

NTGS RECORD 2017-002

Unconventional petroleum resources of the Roper Group, McArthur Basin



D Revie

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BIBLIOGRAPHIC REFERENCE: Revie D, 2017. Unconventional petroleum resources of the Roper Group, McArthur Basin. *Northern Territory Geological Survey, Record 2017-002*.

(Record / Northern Territory Geological Survey ISSN 1443-1149)

Bibliography

ISBN: 978-0-7245-7313-4 (PDF)

Keywords: Northern Territory, McArthur Basin, Beetaloo Sub-basin, Gorrie sub-basin, OT Downs sub-basin, Broadmere Sub-basin, Mesoproterozoic, Roper Group, Kyalla Formation, Velkerri Formation, unconventional petroleum, shale gas, shale oil, petroleum geology, petroleum geochemistry, petroleum exploration, petroleum potential, petroleum resources.

EDITOR: GC MacDonald and TJ Munson. Publication layout and figure preparation: MH Fuller, KJ Johnston and TJ Munson.

Cover photo: Stirling Creek Dolostone reflected in the Stirling Creek, LIMBUNYA 250K mapsheet. Photo by Daniel Revie, 2016.

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SUMMARY

The Proterozoic McArthur Basin of the Northern Territory hosts significant potential for self-sourced continuous petroleum systems (unconventional shale oil and gas). The Mesoproterozoic Roper Group and Palaeoproterozoic McArthur Group have been subjected to low-level exploration for oil and gas for several decades; oil and gas shows have been recorded from formations in both groups. NTGS has been investigating this potential for petroleum resources through a review and compilation of historical and open file literature and data, together with sampling and extensive analyses of available drill core. This work forms the basis for the petroleum resource assessment of key target formations of the Roper Group described herein.

Most interest from explorers has been on the Roper Group, particularly within the Beetaloo, Gorrie, OT Downs and Broadmere sub-basins; these depocentres, together with the adjacent 'shelf region' to the north and northeast, are the main focus of this resource assessment. The main intervals of significance for petroleum accumulations are the lower Kyalla Formation and middle Velkerri Formation lithofacies. The geochemical and geomechanical characteristics of these shales compare favourably with producing shale plays from the USA. The Kyalla Formation has an average total organic carbon (TOC) content of 1.08 wt%; the middle Velkerri Formation has an average of 3.76 wt%. These TOC values place the Kyalla and Velkerri formations in the 'good' and 'excellent' range respectively. Generative potential of the Kyalla Formation ranges between poor to excellent (0.01–22.79; average 2.20 mg HC/g rock). The middle Velkerri Formation has greater generative potential than the Kyalla Formation, with a range between poor to excellent (0 – 70.66; average 7.31 mg HC/g rock).

The Velkerri Formation is comprised of three lithofacies (upper, middle and lower), with the middle being the most prospective for petroleum production potential. Three parasequences through the middle Velkerri Formation, informally named the A, B and C shales, are organic-rich facies with 'very-good' to 'excellent' geochemical parameters and mineralogical composition. The middle Velkerri Formation was originally composed of Type II marine oil-prone kerogens which have thermally matured and undergone petroleum generation and expulsion. The middle Velkerri Formation is within the dry-gas window in several wells that intersect the formation at greater depths within the deeper sub-basin regions of the McArthur Basin. Although data taken from both the Kyalla and Velkerri formations indicate the presence of oil-mature and gas-mature rock, thermal maturity may be a limiting factor in shallower parts of the basin. Retention of overpressure of generated gas within the shales is also at higher risk in the shallower parts of the basin where thermal conversion of oil to gas is limited. Gamma ray and resistivity logs through the middle Velkerri Formation show excursions through the A, B and C organofacies coinciding with distinct geochemical enrichments. The B shale has been the primary target of recent exploration, and the first public announcement of a shale gas discovery was made from intersection and stimulation of the B shale.

A range of thermal maturity has been mapped within the Beetaloo Sub-basin from immature through to the dry-gas window. The dry-gas window extends through the central region of the sub-basin and corresponds to the deepest and thickest intersections analysed. This central region is also the most prospective for oil and gas generation. The Kyalla Formation has been within the early to late oil window across all the sub-basins. The middle Velkerri Formation shows increasing thermal maturity from the oil-mature northern flanks through to the overmature (dry gas mature) southern regions of the Beetaloo Sub-basin. The OT Downs Sub-basin is immature for oil generation in the east, toward the well Broadmere 1, and increases in thermal maturity through to the dry gas window to the west, where maturity is contiguous with that of the Beetaloo Sub-basin.

Comparative volumetric assessment figures for the GIP and OIP of the lower Kyalla and middle Velkerri formations are presented and indicate a wide range of values ranging between P90 to P10 values of 414 – 1164 MMbbl oil in the Kyalla Formation, and 118 – 293 TCF gas in the middle Velkerri Formation.

The Kyalla and Velkerri formations compare favourably with the Barnett Shale in the Fort Worth Basin and the Woodford Shale in the Delaware Basin, with lower average organic content and low thermal maturity being problematic characteristics for the Kyalla Formation.

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INTRODUCTION

The informally named greater McArthur Basin, which includes Palaeo- to Mesoproterozoic successions of the McArthur and Birrindudu basins and Tomkinson Province (**Figure 1**), is the largest sedimentary basin in the Northern Territory that is prospective for unconventional petroleum resources. The basin is vastly underexplored, with only 56 petroleum wells drilled to date. Drilling is mostly localised to the Beetaloo Sub-basin region on the southwestern edge of the McArthur Basin. Exploration in the past five years has extended deeper into this sub-basin, with shale gas resources being discovered within the highly prospective middle Velkerri Formation.

For the purposes of this report, the McArthur Basin is divided into two regions. The first, referred to herein as the shelf region, encompasses the Walton-High, Maiwok Sub-basin, Saint Vidgeon Sub-basin and areas adjacent to the Lagoon Creek Fault Zone. The second, referred to as the Beetaloo Sub-basin region, encompasses the

Gorrie, Beetaloo, OT Downs and Broadmere sub-basins (**Figure 2**).

This report examines the potential shale gas intervals within the Mesoproterozoic Roper Group succession in order to assess their prospectivity. Two of the shales have been identified as highly prospective, the Kyalla and Velkerri formations. These shales were classified according a series of parameters: total organic carbon content for the initial indication of source rock potential; hydrocarbon generation and generative potential (using pyrolysis); maceral reflectance class (R_o , indicating thermal maturity); porosity and permeability; shale thickness; bulk and clay mineral content (using X-ray diffraction, indicating producibility); petroleum generation onset temperatures (using kerogen kinetics); key elemental ratios (for kerogen typing and thermal maturation); and mechanical rock properties (indicating producibility).

MCARTHUR BASIN

The Palaeo- to Mesoproterozoic McArthur Basin is exposed over an area of about 180 000 km² in the northeastern NT. It unconformably overlies Palaeoproterozoic metamorphosed and deformed rocks of the Pine Creek Orogen to the west, Murphy Province to the south, and Arnhem Province to the northeast (**Figure 1**).

The stratigraphic successions of the McArthur Basin have been subdivided into five basin-wide, non-genetic depositional packages, and these have been further divided into stratigraphic groups (**Table 1**). The depositional packages are disconformity or unconformity bounded and each is characterised by similarities in age, stratigraphic position, lithofacies composition, style and type of volcanism, and basin-fill geometry (Ahmad *et al* 2013).

This report focuses on the Roper Group succession of the Mesoproterozoic Wilton package. The Roper Group comprises a regionally extensive, upward-coarsening cyclic succession of mainly marine mudrocks alternating with sandstones, with minor lithologies of pedogenic sedimentary breccia, fluvial sandstone, micritic and intraclastic limestone, and ooidal ironstone (Ahmad *et al* 2013, Munson 2016). It unconformably overlies carbonate and siliciclastic rocks of the Mount Rigg and Nathan groups (Favenc package) and is unconformably overlain by ungrouped Neoproterozoic siliciclastic rocks. The formations and members of the group are listed and summarised in **Table 2**.

The Roper Group is further divided into the Maiwok and Collara Subgroups. The upper formations of the Roper Group are assigned to the Maiwok Subgroup, and the lower formations are assigned to the Collara Subgroup. The Collara Subgroup is characterised by a high proportion of shoreline–inner shelf sandstone relative to the Maiwok Subgroup, which is mudrock dominated (Ahmad *et al* 2013).

REGIONAL CORRELATIONS OF ROPER GROUP

Rocks of equivalent Mesoproterozoic age of the Roper Group are present in the Birrindudu and South Nicholson basins, and the Tomkinson Province (Tennant Region) to the west and south of the McArthur Basin (**Figure 1**). Exposures of these equivalent units are limited; their

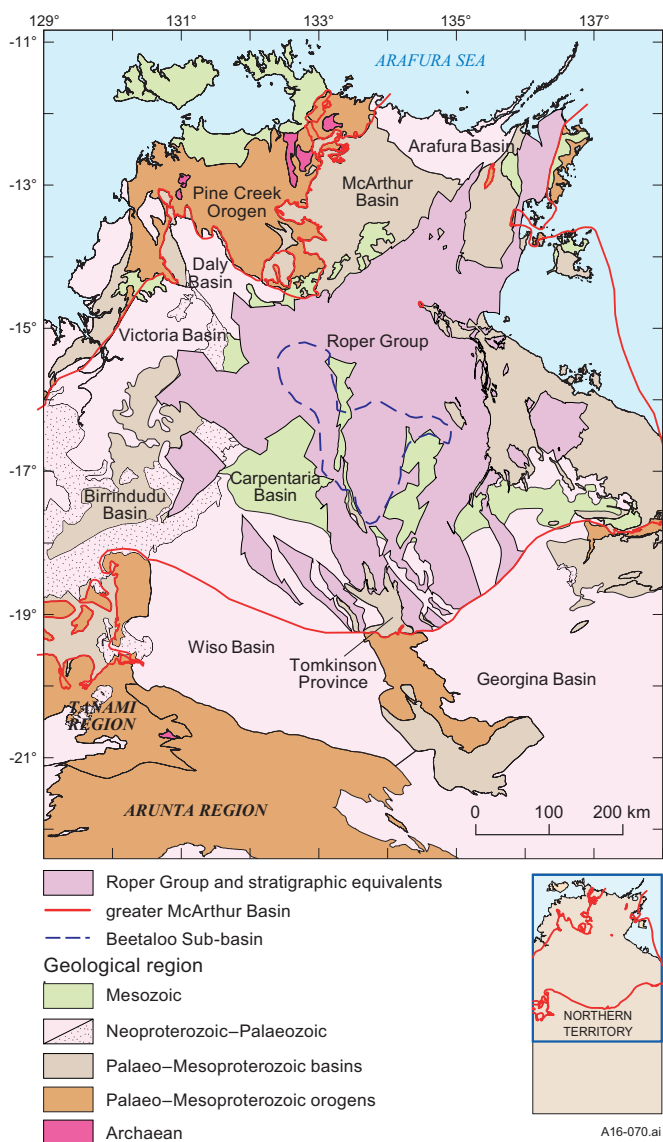


Figure 1. Location of greater McArthur Basin (red outline) and Beetaloo Sub-basin (blue outline in central greater McArthur Basin), showing geographic extent of Wilton package, interpreted from exposures and subsurface geophysical interpretation (Betts *et al* 2015).

successions extend under cover of younger basins, and are almost certainly continuous with coeval portions of the McArthur Basin (Munson 2016).

Recognised Mesoproterozoic stratigraphic equivalents of the Roper Group include the Renner Group of the Tomkinson Province, the Tijunna Group of the Birrindudu Basin, and the South Nicholson Group of the South Nicholson Basin (Figure 2, Ahmad and Scrimgeour 2006, Munson 2016). The exposed and undercover extents of the McArthur Basin and its contiguous regional correlatives are informally referred to as the greater McArthur Basin (Close 2014). Seismic data acquired in 2013 by Pangaea Resources Pty Ltd (Pangaea) has demonstrated the continuity of distinct seismic packages regionally from the Batten Fault Zone outcrop to the Birrindudu Basin (Hoffman 2015).

The regional lithostratigraphic and chronostratigraphic correlations of successions throughout the greater McArthur Basin are covered in greater detail in Munson (2016).

STRUCTURE OF ROPER GROUP

The sedimentary rocks of the Roper Group are dominantly flat-lying; preserved thicknesses range from 1500 m over most areas to greater than 3000 m in the south in the Beetaloo Sub-basin (Silverman *et al* 2007). The Wilton package overlies all older basin packages with a regional unconformity, following a major time break and shift in depocentre (Rawlings 1999). Post-Nathan Group shortening, a basin-wide inversion event in the McArthur Basin, was approximately coincident with the Isan Orogeny, the major

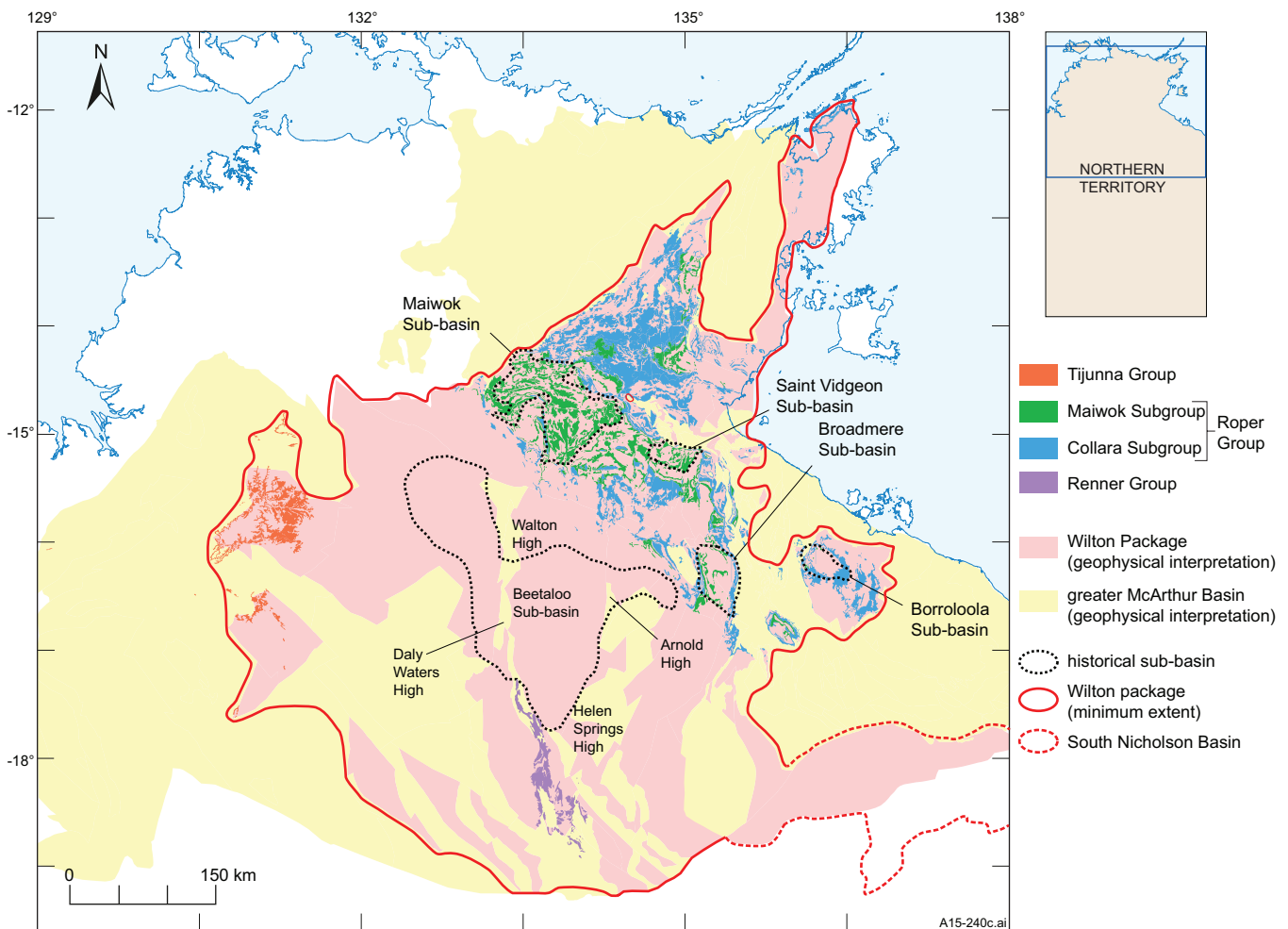


Figure 2. Mapped outcrops of Tijunna, Roper and Renner groups, locations of historical sub-basins involving Wilton package, and approximate positions of significant topographic highs in vicinity of Beetaloo Sub-basin (adapted from Munson 2016). Minimum extent of Wilton package sedimentation and greater McArthur Basin after Betts *et al* (2015).

Table 1. Chronostratigraphic and package subdivisions for McArthur Basin (adapted from Rawlings (1999) and Ahmad and Scrimgeour 2006).

ERA	DEPOSITIONAL PACKAGE (Rawlings 1999)	GROUPINGS	Chronometric subdivision (Ahmad and Scrimgeour 2006)
Mesoproterozoic	Wilton package	Roper Group	P9 (1000–1500 Ma)
	Favenc package	Mount Rigg and Nathan groups	P8 (1500–1600 Ma)
Palaeoproterozoic	Glyde package	McArthur, Vizard, Balma and Habgood groups	E7 (1600–1700 Ma)
	Goyder package	Parsons Range, upper Spencer Creek groups	E7 (1600–1700 Ma)
	Redbank package	Katherine River, Tawallah, Donydji, lower Spencer Creek groups	P6 and P5 (1700–1850 Ma)

Table 2. Stratigraphic succession of Roper Group (adapted from Abbott *et al* 2001).

ROPER GROUP			
MAIWOK SUBGROUP			
Unit, thickness (absolute age)	Lithology	Depositional environment	Stratigraphic relations
Chambers River Formation <300–2000 m	Mudrock, siltstone and sandstone in varying proportions	Storm-dominated marine shelf	Regionally concordant on Bukalorkmi Sandstone; contact not exposed; unconformably overlain by Neoproterozoic Bukalara Sandstone and Phanerozoic rocks
Bukalorkmi Sandstone 5–40 m	Thinly to medium bedded, cross-bedded fine quartz sandstone	Coastal tidal platform	Disconformable on Kyalla Formation
Kyalla Formation 30–844 m	Medium bedded to thinly interbedded and interlaminated siltstone, mudrock and lesser sandstone	Storm-dominated marine shelf	Conformable and gradational on Sherwin Formation or Moroak Sandstone
Sherwin Formation 10–100 m	Interbedded sandstone, siltstone and mudrock; interbeds/lenses of pisolitic ironstone and redbeds	Proximal shallow marine shelf to subaerial/fluvial	Conformable and gradational on Moroak Sandstone
Moroak Sandstone 2.5–420 m	Fine and medium to coarse and minor granule-rich quartz sandstone; minor conglomerate and siltstone	Coastal tidal platform	Conformable/locally disconformable on Velkerri Formation
Velkerri Formation <50–1483 m (1361 ± 21 Ma, 1417 ± 29 Ma)	Interlaminated and thinly interbedded grey and black mudrock and siltstone; minor fine glauconitic sandstone	Shallow to distal marine shelf	Conformable on Bessie Creek Sandstone
Bessie Creek Sandstone 10–417 m	Fine to medium, locally coarse and granule-rich quartz sandstone	Coastal tidal platform	Disconformable to conformable on Corcoran Formation
Corcoran Formation 180–225 m	Interlaminated to finely interbedded green-grey to black siltstone, mudrock and minor fine sandstone	Storm-dominated to distal marine shelf	Undivided Corcoran Formation conformable and gradational on Munyi Member
<i>Munyi Member</i> 13–23 m	Red to brown ferruginous sandstone, siltstone, mudstone, conglomerate and pisolitic ironstone	Shallow-marine to fluvial	Corcoran Formation basal unit; disconformable to conformable on Hodgson Sandstone
COLLARA SUBGROUP			
Abner Sandstone 35–220 m	Fine to medium, less commonly coarse quartz sandstone	Coastal tidal platform	Concordant (conformable and/or disconformable) on Crawford Formation. Equivalent to Arnold–Hodgson sandstones
Hodgson Sandstone <30–266+ m	White to pink, cross-bedded, fine to coarse quartz sandstone	Coastal tidal platform	Conformable on Jalboi Formation with gradational or locally erosive contact
Jalboi Formation 117–230 m	Interbedded fine sandstone and siltstone, alternating with medium to thick beds of medium quartz sandstone	Storm-dominated marine shelf	Unconformable/disconformable on Arnold Sandstone, Crawford Formation, and Showell Member of Mainoru Formation
Arnold Sandstone 20–292+ m	White-weathering, cross-bedded, fine to coarse quartz sandstone	Coastal tidal platform	Concordant (conformable and/or disconformable) on Crawford Formation
Crawford Formation 0–235 m	Thickly bedded, red-brown fine sandstone alternating with recessive thinly interbedded fine sandstone, mudrocks and minor medium quartz sandstone	Storm-dominated marine shelf	Conformable on Showell Member of Mainoru Formation
Mainoru Formation 270–1000 m (1492 ± 4 Ma, 1493 ± 4 Ma)	Non-calcareous and calcareous mudrocks, glauconitic and micaceous sandstone, micritic and intraclastic limestone		
<i>Showell Member</i> 64–346+ m	Green-grey to green-black and black mudrocks, thinly interbedded and interlaminated very fine sandstone, minor limestone near base	Storm-dominated marine shelf	Conformable on Wooden Duck Member
<i>Wooden Duck Member</i> 56–130 m	Grey-green mudrocks interbedded with usually very fine micaceous glauconitic sandstone, rare limestone	Storm-dominated marine shelf	Conformable on Mountain Valley Limestone Member
<i>Mountain Valley Limestone Member</i> 55–88 m	Green laminated mudrocks interbedded with intraclast limestone	Shallow-marine, tidal flat	Conformable on Nullawun Member
<i>Nullawun Member</i> 42–72 m	Massive red-brown siltstone, <i>in situ</i> shale-intraclast breccia, minor claystone and sandstone	Continental fluvial floodplain; brecciated during palaeosol formation	Conformable on Wadjeli Sandstone Member, apparently disconformable on Limmen Sandstone in places
<i>Wadjeli Sandstone Member</i> 15 m	Medium to fine quartz sandstone; minor ironstone and mudrock	Coastal tidal platform, possibly some non-marine	Conformable on Gibb Member
<i>Gibb Member</i> 0–250 m	Dark grey and olive-black mudrocks, fine sandstone	Storm-dominated marine shelf	Conformable on Limmen Sandstone
Limmen Sandstone 15–130+ m	Fine to very coarse and granule-rich quartz sandstone; minor micaceous siltstone	Coastal tidal platform, possibly some fluvial	Sharp and erosive concordant contact with underlying Mantungula Formation
Mantungula Formation <100–174 m	Mudrocks, fine sandstone	Storm-dominated marine shelf, possibly continental floodplain at top	Conformable on Phelp Sandstone
Phelp Sandstone <40–75 m	Quartz sandstone, siltstone, conglomerate, breccia	Shallow marine shelf, possibly some fluvial	Overlies Nathan Group with regional unconformity

orogenic event along the eastern side of the North Australian Craton (de Vries *et al* 2008). The shortening is believed to have led to the Nathan–Roper Group depositional hiatus between 1590 and 1500 Ma (Rawlings 1999), and formed the base-Roper Group unconformity.

Between approximately 1500 and 1400 Ma, eastern proto-Australia was subjected to a period of cooling and exhumation, which has been attributed to lithospheric extension (Betts and Giles 2006). Within this period (ca 1500–1430 Ma) the Roper Group and equivalents were deposited in the McArthur, South Nicholson, Birrindudu and Kimberly basins and the Tomkinson Province. The deposition of the Roper Group was affected by south-directed thrusting in the Arunta Region, which generated episodic subsidence within the McArthur Basin (Abbott and Sweet 2000).

Episodic subsidence resulted in the formation of sub-basin depocentres such as Beetaloo, OT-Downs and Gorrie sub-basins for Roper Group sediments (**Figure 3**). The Beetaloo Sub-basin is centered about 300 km southeast of Katherine and extends over an area of about 15 000 km² (Ahmad *et al* 2013). The informally named OT Downs sub-basin is centered approximately 150 km southwest of Borroloola and extends over an area of about 2500 km²; it is an eastward extension of the Beetaloo Sub-basin to the east of the Arnold High, and contains Roper Group sedimentary rocks that thicken toward the Mallapunyah Fault Zone

(Watters *et al* 2014). The informally named Gorrie sub-basin (see Krassay *et al* 2013) is the westernmost depocentre located to the northwest of the Daly Waters High, and is broadly north-northwest–south-southeast-trending, covering an area of approximately 7500 km².

The Roper Group has undergone limited syn- and post-deposition deformation. Faults associated with the Daly Waters High were periodically reactivated over several tectonic events, disrupting the Roper Group succession in the adjacent Beetaloo Sub-basin (Connors and Krassay 2015). The last compressive phase affecting the Roper Group produced rare large-scale deformation, reactivated large inherited low-angle faults and created small isolated reverse faults, mainly branched, at the base of the Wilton package, as well as possible large-scale positive flower structures (Bruna *et al* 2015).

DEPOSITIONAL ENVIRONMENT OF ROPER GROUP

The Roper Group is a dominantly siliciclastic succession characterised by alternating mudrock-rich and cross-bedded sandstone formations that form large-scale coarsening-upward cycles. Mudrock-rich units are dominated by claystone, siltstone and minor fine-grained sandstone. Abundant evidence for periodic and regular current activity indicates deposition mostly in a shallow-marine mud-dominated shelf setting via wave-induced density flows

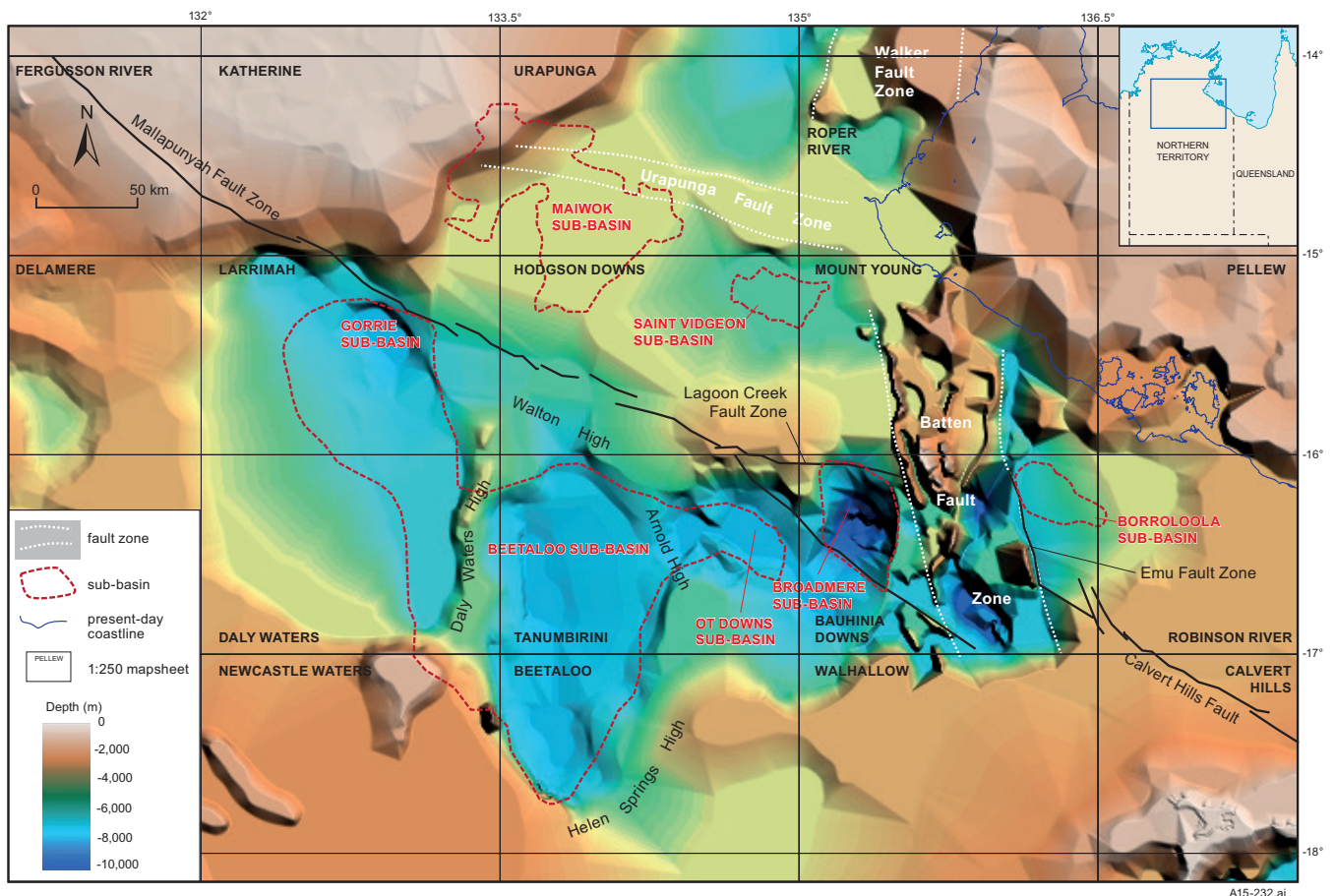


Figure 3. Approximate locations and minimum extents (dashed red lines) of Beetaloo Sub-basin and other historical sub-basins involving Roper Group, on SEEBASE™ depth-to-basement image (after Pryer and Loutit 2005); yellow–brown tones depict interpreted Proterozoic basement highs; blue–green tones are interpreted depocentres. Significant structural features are labelled. Western and eastern portions of Beetaloo Sub-basin are informally known as Gorrie and OT Downs sub-basins respectively. Maiwok, Saint Vidgeon, Borroloola and Broadmere sub-basins were originally defined on outcrop distribution of former McMinn Formation (as then mapped), as shown by dashed outlines. Positions of faults after Betts *et al* (2015). Adapted from Munson (2016).

or turbidity currents, as well as from suspension (Munson 2016). Sandstone-dominated units consist of cross-bedded, fine- to medium-grained, supermature quartz sandstone, deposited in a shoreline to shallow-marine inner shelf setting. They are occasionally capped by thin intertidal to emergent facies.

