>0.83</td>
<td>0.88</td>
<td>3.98</td>
<td>22</td>
<td>87</td>
<td>0.14</td>
<td>5</td>
<td>59</td>
<td>39</td>
<td></td>
</tr>
<tr>
<td>Sever 1 - Low er Velkerri</td>
<td>450</td>
<td>0.90</td>
<td>1.74</td>
<td>7.81</td>
<td>5</td>
<td>171</td>
<td>0.96</td>
<td>2</td>
<td>1</td>
<td>995</td>
<td></td>
</tr>
<tr>
<td>Shenandoah 1A - Low er Velkerri</td>
<td>450</td>
<td>0.99</td>
<td>1.34</td>
<td>6.05</td>
<td>2</td>
<td>132</td>
<td>1.00</td>
<td>1</td>
<td>0</td>
<td>783</td>
<td></td>
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<tr>
<td>Walton 2 - Low er Velkerri</td>
<td>459</td>
<td>0.79</td>
<td>1.19</td>
<td>5.50</td>
<td>25</td>
<td>120</td>
<td>0.00</td>
<td>12</td>
<td>95</td>
<td>0</td>
<td></td>
</tr>
</tbody>
</table>

Table 22. Geochemical Properties and Generation Potential for US Shale plays. Lower Velkerri
wells are color coded for possible shale oil (green) and shale gas (red) prospect type.

LOWER VELKERRI UNCONVENTIONAL OIL & GAS RISK ASSESSMENT

The Mesoproterozoic Lower Velkerri source rocks in the Beetaloo Sub-Basin have been evaluated for
unconventional oil and gas potential. These source rock samples are presented in a modified
geochemical risk assessment diagram (Fig. 68) based upon published results from the Barnett Shale in
the Fort Worth Basin. The data illustrated in the star plot represents average values for all four diagnostic
ratios where available. Also shown are the recommended areas for unconventional oil (in green) and gas
(in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with
low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum
threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas
production. Transformation Ratios (TR) were calculated based upon HI_o estimates using measured and
interpreted fractional composition of kerogen macerals.
The Lower Velkerri source rocks in all of the Beetaloo Sub-Basin wells are interpreted to represent a high geochemical risk for in-situ shale oil/gas production. The average measured TOC contents of all wells are below the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Fig. 68). None of these wells have average TOC content 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 in all wells is interpreted to be oil-prone Type II kerogen.

Thermal maturity parameters from programmed pyrolysis place most of these wells within the early oil to dry gas window on the basis of select data (no reliable $T_{\text{max}}$ data in the Shenandoah 1A well). The average $T_{\text{max}}$ value of 424°C for the Walton 2 well is below recommended minimum value of 435°C for shale oil, but all other wells are above this threshold (Fig. 68). Several wells are also above the minimum of 455°C for shale gas (Fig. 68). This amount of conversion would likely be sufficient to generate/expel minor to moderate amounts of hydrocarbons from this organic lean source facies. Transformation ratios (TR), the least constrained risk parameter, average between 79 to 99% and these values fall above the recommended minimum of 50% for shale oil and most are also above the 80% threshold for shale gas systems (Fig. 68).

In the Lower Velkerri source intervals, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is poor (avg. 1 to 15 bbl oil/acre-ft), which is a potential concern regarding risk assessment for unconventional oil (Figs. 69 & 70). Hydrocarbon yield calculations on as-received samples show estimates of average generated oil from the Lower Velkerri wells interpreted to be in the oil/condensate window at 59 to 135 bbl oil/acre-ft (Figs. 69 & 71). The Altree 2 well is interpreted to be in the condensate/wet gas window and has an estimated 135 bbl oil/acre-ft with an additional 290 Mcf/acre-
ft of secondary cracked gas based upon 32% oil cracking (Fig. 69). 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. 69). These values are higher compared to the Lower Velkerri wells due primarily to differences in organic richness (Barnett Shale oil example has average of 4.70 wt. % TOC).

For the Lower Velkerri wells interpreted to be within the dry gas window, measured in-situ oil saturation determined by programmed pyrolysis S1 yields very low (avg. 1 to 2 bbl oil/acre-ft). Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Lower Velkerri intervals in these wells at 1 to 0 bbl oil/acre-ft. and oil cracking is estimated to have been 96 to 100%, resulting in cracked gas yields of 783 to 995 Mcf/acre-ft (Figs. 69 & 72). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/a-ft (Fig. 69). Both the residual oil and cracked gas generated yields for the Barnett Shale are significantly higher compared to the Lower Velkerri in this well and are primarily due to differences in organic richness (Barnett Shale in gas window has 4.21 wt. % TOC).