Basin setting

The Roper Group and correlative rocks of the Wilton package were deposited in a vast anorogenic intracratonic basin, floored entirely by Archaean–Palaeoproterozoic rocks of the North Australian Craton. A shoreline to shallow-marine shelf environment of deposition has been interpreted for the group, based on sedimentological studies of the successions (Peat *et al* 1978, Jackson *et al* 1986, Rawlings 1999, Abbott *et al* 2001, Munson 2016). However, a lacustrine to restricted marine/lagoon setting has also been suggested, based on geochemical, isotopic and hydrocarbon characteristics that indicate the presence of anoxic, euxinic and oxic environments at various times within the succession (Kralik 1982, Donnelly and Crick 1988, Peters *et al* 2005(a)). These alternative models can be reconciled by invoking an enclosed (silled) marine basin setting (Munson 2016), in which the depositional environment was a dominantly marine epicontinental basin, physically restricted to some extent by land or by chains of islands, but retaining some connection with the open ocean.

In general, the inflow of seawater and outflow of freshwater from rivers into enclosed marine basins (water

balance) results in fluctuating salinities that determine whether the basin is oxic or anoxic at various times. Enclosed marine basins can be favourable settings for the deposition of source rocks when the water balance is positive, that is when the outflow of freshwater exceeds the relatively smaller inflow of deeper saline water from the open sea. These conditions commonly lead to stratification of the water column and anoxic conditions. Biological productivity may also be enhanced via large discharges of river water into the coastal regions, and through the supply of biolimiting nutrients (Allen and Allen 2013). An analogous present-day enclosed marine basin with a positive water balance is the Black Sea (**Figure 4**), which contains a stratified water column and anoxic conditions; organic carbon concentrations are locally up to 15% in the deeper parts of the basin. Under conditions where the water balance is negative, that is when the inflow of seawater exceeds the outflow of freshwater, water circulation is enhanced and the depositional environment is less stratified, resulting in more oxic conditions, as in the present-day Mediterranean Sea.

Depositional environment and source rock potential

An accurate interpretation of Roper Group depositional environments is critical to the characterisation of the source rocks being targeted for unconventional hydrocarbon resources. The exploration focus for shale reservoirs has largely been on marine systems, and although lacustrine source rocks for conventional systems are geographically important, they have generally been untested for unconventional

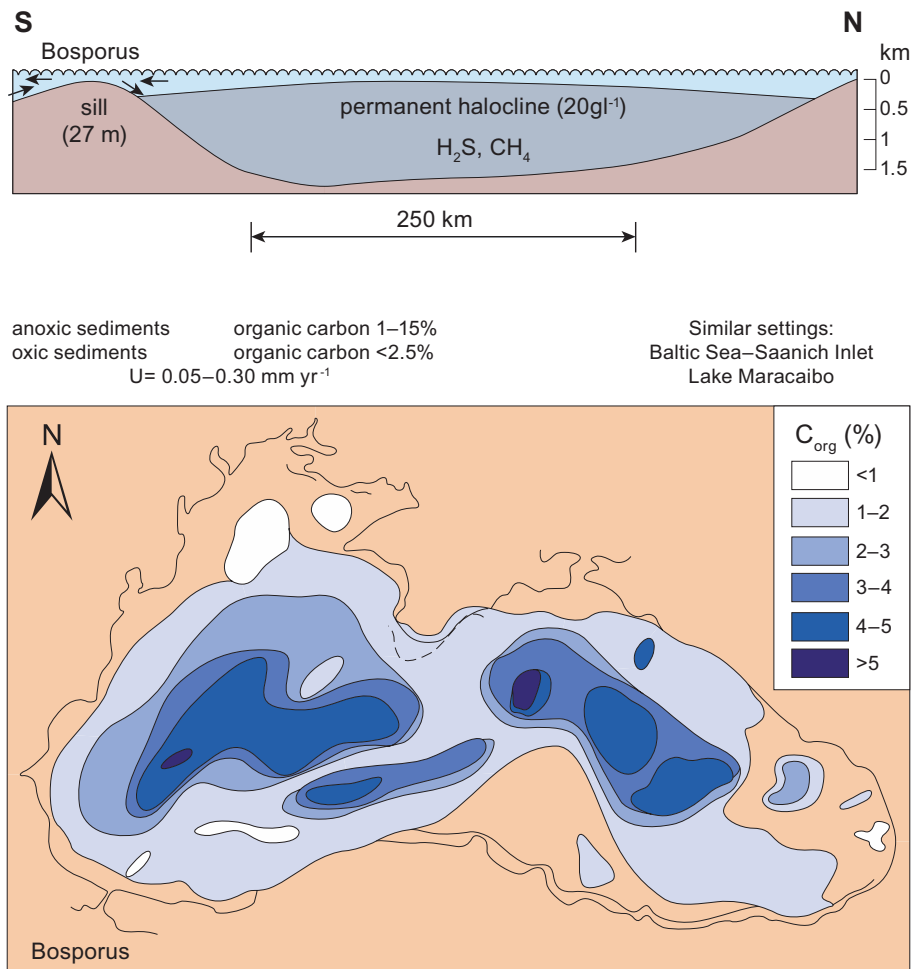
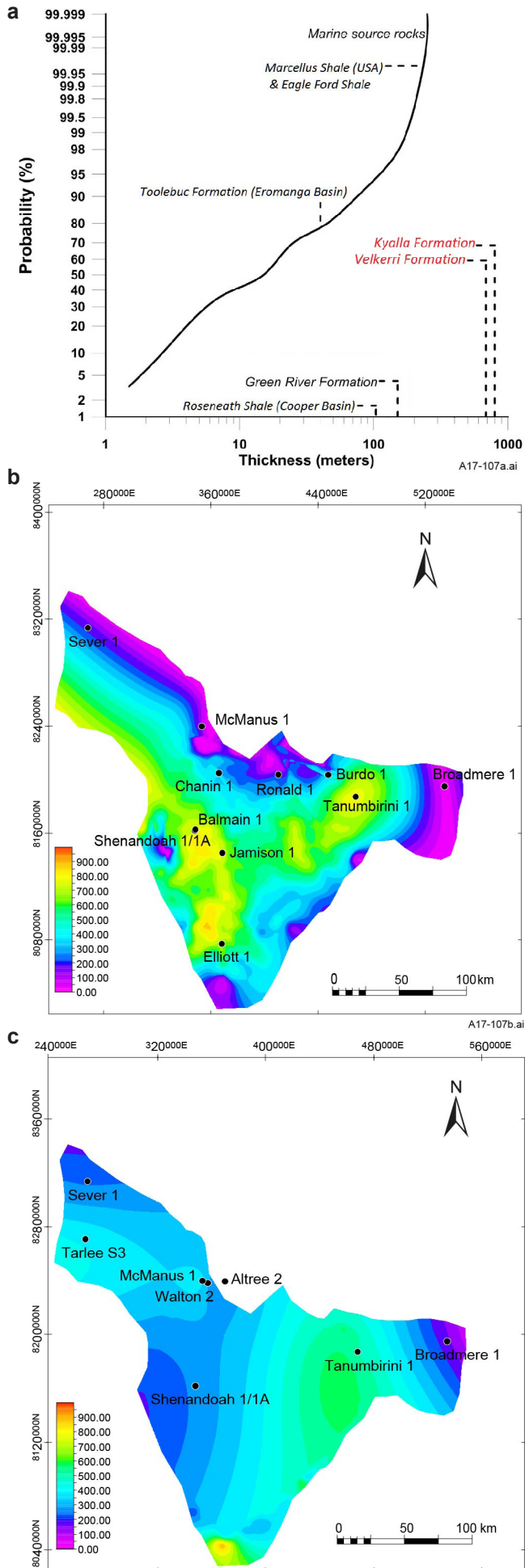


Figure 4. Total organic carbon concentrations in sediments of present-day Black Sea, a silled marine basin with a positive water balance (adapted from Allen and Allen 2013). Depositional environments of Black Sea are analogous to those of Roper Group. Organic carbon concentrations are locally up to 15% at water depths >1 km below stratified water body.



resources (Katz and Lin 2014). Type I and II kerogens are associated with restricted marine and transitional marine to lacustrine environments (Hunt 1995). The Roper Group contains a variety of facies from these depositional settings as is typical of a restricted marine basin setting (**Figure 4**), and therefore contains a mixture of organic matter types, originally dominated by Type II kerogen.

Mudrock-rich intervals of the Roper Group range through black, grey, grey-green, olive-green and brown in colour, and commonly consist of interlaminated and interbedded claystone, siltstone and lesser fine-grained sandstone, with occasional calcareous interbeds (Peat *et al* 1978, Abbott *et al* 2001). The mudrocks are characterised by alternating organic-rich black shale and organic-lean, typically coarser grained shale intervals; this is interpreted as indicating deposition under water conditions that fluctuated between oxic and anoxic/euxinic, based on Rb-Sr isotope studies (Kralik 1982), carbon-sulfur (C/S) and S isotope geochemical studies (Donnelly and Crick 1988, Lambert and Donnelly 1992), and sedimentological characteristics, including the presence of abundant syneresis cracks throughout the succession (Munson 2016). The base of the middle Velkerri Formation has a unique thin carbonate marker bed that has been noted in every well in the Beetaloo Sub-basin that intersects this interval. The carbonate-rich layer has been attributed to a possible hydrocarbon expulsion event (Hoffman 2015), and is a useful marker bed for determination of the stratigraphic position within the Velkerri Formation; for example, the Shenandoah 1/1A well has not passed through this marker horizon, indicating that the well has not penetrated the entire depth of the middle Velkerri Formation.

The thickness of Roper Group mudrocks is greatest in the depocentres of the Beetaloo Sub-basin, the Gorrie sub-basin and the OT Downs sub-basin, where the Velkerri Formation has been intersected to about 750 m (753 m in Sever 1) and the Kyalla Formation to greater than 800 m (843 m in Shenandoah 1/1A). Thick endowments of these formations improve the unconventional resource potential through retention of a higher percentage of generated hydrocarbons than their thinner counterparts. Globally, net source rock thicknesses are typically less than 100 m and are dominated by marine petroleum systems (Sluijk and Nederlof 1984, **Figure 5a**). Isopach thickness maps of the Kyalla Formation (**Figure 5b**) and the middle Velkerri Formation (**Figure 5c**) indicate variation of thickness through the depocentres of the Gorrie, Beetaloo, OT Downs and Broadmere sub-basins. The thickest sections of each formation correlate with the regions of greatest depth of the Proterozoic basement (**Figure 3**).

The delivery of coarse siliciclastic material into the mud-dominated systems of restricted and transitional marine environments results from a number of mechanisms. For the

Figure 5. (a) Comparison of source rock thicknesses of selected formations compared with global net marine source rock thicknesses (black trend line, after Katz and Lin 2014), which are typically less than 100 m (Sluijk and Nederlof 1984). Net thicknesses of Kyalla and Velkerri formations exceed those of 99% of net global marine source rocks. Note logarithmic scales. **(b-c)** Isopach thickness maps of areas used for resource assessment for **(b)** Kyalla Formation and **(c)** middle Velkerri Formation (Weatherford 2017).

Roper Group, sandstone-dominated intervals that alternate with mudrock-dominated intervals were most likely emplaced via seaward progradation of shoreline-inner shelf facies as a response to reductions in accommodation space due to aggradation and/or lower relative sea levels. Coarser facies within heterogeneous mudrock intervals (**Figure 6**) are likely the result of cross-shelf sediment transport, mostly from gravity flow processes, including wave-induced density flows or turbidity currents (Munson 2016).

Intertidal and emergent facies are a minor component of the Roper Group; they cap large-scale coarsening-upward cycles but are only rarely preserved within the succession. These environments are exposed to meteoric waters and are typically thinly bedded, laminated and characterised by desiccation features. They are highly sensitive to changes in the balance between precipitation and evaporation, thereby limiting the areal extent of potentially thick source rock intervals to only those portions of a basin where permanent deep water is present.

PETROLEUM EXPLORATION HISTORY OF ROPER GROUP

Historical exploration

Petroleum exploration in the McArthur Basin began in the 1960s and continued intermittently thereafter, peaking firstly in the 1980s and 1990s, and again from the mid-2000s through to the present-day (Munson 2014). Exploration for petroleum initially focused on conventional reservoirs through programs that included field mapping, geophysical surveys and stratigraphic drilling. Drilling of the Roper Group was conducted by CRA Exploration Pty Ltd and Pacific Oil & Gas Ltd during the 1990s. These drill programs have provided the legacy core that was used and analysed for this study to assess the petroleum prospectivity for unconventional shale gas and shale oil accumulations.

Exploration extended into searching for self-sourced continuous (unconventional) reservoirs within the Roper

Group in the mid-2000s. Sweetpea Petroleum Pty Ltd conducted an exploration program in the Beetaloo Sub-basin that included the drilling of Shenandoah 1 in 2007. Shenandoah 1 was subsequently deepened in 2009 (Shenandoah 1A); this well was interpreted to be terminated in the lower Velkerri Formation, and underwent production testing in 2011 by Falcon Oil & Gas Ltd (Falcon 2012). However, reinterpretation of the Shenandoah 1A well succession by Pangaea Resources now suggests that the well was terminated in the middle Velkerri Formation (Hoffman 2015). This is further supported by chemostratigraphic characterisation of the middle Velkerri Formation indicating that the drilling did not intersect the lower Velkerri Formation

Exploration activity in the Roper Group increased during 2013–2014. Pangaea Resources Pty Ltd acquired 2D seismic data in 2013 across and to the west of the Gorrie sub-basin, and drilled three stratigraphic wells in 2014 – Manbulloo-S1, Hidden Valley-S2 (HVS2) and Tarlee S3 (TS3). HVS2 drilling indicated that the base Roper Group unconformity has truncated the Wattie and Bullita groups of the Birrindudu Basin (Nathan Group equivalents), and has eroded into the upper McArthur Group down to the level of the Barney Creek Formation; this indicates that the Roper Group was deposited in a separate basin to that of the McArthur Group (Hoffman 2015). Well TS3 targeted Roper Group sedimentary rocks and confirmed the lateral continuity of a number of regional markers present in Roper Group strata intersected in correlative wells in the Beetaloo Sub-basin to the east.

In 2013, Santos Ltd acquired 500-km 2D seismic in the OT Downs sub-basin, located in the far east of the Beetaloo Sub-basin region. This was followed by drilling during 2014 to investigate the Roper Group succession, resulting in the drilling of Tanumbirini 1 to a total depth of 3945 m. This well intersected multiple thick intervals of organic-rich rock through the Velkerri Formation, accompanied by significant mud gas shows over a total gross interval in excess of 500 m. The well was cased and suspended for re-entry in 2015 (Santos 2015).



Figure 6. Lithological variability in lower Velkerri Formation (drill core from Walton 2: 771.4–775.9 m depth). Lighter coloured coarse clastic rocks are interbedded with darker, fine-grained siltstones on a centimetre scale.

SELF-SOURCED CONTINUOUS PETROLEUM SYSTEMS

The global oil and gas industry has continually developed new techniques for exploration throughout its 150 year history. Initial exploration techniques focused on isolated structure-bound traps, then subsequently shifted to lithostratigraphic traps, and is currently aimed at continuous unconventional petroleum accumulations. Technological developments in drilling and well completion techniques have stimulated growth in the production of unconventional oil and gas resources.

Continuous unconventional petroleum accumulations are very different from conventional petroleum accumulations. Conventional accumulations are typically characterised by porous and permeable reservoirs, by oil/water or gas/water contacts, and by petroleum that is technically and economically recoverable by vertical wells. Conventional accumulations of oil and gas are formed through buoyancy-driven migration of hydrocarbons, are completely separated from the source and are retained in discrete or clustered traps under a geological seal of low permeability. In contrast, continuous unconventional petroleum accumulations are typically characterised by low permeability and often by low porosity; they lack oil/water or gas/water contacts, and the petroleum cannot be extracted economically using

conventional methods. A continuous accumulation is, in effect, a single large field (commonly of regional dimensions) that is not significantly influenced by the water column, and is not composed of discrete, countable fields delineated by down-dip contacts (Schmoker 2002). Development of a continuous accumulation is usually in areas without distinct boundaries, with production quality dependent on multiple parameters being present simultaneously. Unconventional petroleum resources include tight gas, tight oil, fracture-cavity carbonate oil and gas, volcanic pore-fracture oil and gas, metamorphic fracture oil and gas, coal bed methane, shale oil and gas, deep-basin (basin-centred) oil and gas, bacterial gas, gas hydrate and others (Zou 2013).

In addition to conventional petroleum systems, the McArthur Basin hosts a number of unconventional continuous petroleum accumulations including shale oil and gas, and basin-centred gas (Figure 7).

Parameters used to assess self-sourced continuous accumulations

Classification of shale-gas systems is a complex task because of the high degree of variability among these systems and the range of descriptions from very simple to very detailed (Jarvie 2012). The potential shale-gas systems of the Roper

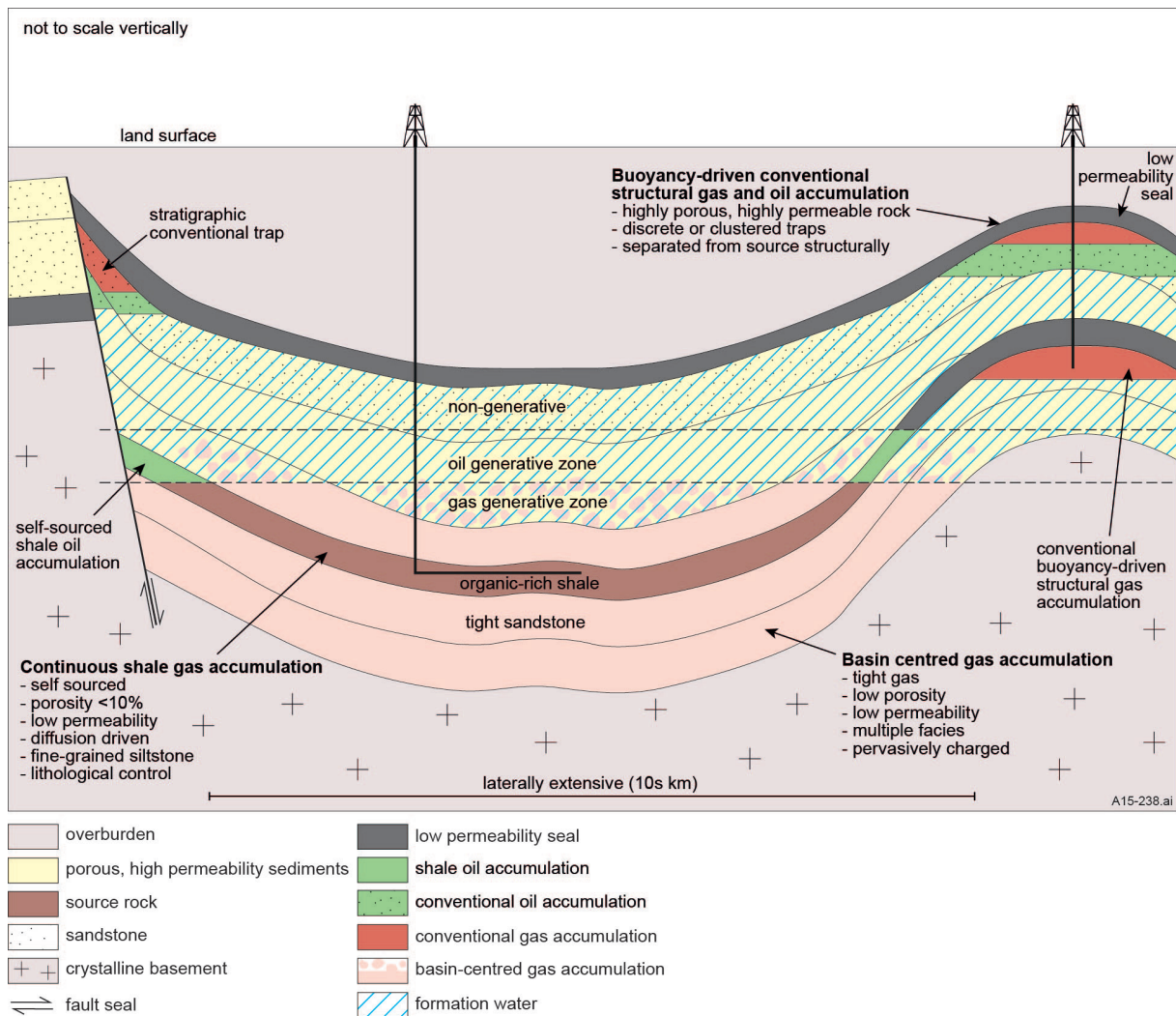
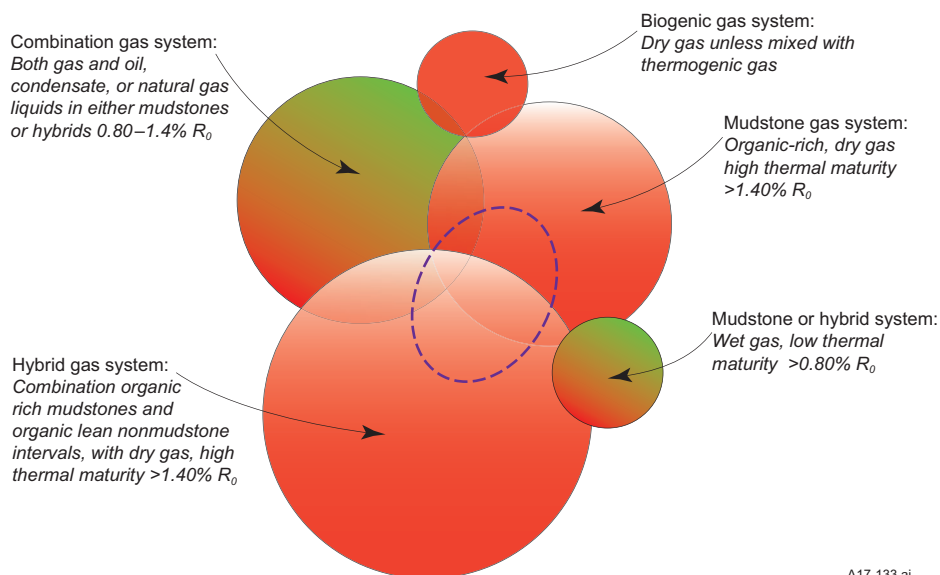


Figure 7. Conventional discrete and continuous–pervasive hydrocarbon resource types potentially present in McArthur Basin (adapted from Schenk and Pollastro 2002).

Figure 8. Simplified classification scheme for shale-gas resource systems (adapted from Jarvie 2012). Size of circle is indication of resource potential. Potential Roper Group shale gas resources fall within dashed circle.



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Group are a mix of hybrid systems and mudstone gas systems (**Figure 8**). Jarvie (2012) defines hybrid systems as having a source rock combined with a higher abundance of organic-lean interbedded or juxtaposed non-clay lithofacies. This is represented in the Roper Group by the Kyalla Formation, which contains intra-formational sands juxtaposed against source intervals. Intervals of the Velkerri Formation hold potential as mudstone gas systems where the formation is thermally mature and organic-rich.

The United States Geological Survey has outlined the qualitative geologic factors to consider for continuous accumulations in shale reservoirs for assessment of highly productive shale gas systems. There are also a number of quantitative geologic factors required for a highly productive shale gas system. All of these factors need to be taken into account during assessment (**Table 3**).

The core area for commercial gas development of shale usually refers to the zone of effective shale. A list of shared characteristics for the zone of effective shale, as used for this report, is shown in **Table 4**.

The requirement for commercial development can be met when the thickness of effective shale is greater than 30–50 m (Zou 2013). The major geological features for favourable shale gas and core area characterisation are summarised in **Table 5**.

The vast regional extent and organic-rich stratigraphy of the onshore McArthur Basin in the Northern Territory indicates potential for self-sourced continuous petroleum resources, and the basin has been estimated as containing significant technically recoverable shale-gas, tight-gas and shale-oil resources (Munson 2014, **Table 6**).

SAMPLING AND ANALYTICAL METHODOLOGY

INVESTIGATION INTO LEGACY AND OPEN-FILED DRILL CORE

As part of the *CORE (Creating Opportunities for Resource Exploration)* initiative (NTGS 2014), NTGS has undertaken a sampling program to analyse the fine-grained mudrocks of the McArthur Basin. Legacy and recent drill core was

Table 3. Qualitative and quantitative geological factors for highly productive shale gas systems.

USGS qualitative geological factors (Charpentier and Cook 2010)	Quantitative geological factors (Ghori 2013)
Thickness	TOC (>2 wt%)
TOC	Clay content (<50 wt%)
Pressures	High in brittle mineral content (30–40 wt%)
Mineralogy	Thermal maturity (>1.5% R_0)
Mechanical stratigraphy (such as existence of barriers to stimulated fracture propagation)	Thickness of net pay (>100 m)
Organic geochemistry	Porosity (>2%)
Natural fractures	Reservoir pressure (ideally overpressured)

Table 4. Shared characteristics of productive shale-gas resource systems in areas of initial production (adapted from Jarvie 2012).

Marine shales commonly described as Type II organic matter (H_{II} : 250–800 mg/g)
Organically-rich source rocks [>1.00 wt% present-day TOC (TOC_{pd})], [>2.0 wt% original TOC (TOC_o)]
Are within the gas window [$1.4\% R_{o(eq)}$]
Have low oil saturations ($<5\% S_o$)
Have significant silica content ($>30\%$) with some carbonate
Have non-swelling clays
Have less than 1000 nd permeability
Have less than 15% porosity, typically 4 to 7%
Have GIP (Gas In Place) values more than 100 bcf/section
Have 45+ m of organic-rich mudstone
Are slightly to highly overpressured
Have very high first-year decline rates ($>60\%$)
Have consistent or known principle stress fields
Are distant from structures and faulting
Are continuous mappable systems

targeted for data compilation and sampling. Sampling density through the historical cores varied from sparse (30–50 m intervals) to dense (1–3 m intervals) through targeted carbonaceous shale intersections. Analysis of the historical and relatively recent drilling for this report was

restricted to open-filed data and drill cores. Sampling and analysis of core from several recent exploration wells drilled in the Beetaloo and Gorrie sub-basins could not be included in this report due to confidentiality clauses. These wells will have a significant impact on any future assessment of the

Table 5. Summary table for major characteristics of shale gas (adapted from Zou 2013).

Geological characteristics	Accumulation and high-production conditions for effective shale
Integrated source rock and reservoir, early reservoir formation, continuous accumulation; no delineated down-dip, buoyancy controlled contact boundaries or capping seals Tight reservoir of nano-scale porosity; natural gas stored in adsorbed gas and free gas pattern Continuous and large area distribution, <i>in situ</i> retention reservoir formation Large resource potential, with localised 'sweet spot' core area with effective shale	TOC >2% (non-residual organic carbon) Brittle mineral content (quartz, carbonates, feldspars) >40%; Clay mineral content <30% Thermal maturity (R _o) 1.1–3.5 Air porosity >2%, Permeability >0.0001 X 10 ⁻³ μm ² Effective shale thickness >30–50 m

Table 6. Estimated shale petroleum resources within onshore McArthur basin, NT (adapted from Munson 2014). Gas resource figures expressed as petajoules (PJ). Original figures standardised to billion standard cubic feet (Bscf). Oil and condensate figures standardised to million barrels (mmbbl), except for Beetaloo Sub-basin prospects, where original figures from RPS (2013) were given in mmstb. Figures relevant as of March 2014.