![Graph showing hydrocarbon yield estimates for the Mesoproterozoic Lower Velkerri source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the oil and gas window.](image)

**Figure 69.** Hydrocarbon yield estimates for the Mesoproterozoic Lower Velkerri source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the oil and gas window.

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 Lower Velkerri source intervals in some of these wells is in the early to late oil window and hydrocarbon saturation is likely to vary from heavy and immobile to fairly light and mobile. Wells in the condensate/wet gas window would be expected have very light in-situ hydrocarbon saturation if any remained within the samples as-received for analysis. However, the presence of solid bitumen in these samples 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 Lower 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 70. The spatial distribution of the S1 Free Oil saturation for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average S1 and are reported as bbl oil/acre-ft.

Spatial distributions in the measured in-situ S1 free oil saturations, estimated generated oil yields and estimated cracked gas yields (Figs. 70 through 72) were evaluated in the context of previous trends within other geochemical parameters. As noted previously, measured in-situ S1 oil saturations are generally low in most of the Lower Velkerri wells evaluated in this study (1 to 15 bbl oil/acre-ft). Geographically, both the Altree 2 and Walton 2 wells located along the northern basin margin of the Beetaloo Sub-Basin have relatively higher S1 content (Fig. 70). The Sever 1 and Shenandoah 1A wells that are interpreted to be in
the dry gas window have essentially no S1 free oil saturation (Fig. 70). Spatial trends in the estimated generated oil yields (Fig. 72) generally follow the patterns observed in the S1 free oil saturation. The Altree 2 and Walton 2 wells have the highest estimated generated oil and the Broadmere 1 is somewhat lower, with the two dry gas wells having no estimated oil. There is high variability within these wells due to differences in geochemical parameters like thermal maturity. Also spatial trends in this parameter are further complicated because estimated oil yields in some wells (e.g. Altree 2) are reduced as a consequence of oil to gas secondary cracking. Further sampling to obtain better statistical averages within the geochemical data will be needed to potentially provide further insights into the origin of these variations.
Figure 71. The spatial distribution of the Estimated Generated Oil Yields for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average generated oil and are reported as bbl oil/acre-ft.

Spatial trends in the estimated secondary cracked gas yields (Fig. 71) closely follow thermal maturity patterns previously established for transformation ratios and Calc. R<sub>o</sub>. This is expected since the algorithm to estimate oil to gas cracking is based upon the measured % Calc. R<sub>o</sub> and/or interpreted Calc. R<sub>o</sub> values. Thus, Sever 1 and Shenandoah 1A wells which are interpreted to be in the early dry gas window have significant amounts of estimated cracked gas (oil associated gas is not factored into this determination). The Altree 2 well is interpreted to be in the condensate/wet gas window and also has a minor amount of secondary cracked gas (Fig. 71).
Figure 72. The spatial distribution of the Estimated Cracked Gas Yields for the Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average secondary cracked gas and are reported as Mcf gas/acre-ft.
LOWER VELKERRI MINERALOGY

LOWER VELKERRI INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Lower Velkerri source rocks in six (6) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Select samples from these wells were analyzed by X-ray diffraction (XRD). The purpose of this testing was to document the mineralogy of the samples in order to evaluate potential organofacies variations, to examine reservoir quality and brittleness for fracture development, and to assess possible controls on porosity and permeability.

LOWER VELKERRI MINERALOGY

XRD data taken from samples in the Lower Velkerri (Table 23; Fig. 73) shows that clays are the most abundant minerals present and total clay content averages 56%. Clay types found are dominated by illite/mica (avg. 23%), illite/smectite (avg. 16%), chlorite (avg. 13%), and kaolinite (avg. 3%). Quartz is the dominant non-clay species and its abundance averages 35%. Classification of these samples by rock type shows that most would be classified as silica-rich argillaceous mudstones, although there are a few samples of clay-rich siliceous mudstones, mixed argillaceous mudstones and quartz-dominated lithologies.

<table>
<thead>
<tr>
<th>Formation</th>
<th>Clays</th>
<th>Carbonates</th>
<th>Quartz</th>
<th>K-spar</th>
<th>Other</th>
<th>Mixed I/S*</th>
<th>TOC</th>
<th>Britteness Index</th>
</tr>
</thead>
<tbody>
<tr>
<td>Lower Velkerri</td>
<td>56</td>
<td>1</td>
<td>35</td>
<td>1</td>
<td>7</td>
<td>16</td>
<td>0.70</td>
<td>37</td>
</tr>
</tbody>
</table>

*ordered interstratified mixed-layer illite/smectite

Table 23. TOC & X-ray diffraction average data (weight %) for Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia.

The shale samples in the Lower Velkerri source intervals are clay dominated, which is a concern for potential fracture stimulation because this is often a fairly ductile mineral assemblage. However, these samples also contain abundant quartz, which is a relatively brittle mineral and conducive to fracture stimulation. Pyrite is present in minor amounts (avg. 1%) and is associated with kerogen that is also a minor component of the overall mineralogy. The minor contribution of these components is usually positive with regard to fracture stimulation in general for organic-rich shales at elevated thermal maturity.

Another potential risk factor for fracture stimulation is the abundance and type of clays within the Lower Velkerri samples. These source rock samples do contain significant amounts of clays (avg. 56%), and these clays also contain abundant ordered interstratified mixed-layer illite/smectite (avg. 16% and comprising 29% of total clays). In general, successful unconventional shale plays tend to have less than 10% total mixed-layer illite/smectite (R. Bruce, personal communication) and the Lower Velkerri samples analyzed in this study are well above this risk threshold. Thus, the abundance of clays in the Lower Velkerri samples would appear to be a negative risk factor for fracture stimulation; however, further testing to include rock-mechanics measurements is warranted to fully evaluate this parameter.
Figure 73. XRD average mineralogy for Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia. Upper diagram shows relative abundance of clays, carbonates, quartz, pyrite and others. Lower diagram shows clay speciation (percentages shown in pie are renormalized).

Mineralogy data can potentially be utilized to further assess rock mechanical properties, including brittleness. Brittleness Index (BI) values were calculated using equation (24) below. The range of BI values vary from 24–44 and average 37 (Table 23), with higher values supposedly indicating more brittle rock. The highest BI values were found in the samples with the lowest overall clay content. A sample analyzed from the Altree 2 well had the highest silica content (44%) of all Lower Velkerri samples in this study and it also had the highest BI of 44. Close examination of the data show that both carbonate and quartz have a strong influence on the brittleness calculation. In the Lower Velkerri source rocks, carbonate is generally in very low abundance and the variability in quartz and clays appears to control the Britteness Index. Recent publications have noted that measured rock mechanical properties were often found to have poor correlations with various formulas for calculating brittleness index values (Yang et al., 2013). Thus, caution should be exercised in using these data for evaluations and any BI values for previously untested source rocks like the Lower Velkerri should be calibrated against measured rock mechanical data.
Mineralogy data can also be used to compare the Lower Velkerri source rock samples against other US Shale plays. Ternary diagrams of the quartz, carbonate, and clay percentages have been constructed using the individual samples from the various Lower Velkerri wells evaluated in the current study (Fig. 74). In these diagrams, most US Shale plays plot along a continuum between the quartz and carbonate endpoints, which are also the locations of the most brittle rocks (Fig. 74). As clay percentages increase (toward the SE corner of the diagram), the brittleness decreases. As noted previously, the Lower Velkerri samples have generally high clay content (avg. 56%), which may be a risk for fracture stimulation. On the mineralogy ternary diagram (Fig. 74), the Lower Velkerri samples appear to plot along the margins of the envelope representing most US Shale samples, but they do overlap with select samples from a variety of plays (e.g. Ohio Devonian, Haynesville, Lower Huron, Devonian, Second White Specs). The relative brittleness of US Shale samples in this region of the ternary diagram tends to be lower in comparison to other samples that are either more quartz-rich or more carbonate-rich (Fig. 74). However, as noted previously, the total clay content should not be considered the only factor in risk assessment, but rather it is the abundance of mixed-layer illite/smectite clay species that is more likely to be the critical factor. In the Lower Velkerri source rocks, these mixed-layer illite/smectite clay species are also in relatively high abundance (avg. 16%). As clearly documented in the mineralogy ternary diagrams, there is considerable variability even within an individual shale play and each shale should be considered based on its own mineralogy and petrophysical attributes. Ultimately, these data need to be calibrated against laboratory measured geomechanical properties for continued improvement in stimulation and completion practices.