SHALE AND TIGHT GAS									
Basin / prospect / formation							Comment	Reference	
McArthur Basin	Prospective resource								
	P90 PJ (Bscf)	P50 PJ (Bscf)	P10 PJ (Bscf)	Mean PJ (Bscf)					
<i>Batten Trough: Barney Creek Fm</i>	4031* (3800.8)	13755* (12 970.5)	41 448* (39 085.1)	19 672* (18 550.5)			Shale gas	MBA (2012)	
McArthur Basin Beetaloo Sub-basin	Potentially in place								
	P90 PJ (Bscf)	P50 PJ (Bscf)	P10 PJ (Bscf)	Low estimate PJ (Bscf)	Best estimate PJ (Bscf)	High estimate PJ (Bscf)			
<i>lower Kyalla Fm</i>	33 373* (31 470)	55 419* (52 260)	92 228* (86 970)	23 150* (21 830)	39 544* (37 290)	67 668* (63 810)	Shale gas	RPS (2013)	
<i>middle Velkerri Fm</i>	68 942* (65 012)	110 521* (104 220)	176 852* (166 770)	47 816* (45 090)	79 004* (74 500)	130 203* (122 780)	Shale gas	RPS (2013)	
<i>Moroak Sst</i>	1442* (1 360)	8759* (8260)	54 338* (51 240)	1007* (950)	6257* (5900)	38 940* (36 720)	Basin-centred gas	RPS (2013)	
<i>Bessie Creek Sst</i>	37 349* (35 220)	66 077* (62 310)	113 501* (107 030)	26 066* (24 580)	46 989* (44 310)	83 225* (78 480)	Basin-centred gas	RPS (2013)	
SHALE OIL AND CONDENSATE									
Basin / prospect / formation							Comment	Reference	
McArthur Basin	Prospective resource								
	P90 (mmbbl)	P50 (mmbbl)	P10 (mmbbl)	Mean (mmbbl)					
Batten Trough: Barney Creek Fm	260.6	1234.1	4434.9	1961.5			Condensate	MBA (2012)	
McArthur Basin Beetaloo Sub-basin	Potentially in place								
	P90 (mmbbl)	P50 (mmbbl)	P10 (mmbbl)	Low (mmbbl)	Best (mmbbl)	High (mmbbl)			
<i>upper Kyalla Fm</i>	49 663	70 985	100 700	1 290	2 654	5 526	Shale oil	RPS (2013)	
<i>lower Kyalla Fm</i>	121 327	159 658	209 528	3 023	5 971	12 011	Shale oil	RPS (2013)	
<i>middle Velkerri Fm</i>	168 927	337 982	673 176	4 942	12 720	32 503	Shale oil	RPS (2013)	
Totals	339 917	568 625	983 404	9 255	21 345	50 040	Shale oil		

petroleum prospectivity of the region as they specifically targeted the Kyalla and middle Velkerri formations as unconventional petroleum plays. There has been at least one public announcement of a shale gas discovery in the Beetaloo Sub-basin related to this drilling.

SAMPLING PROGRAM

The program involved the physical sampling of legacy drill core from the NTGS core library in Darwin and from the Geoscience Australia (GA) Core Repository in Canberra, ACT. The condition of the core varied from excellent to very poor. The GA core repository is climate controlled with excellent preservation of geological specimens (**Figure 9**). However, the NTGS core library is not climate controlled and several of the cores appeared to have been severely affected by the highly variable temperature and humidity of Darwin's tropical climate.

Sampling of the core was carried out by hand and also by mechanical means (core saw). When sampling by hand, broken/fissile core was picked from the tray directly and competent core was separated using a hammer and/or chisel. Large or highly competent core was cut with a diamond saw. A minimum of 60 gm of sample is required for organic geochemistry analysis. Samples were sealed in plastic bags and sent to Weatherford Laboratories Australia for analysis.

ANALYSIS

A variety of analyses were employed to investigate Roper Group sedimentary rocks for unconventional petroleum potential. These included:

- total organic carbon (TOC)
- programmed pyrolysis
- shale rock properties analysis to determine a suite of petrophysical properties including bulk density, grain density, porosity, fluid saturations (oil/gas/water), and matrix permeability
- soxhlet extraction
- kerogen isolation
- kerogen kinetic analysis
- elemental analysis
- gas chromatography mass spectrometry (GCMS)
- X-ray diffraction (XRD)
- desorption isotherms

Weatherford Laboratories analytical methodologies are summarised in NTGS Record 2015-004 (Revie 2015).

Legacy and recent drill core sampling

Historical well data were compiled from historical well completion reports, and any additional information from core sampling records. An extensive sampling and analysis program was undertaken by the NTGS to supplement datasets from wells with a paucity of required information. Analytical results used for this assessment were restricted to open file data and drill cores; data from 2015–2016 closed file exploration wells are not included.

Production characteristics and reserves for shale gas petroleum systems are not available for Australia as none of the prospective plays are in petroleum production. Therefore shale data from the Roper Group were summarised and compared with data from known producing USA shale plays. The common characteristics of currently producing self-sourced continuous petroleum reservoirs (shale plays) in North America were also used as the base parameters for assessment of the Roper Group shales from the McArthur Basin. There are several sources of uncertainty associated with the modelling of this data. Most of the samples taken were from drill core that have been exposed to atmospheric conditions for prolonged periods of time. Fluids in the core, both hydrocarbons and water, may have changed composition as a result of this exposure. Estimated hydrocarbons could be higher or lower depending on how the core was affected. Legacy core data may also have been high-graded in some instances where sampling targeted the intervals with the best potential for hydrocarbons. Any hydrocarbon in-place estimates therefore could have been overestimated and may not be representative of the overall reservoir characteristics for the volume of reservoir used in the calculations. Core sample data alone may not capture the true variability needed to accurately estimate hydrocarbons in place on a basin scale. A complete reservoir model, rather than a core-based approach, would better serve this purpose.

Data reduction and processing

Gross thickness of the Kyalla and Velkerri formations was estimated using well completion reports (WCRs) and all public published well logs from all wells drilled to date in



Figure 9. BMR Urupunga 3 core at the Geoscience Australia core repository, Canberra.

the basin. Net shale gas interval thickness was calculated by high-grading to regions with present-day values of >1 wt% TOC. This resulted in a conservative measurement of the amount of shale that could potentially be a source rock.

Geochemical data were taken from a complete search of all available geochemical datasets, WCRs and historical NTGS core sampling reports (CSRs) and were compiled into NTGS Digital Information Package 14 (Revie 2017). Data compiled for analyses included measurements for initial shale classification, as well as additional RockEval data [T_{max} , S1, S2, S3, Production Index (PI), Hydrogen Index (HI), Oxygen Index (OI)], shale rock properties measurements (porosity, permeability, pore fluid saturations, bulk and grain density), and mineralogy (clay and bulk fractions) from XRD measurements.

The following equations (1–8) were used to quantify source rock potential in a deterministic analysis for the Kyalla and Velkerri formations.

Thermal maturity measurements were undertaken on macerals (bitumen, alginites) from polished thin sections. Further to the thermal maturity data from reflectance analysis, extracted hydrocarbons were analysed for their biomarker content. The estimated onset temperature for oil generation was then estimated using extracted biomarker ratios (**Equation 1**).

$$^{\circ}C_{temp} = 140 + 15(\ln[2,4\text{-DMP}/2,3\text{-DMP}])$$

Equation 1. Temperature of generation ($^{\circ}C_{temp}$) for primary oils, based on 2,4-dimethylpentane/2,3-dimethylpentane (2,4-DMP/2,3-DMP) biomarker ratios being independent of source or heating rates (from Mango 1997).

In the absence of polished maceral reflectance data, a calculated reflectance index (R_o) was determined using T_{max} data from programmed pyrolysis (**Equation 2**).

$$\text{Calculated } R_o = (0.0180)(T_{max}) - 7.16$$

Equation 2. Calculated equivalent vitrinite reflectance values based on T_{max} values from programmed pyrolysis (Jarvie *et al* 2001).

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* 2005a). The remaining generative potential, as measured by present-day quantity of organic matter (TOC_{pd}) and present-day hydrogen index (HI_{pd}), can be used to estimate the volume of expelled oil and the expulsion efficiency by making some reasonable assumptions based on core geochemical data and published regional information (Peters *et al* 2005a, Jarvie *et al* 2007).

HI_o values can be computed from visual kerogen assessments and assigned kerogen-type HI_o average values using the following formula (**Equation 3**):

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

Equation 3. HI_o assessment equation using visual kerogen assessments and assigned kerogen-type HI_o average values (Jarvie *et al* 2007).

The extent of the petroleum-generation process, or transformation ratio (TR) which is also called fractional conversion, can be calculated as follows (**Equation 4**):

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

Equation 4. Calculation of transformation ratio (TR), using measured present-day values for hydrogen index (HI_{pd}) and production index (PI_{pd}) from source rock samples (after Jarvie *et al* 2007). HI_o and PI_o are original HI and PI values for immature organic matter in the rock. Original production index (PI_o) has an assumed value of 0.02 (Peters *et al* 2005a).

Source rock TOC_o before burial and thermal maturation is constrained by mass balance considerations (**Equation 5**). This calculation uses present-day TOC and HI:

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

Equation 5. Mass balance calculation for assessing original total organic carbon content (TOC_o) in source rocks prior to burial and thermal maturation (adapted from Jarvie *et al* 2007). k is a correction factor based on residual organic carbon being enriched in carbon over original values at high maturity. 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%), 83.33 is the percentage of carbon in generated petroleum, and the correction factor k is then $TR_{HI} \times C_R$.

The original generational potential ($S2_o$, in mg HC/g rock) of the formation source rocks can be calculated using **Equation 6**:

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

Equation 6. Original generational potential ($S2_o$) in petroleum source rocks.

For formation source rocks, average $S2_o$ values are calculated in mg HC/g rock, and then converted to bbl/acre-ft units [multiply $S2_o$ by 21.89 to calculate barrels/acre-foot (Jarvie and Tobey 1999)]. Knowing the measured remaining generational potential (S2) from programmed pyrolysis and using the calculated original generational potential ($S2_o$), the amount of hydrocarbons generated can then be determined. A VR_o algorithm (**Equation 7**) applied to estimate fractional oil cracking can be used to estimate oil and cracked gas (reported as Mcf/acre-ft or thousand cubic feet/acre-ft).

Original ($S2_o$) – Remaining (S2) = Generated hydrocarbons

Equation 7. Determination of generated hydrocarbons using estimated ($S2_o$) and measured (S2) hydrocarbon yields.

For shale oil systems, the amount of hydrocarbon (oil + gas) expelled from the rocks can be estimated as the difference between the amount of residual oil measured (S1) and the amount of estimated generated hydrocarbon yields, determined from **Equation 7**. The expulsion efficiency (ExEf) can then be calculated

as a direct proportion of the measured retained oil saturations and the average generated hydrocarbon yields (**Equation 8**):

$$\text{ExEf} = 1 - \frac{(1 - \text{TR}_{\text{HI}}) \left[\frac{\text{PI}_{\text{pd}}}{(1 - \text{PI}_{\text{pd}})} \right]}{\text{TR}_{\text{HI}} + \left[\frac{\text{PI}_{\text{o}}}{(1 - \text{PI}_{\text{o}})} \right]} \times 100$$

Equation 8. Expulsion efficiency (ExEf) calculation for petroleum source rocks (after Peters *et al* 2005a).

The relative Brittleness Index (BI) provides insights into the geomechanical properties of shale. High BI values supposedly indicate an increased brittle tenacity for the rock. However, deformation of the rock is controlled by many factors, including microstructure and the distribution of the minerals within the matrix, so it cannot be simply described by a single parameter (Yang *et al* 2013). Furthermore, at the injection rates encountered during hydraulic stimulation, the ensuing strain rates governing the deformation process are such that most lithologies encountered in unconventional resource plays undergo brittle deformation. The Brittleness Index is therefore not suitable for indicating the propensity of a formation to undergo brittle failure; it is essentially a lithology indicator, with high BI typically associated with high quartz content or high dolomite content (Herwanger *et al* 2015). BI can be determined using mineral content proportions determined through XRD, and calculated using **Equation 9**:

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

Equation 9. Brittleness Index (BI) calculated by the relative proportion of minerals within the formation (Weatherford 2016).

Rock volumes were produced by combing areal extent and shale thickness to produce thickness isopach maps. The areal extent of the isopach mapping was constrained to the major depocentres of the Gorrie, Beetaloo, OT Downs and Broadmere sub-basins.

NOMENCLATURE

HI = hydrogen index (remaining potential (S2) divided by TOC x 100), mg HC/g TOC

k = correction factor for enriched residual organic carbon at high maturity

PI = production index [S1/(S1 + S2)], values from 0.00 to 1.00

R₀ = vitrinite reflectance or its equivalent, values from 0.00 to ~3.00%

TOC = total organic carbon, wt%

TR = transformation ratio

φ = porosity

Subscripts used with terms:

_{pd} = present day

_o = original

RESULTS

The complete dataset of results is available in Digital Information Package 014 (Revie 2017). Summaries of the raw unfiltered analyses are presented below. The analyses are on regional datasets, using the formal stratigraphic divisions of the Roper Group. Data are presented for the whole of the Velkerri Formation, and also separately for the three informal lithofacies (*upper, middle and lower* facies) recognised within this unit.

TOC and Pyrolysis data

The results of the TOC and pyrolysis analyses are summarised in **Table 7**.

Elemental Kerogen analysis

A summary of results of the CHNOS (carbon, hydrogen, nitrogen, sulfur and oxygen) elemental ratios taken from elemental kerogen analysis is shown in **Table 8**. The full table of results for individual sample analyses is available in Revie (2017).

X-Ray diffraction analysis

Results of XRD analyses on selected samples of the Roper Group succession are shown in **Table 9**. The results have been grouped into quartz content, clay mineral content, carbonate mineral content and other mineral content. The proportion of non-swelling clay minerals within the clay mineral component has been grouped. The full table of results for individual sample analyses is available in Revie (2017).

Pore fluid saturations, permeability and porosity analysis

Pore volume fluid saturation, bulk volume water saturation, porosity and permeability values for selected samples of the Kyalla Formation and Velkerri Formation are presented in **Table 10**. The full table of results for individual sample analyses is available in Revie (2017).

DISCUSSION OF RESULTS

TOC AND PYROLYSIS DATA

Geochemical parameters that are used to describe the generative potential of source rocks in general include measurements relating to quantity of organic matter (OM) through total organic carbon (TOC) and the fraction of TOC that is generated as hydrocarbons and other compounds by pyrolysis (Peters 1986). TOC and programmed pyrolysis data are useful for screening for potential petroleum source rocks (**Table 11**). The data are also useful for recognising potentially producible oil within the rocks (Jarvie 2012).

The measured parameters of S1, S2 and S3 from the Rock-Eval technique are representative of: (S1) free hydrocarbons C₁ to about C₂₃ thermally liberated at the 300°C isotherm; (S2) hydrocarbons cracked from kerogen

Table 7. TOC and Pyrolysis unfiltered data for fine-grained siltstone and mudstone formations of Roper Group (data from Revie 2017).

Formation	n samples	TOC _{pd} (range) Average (wt %)	S1 _{pd} (range) Average (mg HC/g rock)	S2 _{pd} (range) Average (mg HC/g rock)	S3 _{pd} (range) Average (mg HC/g rock)	S1+S2 (range) Average (mg HC/g rock)	S2/S3 (range) Average (mg HC/g rock)	T _{max} (range) °C	PI _{pd} (range)	HI _{pd} (range) mg HC/g TOC	OI _{pd} (range) mg CO ₂ /g TOC
Hayfield mudstone	63	(0.02–0.66) 0.24	(0.01–0.11) 0.06	(0–0.28) 0.04	(0.02–1.95) 0.39	(0.04–0.36) 0.10	(0–1.75) 0.23	324–548	0.18–0.83	0–200	8–1211
Jamison sandstone	34	(0.05–0.85) 0.30	(0.02–0.19) 0.07	(0.03–1.24) 0.21	(0.04–1.02) 0.25	(0.07–1.43) 0.27	(0.10–19.75) 1.70	319–599	0.07–0.75	6–253	9–380
Kyalla Formation	703	(0.03–8.97) 1.08	(0.01–3.59) 0.43	(0.01–22.79) 2.20	(0.01–6.62) 0.56	(0–24.74) 2.63	(0.04–221.29) 11.09	281–537	0.02–0.85	0–1055	0–1003
Velkerri Formation upper	633	(0.11–10.60) 0.93	(0.01–4.36) 0.42	(0.02–27.91) 1.13	(0.01–6.45) 0.50	(0.03–30.95) 1.55	(0.02–186.07) 5.92	277–521	0.04–0.78	2–461	1–993
Velkerri Formation middle	1079	(0.08–29.93) 3.76	(0.01–16.79) 1.51	(0–70.66) 7.31	(0–7.76) 0.53	(0.04–74.84) 8.82	(0.02–624.80) 21.41	220–570	0–0.92	0–730	0–1820
Velkerri Formation lower	500	(0–7.01) 0.80	(0–6.10) 0.31	(0–22.13) 0.93	(0–13.00) 0.29	(0.03–22.88) 1.23	(0.01–194.00) 6.59	246–611	0–0.96	0–766	0–1757
Velkerri Formation	2212	(0–29.93) 2.28	(0–16.79) 0.94	(0–70.66) 4.19	(0–13.00) 0.47	(0.03–74.84) 5.13	(0.01–624.80) 13.91	220–611	0–0.96	0–766	0–1820
Corcoran Formation	222	(0–2.6) 0.28	(0–.22) 0.04	(0–1.16) 0.10	(0–2.83) 0.23	(0–1.21) 0.11	(0.01–38.67) 2.67	203–850	0–0.78	0–1600	0–506
Jalboi Formation	8	(0.02–0.39) 0.18	(0.03–0.06) 0.04	(0.01–0.02) 0.02	(0.01–0.65) 0.24	(0.03–0.08) 0.05	(0.03–1.00) 0.37	184–255	0.67–0.75	7–50	33–725
Crawford Formation	32	(0–0.53) 0.16	(0–0.79) 0.07	(0–0.59) 0.09	(0.01–1.94) 0.52	(0–1.3) 0.14	(0–1.63) 0.56	176–417	0–0.88	0–126	11–900
Mainoru Formation	51	(0.09–0.94) 0.27	(0.01–1.72) 0.23	(0.01–1.39) 0.19	(0.02–2.53) 0.21	(0.02–3.11) 0.34	(0.14–7.00) 1.79	172–456	0.24–1.0	13–162	3–294

Table 8. Elemental kerogen CHONS ratios from analyses of selected samples of Roper Group succession (data from Revie 2017).

Formation	n samples	Atomic H/C (range) Avg	Atomic O/C (range) Avg	Atomic S/C (range) Avg	Atomic C/N (range) Avg	Atomic S _{org} /C (range) Avg
Hayfield mudstone	0	-	-	-	-	-
Jamison sandstone	1	0.94	0.09	0.00	50.47	-
Kyalla Formation	59	(0.43–6.75) 1.37	(0.01–0.71) 0.10	(0–0.26) 0.05	(16.46–293.47) 72.03	(0–0.48) 0.10
Velkerri Formation upper	33	(0.41–2.58) 1.00	(0.02–0.26) 0.07	(0–0.85) 0.21	(25.39–111.24) 59.06	(0.01–0.03) 0.02
Velkerri Formation middle	89	(0.02–8.31) 0.97	(0.01–0.28) 0.05	(0–0.89) 0.09	(24.05–634.75) 74.47	(0–0.83) 0.05
Velkerri Formation lower	32	(0.38–11.85) 1.61	(0.01–1.00) 0.14	(0–0.80) 0.15	(4.19–168.12) 66.20	(0.01–0.35) 0.05
Velkerri Formation	154	(0.02–11.85) 1.11	(0–1.0) 0.07	(0–0.89) 0.13	(4.19–634.75) 69.59	(0–0.83) 0.05
Corcoran Formation	11	(0.42–29.79) 7.18	(0.05–5.23) 1.54	(0–1.13) 0.36	(1.41–91.95) 35.48	-
Jalboi Formation	1	0.40	-	0.13	56.24	-
Crawford Formation	0	-	-	-	-	-
Mainoru Formation	8	(0.47–5.92) 2.17	(0.16–1.01) 0.35	(0.07–1.52) 0.55	(18.15–94.49) 50.99	(0.06–1.00) 0.33

Table 9. X-Ray diffraction results for bulk and clay mineral fractions for various Roper Group formations, grouped into quartz, clay mineral, carbonate mineral and other mineral categories (data from Revie 2017). Non-swelling mineral component of clay group is based on smectite, mixed-layer illite/smectite and mixed-layer chlorite smectite within clay mineral proportion.

Formation	n samples	Quartz % (min-max) Avg	Clay mineral % (min-max) Avg	Carbonates % (min-max) Avg	Other minerals % (min-max) Avg	Clay proportion non-swelling clay % (min-max) Avg
Hayfield mudstone	3	(34–42) 37.6	(37–48) 40.6	(1–2) 1.6	(17–25) 20.6	100
Jamison sandstone	2	(62–86) 74	0	(3–15) 9	(8–16) 12	0
Kyalla Formation	56	(18–71) 35.5	(56–79) 54.9	(0–22) 1.9	(2–22) 7.75	(66–100) 93
Velkerri Formation <i>upper</i>	40	(8–77) 40.1	(14–71) 48.8	(0–77) 3.9	(1–23) 10.1	(51–100) 77
Velkerri Formation <i>middle</i>	129	(0.8 - 77) 44.4	(1.1–80) 33.9	(0–87) 6.27	(0–34) 15.4	(11–100) 67
Velkerri Formation <i>lower</i>	41	(22–88) 41.7	(12–71) 50.2	(0–12) 0.8	(0–24) 7.3	(31–100) 71
Velkerri Formation	210	(0.8–88) 43.1	(1.1–210) 39.3	(0–87) 4.8	(0–34) 12.8	(11–100) 70
Corcoran Formation	14	(27–39) 31.8	(57–70) 64.9	(0–1) 0.07	(2–5) 3.1	(39–99) 67
Jalboi Formation	13	(29–100) 63.8	(0–67) 30.6	(0–2) 0.4	(0–15) 5.2	(0–100) 77
Crawford Formation	5	(67–98) 85.8	(0–21) 8	(0–4) 1.2	(0–9) 5	(0–100) 95
Mainoru Formation	14	(25–37) 30.6	(47–69) 60.1	(0–1) 0.2	(4–21) 9.1	(55–90)

Table 10. Pore fluid saturations of pore volume (PV) and water saturation of bulk volume (BV), pressure decay permeability and dry helium porosity values (BV) from selected samples of Roper Group succession (data from Revie 2017).

Formation	A-R water saturation % of PV (range) Avg	A-R oil saturation % of PV (range) Avg	A-R gas saturation % of PV (range) Avg	A-R water saturation % of BV (range) Avg	A-R press decay permeability (mD) Avg	Dry helium porosity % of BV (range) Avg
Kyalla Formation <i>n</i> = 7	(50.4–71.5) 57.9	(0.86–18.28) 7.5	(26.65–48.75) 34.6	(0.97–3.53) 1.9	3.85 x 10 ⁻⁵	(3.5–7.2) 5.4
Velkerri Formation <i>upper</i> <i>n</i> = 2	(53.22–55.65) 54.44	(4.18–8.40) 6.29	(35.94–42.61) 39.27	(3.27–3.71) 3.49	1.14 x 10 ⁻⁴	(7.69–10.31) 9.0
Velkerri Formation <i>middle</i> <i>n</i> = 5	(22.40–79.09) 56.23	(0.62–12.11) 5.35	(19.88–76.98) 38.42	(0.94–5.67) 2.61	1.28 x 10 ⁻⁴	(3.22–9.75) 6.33

or from C₂₄+ bitumens by heating to 600°C; (S3) organic carbon dioxide released between 300°C and 390°C (Hunt 1995).

The use of Rock-Eval pyrolysis carries inherent problems depending on the mineralogy and geochemistry of the sample. Ratings given to TOC values indicating whether they represent non-source or fair–excellent source rocks can differ, depending on the investigator, and can vary by organic maceral type and basin. TOC is not a clear indicator of petroleum potential. For example, the presence of graphite (inert carbon) can produce elevated TOC results, but only reactive carbon generates hydrocarbons.

In a lean source rock, oil saturation is not high enough to form a continuous oil network, preventing primary migration into the draining formation (Lewan 1987). Observations suggest that 1% TOC would be a reasonable cut-off for oil source rocks and 0.5% for gas source rocks (Hunt 1995); however, these cut-offs are only guidelines. The TOC of major gas-bearing shale reservoirs in North America is usually >2 wt% (Zou 2013). Further to this, data

Table 11. Geochemical parameters describing source rock generative potential (quantity of organic matter; modified from Peters 1986).

QUANTITY	TOC (wt%)	S1 (mg HC/g rock)	S2 (mg HC/g rock)
Poor	0–0.5	0–0.5	0–2.5
Fair	0.5–1	0.5–1	2.5–5
Good	1–2	1–2	5–10
Very good	2–4	2–4	10–20
Excellent	4+	4+	20+

suggest that rocks having <2.5 wt% TOC are incapable of establishing a continuous bitumen network to facilitate hydrocarbon expulsion (Lewan 1987, Jones 1981). For the intents of this study into the potential of the Roper Group shales, the TOC content for an *effective* petroleum source rock (meaning a unit that can both generate and expel hydrocarbons but which may not be of significant volume to be commercial) is a minimum requirement of 1 wt%; for

an *economic* petroleum source rock, a minimum of 2 wt% is required.

Histograms showing sample frequency versus present-day TOC (in wt%) for organic-rich and organic-lean formations of the Roper Group are presented in **Figures 10** and **11**, respectively.

Filtering the data

There are several ways to filter out potentially anomalous results within the dataset.

From the samples analysed by Rock-Eval pyrolysis, non-source units can be identified and filtered out as those lacking significant hydrocarbon generative potential ($S1 + S2 < 2$ mg HC/g rock; Peters and Cassa 1994).

When T_{max} and Production Index [PI, where $PI = S1/(S1+S2)$] values are used in thermal maturity modelling, the quality

of the data can be improved by filtering for any anomalous results. T_{max} values at the threshold of oil generation vary among petroleum source rocks due to differences in OM type. Most OM enters the oil-generative window at a T_{max} of about 435°C and PI values of 0.1; lower values generally indicate that the OM is immature in Type I and Type II kerogens (Peters 1986). Pyrolysis T_{max} can be significantly different for Type I kerogen or for kerogen containing a high sulfur concentration and is not a reliable indicator of maturity for these kerogen types. Results of T_{max} below values of 395°C are excluded from thermal maturity modelling in the analysis in this report as they are likely to be erroneous. Organic-lean samples of <0.4 wt% TOC are most likely to be strongly affected by adsorption of pyrolysate by the mineral matrix, resulting in reduced S2 and HI, and increased T_{max} and OI (Peters 1986); these samples were also excluded from calculations relating to source rock characterisation in this report.

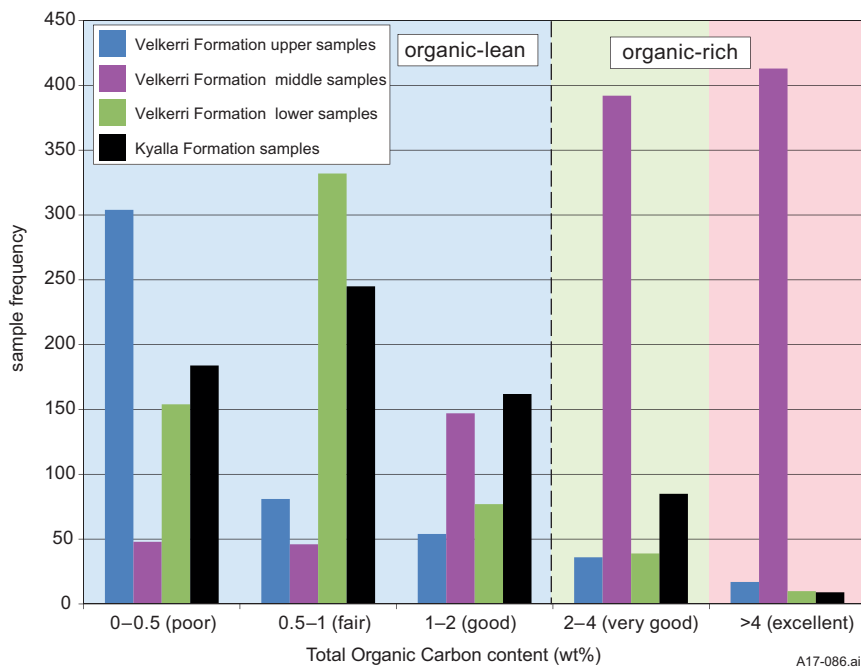


Figure 10. Present-day TOC wt% histogram for organic-rich formations of Roper Group.

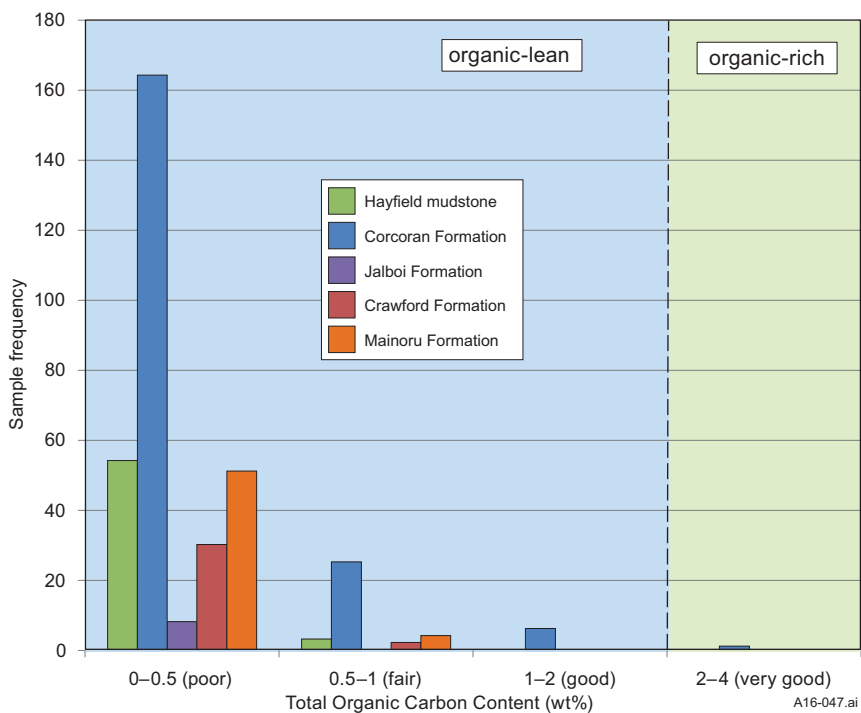


Figure 11. Present-day TOC histogram for organic-lean formations of Roper Group (data from Revie 2017).

Unreliable HI and OI values can result from small S2 or S3 peaks, particularly when the TOC is also low. S2 values of less than 0.2 mg HC/g rock render much of the pyrolysis data unsound, with neither the Production Index [PI, where $PI = S1/(S1+S2)$] nor the T_{max} being valid (Zou 2013).

ORGANIC MATTER (OM) TYPE

Kerogen types are generally grouped into five basic categories (**Table 12**). 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; it is also an indication of the source rock depositional environment. Well preserved algae typically dominate Type I kerogen, which usually indicates a lacustrine depositional environment (but is 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 and II source rocks generate mainly oil and only a limited amount of gas. As maturation proceeds through higher temperatures, secondary thermal conversion 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 transported into nearby marine environments where it can form 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*.

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 the hydrogen content of the organic matter and not necessarily the maceral type. For example, oxidation, the reworking of kerogen, and increasing thermal stress all lower the HI value, even

Table 12. Kerogen type and expelled product (quality of organic matter).

Kerogen type	Hydrogen Index (HI) mg HC/g TOC	S2/S3	Atomic H/C	Main product at peak maturation
I	>600	>15	≈ 1.5	oil
II (II-S)	300–600	10–15	1.2–1.5	oil
II/III	200–300	5–10	1.0–1.2	mixed oil and gas
III	50–200	1–5	0.7–1.0	gas
IV	<50	<1	<0.7	none

if the organic material was deposited as hydrogen-rich Type I or Type II kerogen

The Mesoproterozoic age of the Roper Group limits the types of organic matter that is present in potential source rocks. Primitive marine cyanobacteria were likely to have been dominant at the time of deposition and these are associated with Type I and/or Type II kerogen (Summons *et al* 1994, Taylor *et al* 1994, Law *et al* 2010).

Analytical results show that the Roper Group is dominated by Type II sapropelic oil-prone kerogen, with occurrences of Type I sapropelic oil-prone kerogen. However in some instances, poorly preserved organic matter with elevated oxygen content (high Oxygen Index and elemental O/C ratios) indicates the presence of inert Type IV organic material.

Organic petrology work (Revie 2016a) has identified alginite as the dominant maceral present in the Kyalla and Velkerri formations. Minor occurrences of telalginite and fluorescing lamalginite are also present. These macerals are derived from sapropelic algal organic matter, deposited in subaquatic muds under oxygen-restricted conditions. Bitumen occurrences are common in petrographic samples taken from the Roper Group succession. The formation of a bitumen intermediate is typical of many Type I and II kerogens (Shen *et al* 1984) but not necessarily of Type III or IV kerogens.

The T_{max} values listed above (see **Filtering the data**) are generalised with regard to maturity; in practical terms, the maturity scale is kerogen-type-dependent (see Huc 2013). Thermal maturity guidelines for Type I and Type II kerogens, based upon organic petrology and programmed pyrolysis, are shown in **Table 13**. T_{max} values from pyrolysis indicate the temperature (°C) at the highest yield (S2) of hydrocarbons from the sample being analysed. Note that some Type I kerogen enters the oil window at a T_{max} of ca 440–442°C and exits at ca 446–450°C due to the very narrow range of activation energies for this type of organic matter. Type II kerogen has a wider range, entering the oil window at T_{max} values of ca 425–435°C and exits at ca 445–450°C. Sulfur-rich Type II-S kerogen enters the oil window at ca 420°C and exits ca 450°C due to differences in relative bond strength with S-C bonds being significantly weaker than C-C bonds.

Analysis of the CHNOS elemental ratios present within the kerogen show a range of present-day atomic H/C ratio values within the range of Type I and Type II kerogens. Type II kerogen atomic H/C ratio values dominate (69%) the sampled range of values for all of the Roper Group

Table 13. Thermal maturation for Type I and Type II kerogen.

Maturity	%R _o	T_{max} (°C) Type II kerogen	T_{max} (°C) Type I kerogen	Production Index (PI)
Immature	<0.50	<425	<440	<0.10
Early oil	0.50–0.65	425–435	440–442	0.10–0.15
Peak oil	0.65–0.90	435–445	442–446	0.15–0.25
Late oil	0.90–1.1	445–450	446–450	0.25–0.35
Condensate / wet gas	1.1–1.4	450–470	450–470	>0.4
Dry gas	>1.4	>470	>470	-

shales (Figure 12). Original atomic ratio values, prior to thermal maturation of the kerogen, indicate that the OM of the Roper Group was within the kerogen types I and II range (Figure 13).

Present-day hydrogen index (HI) values, obtained through hydrous pyrolysis techniques, show that shallow immature rocks of the Velkerri and the Kyalla formations consistently contain Type II kerogen with HI values >500 and

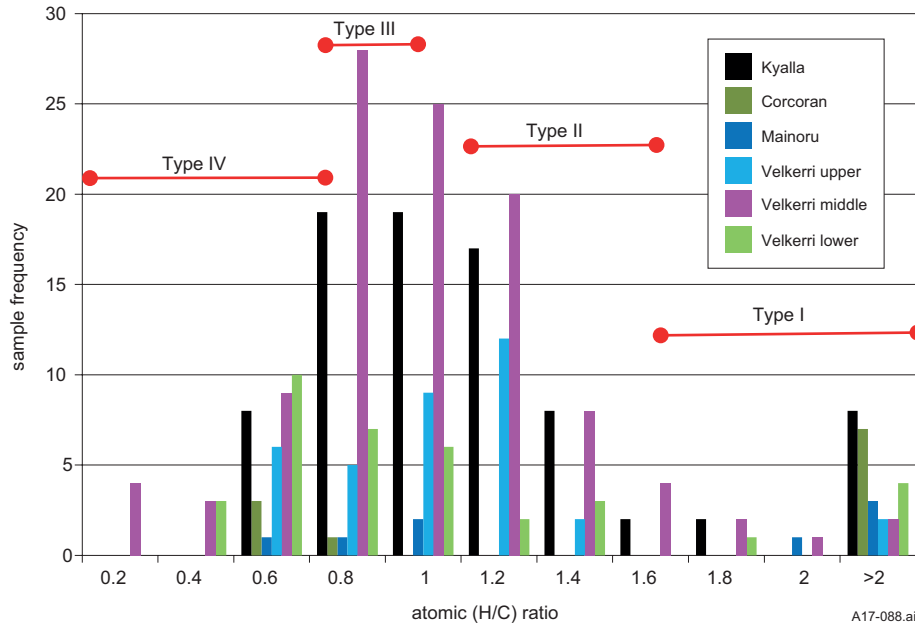


Figure 12. Present-day atomic (H/C) ratios from elemental kerogen analysis of selected formation of Roper Group (data from Revie 2017). Immature H/C ratio values are not shown. Thermal maturation of kerogen and generation of hydrocarbons results in a decreased H/C ratio, indicating that immature original values would be higher than shown here.

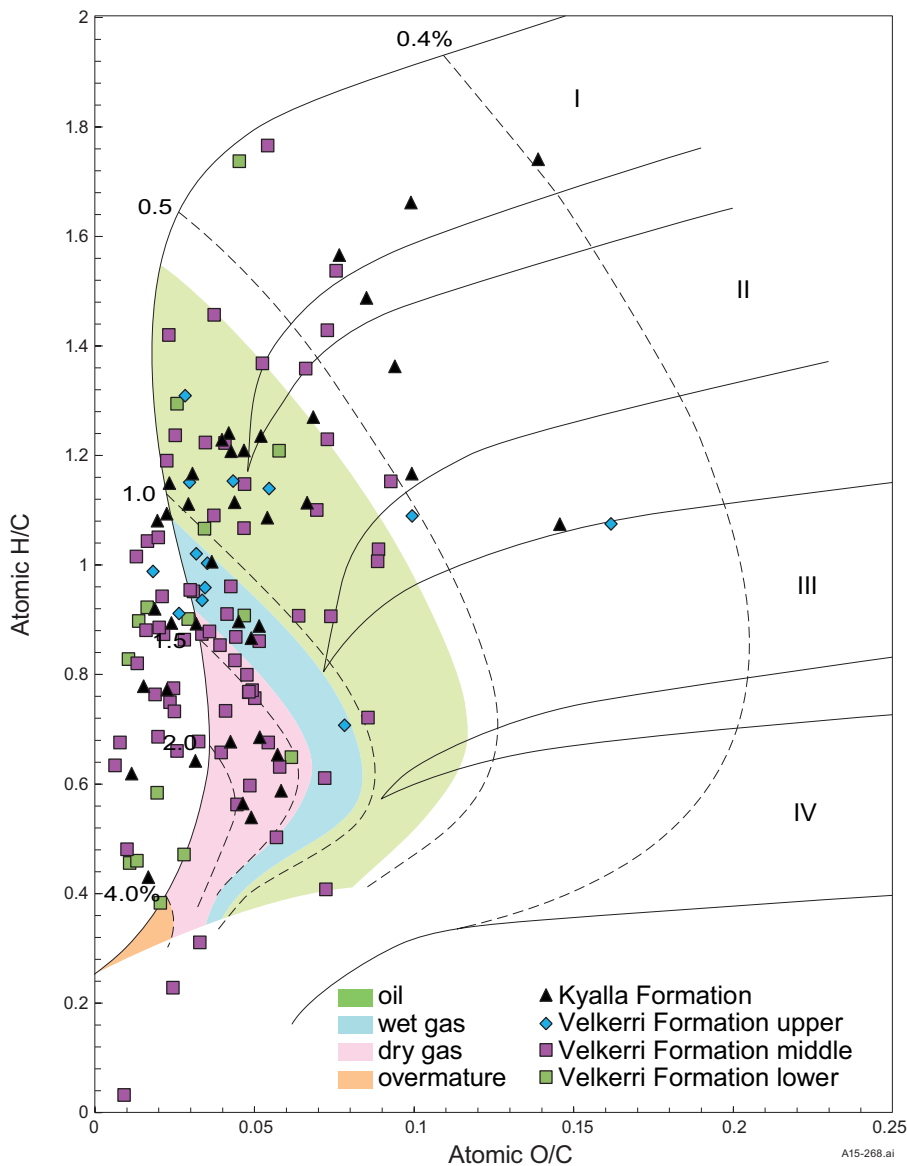


Figure 13. Van Krevelen diagram of present-day elemental kerogen atomic ratios for selected formations of Roper Group (data from Revie 2017). Maturation pathways increase to bottom left. Original ratio values place data points within kerogen Type I/II range.

have a very low oxygen content, supporting the elemental kerogen analytical results reported above (Figure 14).

These results collectively indicate that the OM of the Roper Group is dominated by marine-sourced, oil-prone sapropelic Type II kerogen, composed mainly of alginite macerals.

ORGANIC PETROLOGY

Selected mudrock samples from the Roper Group were analysed for the presence of organic macerals, including: telalginite, alginite, zooclasts/altered bitumen, bitumen, bitumenite, pyrobitumen/solid hydrocarbons (SHC), bitumen thucolite, angular SHC, fluorescing lamalginite and undefined organoclasts. The reflectance of these macerals was measured relative to equivalent vitrinite values (Table 14).

Organic petrographic observations indicate that much of the organic matter comprises diffuse and abundant alginite; this is the dominant maceral (86%) throughout the sampled Roper Group succession (Table 15). Alginite belongs to the liptinite maceral group and has probable origins from algae; it is typical of Type I (very oil prone) kerogen (Peters *et al* 2005). Bitumen intermediates were also identified in selected samples of the Roper Group succession and are the most commonly occurring intermediate in thermally mature samples (Table 15). High proportions of bitumenite also occur in thermally immature samples taken from Walton 2 (Origin Energy 2015); this is a liptinite maceral typical of Type II kerogen with probable origins from degraded algae (Peters *et al* 2005b).

The full table of results for the individual sample analysis is available in Revie (2017).

MACERAL REFLECTANCE

Organic petrology is used as an indicator for thermal maturity, with the reflectance of the macerals measured and expressed in equivalent vitrinite reflectance values [$R_{o(eq)}$]. Bitumen reflectance also provides proxy values for thermal maturity and is also expressed in vitrinite reflectance values (BR_o , Figure 15).

Vitrinite equivalence values from measurements taken on maceral types other than vitrinite (especially in lacustrine and marine sediments) may differ significantly from actual vitrinite reflectance values (Allen and Allen 2013). Organic petrography for thermal maturity can be used in combination with chemical parameters determined through pyrolysis [T_{max} and Production Index (PI)], elemental kerogen CHNOS content and ratios (C wt%, H wt%, H/C wt% and O/C wt%), and gas chromatography and biomarker ratios. The use of these additional parameters helps to reduce the impact of anomalous results that can present with the use of each technique. How these techniques inter-relate is shown in Table 16.

T_{max}

T_{max} is useful for estimating maturity in sediments that do not contain vitrinite, such as the Roper Group succession; however, the technique can have variable results relative to changes in the hydrogen content of OM (Hunt 1995).

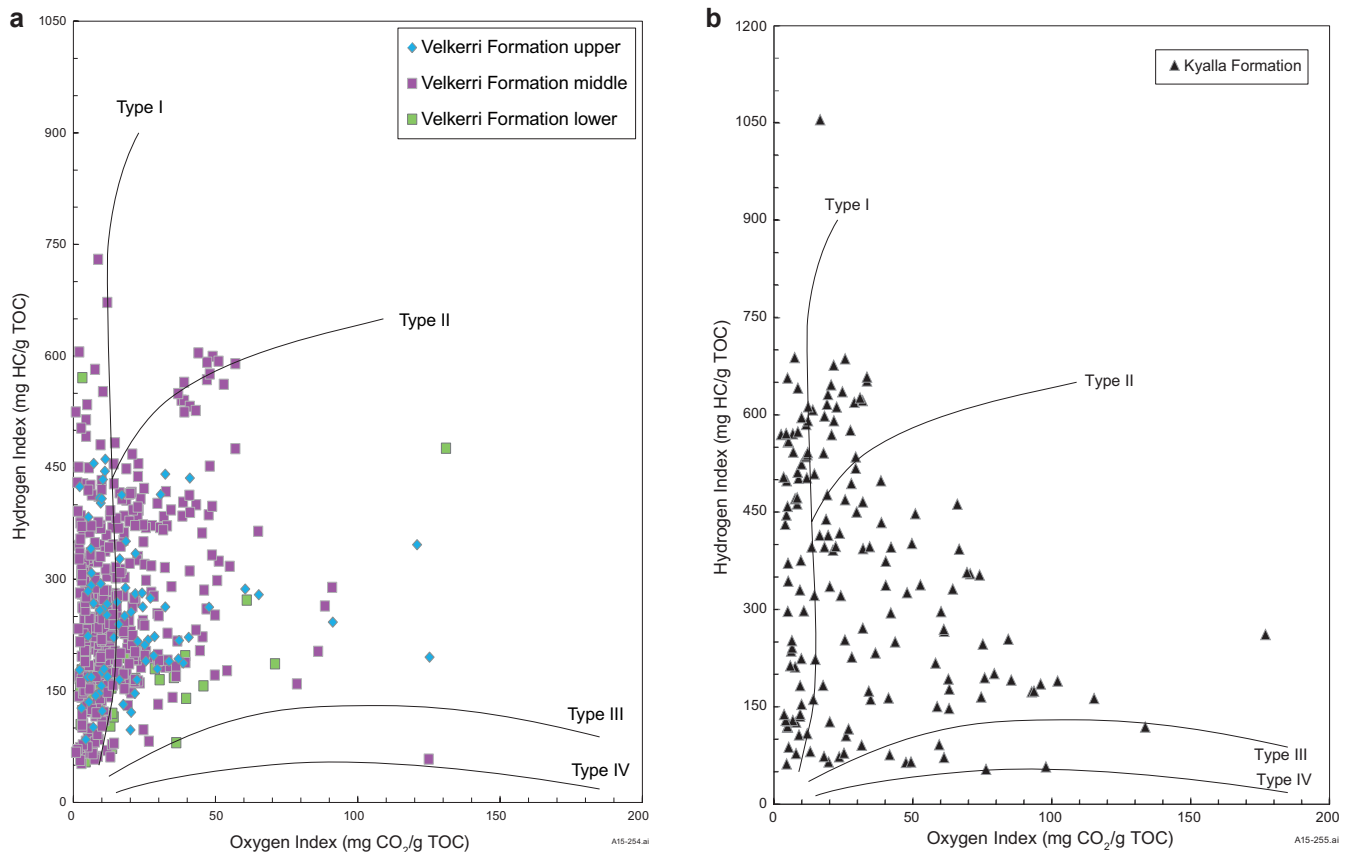


Figure 14. Hydrous pyrolysis HI vs OI values for (a) Velkerri Formation and (b) Kyalla Formation of Roper Group (data from Revie 2017).

Table 14. Organic petrology reflectivity data for selected samples of Roper Group formations (data from Revie 2017). Mean, minimum and maximum values are measured vitrinite equivalence values ($R_{\text{vitr}}(\%)$) taken in oil at 546 nm. Number is count of individual measurements taken.

Maceral	Telalginite				Non-fluorescing alginite				Zooclasts/altered bitumen			
Formation	Mean	Min	Max	n	Mean	Min	Max	n	Mean	Min	Max	n
Corcoran Formation					0.88	0.76	0.98	8				
Hayfield mudstone					0.60	0.29	0.85	62	1.10	0.85	1.61	36
Jamison sandstone					0.39	0.39	0.83	10	1.06	1.01	1.13	3
Kyalla Formation					1.25	0.25	2.79	886	1.00	0.81	1.16	19
Mainoru Formation - Wooden Duck Member												
Moroak Sandstone					1.73	0.27	3.37	83	1.16	1.00	1.46	6
Velkerri Formation lower					4.41	2.90	8.00	90				
Velkerri Formation middle	0.74	0.45	0.96	75	1.30	0.27	4.02	334	1.21	1.15	1.30	3
Velkerri Formation upper	0.41	0.21	0.66	51	1.23	0.31	3.51	187	0.92	0.78	0.98	5
Maceral	Bitumen				Low reflectance solid bitumen				High-reflectance solid bitumen			
Formation	Mean	Min	Max	n	Mean	Min	Max	n	Mean	Min	Max	n
Corcoran Formation					1.10	0.82	1.27	125	1.36	1.32	1.42	3
Hayfield mudstone	0.57	0.58	0.80	6								
Jamison sandstone												
Kyalla Formation	0.98	0.33	2.55	269	0.99	0.49	1.23	94	1.40	1.17	1.92	141
Mainoru Formation - Wooden Duck Member					1.23	1.22	1.23	2	1.66	1.37	1.95	22
Moroak Sandstone	2.02	0.60	3.42	4								
Velkerri Formation lower	2.78	2.13	3.39	30								
Velkerri Formation middle	1.72	0.25	5.57	167	0.88	0.61	1.23	215	2.06	1.40	2.89	122
Velkerri Formation upper	1.77	0.39	4.49	44	0.91	0.68	1.21	106	1.28	1.28	1.28	3
Maceral	Fluorescing lamalginite				Pyrobitumen				Bitumenite			
Formation	Mean	Min	Max	n	Mean	Min	Max	n	Mean	Min	Max	n
Corcoran Formation												
Hayfield mudstone												
Jamison sandstone												
Kyalla Formation	0.51	0.37	0.62	27								
Mainoru Formation - Wooden Duck Member												
Moroak Sandstone												
Velkerri Formation lower												
Velkerri Formation middle	0.64	0.57	0.67	9	1.22	0.82	1.65	162	0.23	0.12	0.42	60
Velkerri Formation upper	0.64	0.64	0.64	1	1.08	1.03	1.14	5	0.18	0.14	0.23	10
Maceral	Organoclasts (undefined)											
Formation	Mean	Min	Max	n								
Corcoran Formation												
Hayfield mudstone												
Jamison sandstone												
Kyalla Formation												
Mainoru Formation - Wooden Duck Member												
Moroak Sandstone												
Velkerri Formation lower	1.43	1.13	2.07	70								
Velkerri Formation middle												
Velkerri Formation upper												

Estimating the thermal maturity of OM in the Roper Group is challenged by the limited range of organic macerals, the age of the rocks, and the varying reliability of techniques used.

Pyrolysis results have previously been used to demonstrate a relationship between T_{max} and depth in the Beetaloo Sub-basin (Silverman and Ahlbrandt 2011), but this was based on limited datasets. Additional information from Revie

(2017) has been used to define a maturity trend through the Roper Group succession (**Figure 16**). The level of reliability in the determination of T_{max} is highest in samples with S2 values >2 mg HC/g rock, as shown in **Figure 16**. Trends observed in the T_{max} values show the onset of significant oil generation at ca 600 m depth, wet-gas/condensate generation at ca 1100 m depth, and dry gas generation at ca 1600 m depth. These trends correlate with similar thermal maturation

results from maceral reflectance analysis (**Figure 17**) and are probably due to the consumption of S2 with depth as thermal degradation of kerogen to form hydrocarbons occurs. Note that the depths do not correlate with present-day depths to the oil/condensate/dry gas windows as determined by the thermal gradient. The data indicate that the formations sampled at the present depths have previously been within these generation zones, and subsequently have been subjected to uplift.

Values of S2 decline below reliable values (<2 mg HC/g rock) at depths exceeding ca 1700 m, indicating that the potential for further oil generation in sediments exceeding this depth is low, and that the generation of gas is driven by the cracking of oil and condensate hydrocarbon fractions that have already been generated. This suggests that the sediments have been exposed to higher temperatures, either through burial or exposure to higher heat flows, and therefore have undergone high levels of conversion to hydrocarbons.

TEMPERATURE OF GENERATION

Generation of primary oils occurs in the calculated temperature ($^{\circ}\text{C}_{\text{temp}}$) range ca 95–140 $^{\circ}\text{C}$, with an average at ca 125 $^{\circ}\text{C}$; these values are based on a large oil database interrogated by BeMent *et al* (1995) and are consistent with current kinetic models of oil generation (Peters *et al* 2005a). Wet gas components (C2–C7) can form during diagenesis via low-temperature carbonium ion or free-radical reactions; however, at temperatures >50 $^{\circ}\text{C}$, there is an exponential increase in hydrocarbon formation. The wet gas window is in the $^{\circ}\text{C}_{\text{temp}}$ range 70–150 $^{\circ}\text{C}$, with peak generation at about 120 $^{\circ}\text{C}$, and the methane window peaks at about 150 $^{\circ}\text{C}$ (Hunt 1995).

Temperature of generation of oils from Roper Group sedimentary rocks can be determined by analysing the extracted oil from sampled cores. Based on modelling by BeMent *et al* (1995), 2,4-dimethylpentane /

Table 15. Maceral, bitumen and bituminous intermediaries count and relative occurrence in selected samples of Roper Group succession (data from Revie 2017). SHC: Solid Hydrocarbons.

MACERAL	Count	%
Non-fluorescing alginite	1660	88%
Telalginite	126	7%
Organoclasts (undefined)	70	4%
Fluorescing lamalginite	37	2%
BITUMENOUS INTERMEDIARY		
	Count	%
Low-reflectance solid bitumen	542	48%
Bitumen	520	46%
High-reflectance solid bitumen	291	26%
Pyrobitumen	167	15%
Zooclasts/altered bitumen	72	6%
Bitumenite	70	6%

2,3-dimethylpentane ratios (2,4-DMP/2,3-DMP) are independent of source and heating rates, and correspond to the temperature of generation (**Equation 1**).

Extracted fluids from a limited number of samples of the Velkerri and Kyalla formations were analysed for their constituents via gas chromatography–mass spectrometry (GCMS). The generation $^{\circ}\text{C}_{\text{temp}}$ range was then calculated for the extracted oil (**Table 17**).

Velkerri Formation oil samples, taken from drillholes MANT-79-2 and Borrowdale 2, have a generation $^{\circ}\text{C}_{\text{temp}}$ range of 124.85–130.85 $^{\circ}\text{C}$. Intra-organofacies variation is indicated within the informal Velkerri Formation middle facies, but further investigations are needed to determine if the informal A, B and C organofacies from this interval each contain unique $^{\circ}\text{C}_{\text{temp}}$ values for oil generation. The Kyalla Formation has an oil generation $^{\circ}\text{C}_{\text{temp}}$ value of 134 $^{\circ}\text{C}$. The $^{\circ}\text{C}_{\text{temp}}$ values of both formations fall within the

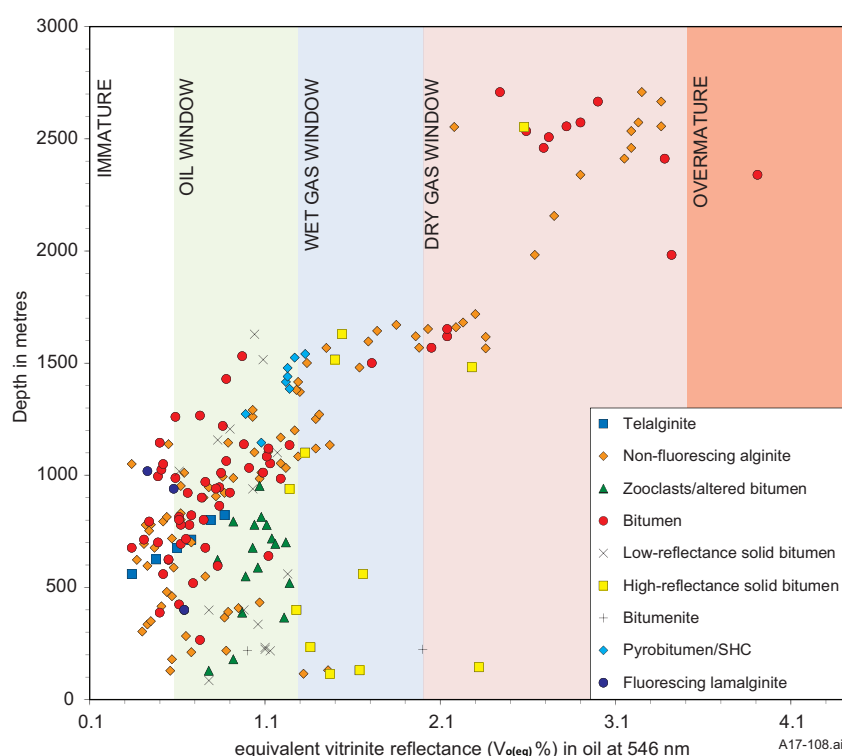
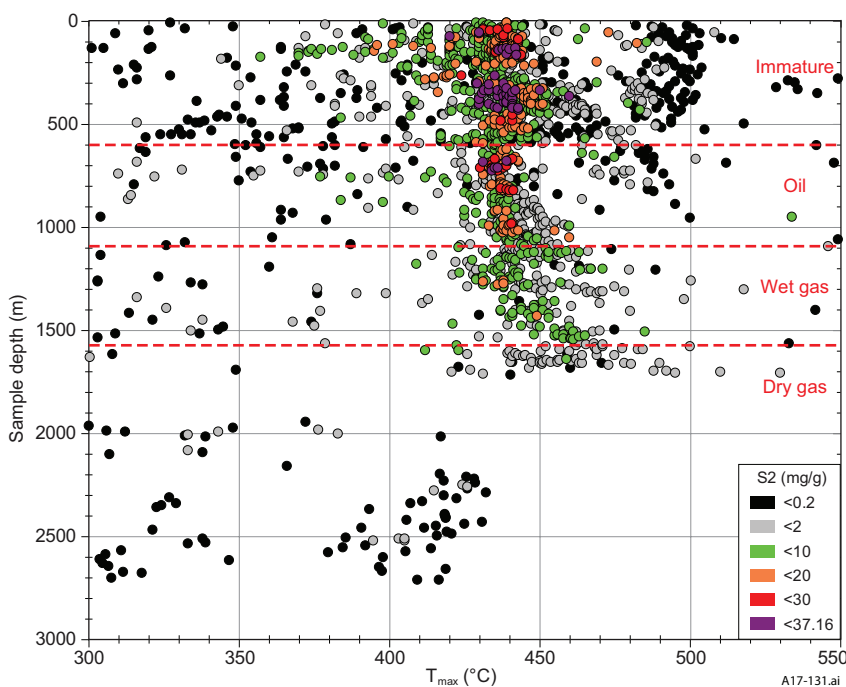


Figure 15. R_o profile of Roper Group maceral reflectance versus depth (data from Revie 2017). All values expressed in vitrinite reflectance equivalent values ($R_{o(\text{eq})}$ %). Values superimposed on petroleum thermal maturity windows as defined by Hunt (1995).