\[
BI = \frac{1.3(\text{Qtz}) + (\text{Kspar}) + (\text{Plag}) + 1.2(\text{Carb})}{\text{Numerator} + 2(\text{Mixed}) + 1.5(\text{Chlor} + \text{Kaol} + \text{Ill}) + (\text{Pyr}) + (\text{Apa}) + (\text{Bar})}
\]  

(24)

Figure 74. XRD mineralogy ternary diagram for Lower Velkerri source rock samples in the Beetaloo Sub-Basin, Australia (left) compared to published data for US Shale plays (right) (Rickman et al., 2008). Sizes of symbols represent the relative brittleness determined by XRD within the published data set, but this is not illustrated in the data from the current study.
CORMORAN PETROLEUM GEOCHEMISTRY

CORCORAN INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Corcoran Formation source rocks in three (3) wells located in the Beetaloo Sub-Basin, Northern Territory, Australia. Samples from these wells were analyzed by a variety of geochemical techniques, including total organic carbon (TOC, LECO®) and programmed pyrolysis (SRA). All data evaluated from the Corcoran Formation in these wells was client supplied published geochemical data. The select results of these analyses are documented in the individual well reports and are summarized in Table 24. Formation specific integrated geochemical interpretations are considered within the context of the current document. However, only one well (Sever 1) had sufficient TOC values to be considered a potential viable source rock and this well is the only one for which hydrocarbon yield calculations were performed. Due to the limited geochemical data set available, no maps illustrating spatial trends other than TOC were incorporated into this report.

<table>
<thead>
<tr>
<th>Well Name</th>
<th>Formation</th>
<th>Main Product</th>
<th>Thermal Maturity</th>
<th>Source Rock Richness</th>
<th>Organic Matter Type</th>
<th>Shale Gas Risk</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sever 1</td>
<td>Corcoran</td>
<td>Estimated Original → Good (1.03% TOC)</td>
<td>Oil-prone Type II</td>
<td>High</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Measured Currently → Dry Gas</td>
<td>Dry Gas Window</td>
<td>Fair (0.58% TOC)</td>
<td>Inert Type IV</td>
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<td></td>
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</table>

Table 24. Corcoran Geochemical Summary

CORCORAN GENERATIVE POTENTIAL

The Corcoran Formation source rock samples analyzed from the Beetaloo Sub-Basin have dominantly poor generative potential (Table 24; Fig. 75). Organic richness varies from 0.00 wt.% (poor) to as high as 1.19 wt.% (good) TOC, with an average value of 0.10 wt. % TOC (poor). The histogram plot of TOC distributions (Fig. 75) illustrate that the dominant population is within the 0 to 0.5 wt. % range. Outside of this range there appears to be a trend of progressive and rapid decrease in frequency of samples with increasing TOC content. Only 1% of these samples (as represented by a single sample) have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks and none of the samples have TOC content above the minimum requirement of 2 wt.% for economic petroleum source rocks, which is a significant risk factor for unconventional resource development.
Figure 75. Histogram plot of Total Organic Carbon (TOC) distributions for Corcoran source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.%, while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.

The distribution of elevated Corcoran TOC values is noted to be restricted predominantly to a single well within the Beetaloo Sub-Basin, the Sever 1. All samples with TOC values > 0.2 wt. % are found within this well. This is also illustrated on the base map showing spatial distributions of measured Corcoran TOC within the Beetaloo Sub-Basin (Fig. 76). On this map, the average TOC values are shown and the Sever 1 well clearly has higher organic richness (avg. 0.58 wt. %) in comparison to all other wells in this region. The elevated TOC content in this well may be partially a consequence of more frequent sampling and a better statistical average in comparison to other Corcoran wells, some of which contained only a few samples for evaluation. Geographically, the apparent trend in organic richness on the basis of this limited data set shows more elevated TOC in the far NW region of the study area (Fig. 76). Further well sampling within the Beetaloo Sub-Basin and integration of the geochemical data with regional geology will be needed to potentially provide additional insights into the origin of these TOC variations.
Pyrolysis S2 yields in the Corcoran Formation samples vary from 0.00–0.16 mg HC/g rock (Fig. 77) and within the Sever 1 well they average 0.03 mg HC/g rock or 1 bbl/a-ft. These indicate a very poor amount of remaining primary hydrocarbon generation potential (likely only gas), which is consistent marginal organic richness and high levels of primary thermal conversion in the dry gas window. All Corcoran samples have generally low TOC and very low S2 values and these samples plot along the x-axis of the main cross-plot of TOC versus S2 (Fig. 77). This is consistent with inert carbonaceous residue typically associated with Type IV kerogen (see Langford and Blanc-Valleron, 1990). Most of these samples extend into the box associated with organic lean source rocks (Fig. 77). These data represent samples that are highly converted due to their thermal maturity (dry gas). All of these samples have been assumed to contain original oil-prone Type II kerogen for purposes of hydrocarbon yield estimations in this study,