Maturation rank	Max. palaeo Temp °C	Microscopic parameters		Chemical parameters					
		Vitrin Refl. %R _o	Fluorescence		Pyrolysis		C wt%	H wt%	H/C wt%
Colour of alginite	λ Max (nm)		T _{max}	P.I.					
Diagenesis	0.2	Blue green	500	400	0.1	67	8	1.5	Bacterial gas
	0.3	Greenish yellow				70	8	1.4	Immature heavy oil
	0.4	Golden yellow	425	75		8	1.3		
	0.5		540	80		7	1.1	Wet gas and oil	
Catagenesis	0.6	Dull yellow	435	85	6	0.85			
	0.7		600	87	5	0.7	Condensate		
	0.8	Orange	450	90	4	0.5	Dry gas		
	0.9	Red	640	94	3	0.38			
	1.0		680	96	2	0.25			
Metagenesis	1.3	Nonfluorescent	500						
	1.5		550						
	2.0								

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Table 16. Table of organic maturation. R_o = reflectance with oil immersion objective; PI = production index (modified from Hunt 1995).



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Figure 16. T_{max} versus depth by S2 values for Roper Group (data from Revie 2017). S2 values below 0.2 mg HC/g rock (black) are not reliable for estimating T_{max} values. S2 values <2 mg HC/g rock (grey) have poor generative qualities, and low reliability T_{max} values. Changes in T_{max} depend primarily on time/temperature conditions, and can only be used to approximate petroleum generation stages in different rock types. Blue line represents average change in T_{max} with depth. T_{max} less than ca 435°C indicates immature organic matter that has generated little to no petroleum; T_{max} >470°C coincides with wet gas zone; T_{max} greater than ca 500°C coincides with high-maturity samples in dry gas zone (Peters *et al* 2005b).

effective temperature range for conditions associated with oil expulsion, which is between ca 95 and 135°C (Peters *et al* 2005a). These °C_{temp} values also correlate to the generation of wet gas within both formations, assuming that depth of burial is adequate to place the formations in these generation temperature ranges.

Kerogen kinetic assessments of the Velkerri and Kyalla formations indicate varying time–temperature relationships for the onset of oil generation [significant onset around 10% TR]. TR is the ratio of extracted bitumen to TOC (Bit/TOC) in fine-grained non-reservoir rocks; it is a direct measure of the threshold peak temperature and %R_o values of oil generation (Table 18).

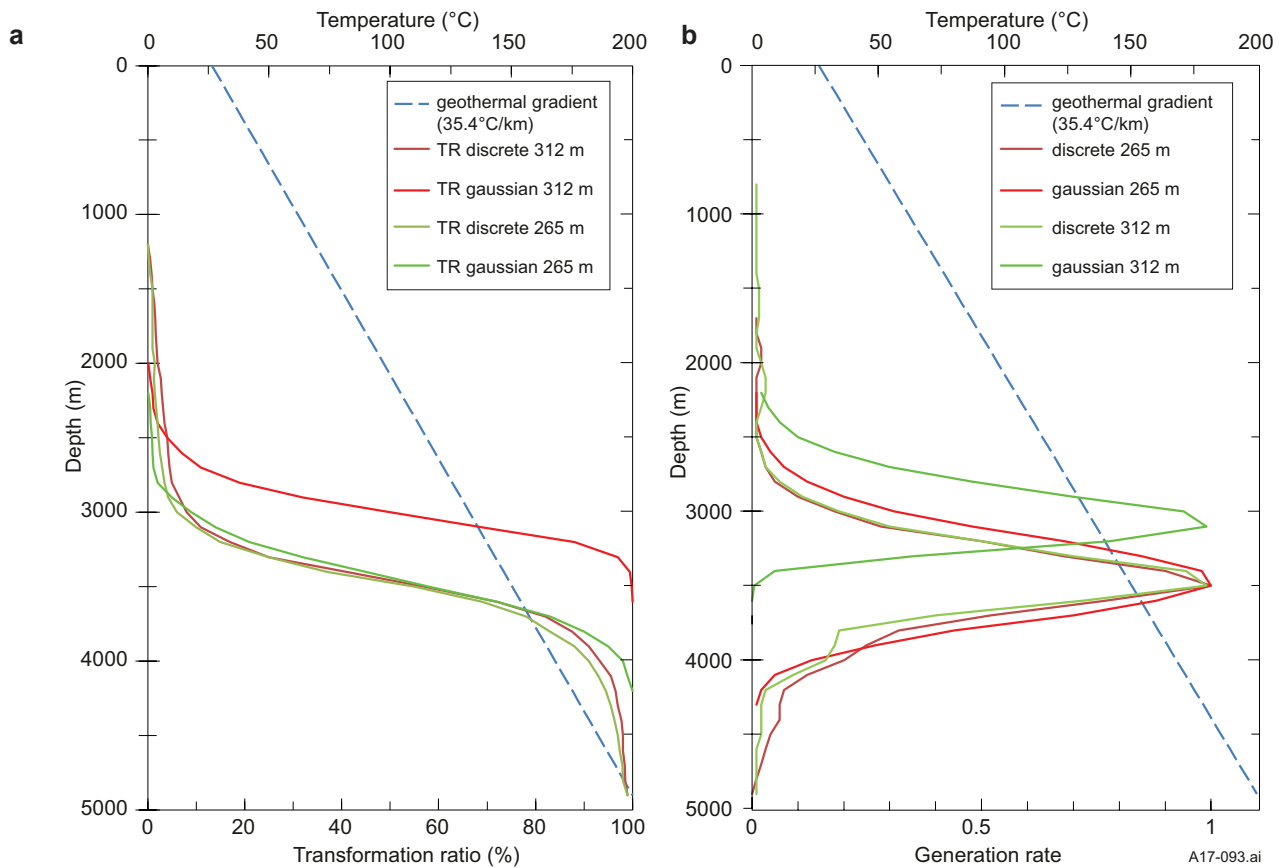


Figure 17. (a) Kerogen transformation ratio and temperature versus depth, and (b) computed oil generation rate for middle Velkerri Formation samples taken from Walton 2, computed using a 3.3°C/million years constant heating rate. Geothermal gradient of 35.4°C/km sourced from Shenandoah 1 (Falcon 2009). Transformation ratio correlates with Type IIC (2C) kerogen. Kinetics data sourced from Revie (2017). TR = Transformation Ratio.

Table 17. C₇ hydrocarbon ratios based on steady-state kinetic model of light-hydrocarbon generation (Mango 1997) used to derive temperature of generation (°C_{temp}) of oils extracted from samples of Velkerri and Kyalla formations (data from Revie 2017).

Hole ID	Sample ID	Formation	Sample depth (m)	ln(2,4-DMP/2,3-DMP) ratio	°C _{temp}
Borrowdale 2	HD14DJR077	Velkerri Formation <i>middle</i>	478.00	-1.01	124.85
MANT-79-2	HD14DJR053	Velkerri Formation <i>middle</i>	355.00	-0.61	130.85
MANT-79-2	HD14DJR073	Velkerri Formation <i>upper</i>	419.00	-0.65	130.25
Scarborough 1	TN14DJR171	Kyalla Formation	976.04	-0.34	134.9

Table 18. Modelled oil generation temperature and vitrinite reflectance values (equivalent) based on kerogen kinetic parameters (data from Revie 2017). Samples extracted from intersections of formation in low thermal maturity (immature to early oil maturity) range. TR = Transformation Ratio of extractable bitumen to TOC.

Formation	Well	Discrete model (calculated results using 3.3°C/million years)		Gaussian model (calculated results using 3.3°C/million years)	
		Computed onset (10% TR) and (peak) T (°C)	Computed onset and (peak) generation %R _o value	Computed onset (10% TR) and (peak) T (°C)	Computed onset and (peak) generation %R _o value
Kyalla Formation	Shea 1	131–135 (152–155)	0.76–0.8 (1.0–1.07)	134–135 (150–152)	0.79–0.80 (0.98–1.01)
Velkerri Formation middle	Walton 2	134–137 (150–151)	0.79–0.82 (0.97–0.92)	121–134 (135–149)	0.70–0.79 (0.80–0.97)

The oil generation $^{\circ}\text{C}_{\text{temp}}$ value (134°C) of the Kyalla Formation extract correlates with the computed onset (10% TR) of oil, as determined by kerogen kinetics. The middle Velkerri Formation facies $^{\circ}\text{C}_{\text{temp}}$ range between $124.85\text{--}130.85^{\circ}\text{C}$ correlates with the modelled onset of oil generation determined by kerogen kinetic analysis ($121\text{--}134^{\circ}\text{C}$).

Peak oil generation temperatures do not necessarily correlate with peak oil yields from the formations. The yield of oil within a formation increases when the generation of oil is greater than migration of oil from the formation plus the conversion of oil to gas. The temperature range for the onset of significant oil generation (10% TR) is calculated for the maximum burial depth attained by the sedimentary section, keeping in mind that the present-day burial depth does not necessarily represent the depth interval of generation.

The relatively shallow sample depths for the extracted oils shown in **Table 17** suggest significant burial of the sedimentary rocks to reach the oil window, followed by subsequent uplift and erosion.

KEROGEN KINETICS IN DETERMINING GENERATION DEPTH

In the plug and abandonment report for Shenandoah 1A, Falcon (2012) recorded a temperature of 82°C at 1553 m, and a bottom hole static temperature (BHST) of 114°C at 2714 m. In June 2009, they reported a bottom hole temperature of 136°C at a depth of 3100 m. This information was used in conjunction with a mean annual surface temperature of 26.50°C to calculate a present-day temperature gradient of $3.54^{\circ}\text{C}/100.0\text{ m}$ (Falcon 2009). Correlating this temperature gradient with computed onset of generation values determined through kinetics, the 10% TR (onset of significant oil generation) depth would be in the range 2600–3050 m for the middle Velkerri Formation (**Figure 17**), and 2950–3050 m for the Kyalla Formation (**Figure 18**).

The onset of minor oil generation (<10% TR) in Roper Group shales would occur at approximately 800 m depth, given the present-day geothermal gradient. The maximum oil generation rate (generation rate = 1) for both the Kyalla and middle Velkerri formations occurs at a temperature of approximately 150°C , which corresponds to a burial depth of around 3500 m. Petroleum wells in the Beetaloo

Sub-basin region have intersected these formations at depths within the oil generating window. Both formations are present at depths of maximum generation rate in Shenandoah 1 (Falcon 2012). Exploration drilling by Origin Energy Ltd intersected the Kyalla Formation in Amungee NW1 between 1000 m and 1400 m, and the middle Velkerri Formation at depths in the range 1000–2500 m in Kalala S1 and Amungee NW1 (Close *et al* 2016). The Pangaea Resources exploration well Tarlee S3, situated in the Gorrie Sub-basin, intersected the Kyalla Formation at depths of approximately 750–830 m, and the middle Velkerri Formation at approximately 1200–1600 m. Tanumbirini 1, drilled by Santos Ltd in 2014, intersected the Kyalla Formation between 1297 and 2069 m; the formation is likely to have entered the oil window at these depths, with the onset of minor generation occurring.

Wet gas (C_2H_6+) generation occurs alongside oil generation from sapropelic OM in and below the oil window and from thermal decomposition of oil, with peak methane (dry-gas, CH_4) generation from OM occurring at about 150°C (Hunt 1995). Generated oils present at temperatures $>150^{\circ}\text{C}$ (present-day depths $>3500\text{ m}$ in the Beetaloo Sub-basin) will eventually be converted to gas by thermally induced secondary cracking.

GENERATIVE POTENTIAL: SHELF REGION

This section is a summary of available analyses that can be used to determine/estimate the petroleum generative potential of the Kyalla Formation and middle Velkerri Formation. Individual well reports detailing the generative potential of the fine-grained formations in each well that were incorporated into this study are compiled into CSR0413 (Revie 2016b).

Appendix 1 (McArthur Basin Interpretive Summary Kyalla-Mainoru Interval) provides more details of these units, as well as results for the upper and lower Velkerri Formation, Corcoran Formation and Mainoru Formation.

KYALLA FORMATION GENERATIVE POTENTIAL

Kyalla Formation source rock samples analysed from the shelf region of the McArthur Basin have good generative potential, based on analyses from two wells (Scarborough 1 and Shea 1) with significant intersections of the formation (**Table 19**).

Table 19. Kyalla Formation geochemical summary from shelf region of greater McArthur Basin. Current TOC averages represent all data available; original TOC averages are high-graded samples that had present-day TOC values $>0.4\%$ TOC and have programmed pyrolysis data.

Well name	Formation	Main product	Thermal maturity	Source rock richness	Organic matter type	Shale oil risk
Scarborough 1	Kyalla	Estimated original →		Very good (2.22% TOC)	Oil-prone Type II	Moderate
		Measured currently →	Oil	Peak oil window	Very good (2.06% TOC)	
Shea 1	Kyalla	Estimated original →		Good (1.81% TOC)	Oil-prone Type I/II	High
		Measured currently →	Minor oil	Early oil window	Good (1.73% TOC)	

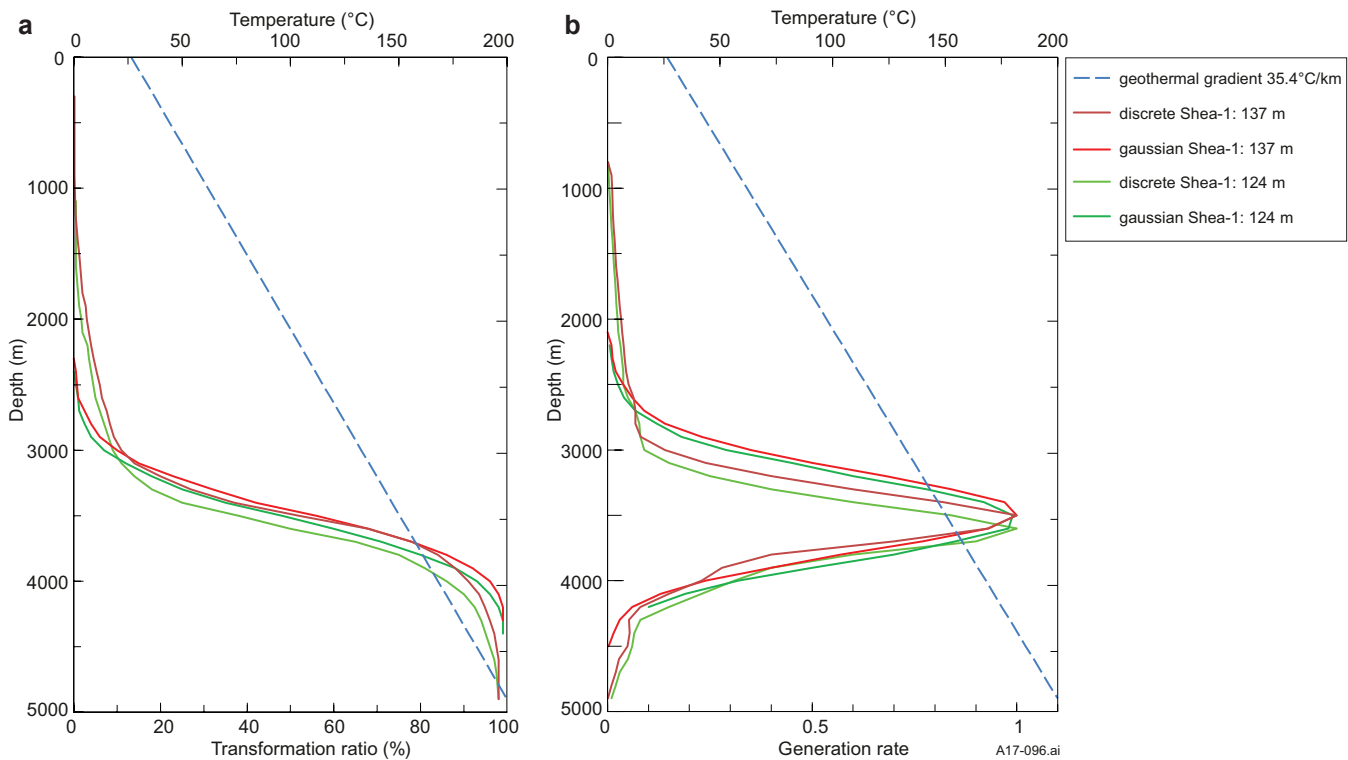


Figure 18. (a) Kerogen transformation ratio and temperature versus depth, and (b) computed oil generation rate for Kyalla Formation from Shea 1. Geothermal gradient of 35.4°C/km sourced from Shenandoah 1 (Falcon 2009). Transformation ratio correlates with Type IIC (2C) kerogen. Computed using a 3.3°C/million years constant heating rate. Samples taken from Shea-1 and GR10. Kinetics data sourced from Revie (2017). TR = Transformation Ratio.

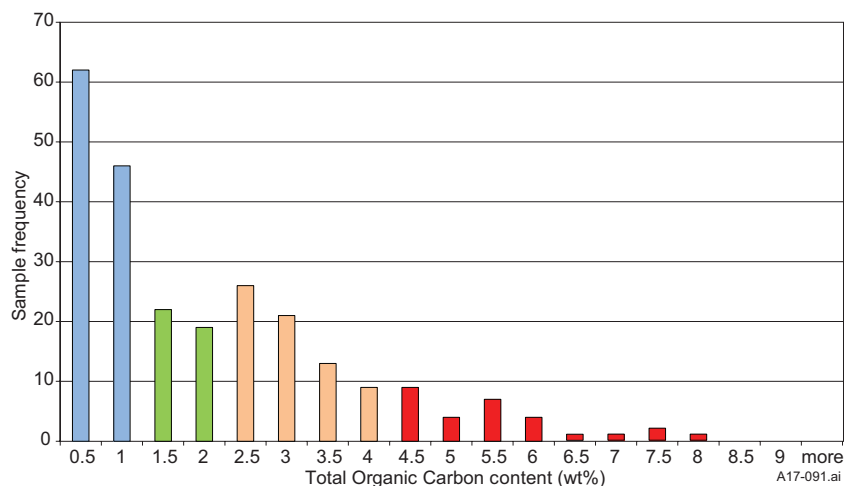
Organic richness varies from 0.55 wt% (fair) to as high as 4.28 wt% (excellent) TOC, with an average value of 1.75 wt% TOC (good). A histogram plot of TOC distributions illustrates that the dominant population is within the 0.5 to 1.0 wt% range (Figure 19). Outside of this range, there appears to be a general trend of progressive decrease in frequency of samples with increasing TOC content. More than three-quarter of these samples have TOC contents above the minimum requirement of 1 wt% for effective petroleum source rocks. About half of the samples also have TOC content above the minimum requirement of 2 wt% for economic petroleum source rocks, which is a favourable factor for unconventional resource development.

Pyrolysis S2 yields for Kyalla Formation samples vary from 0.25–22.68 mg HC/g rock (Figure 20) and average

values within individual wells vary in the range 3.22–8.83 mg HC/g rock or 71–193 bbl/acre-ft. These indicate a fair 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 peak oil window. There are two dominant populations of data for the Kyalla Formation samples that would appear to correspond to two different organofacies within this interval.

This difference in remaining generation potential is predominantly a consequence of interpreted thermal maturity differences. Shea 1 has been matured to the early oil window and Scarborough 1 to the peak oil window. Further integration of the geochemical data with regional geology and additional well data points would be needed to provide further insights into the origin of these S2 variations. The

Figure 19. Histogram plot of Total Organic Carbon (TOC) distributions for Kyalla Formation source rocks in shelf region of greater McArthur Basin. Data is organised into 0.5 wt% TOC bins; colour codes correspond to TOC designations shown in Table 11. Data from Revie (2017), and derived from Scarborough 1 and Shea 1.



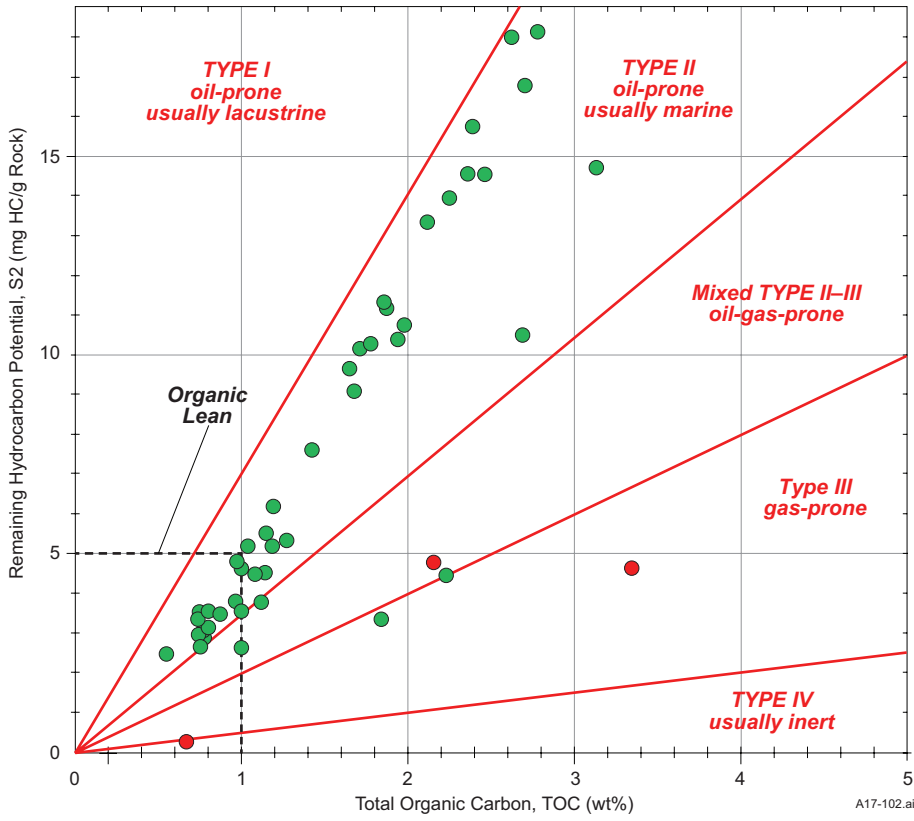


Figure 20. Kyalla Formation TOC versus S2 remaining hydrocarbon potential for shelf region of greater McArthur Basin (data from Revie 2017). Red dots are samples from Scarborough 1; green dots are from Shea 1. Two population groups are indicated; these might be a product of thermal maturity differences between the wells, or might potentially represent two separate organofacies within Kyalla Formation.

spatial distribution of S2 content for the Kyalla Formation samples shows significant variations between the two wells (which is not apparent in TOC). Shea 1 in the western region of the study area has a much higher S2 content in

comparison to Scarborough 1, which is located in the far east of the study area (**Figure 21**).

Kyalla Formation samples from the shelf area form two relatively distinct groups on a plot of hydrogen index versus

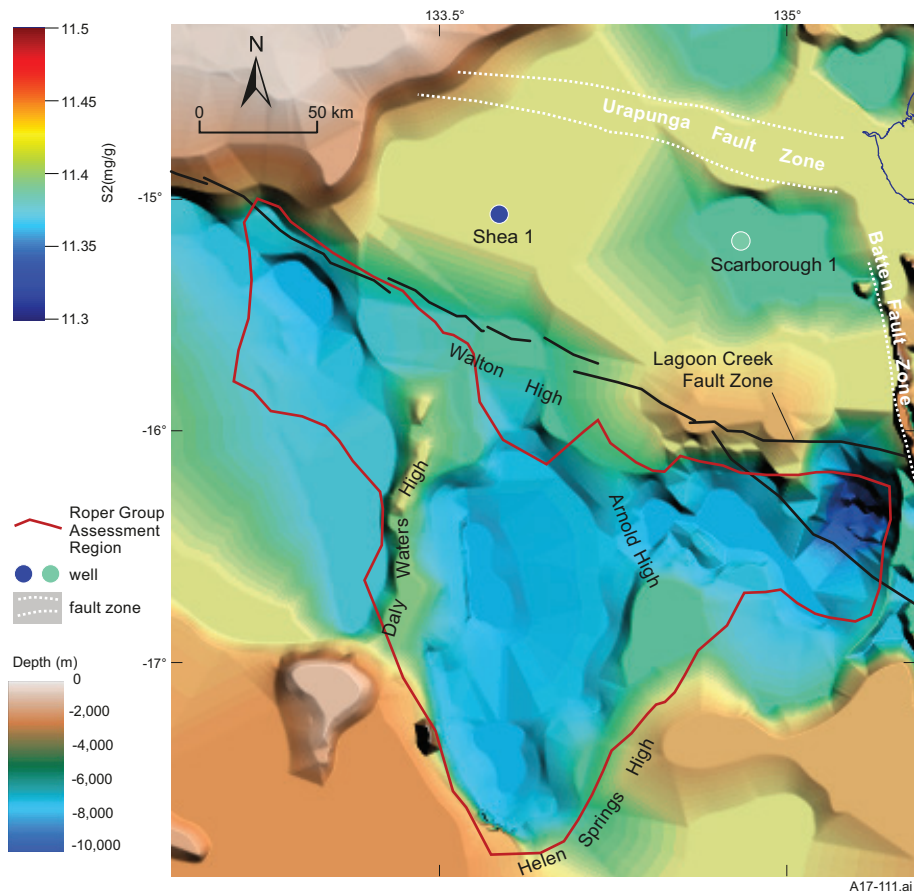


Figure 21. Spatial distribution of Shea 1 and Scarborough 1, coloured by S2 value (mg HC/g rock) for remaining hydrocarbon generation potential.

oxygen index (**Figure 22**). One group is characterised by a high TOC content and very high HI values of ca 500–700 mg HC/g TOC. These values represent well preserved, oil-prone, marine Type I kerogen containing filamentous algae and/or cyanobacterial biomass, similar to that found in Jamison 1 (see **Figure 23**). The other group of samples may represent a type of facies associated with less prospective source rock lithologies. The diagnostic feature is that these samples have lower HI values of <500 mg HC/g TOC and much higher OI values of >30 mg CO₂/g TOC. They most likely represent lower-quality preserved Type II organic matter that has been partially

oxidised 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. These Kyalla source rocks are considered early to peak mature with regard to oil generation. The kerogen HI values have been reduced only slightly as a consequence of thermal maturity; thus, they indicate primarily mixed oil-prone Type I/II kerogen quality at the present day.

Plotted measured OI values in Kyalla Formation samples vary from 4 to 74 mg CO₂/g TOC and there are several samples with elevated OI >35 (**Figure 22**). These samples would appear to plot more in the region

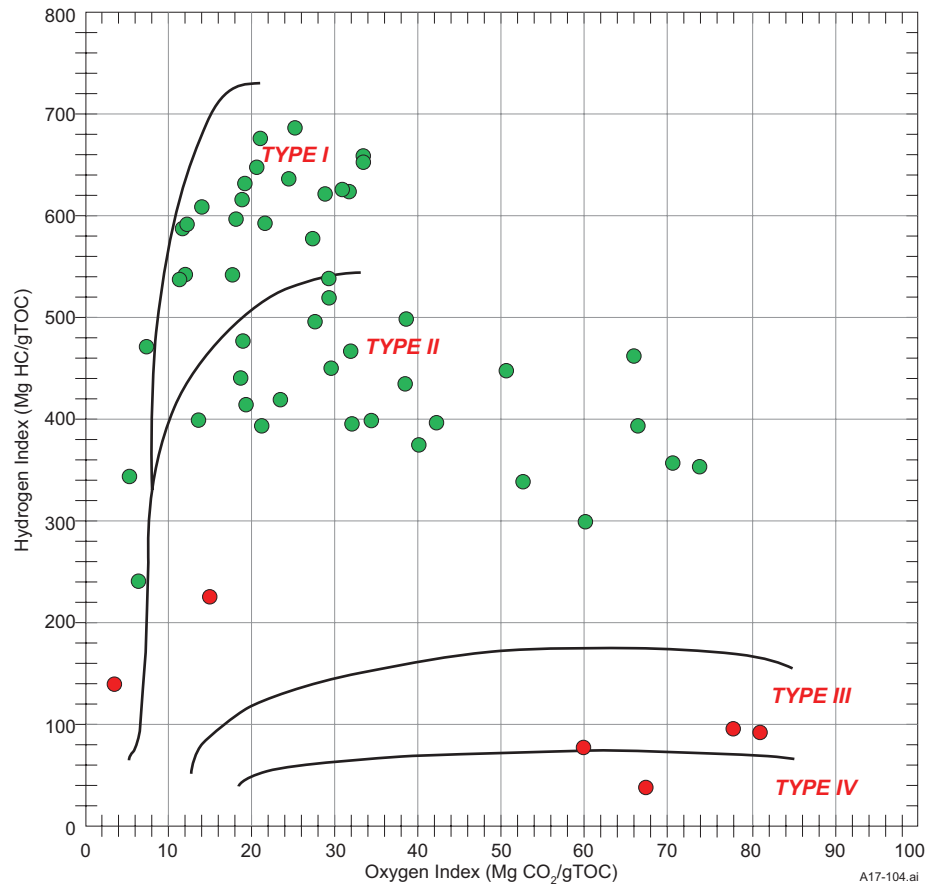


Figure 22. HI (hydrogen index) versus OI (oxygen index) for Kyalla Formation in shelf region of greater McArthur Basin. Red dots are samples from Scarborough 1; green dots are from Shea 1.