Figure 76. The spatial distribution of organic richness for the Corcoran source rock samples in the Beetaloo Sub-Basin, Australia. Mapped values are for average LECO TOC content and are reported as wt.%. 
however, they could represent oxidized organic that was initially a mixture of Type II/IV kerogen. Further organic petrology work will be necessary to evaluate these samples in greater detail.

![Graph showing Total Organic Carbon (TOC) versus Remaining Hydrocarbon Generation Potential (S2) for the Corcoran source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.]

**CORCORAN KEROGEN TYPE AND EXPPELLED PRODUCT**

The Corcoran Formation is reported to contain relatively fine-grained siliciclastic sediments that were deposited in a dominantly marine shelf setting and sub-wave-base organic facies may therefore have source potential (Munson, 2014). These depositional conditions and the geologic age of these samples would be conducive to preservation of source rocks with a dominant cyanobacterial oil-prone kerogen (Type I and Type II) along with possible significant amounts of oxidized Type IV organic material.

The Corcoran source rock samples analyzed in this study area appear to be characterized by relatively low TOC content. These samples are also distinctive in having low hydrogen index (HI) values < 10 mg
HC/g TOC (Fig. 78) and are interpreted to be within the dry gas window. Some of these samples also have high oxygen index (OI) values > 20 mg CO$_2$/g TOC (Fig. 78). These samples likely represent lower quality preserved Type II organic matter that has been partially oxidized prior to preservation. However, the elevated thermal maturity precludes a definitive kerogen classification on the basis of this data.

Measured present day HI values in the Corcoran samples range from 3 to 9 mg HC/g TOC (Fig. 78) and average 3 mg HC/g TOC in the Sever 1 well. On a plot of HI versus Oxygen Index (OI) (pseudo van Krevelen diagram), all samples appear to plot along the x-axis and appear to follow the maturation pathway for Type IV kerogens (Fig. 78). Since these Corcoran source rocks are considered post mature with regard to oil generation, the kerogen HI values have been reduced significantly as a consequence of thermal maturity; thus, they indicate primarily inert Type IV kerogen quality at present day (Fig. 78).

Measured OI values in Corcoran samples vary widely from 4 to 420 mg CO$_2$/g TOC and the samples appear to be split into two clusters with relatively high and low OI values (Fig. 78) based upon the limited oxidized inert organic matter. Organic petrology kerogen examination of additional samples to examine the possible presence of oxidized material could help confirm such a depositional interpretation. Sampling available. These samples likely to represent a mixture of Type II marine algal and Type IV Examination of three samples from the Corcoran Formation in the Beetaloo Sub-Basin shows that the dominant kerogen present is oil-prone Type II material which is composed of variable amounts of amorphous organic matter in lens/layer, inert and diffuse forms. These samples represent relatively elevated TOC (all > 1.5 wt. %) and representative examples from less organic rich horizons may need to be evaluated to properly assess the presence of oxidized inertinite organic material in the Beetaloo Sub-Basin samples.
Figure 78. Hydrogen Index versus Oxygen Index (pseudo-van Krevelen plot) for the Corcoran source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

COCORAN THERMAL MATURITY

The organic-matter in the Corcoran source rocks evaluated in the current investigation appears to have entered into the dry gas generation window for the Sever 1 well and may also be within the gas window for the other well in which T_max data is available (Broadmere 1).

Programmed pyrolysis T_max values from samples in which T_max was considered reliable vary from 454˚ to 495˚C (Figs. 79 & 80). Measured T_max between 450˚ and 470˚C typically indicates condensate/wet gas window for Type II kerogen, while values > 470˚C are generally associated with post-mature source rocks in the dry gas window. Using the formula published by Jarvie et al. (2007) for Type II kerogen (Calculated Ro = (0.0180)(T_max) – 7.16), the measured T_max values between 454˚C and 495˚C are equivalent to Calc. %R_o values of 1.01% and 1.75%. No reliable T_max values were found in the Corcoran samples and interpretation of thermal maturity is based upon extrapolation of data from the overlying source rock intervals, which would suggest an average R_o value of ~3.2% within the late dry gas window.
Figure 79. Hydrogen Index versus $T_{\text{max}}$ for the Corcoran source rock samples in the Beetaloo Sub-Basin, Australia. Plot symbology defined in Fig. 4.

The $T_{\text{max}}$ values shown on Fig. 79 illustrate that most of the Broadmere 1 Corcoran samples are within the late oil to dry gas windows and plot within maturity envelopes that are associated with Type II/III and Type IV kerogen. The use of $T_{\text{max}}$ values for thermal maturity assessment should be undertaken with caution when $S_2$ values are very low (generally < 0.2 mg HC/g rock) and all of the Corcoran samples from the Beetaloo Sub-Basin have such low $S_2$ values.

Production Index (PI) values in these Corcoran source rock samples vary from 0.11 to 1.00 (Fig. 80) and average 0.79 for Corcoran source rocks in the Sever 1 wells. These dispersed and sometimes very elevated PI values are not considered reliable for maturity assessment and are more a consequence of data scatter due to very low $S_1$ and $S_2$ values.
The S1 values in the Corcoran source rock samples in the Sever 1 well average only 0.07 mg HC/g rock (1 bbil oil/acre-ft). The S1 values imply poor in-situ hydrocarbon saturation and are consistent with a dry gas window thermal maturity.

Estimated kerogen transformation ratios in the Corcoran samples based upon interpreted original and measured present HI average 100% in the Sever 1 well. These transformation ratios were calculated using the limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type II kerogen. This average transformation ratio is well above the recommended minimum threshold of 50% for shale oil systems and also above the recommended minimum of 80% for thermogenic shale gas systems. This is consistent with the interpreted dry gas thermal maturity in the Sever 1 well.
**CORCORAN ORIGINAL GENERATIVE POTENTIAL AND HYDROCARBON YIELD CALCULATIONS**

Petroleum generative capacity depends on the original quantity of organic matter (TOC<sub>o</sub>) and the original type of organic matter (HI<sub>o</sub>) (Peters et al., 2005, p. 97). The petroleum generation process has likely decreased the remaining generative potential as measured by TOC<sub>pd</sub> and HI<sub>pd</sub> in the Corcoran 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<sub>o</sub> values can be computed from visual kerogen assessments and assigned kerogen-type HI<sub>o</sub> average values using the following equation (Jarvie et al., 2007):

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

This equation requires the input of maceral percentages from visual kerogen assessment of a source rock. For the present study, only limited kerogen data were available. Where available, these kerogen data sets were used. In the absence of other measured kerogen data original kerogen type were interpreted in the context of measured present day TOC, HI and OI values to arrive at an appropriate kerogen mix for each sample examined in this investigation. All samples were modeled using appropriate kerogen mix to maintain an appropriate transformation ratio consistent with the interpreted thermal maturity. The average maceral percentage in the various wells evaluated in the current study are shown in Table 25, along with the resultant average original HI<sub>o</sub> values calculated using equation (25) 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).

<table>
<thead>
<tr>
<th>Well</th>
<th>%Type I 750 HI&lt;sub&gt;o&lt;/sub&gt;</th>
<th>%Type II 450 HI&lt;sub&gt;o&lt;/sub&gt;</th>
<th>%Type III 125 HI&lt;sub&gt;o&lt;/sub&gt;</th>
<th>%Type IV 50 HI&lt;sub&gt;o&lt;/sub&gt;</th>
<th>HI&lt;sub&gt;o&lt;/sub&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sever 1</td>
<td>0</td>
<td>100</td>
<td>0</td>
<td>0</td>
<td>450</td>
</tr>
</tbody>
</table>

Table 25. Average Kerogen Estimations for Corcoran source rock samples in the Beetaloo Sub-Basin, Australia.