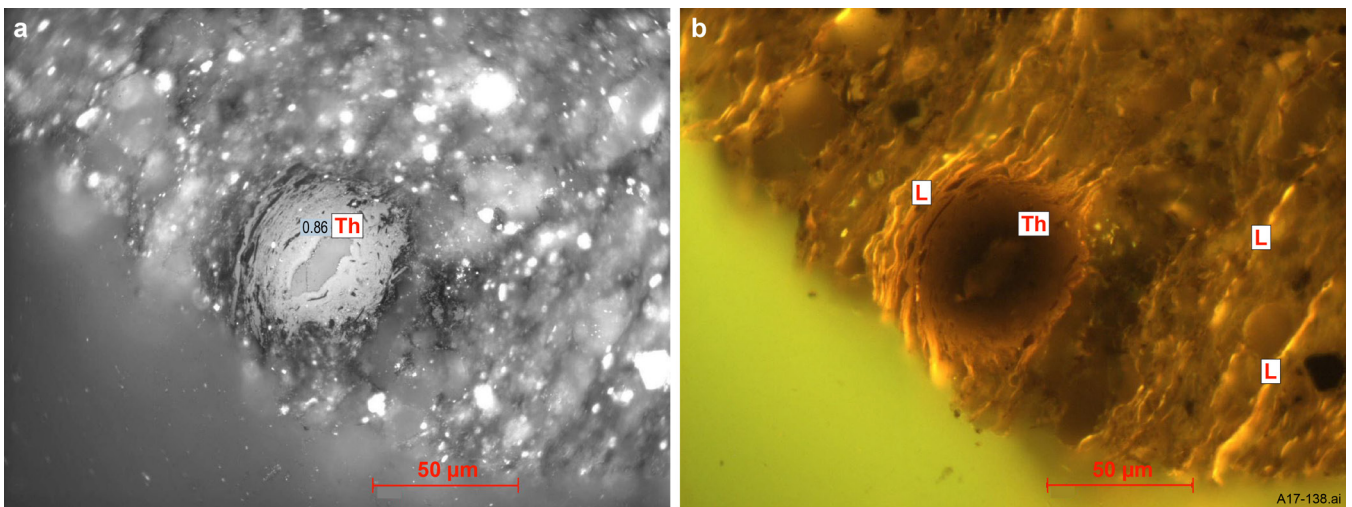


Figure 23. Photomicrograph of Kyalla Formation shale from Jamison 1 (sample TN14DJR008 from 1018.7 m depth), showing (a) low reflectance solid bitumen and likely thucholite (Th) grain, $R_o=0.86\%$, mean $BR_o=0.79\%$ (reflected white light); and (b) thucholite (Th) grain surrounded by yellow orange fluorescing lamellae of lamalginite (L) (reflected UV light).

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 the Mesoproterozoic. Thus, these samples are more likely to represent a mixture of Type II marine algal and Type IV oxidised inert organic matter.

MIDDLE VELKERRI FORMATION PETROLEUM GEOCHEMISTRY

Eight wells that intersect the middle Velkerri Formation in the shelf region of the McArthur Basin were assessed for petroleum geochemistry and characterisation (Table 20). Samples from these wells were analysed using a variety

of geochemical techniques, including TOC content, programmed pyrolysis (SRA) and organic petrology with measured maceral reflectance (R_o). The interpreted maximum thermal maturity reached in the middle Velkerri Formation source intervals in most of these wells is the peak oil window, and hydrocarbon saturation is likely to be fairly light and mobile. The source intervals may have occluded or restricted microporosity due to the presence of solid bitumen, as determined from organic petrology analyses.

Generative potential

The present-day organic richness of middle Velkerri Formation samples from the shelf region of the McArthur Basin indicates very good generative potential (average

Table 20. Geochemistry of middle Velkerri Formation intersections in McArthur Basin shelf region. Current TOC averages represent all data available; original TOC averages are only high-graded samples that have programmed pyrolysis data (>0.4 wt% TOC).

Well name	Formation	Main product	Thermal maturity	Source rock richness	Organic matter type	Shale oil risk
Alexander 1	middle Velkerri	Estimated original →		↓ Excellent (5.30% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Excellent (4.31% TOC)	↓ Mixed Type II/III	
Urapunga 3	middle Velkerri	Estimated original →		↓ Excellent (5.50% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Excellent (4.74% TOC)	↓ Mixed Type II/III	
Urapunga 4	middle Velkerri	Estimated original →		↓ Excellent (4.39% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Very good (3.07% TOC)	↓ Oil-prone Type II	
Borrowdale 2	middle Velkerri	Estimated original →		↓ Excellent (7.09% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Early oil window	↓ Excellent (6.05% TOC)	↓ Gas-prone Type III	
Friendship 1	middle Velkerri	Estimated original →		↓ Very good (3.98% TOC)	↓ Oil-prone Type II	Low (gas)
		Dry gas	Dry Gas window	↓ Very good (3.04% TOC)	↓ Gas-prone Type III	
Lady Penrhyn 2	middle Velkerri	Estimated original →		↓ Very good (3.09% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Very good (2.50% TOC)	↓ Mixed Type II/III	
Scarborough 1	middle Velkerri	Estimated original →		↓ Very good (3.80% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Very good (2.85% TOC)	↓ Gas-prone Type III	
Shea 1	middle Velkerri	Estimated original →		↓ Excellent (4.43% TOC)	↓ Oil-prone Type II	Low (oil)
		Oil	Peak oil window	↓ Very good (3.68% TOC)	↓ Mixed Type II/III	

3.83 wt% TOC). TOC values vary from 0.08% (poor) to 22.93% (excellent). The distribution of the TOC values indicates that the dominant population is within the range 2.5–3.0 wt% (Figure 24). Approximately 80% of the samples have >2 wt% TOC content, the minimum requirement for economic petroleum source rocks. This is very favourable for unconventional resource development.

The spatial distribution of measured TOC content in the middle Velkerri Formation is varied across the shelf region and no trend or pattern is obvious within the dataset. Variations in palaeo-depositional environment or organic productivity could have imparted geographic variations in the abundance of preserved organic matter within the source rock interval.

Sediment provenance studies (Cox *et al* 2016) proposed that the high organic matter flux in the middle Velkerri Formation might have resulted from increased nutrient loading into the ‘Roper Seaway’, due to a shift in provenance from felsic lithologies to the weathering of more mafic (basalt) precursor lithologies.

Unconventional oil and gas potential

The unconventional oil and gas potential of the middle Velkerri Formation in the shelf region of the McArthur Basin can be assessed against published results from the Barnett Shale in the Fort Worth Basin (USA). Data for each of the well intersections is shown on a star plot of the average values of the diagnostic ratios (Figure 25).

The middle Velkerri Formation in the shelf region is interpreted to represent a relatively low geochemical risk for *in situ* shale oil production. Thermal maturity parameters based on T_{max} values indicate that the shale has reached the early to peak oil window (Figure 25). This amount of conversion would be enough have generated/expelled significant amounts of hydrocarbons from organic-rich facies. None of the analysed samples had T_{max} values above the minimum threshold of 455°C for shale gas. Transformation ratios (TR) average 48–76% for wells interpreted to be in the oil window, and generally fall above the recommended minimum of 50% for shale oil (Figure 25). Friendship 1 has

Figure 24. Histogram plot of TOC distributions for middle Velkerri Formation in shelf region of greater McArthur Basin (data from Revie 2017). Data is organised into 0.5 wt% TOC bins; colour codes correspond to TOC designations shown in Table 11.

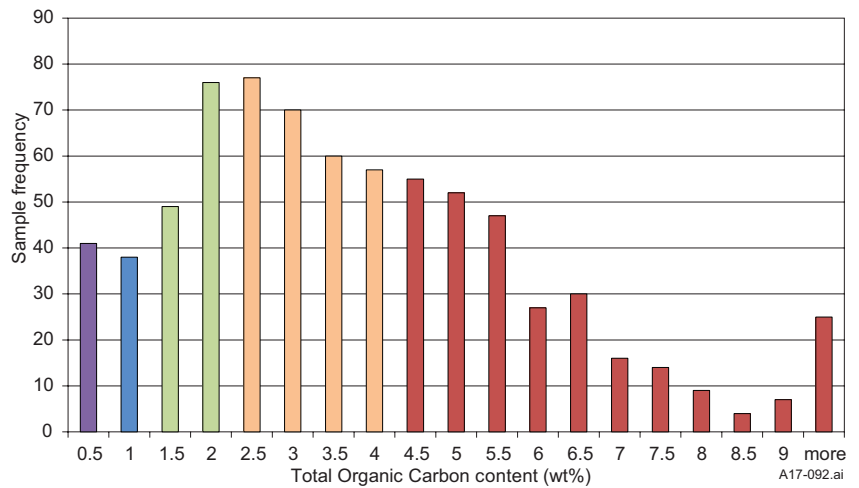
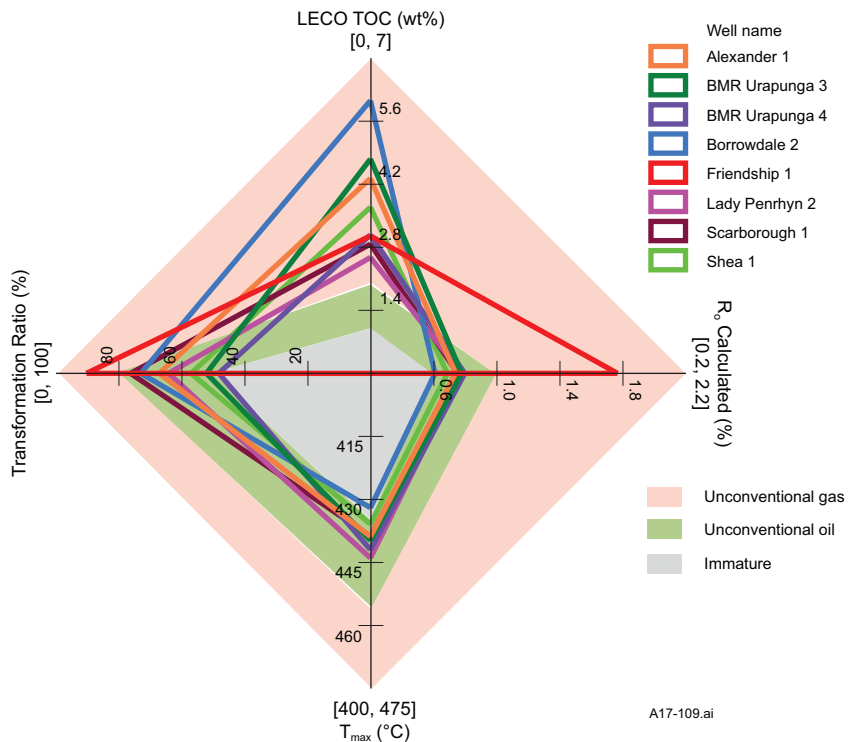


Figure 25. Geochemical risk assessment diagram for middle Velkerri Formation in shelf region of McArthur Basin. Data that lies above minimum threshold and within shaded areas indicate samples with low geochemical risk for either thermogenic oil or gas production. Data that lie below minimum threshold and fall in immature region (in grey) indicate 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 highest interpreted TR of 90%, placing it above the gas window minimum threshold of 80%.

Three reliable solid bitumen reflectance values (0.78% R_o) place the formation within the oil window.

Measured *in situ* oil saturation of the samples are fair to very good (average 17–75 bbl oil/acre-ft), which is positive

for shale oil risk assessment (Figure 26). The oil saturation measured in Friendship 1 is fair (average 17 bbl/acre-ft) and likely to have been the result of thermal conversion (cracking) of oil to gas. Oil cracking in Friendship 1 is estimated to have been 96%, resulting in cracked yields of 1997 Mcf/acre-ft (Figure 27).

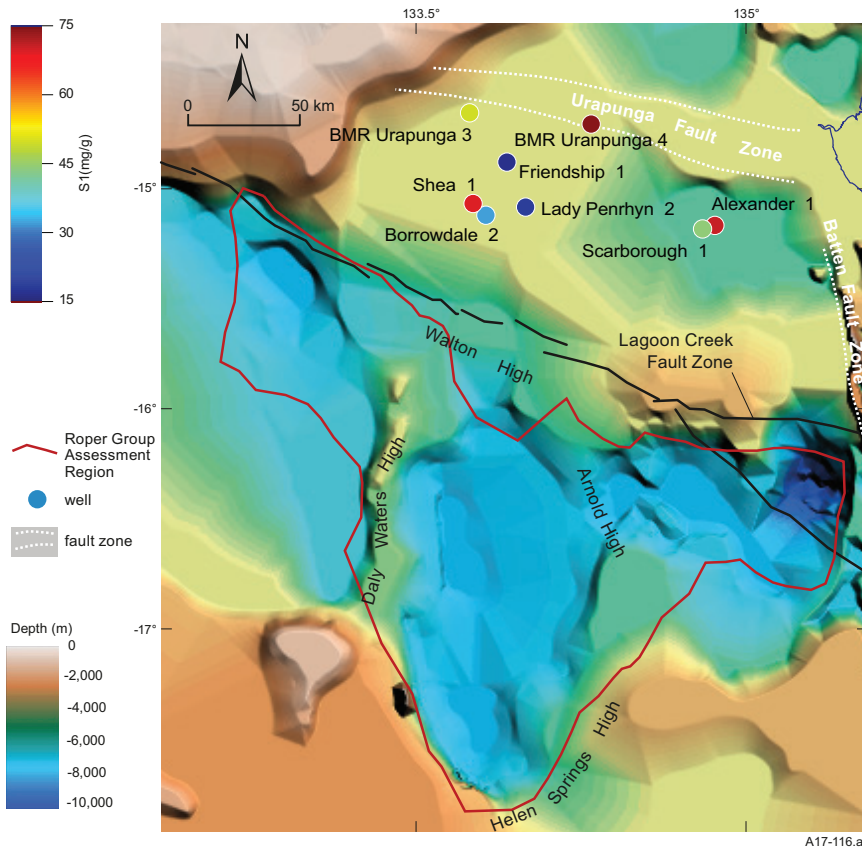


Figure 26. Spatial distribution of S1 free oil saturation for middle Velkerri Formation in shelf region of McArthur Basin. Mapped values are for average S1 and are reported as bbl oil/acre-ft.

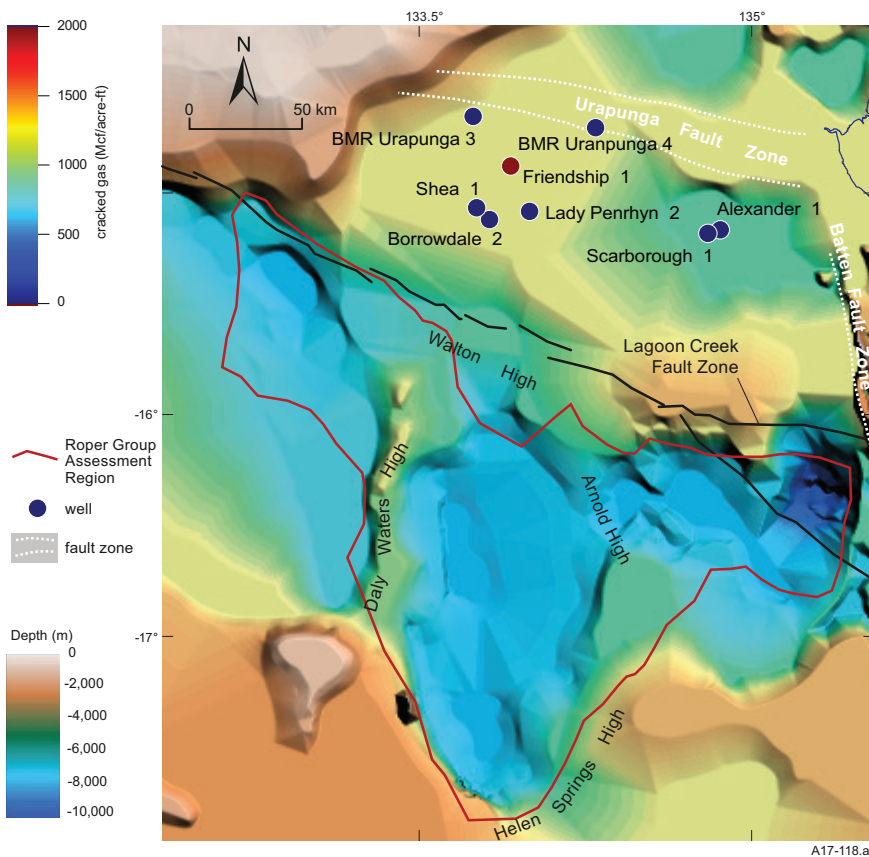


Figure 27. Spatial distribution of estimated cracked gas yields for middle Velkerri Formation in shelf region of McArthur Basin. Mapped values are for average secondary cracked gas and are reported as Mcf gas/acre-ft.

GENERATIVE POTENTIAL: BEETALOO SUB-BASIN REGION

The Beetaloo Sub-basin and the associated Gorrie, Broadmere-and OT Downs sub-basins (Figure 5) are prospective for unconventional hydrocarbon plays, particularly within the Kyalla and middle Velkerri formations. Nine wells located in this region were investigated for formation source rock geochemistry in order to assess hydrocarbon prospectivity.

Appendix 2 (Beetaloo Sub-basin Interpretive Summary Kyalla-Mainoru Interval) provides more details of these units, as well as results for the upper and lower Velkerri formation, Corcoran Formation and Mainoru Formation.

KYALLA FORMATION

Analyses of Kyalla Formation source rock samples from nine wells in the Beetaloo Sub-basin region are summarised in Table 21. The source rocks have poor to good petroleum

Table 21. Kyalla Formation geochemical summary from Beetaloo Sub-basin region. Current TOC averages represent all data available; original TOC averages are only high-graded samples that have programmed pyrolysis data (>0.4 wt% TOC).

Well name	Formation	Main product	Thermal maturity	Source rock richness	Organic matter type	Shale oil risk
Balmain 1	Kyalla	Estimated original →		Good (1.94% TOC)	Oil-prone Type I/II	Moderate
		Measured currently →	Minor Oil	Early oil window	Good (1.32% TOC)	
Burdo 1	Kyalla	Estimated original →		Good (1.09% TOC)	Oil-prone Type II	High
		Measured currently →	Oil	Peak oil window	Fair (0.85% TOC)	
Chanin 1	Kyalla	Estimated original →		Good (1.27% TOC)	Oil-prone Type II	High
		Measured currently →	Oil Wet gas	Late oil window	Fair (0.79% TOC)	
Elliott 1	Kyalla	Estimated original →		Good (1.46% TOC)	Oil-prone Type II	High
		Measured currently →	Oil	Peak oil window	Fair (0.87% TOC)	
Jamison 1	Kyalla	Estimated original →		Very good (2.37% TOC)	Oil-prone Type II	Low
		Measured currently →	Oil Wet Gas	Late oil window	Good (1.65% TOC)	
McManus 1	Kyalla	Estimated original →		Fair (0.88% TOC)	Oil-prone Type II	High
		Measured currently →	Oil	Early oil window	Poor (0.40% TOC)	
Ronald 1	Kyalla	Estimated original →		Good (1.04% TOC)	Oil-prone Type II	Moderate
		Measured currently →	Oil	Peak oil window	Fair (0.74% TOC)	
Sever 1	Kyalla	Estimated original →		Fair (0.93% TOC)	Oil-prone Type II	High
		Measured currently →	Oil	Peak oil window	Fair (0.72% TOC)	
Shenandoah 1A	Kyalla	Estimated original →		Very good (2.37%TOC)	Oil-prone Type II	Moderate
		Measured currently →	Oil Wet gas	Late oil window	Good (1.39% TOC)	

generative potential. Organic richness averages 1.15 wt% TOC (good) with variability between 0.03 wt% TOC (poor) and 8.97 wt% TOC (excellent). The distribution of TOC values (**Figure 28**) indicates a dominant population within the fair range (0.5–1.0 wt% TOC), and a progressive decrease in samples with increasing TOC content. About 15% of these samples have ≥ 2.0 wt% TOC content.

The central region of the Beetaloo Sub-basin contains more than 70% of TOC values >2 wt%, distributed between the wells Jamison 1, Shenandoah 1A and Balmain 1. Wells located along the sub-basin margins have lower average TOC contents within the formation. Organic productivity and preservation appears to be better within the central regions of the sub-basin, and indicate a difference in palaeo-depositional environment to its margins.

Pyrolysis S2 yields from the Kyalla Formation samples vary between 0.05–20.12 mg HC/g rock (poor to excellent remaining hydrocarbon generation potential); average values within individual wells are in the range 0.70–8.29 mg HC/g rock (poor to good remaining hydrocarbon generation potential). This is consistent with primary thermal conversion levels varying within the early to late oil window.

The Kyalla Formation appears to have two distinct facies, indicated by two dominant populations within a plot of TOC versus S2 (**Figure 29**). Samples from the first population have variable TOC, generally elevated S2 values and mostly plot within the oil-prone Type II (marine) kerogen region. These samples are well preserved and have undergone minimal thermal conversion. The second population has lower S2 values and relatively higher TOC content, is more dispersed and is represented by samples only partially converted to petroleum due to moderate thermal maturity (early/late oil); these have limited original generational potential (**Figure 30**). It is interesting to note that the Kyalla Formation intersection in Balmain 1 is of lower thermal maturity than in Shenandoah 1/1A, despite their close proximity (450 m). Balmain 1 is in the early oil window, and has higher remaining generational potential (good to excellent), whereas Shenandoah 1/1A is in the late oil window and averages poor remaining generational potential. Balmain 1 terminated in the Kyalla Formation (total depth 1050 m), partially intersecting the lower facies. Shenandoah 1/1A drilled through the base of the formation at 700 m greater depth (1716 m). At this greater depth, the

formation was subjected to higher thermal maturity and conversion, resulting in the differences observed in the data populations. The two data populations also occur within Jamison 1, with population variability due to increasing thermal maturity and decreasing S2 with depth. TOC increases from the organically-lean upper facies down to the organically-rich lower facies.

Two distinct lithofacies, informally named the lower and upper Kyalla Formation, are present in the Beetaloo Sub-basin. The lower Kyalla Formation has yielded the most prospective samples; these are characterised by high S2 and moderately high TOC content, and have distinctly high hydrogen index (HI) values in the range ca 500–700 mg HC/g TOC (**Figure 30**). Organic matter in this lithofacies is dominated by oil-prone Type II kerogen consisting of variable abundances of amorphous organic matter (AOM), inert AOM, and minor exsudatinite along with solid bitumens.

The upper Kyalla Formation is a less prospective source rock. This lithofacies generally contains a lower TOC content, although it does have a grouping of samples with a very high TOC content. More diagnostic of the upper Kyalla Formation are low HI values (<400 mg HC/g TOC) and elevated oxygen index (OI) values greater than 30 mg CO₂/g TOC (**Figure 30**), within measured values in a wide range of 0–1003 mg CO₂/g TOC. This probably represents a lower quality of preservation of Type II organic matter that has been oxidised prior to preservation. The oxidation of the organic matter would classify the material as Type II/III, Type III and/or Type IV in some instances, although structured organic matter of these types was not present during the Mesoproterozoic. More likely is a mixture of Type II marine algal and Type IV oxidised inert organic matter.

Measured elemental H/C versus O/C ratios from isolated kerogen indicates that Kyalla Formation source rock samples from the more prospective lower organofacies contain oil-prone Type I and Type II/III kerogen in the present-day (**Figure 31**). Thermal maturity has lowered the H/C and O/C ratios from their original immature positions. Given that the partially matured kerogens are presently in the early to late oil window, the original positions of these samples would be in the Type I and Type II kerogen regions. The samples shown in this analysis have low O/C ratios, and are likely to have followed the maturation pathway for Type I kerogen.

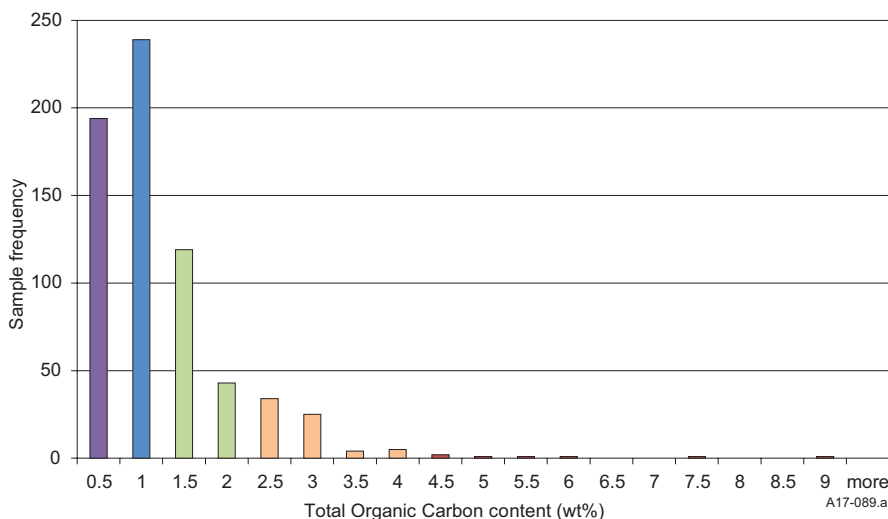


Figure 28. Histogram of Total Organic Carbon (TOC) distribution for Kyalla Formation samples within Beetaloo Sub-basin region of greater McArthur Basin (data from Revie 2017). Data is organised into 0.5 wt% TOC bins, colour codes correspond to TOC designations shown in **Table 11**.

Thermal maturity

The Kyalla Formation in the Beetaloo Sub-basin region appears to have entered the early to late stage of the conventional oil generation window in most wells included in this investigation. T_{max} values that are considered to be reliable from programmed pyrolysis measure between 428 and 456°C, indicating the early oil to late oil window.

Calculated equivalent vitrinite reflectance values [% $R_{o(eq)}$] were derived using T_{max} values for Type II kerogen (Equation 2), resulting in [% $R_{o(eq)}$] values of between 0.54% and 1.05%.

Figure 32 is a plot of hydrogen index versus T_{max} for Kyalla Formation source rock samples. Many of the samples plot within the main oil window and are within maturity envelopes associated with Type I and Type II kerogen. However, a large number of samples plot in the low maturity range and are associated with Type II/III and Type III kerogen regions.

The samples plot in two main groups/trends, which are also indicated by other geochemical parameters (eg HI vs OI; see above).

A twofold grouping is also similar to that seen in the shelf areas. Both trends contain samples that have more elevated levels of thermal maturity into the condensate/

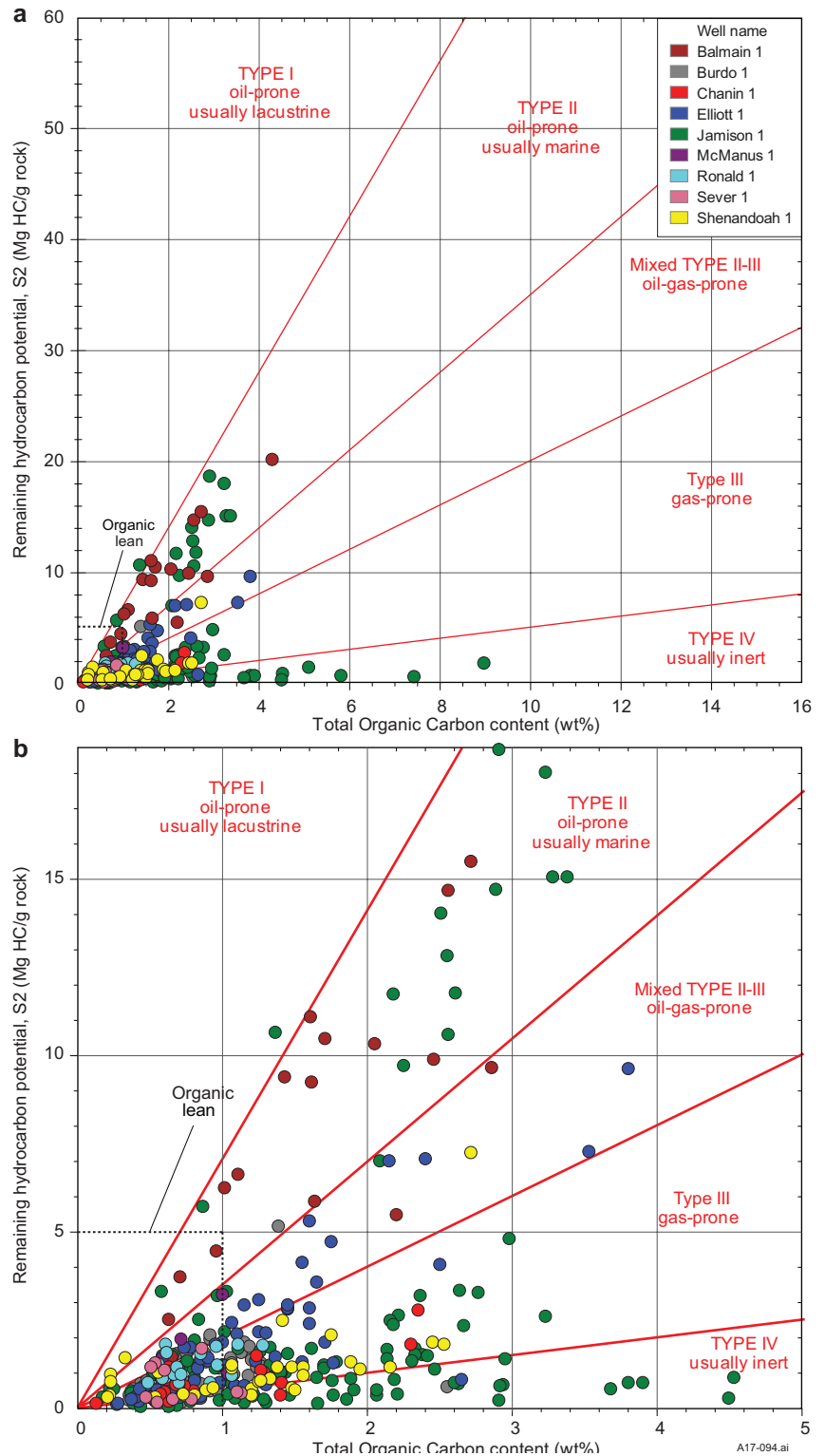


Figure 29. (a) Total Organic Carbon (TOC) versus remaining hydrocarbon potential (S2) for Kyalla Formation source rock samples in Beetaloo Sub-basin (data from Revie 2017). (b) Expanded view of (a) to increase detail.

wet gas and dry gas windows. These higher values are primarily represented by samples from the basal portions of Shenandoah 1/1A and Jamison 1, and also by some samples that may contain a higher proportion of oxidised inert Type IV kerogen, which tends to give elevated T_{max} readings, even at moderate maturity levels.