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):

\[
TR_{III} = 1 - \frac{HI_{pd} \left[ 1200 - HI_{o} (1 - PI_{o}) \right]}{HI_{o} \left[ 1200 - HI_{pd} (1 - PI_{pd}) \right]}
\]

HI<sub>pd</sub> and PI<sub>pd</sub> are the measured HI and PI values for the various source rock samples in these wells. The average HI<sub>pd</sub> and PI<sub>pd</sub> for the formations evaluated in the current study are shown in Table 26. HI<sub>o</sub> and PI<sub>o</sub> 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<sub>o</sub> values of 450 mg HC/g TOC (Table 25). We assume a PI<sub>o</sub> of 0.02 (see Peters et al., 2005). Using these values in equation 26, the extent of fractional conversion of HI<sub>o</sub> to petroleum is 1.00 (Table 26), i.e., on average an estimated 100% of the petroleum generation process has been completed.

The original TOC<sub>o</sub> in the source rocks before burial and thermal maturation is constrained by mass balance considerations as follows (corrected from Jarvie et al., 2007):
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 CR 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 \( TR HI \times CR \). The kerogen mix for each individual sample was used in this calculation.

Using equation 27, the estimated original TOCo for the Corcoran source rock samples before petroleum generation was calculated (Table 26).

The original generation potential \( S2o \) can be calculated using the following equation:

\[
S2o = \frac{HLo \times TOCo}{100}
\]  

(28)

For the Corcoran source rocks examined in the various wells in this study, the average \( S2o \) values are calculated as mg HC/g rock and also converted to bbl/acre-ft units (multiply \( S2o \) by 21.89 to calculate barrels/acre-ft, Jarvie and Tobey, 1999) (Table 26).

Knowing the measured remaining generation potential \( S2 \) from programmed pyrolysis and using the calculated original generation potential \( S2o \) enables a determination of the amounts of hydrocarbons generated. A VRo 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).

\[
\text{Original (} S2o \text{)} - \text{Remaining (} S2 \text{)} = \text{Generated HCs}
\]  

(29)

Using this methodology for the Corcoran source rock samples analyzed in the current study, the estimated generated oil and cracked gas yields are given in Table 26.

<table>
<thead>
<tr>
<th>Well</th>
<th>TOCpd bbl/a-ft</th>
<th>Hi pd</th>
<th>S2pd bbl/a-ft</th>
<th>Hi o</th>
<th>TR</th>
<th>TOCo bbl/a-ft</th>
<th>( S2o ) Free Oil bbl/a-ft</th>
<th>( S1 ) Oil bbl/a-ft</th>
<th>Est. Cracked Gas Mcf/a-ft</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sever 1</td>
<td>0.75</td>
<td>3</td>
<td>1</td>
<td>450</td>
<td>1.00</td>
<td>1.03</td>
<td>101</td>
<td>1</td>
<td>605</td>
</tr>
</tbody>
</table>

Table 26. Hydrocarbon Yields average data for Corcoran source rock samples in the Beetaloo Sub-Basin, Australia.

The Corcoran source rock samples in the Sever 1 well examined in the current study are interpreted to be in the dry gas window and hydrocarbon yield calculations suggest only minor amounts of generation have occurred (exclusively secondary cracked gas). From an exploration risk perspective, this is generally unfavorable. However, it is useful to relate these hydrocarbon yields to other productive unconventional US Shale plays (Table 27). In doing so, the potential critical value is not necessarily the generated oil and gas yields, but also the original \( (S2o) \) 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 Corcoran source rock samples, original generation potential \( (S2o) \) averages only 101 bbl oil/acre-ft (Table 26). This Corcoran value falls far below the other formations on the list of unconventional US Shale plays shown below, which is why this interval is considered a high risk for unconventional resource development.
Table 27. Geochemical Properties and Generation Potential for US Shale plays. Corcoran wells are color coded for possible shale oil (green) and shale gas (red) prospect type.

**CORCORAN UNCONVENTIONAL OIL & GAS RISK ASSESSMENT**

The Mesoproterozoic Corcoran source rocks in the Beetaloo Sub-Basin have been evaluated for unconventional oil and gas potential. These source rock samples are presented in a modified geochemical risk assessment diagram (Fig. 81) based upon published results from the Barnett Shale in the Fort Worth Basin. The data illustrated in the star plot represents average values for two of four of the diagnostic ratios (no measured Ro data available and T_max values were considered unreliable). Also shown are the recommended areas for unconventional oil (in green) and gas (in red). Data that lies above the minimum threshold and within the shaded areas indicates samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below the minimum threshold and fall in the immature region (in grey) indicate a high risk for commercial shale oil or gas production. Transformation Ratios (TR) were calculated based upon HI_o estimates using measured and interpreted fractional composition of kerogen macerals.
The Corcoran source rocks in the Sever 1 well within the Beetaloo Sub-Basin are interpreted to represent a high geochemical risk for in-situ shale gas production. The average measured TOC content of 0.58 wt. % is well below the generally accepted minimum value of 1% TOC to be considered an effective source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Fig. 81). It is also well 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 in this interval is interpreted to be oil-prone Type II kerogen.