A great deal of caution should be used when evaluating T_{max} data for samples within the early to peak oil window

that often contain elevated S1 peaks. Oil-prone source rocks within the oil window are usually characterised by a predominant S2 peak and an elevated S1 peak of variable intensity. Depending on oil characteristics, there can be some carry over from the S1 peak to the S2 peak, which is commonly expressed by a low temperature S2 shoulder and asymmetry in both peaks: this is apparent in pyrograms of some of the Kyalla Formation samples (eg,

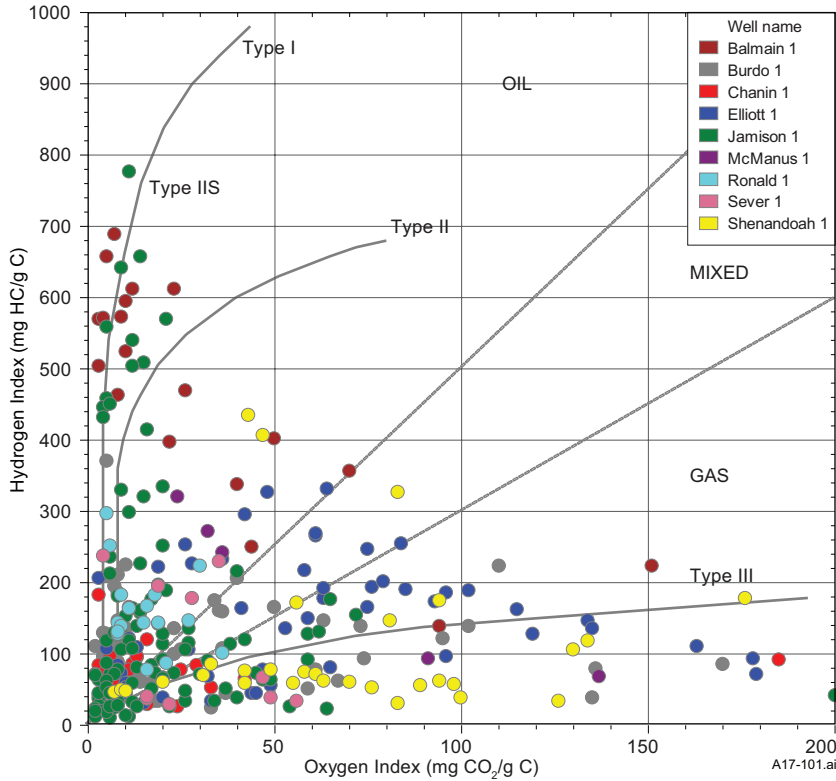


Figure 30. Present-day HI (hydrogen index) versus OI (oxygen index) kerogen quality plot for Kyalla Formation source rock samples in Beetaloo Sub-basin. Samples from Balmain 1 and upper portions of Jamison 1 are consistent with oil-prone Type II kerogen that has undergone minimal thermal conversion. Samples from other wells are more dispersed and are associated with gas-prone Type III and inert Type IV kerogen; these are interpreted as having originally matured from Type II oil-prone kerogen.

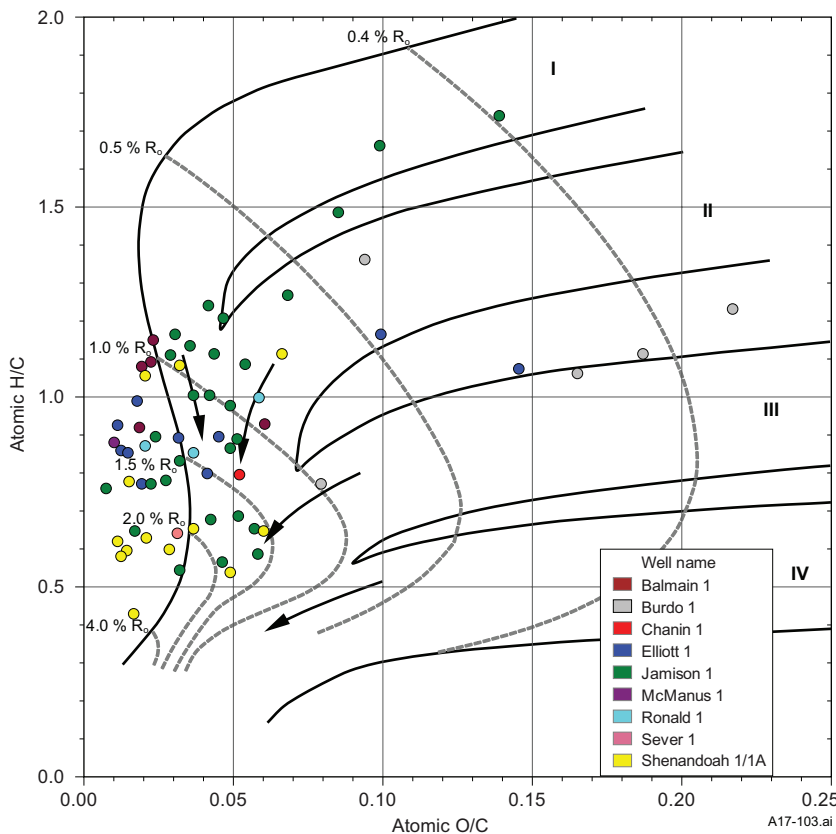
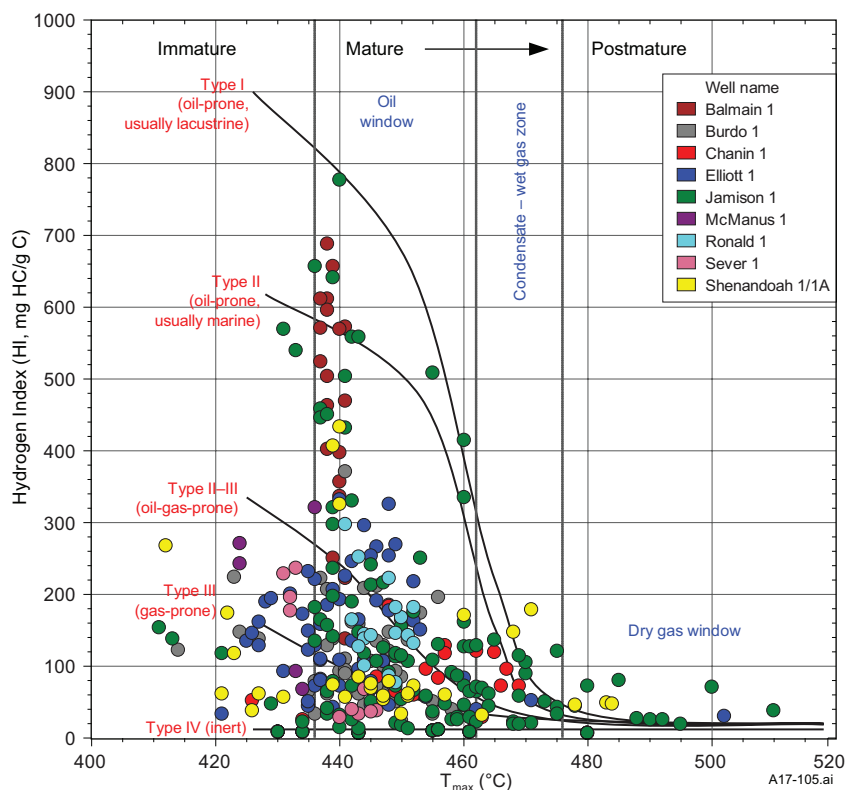


Figure 31. Van Krevelen plot for elemental hydrogen/carbon (H/C) versus oxygen/carbon (O/C) from isolated kerogen for Kyalla Formation source rock samples in Beetaloo Sub-basin (data from Revie 2017).

Figure 32. Hydrogen Index versus T_{max} for Kyalla Formation source rock samples in Beetaloo Sub-basin (data from Revie 2017).



see **Figure 33**). The likely explanation is that constituents present in the oil or bitumen, such as high-molecular-weight waxes, asphaltenes or other compounds, have volatilised at $>300^{\circ}\text{C}$ (S1 vapourisation temperature) and have carried through to the S2 peak. This could potentially have lowered the measured T_{max} value (444.85°C in the sample in **Figure 33**) during programmed pyrolysis, and the value should therefore be considered a minimum due to this uncertainty. The presence of low-temperature shoulders in Kyalla Formation samples can also cause elevated hydrogen index (HI) values in comparison to the true readings.

Production Index (PI) values in the Kyalla Formation samples vary from 0.03 to 0.67 (**Figure 34**) and average 0.06–0.34 in individual wells. The values are interpreted to be within the early to late oil window, and generally plot within the region associated with intensive oil generation and expulsion. The elevated PI values also plot mostly on or within the Weatherford Laboratories oil window trend envelope (dashed line in **Figure 34**), which illustrates how PI increases with thermal maturity through the main oil window, and subsequently decreases with increasing oil-to-gas secondary cracking through the condensate/wet gas window. Low PI values for Sever 1 samples are inconsistent with their interpreted peak oil window thermal maturity. The relatively low *in situ* oil saturation of these samples might be due to shallow burial depths ($<330\text{ m}$) and/or the loss of hydrocarbons due to uplift and erosion. Samples with elevated T_{max} values and relatively high PI values from Shenandoah 1/1A, Jamison 1 and Elliot 1 are generally inconsistent with a dry gas thermal maturity level. It is likely that these samples contain a higher abundance of inert Type IV kerogen that is producing anomalously elevated T_{max} values.

The average pyrolysis S1 values in the Kyalla Formation samples vary from 0.1 to 1.1 mg HC/g rock. This indicates

generally poor to fair *in situ* hydrocarbon saturation and is generally inconsistent with the elevated TOC and generation potential of these oil-prone source rocks. These samples are interpreted to have been in the early to late oil window, and have sufficient thermal maturity to have generated oil, so relatively low *in situ* hydrocarbon saturation values are a clear risk factor for successful unconventional shale oil development.

Estimated average kerogen transformation ratios, based upon interpreted original and measured present-day HI values, vary in the range 38–88% for the Kyalla Formation samples. The ratios were calculated using interpreted and limited measured kerogen maceral distributions of

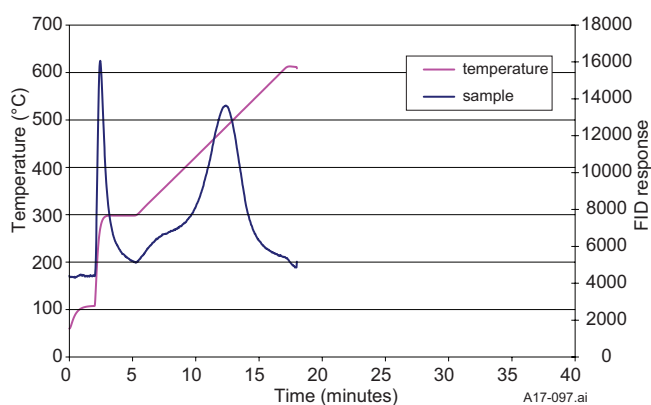


Figure 33. Low-temperature S2 shoulder with ‘shark fin’ appearance and asymmetry in both S1 peak (blue line, left) and S2 peak (blue line, right) in pyrogram of Kyalla Formation sample TN14DJR025 taken from Jamison 1 (1272.1 m). Sample plots in early oil window and is associated with Type III kerogen. This suggests that volatile constituents could be high molecular weight waxes or asphaltenes that are volatilising at $>300^{\circ}\text{C}$ (S1 vapourisation temperature) and are carrying over to S2 peak. This could potentially have lowered measured T_{max} value (444.85°C) during programmed pyrolysis; value should therefore be considered a minimum due to this uncertainty.

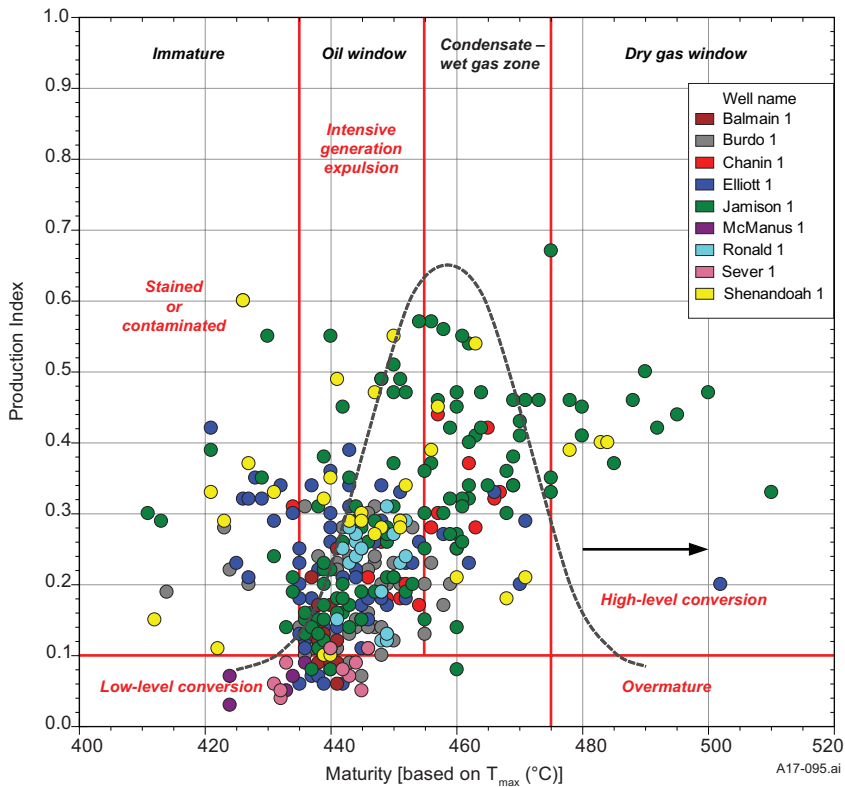


Figure 34. Production Index (PI) versus T_{max} for Kyalla Formation source rock samples in Beetaloo Sub-basin. Trend envelope is based on Weatherford Laboratories analysis of over 5000 shale samples (data from Revie 2017).

dominant oil-prone Type I and Type II kerogen. They are below the recommended minimum threshold of 50% for shale oil systems in one well (Balmain 1) and above the recommended minimum of 80% for thermogenic shale gas systems in five of the wells. Overestimation of transformation ratios (TR) appears to have occurred, probably as a result of the over estimation of original HI values. The geographical distribution of the TR indicates that the wells in the central region of the Beetaloo Sub-basin (Shenandoah 1/1A, Balmain 1 and Jamison 1) have a higher TR than wells on the edges of the sub-basin (Chanin 1 and McManus 1). Sever 1 in the Gorrie Sub-basin has an anomalously high TR value; the higher thermal maturity might be attributable to a dolerite intrusion within the succession.

The thermal maturity of the Kyalla Formation source rocks was evaluated by measured Kübler Index from XRD, based on illite crystallinity. Average Kübler Index values of 0.175–0.296 were measured in the samples, equivalent to vitrinite reflectance values of 2.75 to >4% (peak oil window to late stage metagenesis). These values are inconsistent with other geochemical maturity ratios, suggesting the

Kübler Index should be used with caution to evaluate thermal maturity in Mesoproterozoic source rocks.

Kyalla Formation generative potential and hydrocarbon yield calculations

A visual kerogen assessment was used to determine the maceral percentages present within samples of Kyalla Formation source rocks but only limited data were available. All samples were modelled using an appropriate kerogen mix to maintain a suitable transformation ratio consistent with interpreted thermal maturity. The average visual kerogen counts for the determination of the maceral percentages in the various wells are shown in **Table 22**.

The original source rock quality of the Kyalla Formation was estimated using Equations 3, 4 and 5, resulting in an average HI_0 of 450–465 mg HC/g TOC (**Table 22**). An assumed PI_0 value of 0.02 is used (Peters *et al* 2005b). Using the values in Equation 4, the extent of fractional conversion of HI_0 to petroleum varies from 0.38 to 0.88 (**Table 23**), indicating that on average, 38 to 88% of

Well	%Type I 750 HI_0	%Type II 450 HI_0	%Type III 125 HI_0	%Type IV 50 HI_0	HI_0
Balmain 1	46	54	0	0	588
Burdo 1	0	100	0	0	450
Chanin 1	0	100	0	0	450
Elliott 1	0	100	0	0	450
Jamison 1	5	95	0	0	465
McManus 1	0	100	0	0	450
Ronald 1	0	100	0	0	450
Sever 1	0	100	0	0	450
Shenandoah 1/1A	0	100	0	0	450

Table 22. Average Kerogen Estimations for Kyalla Formation source rock samples from Beetaloo Sub-basin. Data collated from Revie (2017) from visual kerogen estimation performed on selected samples.

Well	TOC _{pd}	HI _{pd}	S _{2pd} (bbl/a-ft)	HI _o	TR	TOC _o	S _{2o} (bbl/a-ft)	S1 free oil (bbl/a-ft)	Est. oil (bbl/a-ft)	Cracked gas (Mcf/a-ft)
Balmain 1	1.73	471	182	588	0.38	1.94	250	24	69	0
Burdo 1	0.85	115	22	450	0.82	1.09	108	5	84	8
Chanin 1	0.96	91	19	450	0.86	1.27	126	11	93	83
Elliott 1	1.16	151	44	450	0.76	1.46	144	13	100	5
Jamison 1	1.83	123	49	465	0.82	2.37	243	16	147	277
McManus 1	0.77	278	70	450	0.50	0.88	87	3	39	0
Ronald 1	0.81	162	27	450	0.74	1.04	102	9	73	9
Sever 1	0.72	108	15	450	0.82	0.93	92	1	76	0
Shenandoah 1/1A	1.60	80	31	450	0.88	2.10	207	13	170	36

Table 23. Hydrocarbon yields average data for Kyalla Formation source rock samples from Beetaloo Sub-basin (data derived from Appendix 2).

the petroleum generation process has been completed.

When estimating the TOC_o for Kyalla Formation source rocks in the Beetaloo Sub-basin, the kerogen mix for each individual sample was used in the calculation. TOC_o for each well was estimated using Equation 5; the results are shown in Table 23.

The original generational potential (S_{2o}, in mg HC/g rock) of the Kyalla Formation source rocks was calculated using Equation 6. This methodology was used for Kyalla Formation source rock samples, and estimated generated oil and cracked gas yields were calculated using Equation 7, and are given in Table 23, referenced in acre-foot volume (Figure 35).

Expulsion efficiency

Using Equation 8, the resulting expulsion efficiency varies in the range 66–99% for Kyalla Formation source rocks in wells determined to be within the peak oil window in the Beetaloo Sub-basin, which is consistent with early oil to dry gas window maturity. This implies that retained oil saturation is elevated in some low-maturity wells, whereas in other wells, most of the generated hydrocarbons have been expelled from the source rock interval.

The Kyalla Formation source rock samples from the various wells examined in this study are interpreted to be in the early to late oil window; hydrocarbon yield calculations suggest that significant amounts of generation have occurred (predominantly oil with some associated gas in most wells). From an exploration risk perspective, this is generally favourable. However, it is useful to relate these hydrocarbon yields to productive unconventional USA shale plays. The comparison uses multiple values including the generated oil and gas yields, but also the original (S_{2o}) generation potential of the source rocks. These values relate to the ultimate yields of hydrocarbon that could be generated at depth in the basin. For the Kyalla Formation in the Beetaloo Sub-basin, source rock samples have average original generational potential (S_{2o}) between 87 to 250 bbl oil/acre-ft (Table 24). These values fall below those of the producing US shale plays.

Kyalla Formation unconventional oil and gas risk assessment

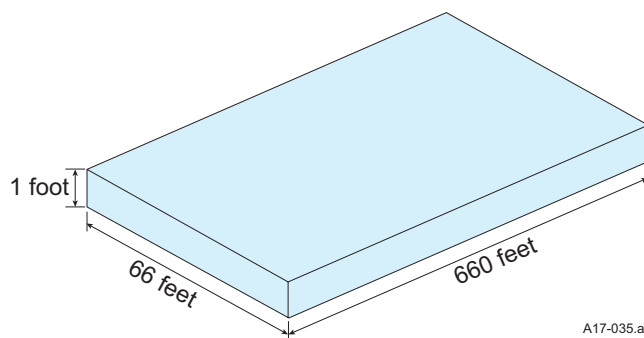
Kyalla Formation source rocks from the Beetaloo Sub-Basin were evaluated for unconventional oil and gas potential by

Weatherford Laboratories on behalf of NTGS. Figure 36 is a modified geochemical risk assessment diagram for these source rock samples, based upon published results from the Barnett Shale in the Fort Worth Basin, USA.

The Kyalla Formation source rocks are interpreted to represent a moderate to high geochemical risk for *in situ* shale oil production with the exception of those from Jamison 1, which are considered to be a low risk for shale oil.

The average measured TOC contents for source rocks in most wells are below the generally accepted minimum value of 1 wt% TOC to be considered an *effective* source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems (Figure 36). Wells with source rock TOCs that are above this threshold include Balmain 1, Jamison 1 and Shenandoah 1/1A. None of these wells have Kyalla Formation average TOC content above the minimum requirements of 2 wt% TOC 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 the Kyalla Formation in these wells within the early to late oil window. Average T_{max} values between 428 to 456°C are mostly above the recommended minimum value of 435°C for shale oil and below the minimum of 455°C for shale gas (Figure 36). The exception is McManus 1, where the thermal maturity of the Kyalla Formation falls below the minimum shale oil threshold. For the other wells, this



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Figure 35. Diagram of acre-foot volume (43 560 cubic feet; 1233 m³). Not to scale.

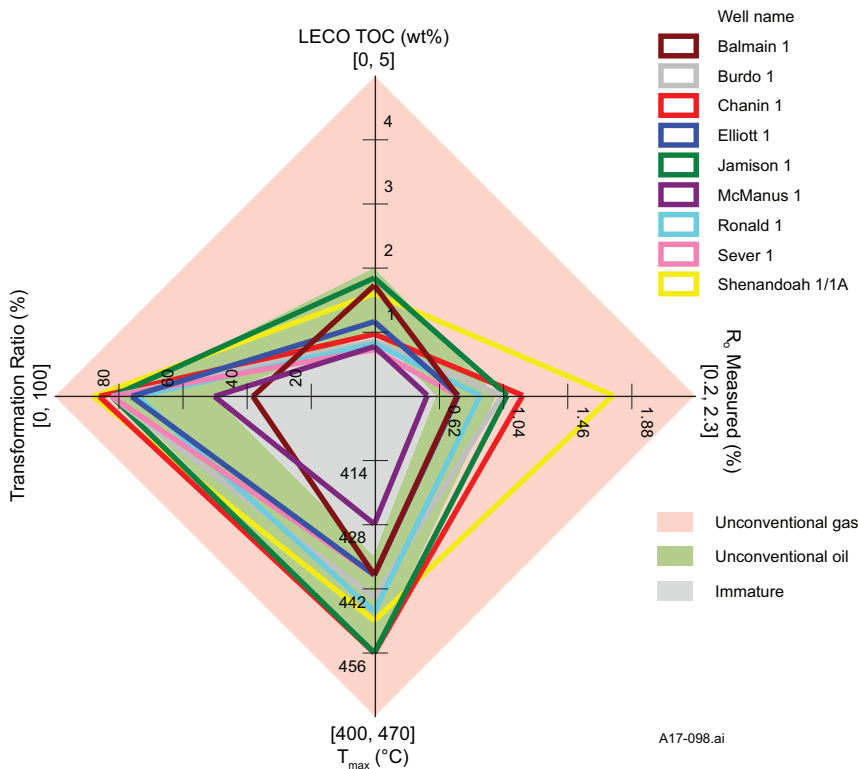


Figure 36. Geochemical risk assessment diagram for Kyalla Formation source rock samples in Beetaloo Sub-basin. Assessment performed by Weatherford (2016) based upon published results from Barnett Shale in Fort Worth Basin, USA. Data illustrated in star plot represent average values for all four diagnostic ratios where available, with recommended areas for unconventional oil (green) and gas (red). Immature region below minimum threshold is shown in grey.

Table 24. Geochemical properties and generational potential for USA shale plays compared to samples of Kyalla Formation from Beetaloo Sub-basin region. Kyalla Formation wells are colour coded for possible shale oil (green) and shale gas prospect type. Barnett Shale data from Jarvie *et al* (2007).

Sample Database Averages TOC>1%	HI _o (mg/g TOC)	TR	TOC _o	S2 _o	Remaining potential (bbl/a-ft)	Original potential (bbl/a-ft)	Oil cracked (%)	S1 Free Oil (bbl/a-ft)	Estimated oil (bbl/a-ft)	Cracked gas (Mcf/a-ft)
Barnett Shale, Fort Worth Basin	435	0.84	5.38	23.40	94	513	40	33	251	1005
Barnett Shale, Delaware Basin	435	0.91	5.25	22.84	52	500	80	32	90	2149
Woodford Shale, Delaware Basin	480	0.89	6.41	30.79	139	674	89	46	60	2854
Haynesville Shale, East Texas Basin	400	0.98	3.93	15.73	7	344	100	3	0	2022
Fayetteville Shale, Arkoma Basin	435	0.95	3.34	14.53	15	318	100	10	0	1820
Woodford Shale, Arkoma Basin	520	0.87	5.15	26.80	12	587	70	87	170	2431
Eagle Ford Shale, Gulf Coast Basin	520	0.85	3.19	16.61	61	364	47	22	161	848
Marcellus Shale, Appalachian Basin	600	0.97	6.44	38.66	34	847	100	24	0	4875
Utica Shale, Appalachian Basin	450	0.98	2.74	12.32	6	270	100	12	0	1585
Barnett Shale Oil	450	0.47	5.47	24.64	326	540	0	79	308	0
Barnett Shale Gas	450	0.96	5.58	25.13	23	550	87	7	68	3657
Balmain 1 – Kyalla	588	0.38	1.94	11.43	182	250	0	24	69	0
Burdo 1 – Kyalla	450	0.82	1.09	4.92	22	108	2	5	84	8
Chanin 1 Kyalla	450	0.86	1.27	5.74	19	126	14	11	93	83
Elliott 1 – Kyalla	450	0.76	1.46	6.57	44	144	0	13	100	5
Jamison 1 – Kyalla	465	0.82	2.37	11.09	49	243	19	16	147	277
McManus 1 – Kyalla	450	0.50	0.88	3.96	48	87	0	3	39	0
Ronald 1 – Kyalla	450	0.74	1.04	4.66	27	102	2	9	73	9
Sever 1 – Kyalla	450	0.82	0.93	4.18	15	92	0	1	76	0
Shenandoah 1/1A - Kyalla	450	0.88	2.10	9.44	31	207	4	13	170	36

amount of conversion would likely be sufficient to generate/expel moderate amounts of hydrocarbons from the fairly organic-lean source facies. Transformation ratios (TR), the least constrained risk parameter, average 38% for the Kyalla Formation in Balmain 1, which is interpreted to be in the early oil window but are below the recommended minimum of 50% for shale oil (Figure 36). The Kyalla Formation in all other wells is at or above the 50% threshold. In several wells, TRs that are interpreted to be in the peak to late oil window exceed the recommended minimum 80% threshold for shale gas systems (Figure 36).

Oil saturations

Measured *in situ* oil saturation for Kyalla Formation source intervals, as determined by programmed pyrolysis S1 yields, is poor to fair (average 3–24 bbl oil/acre-ft); this is a significant concern regarding risk assessment for unconventional oil (Figure 37).

Hydrocarbon yield calculations show that estimates of average generated oil from the Kyalla Formation in wells where it is interpreted to be in the oil window, are in the range 39–170 bbl oil/acre-ft. Figure 37 compares these values to a representative example from the core area of oil production of the Barnett Shale in the Fort Worth Basin, USA, which has an estimated generated oil yield of 308 bbl/acre-ft and a measured *in situ* oil saturation of 79 bbl/a-ft (Jarvie *et al* 2007). The Barnett Shale example has a higher average TOC (4.70 wt% TOC) than the Kyalla Formation in the Beetaloo Sub-basin; this is the primary reason for higher estimated generated oil yields. Furthermore, *in situ* hydrocarbon saturations are significantly lower in the Kyalla Formation, likely a consequence of expulsion and/or uplift and erosion within the basin.

In situ S1 free oil saturations are generally low for the Kyalla Formation in Beetaloo Sub-basin wells (3–24 bb oil/

acre-ft). Although minor, the differences between wells show a trend of relatively higher S1 free oil content in wells located in the central region of the sub-basin (Figure 38). Balmain 1 has retained a higher average S1 content than other wells in the Beetaloo Sub-basin. The nearby well Shenandoah 1/1A has a lower average S1 free oil saturation; this could be attributable to the well intersecting the complete Kyalla Formation and being subjected to higher thermal maturity than in Balmain-1.