No reliable $T_{\text{max}}$ values were found in the Corcoran samples in the Sever 1 well and interpretation of thermal maturity is based upon extrapolation of data from the overlying source rock intervals, which would suggest an average $R_0$ value of ~3.2% within the late dry gas window. This value was arbitrarily applied to the Corcoran interval for purposes of hydrocarbon yield estimations. Transformation ratios (TR), the least constrained risk parameter, average 100% for Corcoran samples in the Sever 1 well and fall above the recommended minimum of 50% for shale oil and above the 80% threshold for shale gas systems (Fig. 81).

In the Corcoran source interval in the Sever 1 well, measured in-situ oil saturation determined by programmed pyrolysis S1 yields is very poor (avg. 1 bbl oil/acre-ft), which is expected for these samples that are interpreted to be in the dry gas window (Fig. 82). Hydrocarbon yield calculations on the as-received sample shows estimates of average generated oil from the Corcoran intervals in this well at 0 bbl oil/acre-ft. and oil cracking is estimated to have been 100%, resulting in a cracked gas yield of 605 Mcf/acre-ft (Fig. 82). As a comparison, a representative example from the core area of Barnett Shale gas production in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured in-situ oil saturation of 7 bbl/a-ft (Fig. 82). Both the
oil and gas generated yields for the Barnett Shale are much higher compared to the Corcoran and are primarily due to differences in organic richness (Barnett Shale in gas window has avg. 4.21 wt. % TOC).

Figure 82. Hydrocarbon yield estimates for the Mesoproterozoic Corcoran source rock samples in the Beetaloo Sub-Basin compared to Barnett Shale in the gas window.
MAINORU PETROLEUM GEOCHEMISTRY

MAINORU INTRODUCTORY NOTE

A geochemical investigation has been conducted to assess hydrocarbon prospectivity of the Mainoru Formation source rocks in one (1) well located in the Beetaloo Sub-Basin, Northern Territory, Australia. Client supplied published geochemical data from the Broadmere 1 well was the only available data to be incorporated into the interpretive evaluation. Due to low organic richness, no hydrocarbon yield calculations were performed on samples from this formation in the Beetaloo Sub-basin nor are the published programmed pyrolysis results discussed in detail. The results of published TOC analyses are documented in this report and are discussed below.

MAINORU GENERATIVE POTENTIAL

The Mainoru Formation source rock samples analyzed from the Beetaloo Sub-Basin have dominantly poor generative potential (Fig. 83). Organic richness varies from 0.12 wt.% (poor) to as high as 0.86 wt.% (fair) TOC, with an average value of 0.21 wt. % TOC (poor). The histogram plot of TOC distributions (Fig. 83) illustrate that the dominant population is within the 0 to 0.5 wt. % range. Outside of this range there appears to be a general trend of progressive rapid decrease in frequency of samples with increasing TOC content. None of these samples have TOC contents above the minimum requirement of 1 wt.% for effective petroleum source rocks, nor are they above the minimum requirement of 2 wt.% for economic petroleum source rocks. This is a significant risk factor for unconventional resource development and these source rocks would be considered high risk based upon the limited sampling and analyses completed to date.
Figure 83. Histogram plot of Total Organic Carbon (TOC) distributions for Mainoru Formation source rocks in the Beetaloo Sub-Basin. Data is organized into 0.5 wt.% TOC bins, thus the first bar on the left side of the histogram represents all samples with TOC between 0.0–0.5 wt.%, while the second bar represents all samples with TOC between 0.5–1.0 wt.% and so on. Color codes correspond to TOC designations shown in Table 1.
REFERENCES CITED


Jacob, H., 1985, Disperse solid bitumens as an indicator for migration and maturity in prospecting for oil and gas, Erdöl und Kohle-Erdgas-Petrochemie, v. 38, no. 8, p. 365.