Spatial trends in the estimated secondary cracked gas yields show that there is not any cracked gas in most of the wells where the Kyalla Formation was evaluated within the sub-basin. The major exception was Jamison-1, which is interpreted to be in the late oil window (Figure 39). In this well, there has been a moderate amount of secondary cracked gas generated (estimated 19% oil to gas cracking). The presence of secondary cracked gas along with any associated gas is generally considered favourable for oil mobility in unconventional shale oil systems.

Kyalla Formation mineralogy

X-ray diffraction (XRD) was used to analyse the mineralogy and tenacity of selected samples of the Kyalla Formation from nine wells. This analysis gives an indication as to potential organofacies variations, reservoir quality and formation brittleness for fracture propagation, and enables the assessment of possible mineralogical controls on porosity and permeability. All XRD analysis data is summarised in Revie (2017).

XRD analyses (Table 25) indicate that clays are the most abundant minerals in the Kyalla Formation, with an average total clay content of 54%. The clay minerals are dominated by illite/mica (35%), chlorite (8%), kaolinite (7%), and mixed-layer illite/smectite (4%). Non-clay mineralogy is dominated by quartz (36%). The Kyalla Formation source

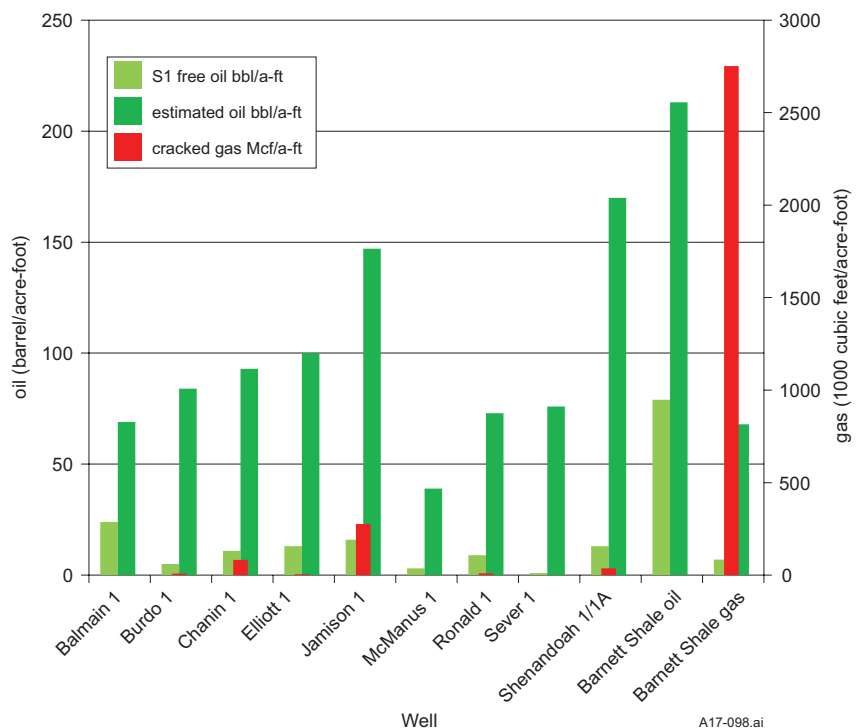


Figure 37. Average hydrocarbon yield estimates by well for Kyalla Formation source rock samples in Beetaloo Sub-basin compared to Barnett Shale (USA) in oil window.

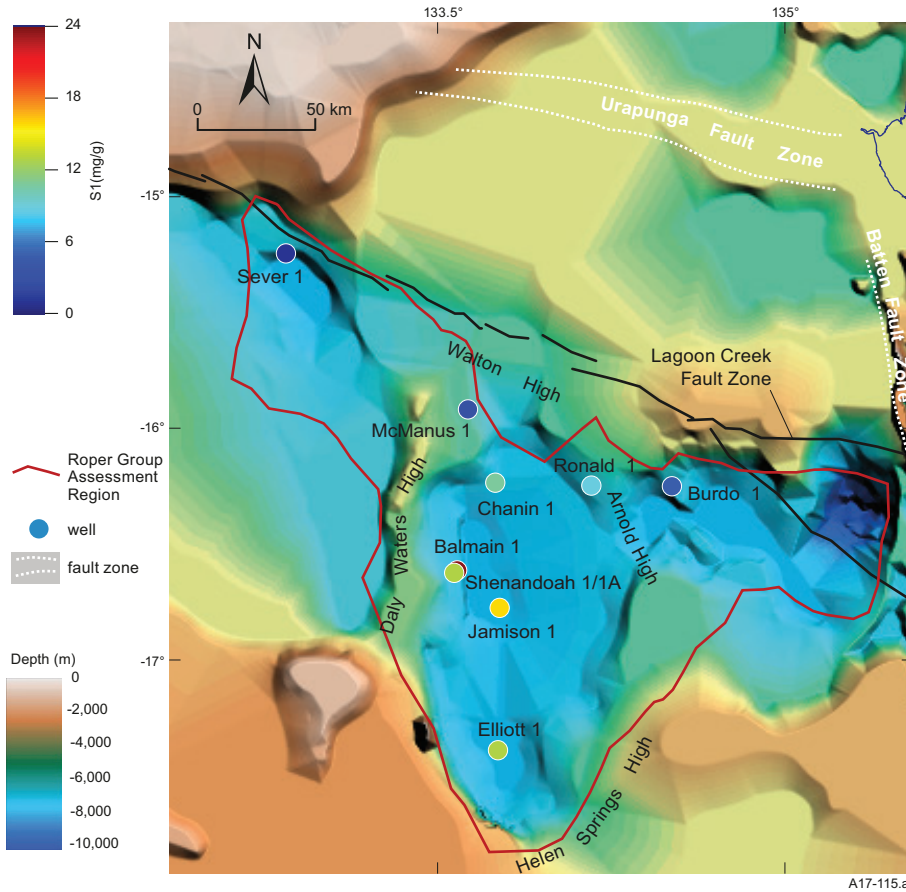


Figure 38. Spatial distribution of S1 free oil saturation for Kyalla Formation source rocks in Beetaloo Sub-basin. Mapped values are for average S1 values for all samples and are reported in bbl oil/acre-ft.

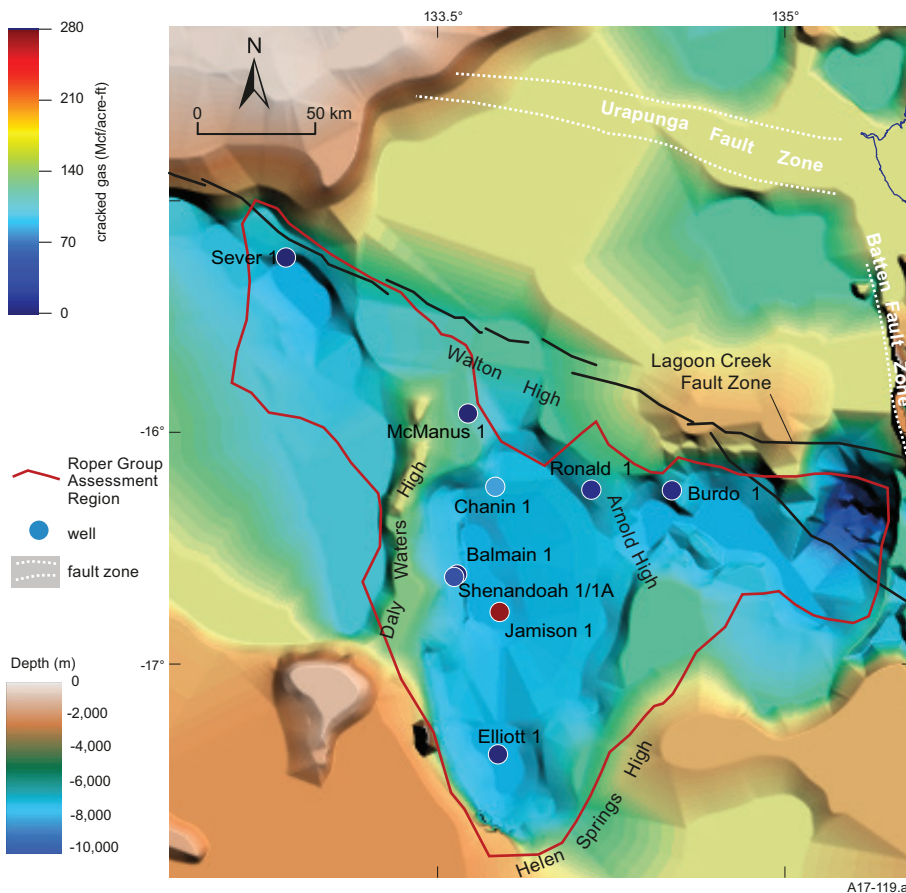


Figure 39. Spatial distribution of estimated average cracked gas yields for Kyalla Formation source rock samples in wells located within Beetaloo Sub-basin, reported as Mcf gas/acre-ft.

rocks can be classified as either silica-rich argillaceous mudstones or clay-rich siliceous mudstones, with a minor amount of argillaceous-siliceous mudstones.

The dominance of clays in the source intervals is a concern for potential fracture stimulation, as these assemblages are often fairly ductile. However, although the clay content is

Table 25. TOC and X-ray diffraction data (wt%) for Kyalla Formation source rock samples from Beetaloo Sub-basin. *ordered interstratified mixed-layer illite/smectite.

Formation	Clays	Carbonate minerals	Quartz	K-spar	Other	Mixed I/S*	TOC	Brittleness Index
Kyalla	54	2	36	6	2	4	1.15	41

Table 26. Triaxial compression test data for Kyalla Formation in Beetaloo Sub-basin (data from Revie 2017).

Well	Depth (m)	Formation	Confining pressure (MPa)	Compressive strength (MPa)	Static Young's Modulus MPa (psi)	Static Poisson's Ratio
Elliott 1	1176.62	Kyalla Formation	9.17	149.31	50154 (7.3 x 10 ⁶)	0.23
Jamison 1	1637.33	Kyalla Formation	12.82	93.84	7319 (1.1 x 10 ⁶)	0.17
Shenandoah 1	1590.22	Kyalla Formation	12.76	87.22	12480 (1.8 x 10 ⁶)	0.10

generally high, quartz is abundant and has a brittle tenacity conducive to fracture stimulation treatment. The presence of pyrite in minor amounts (1%) is associated with the minor presence of kerogen, and this mineral also generally makes a positive contribution to fracture stimulation processes.

The clays contain ordered interstratified mixed-layer illite/smectite (4% of total mineral composition, and comprising 13% of total clays). Geomechanical properties of the Kyalla Formation (**Table 26**) give further insight into the strength and stiffness of the shale, and the likelihood of fractures initiating and propagating.

Static Young's Moduli yields are in the range 7–50 GPa for the Kyalla Formation samples (**Table 26**); these values are typical of a high cohesive and unconfined compressive strength in the material. A sample from Elliott 1 returned the highest Static Young's Modulus result of 50 GPa. This sample

has a fabric of laminated shale and sand grains that impinge on each other (**Figures 40, 41**); such rigid grain interactions significantly strengthen and stiffen the shale, making it much more likely to be able to support open fractures (Josh *et al* 2012). Prospective shales, based on historical data, have Static Young's Moduli in excess of 24.13 GPa (Britt and Schoeffler 2009). This is a risk for the Kyalla Formation in the Beetaloo Sub-basin, where only one sample (from Elliott 1) returned a result above this threshold.

BI values for the Kyalla Formation were calculated using the relative percentage composition of the shale minerals via **Equation 9**. They vary in the range 23–69 and average 41 (**Table 25**).

Although brittle deformation does occur in most lithologies at hydraulic stimulation injection rates, *successful* shale plays in North America have clay constituents generally less than 40% (Britt and Schoeffler 2009). The Kyalla Formation samples generally contain a relatively high clay content mineralogy of 55% (**Figure 42**).

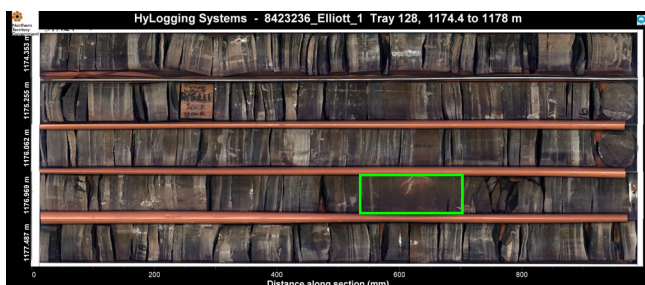


Figure 40. Kyalla Formation sample (highlighted by green box) from Elliott 1 (1176.2 m) used for triaxial compression testing. Note sandy laminated lithology, resulting in rigid grain/clay interactions and significantly stiffening of sample. This could account for a high (50 GPa) Static Young's Modulus result. Image derived from NTGS HyLogger™ TSG dataset.

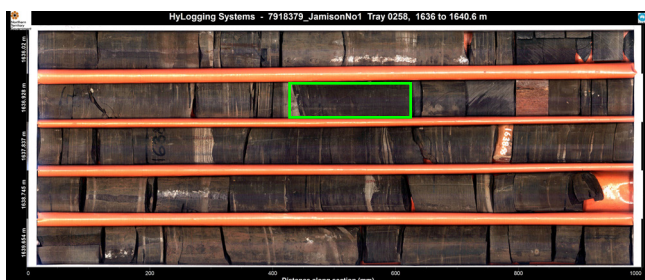


Figure 41. Kyalla Formation sample (highlighted by green box) from Jamison 1 (1637.3 m) used for triaxial compression testing. Image derived from NTGS HyLogger™ TSG dataset.

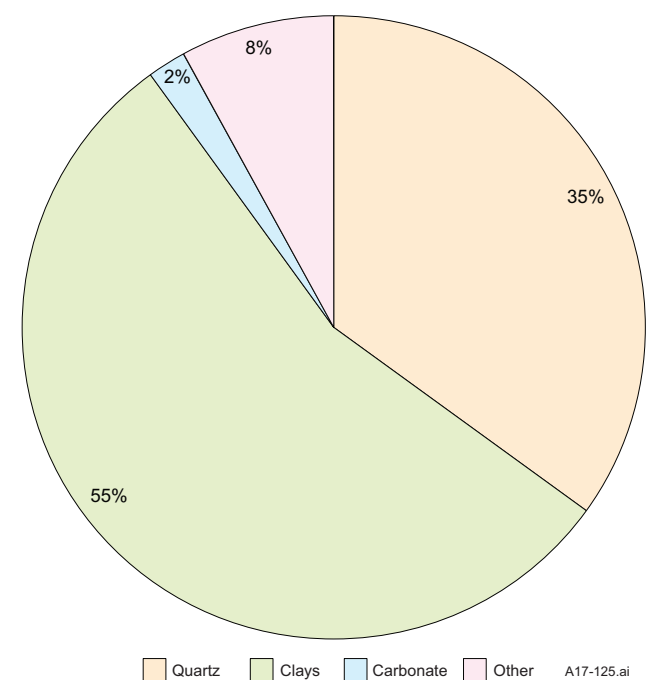


Figure 42. XRD average mineralogy for Kyalla Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Average clay content (55%) is above 40% upper limit of most successful North American plays.

A ternary plot (Figure 43) shows the relative weight percentages of carbonate minerals, clays and quartz, as determined by XRD, for Kyalla Formation source rock samples compared to published data for USA shale plays. The mineral composition widely varies in the producing shale-gas reservoirs of the Eagle Ford and Barnett shales. Current producing fields tend to lie below the 50% clays line, and reservoirs that contain greater than 50% quartz or carbonates tend to have a more brittle character that responds well to current well stimulation practices (Passey *et al* 2010). It can be noted from Figure 43 that the Kyalla Formation is comparatively clay-rich compared to the US examples.

MIDDLE VELKERRI FORMATION

The middle Velkerri Formation source rock samples analysed from the Beetaloo Sub-basin have dominantly very good (>10 mg HC/g rock) generative potential and present-day TOC values (Table 27). A histogram plot of TOC distributions (Figure 44) illustrates that the dominant

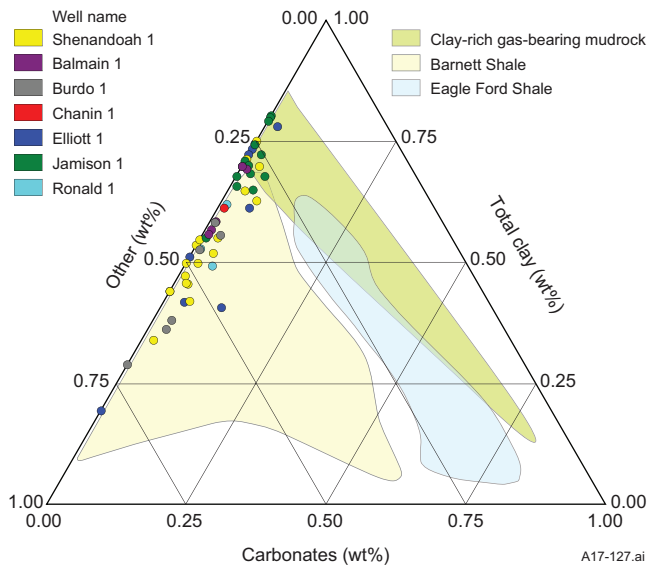


Figure 43. XRD mineralogy ternary plot of Kyalla Formation source rock samples in Beetaloo Sub-basin compared to published data for USA shale plays (after Passey *et al* 2010).

population is within the range 2.0–4.0 wt% (very good to excellent). About 95% of these samples have TOC >1 wt%, the minimum requirement for effective source rocks. Furthermore, 83% of these samples have TOC content >2 wt% the minimum requirement for economic petroleum source rocks. This reduces the risk for the middle Velkerri Formation as a potential unconventional resource.

The distribution of elevated TOC values in the middle Velkerri Formation is across multiple wells in the Beetaloo Sub-basin. No obvious trend or pattern can be observed within the data; however, localised zones of low average TOC values are identified on a well-to-well basis. This is observed in Shenandoah 1/1A, located in the centre of the Beetaloo Sub-basin, which has a relatively low, average estimated original TOC value (‘good’ – 1.74 wt%). This could possibly indicate a zone of low organic productivity and/or preservation, or it could be linked to mineral dilution in the marine depocentre of the sub-basin. Sever 1, in the northern Gorrie sub-basin, has elevated TOC values in excess of 15 wt%; this is consistent with the increased TOC values of a condensed section within the shale.

The higher TOC content within the middle Velkerri Formation relative to the upper and lower Velkerri facies has been interpreted as reflecting a change in water column biochemistry (Warren *et al* 1998) during the deposition of the lower, middle and upper facies. This has been further investigated by Cox *et al* (2016) who suggested that the high TOC content of the middle Velkerri Formation can be reconciled through a transition in sediment provenance to more mafic sources, delivering increased phosphorus that potentially enhanced primary productivity. There is an absence of changes in grain size, sedimentary structures or matrix mineralogy in the adjacent organically-lean intervals. If the differences in TOC content were not controlled by biochemical processes but by substantial changes in water depth or depositional energy, these processes would be reflected in changes in matrix grain size, sedimentary structures, or mineralogy (Warren *et al* 1998).

Organofacies of the middle Velkerri Formation

The middle Velkerri Formation forms a continuous stratigraphic unit across the Gorrie, Beetaloo and OT Downs sub-basins, and adjacent shelf areas to the north (eg in BMR

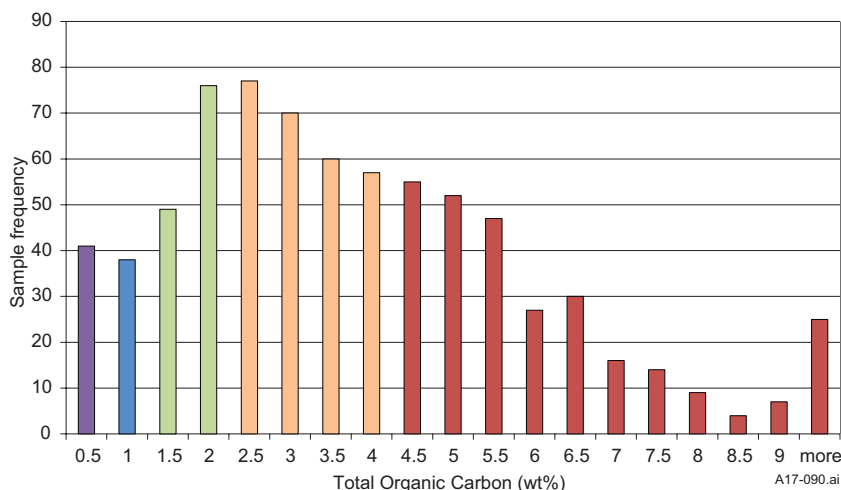


Figure 44. Histogram plot of Total Organic Carbon (TOC) distributions for middle Velkerri Formation in Beetaloo Sub-basin (data from Revie 2017). Data is presented in 0.5 wt% bins. Colour coding corresponds to TOC designations shown in Table 11.

Urapunga 4). Organic-rich shales within the middle Velkerri Formation are composed of three discrete sedimentary units that are informally named, in ascending stratigraphic order, the A, B and C shales. These three organic-rich intervals have been previously recognised within the middle Velkerri Formation (Lanigan *et al* 1994, Warren *et al* 1998), and were originally identified as Organic-Rich Units 1, 2 and 3. The three distinct cycles of elevated TOC within the middle Velkerri Formation source interval are consistently present throughout the wells intersecting the formation (**Figure 45**), although the thicknesses of the zones varies from well to well. Within each organofacies, the organic carbon content is highest near the base, and gradually decreases upward to

background levels near 1 wt% TOC. Relatively high TOC, sharp-based units are often observed stacked one on top of another in marine shales (Creaney and Passey 1993), and a similar cyclicity of organic carbon has been described previously in the Jurassic Kimmeridge Clay (UK) and in Toarcian units within the Paris Basin (France; Cox and Gallois 1981). The stacking of high TOC units is probably characteristic of prolonged sediment starvation and would occur more commonly in basin center locations (Creaney and Passey 1993).

The three organic-rich intervals in the middle Velkerri Formation could be associated with transgressive systems tracts (TST) in a series of retrogradational and aggradational

Table 27. Geochemical summary of middle Velkerri Formation in Beetaloo Sub-basin (data from Revie 2017). Current TOC averages represent all publicly available data. Original TOC averages are only high-graded samples that have programmed pyrolysis data.

Well name	Formation	Main product	Thermal maturity	Source rock richness	Organic matter type	Shale oil risk
Atree 2	middle Velkerri	Estimated original →		↓ Excellent (5.10% TOC)	↓ Oil-prone Type II	Low (oil)
		Measured currently →	Oil	Early oil window	↓ Very good (3.75% TOC)	
Broadmere 1	middle Velkerri	Estimated original →		↓ Very good (3.36% TOC)	↓ Oil-prone Type II	Moderate (oil)
		Measured currently →	Oil	Early oil window	↓ Very good (2.89% TOC)	
McManus 1	middle Velkerri	Estimated original →		↓ Excellent (5.52% TOC)	↓ Oil-prone Type II	Low (oil)
		Measured currently →	Oil	Peak oil window	↓ Very good (3.91% TOC)	
Sever 1	middle Velkerri	Estimated original →		↓ Excellent (4.93% TOC)	↓ Oil-prone Type II	Low (gas)
		Measured currently →	Dry gas	Dry gas window	↓ Very good (3.79% TOC)	
Shenandoah 1/1A	middle Velkerri	Estimated original →		↓ Good (1.74% TOC)	↓ Oil-prone Type II	High (gas)
		Measured currently →	Gas	Dry gas window	↓ Good (1.32% TOC)	
Tanumbirini 1	middle Velkerri	Estimated original →		↓ Excellent (4.20% TOC)	↓ Oil-prone Type I/II	Low (gas)
		Measured currently →	Dry gas	Dry gas window	↓ Very good (3.13% TOC)	
Tarlee S3	middle Velkerri	Estimated original →		↓ Excellent (5.42% TOC)	↓ Oil-prone Type II	Low (gas)
		Measured currently →	Dry gas	Dry gas window	↓ Excellent (4.11% TOC)	
Walton 2	middle Velkerri	Estimated original →		↓ Excellent (7.15% TOC)	↓ Oil-prone Type II	Moderate (oil)
		Measured currently →	Oil	Early oil window	↓ Excellent (6.36% TOC)	

parasequences. Condensed sections (exceptionally organic-rich, >10 wt% TOC), such as the apparent condensed sections observed in the wells of the Beetaloo Sub-basin (Table 28) occur during times of transgression and are consistent with TST depositional sequences; they correspond to maximum flooding surfaces. Parasequences making up the TST are commonly retrogradational, with strong onlap in a landward direction and downlap onto the transgressive surface in a basinward direction. Identified condensed sections are present in the middle Velkerri Formation, and are identified as the A, B and C shales; each is an individual organofacies and is recognised as uniquely identifiable shale parasequence.

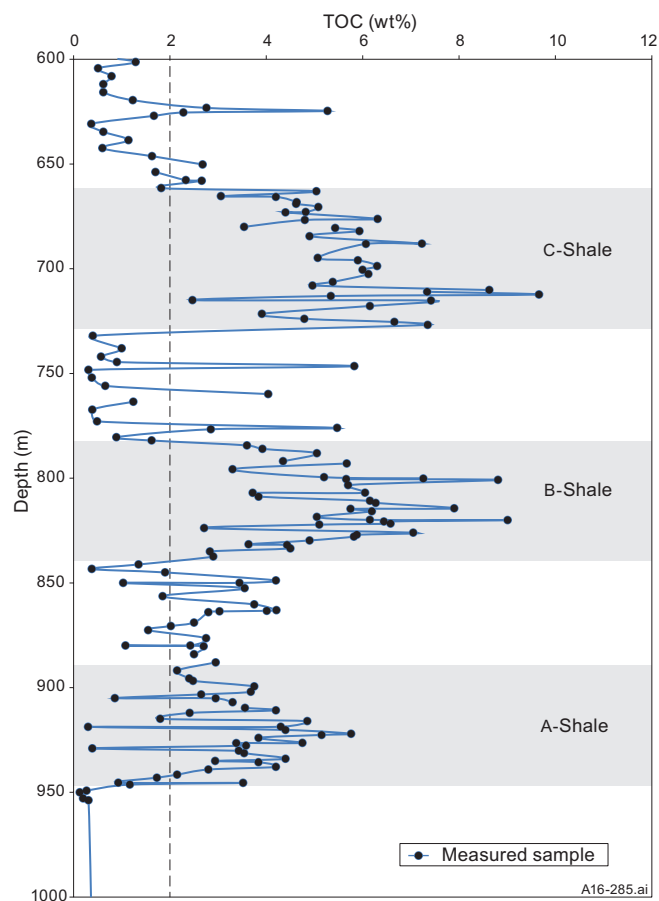


Figure 45. Atree 2 measured absolute TOC values versus depth through middle Velkerri Formation (data from Revie 2017). Organofacies A, B and C are shown in grey-banded intervals. Distinctive TOC values in excess of 3 wt% TOC are reflective of changing water column biochemistry. Minimum TOC threshold for economic shale gas play indicated by 2 wt% dashed line.

Table 28. Identified condensed sections in middle Velkerri Formation, where TOC exceeds 10 wt% (data from Revie 2017). These intersections correlate with organic-enriched A, B and C parasequences within middle Velkerri Formation.

Well name	Depth: from – to (m)	Average wt% TOC
Sever 1	730.30 – 882.55	14.45
Borrowdale 2	71.80 – 131.40	20.49
Walton 2	304.72 – 422.90	11.24
Tarlee S3	1480.52 – 1480.54	12.20
McManus 1	1530.67	10.85

Increasing thermal maturation appears to have an inverse relationship with the excursion length of the gamma ray traces through the organofacies of the middle Velkerri Formation. Comparable gamma ray trace excursion shapes for each of the A, B and C organofacies exist between the early oil-mature Atree 2 and the dry gas-mature Tanumbirini 1, with relatively lower gamma API value responses in the more thermally mature shale (Figures 46 and 47). This is likely a result of relatively lower organic content in Tanumbirini 1 in comparison to Atree 2 due to increased thermal maturation. There may be further reasons for the differences in response in the API values that could change the application of the gamma ray responses as indicating a time-synchronous marker horizon between organofacies intersections.

Gamma-ray and resistivity logs of the middle Velkerri Formation show excursions occurring in conjunction with elevated TOC, U, Ni, V, Mo, Cu and Zn values from chemostratigraphic analysis (Figure 46). These excursions are interpreted as the A, B and C shales. Intersections of these organofacies have been encountered across multiple wells drilled within the assessment area. These include: Shenandoah 1/1A (Falcon 2012); Walton 2; Sever 1 and Tarlee S3 (Hoffman 2015); Kalala S 1 and Amungee NW 1 (Close *et al* 2016); Tanumbirini 1 (Santos 2014: interpretation from gamma ray log); McManus 1 and Atree 2 (Warren *et al* 1998, who identified them as Organic Rich Units 1–3); and BMR Urupunga 4 (Sweet and Jackson 1986, who highlighted them as organic-rich intervals).

The thickness and richness of the organic-rich facies of the middle Velkerri Formation is dependent on their palaeogeographic position, with the thickest and most organically-endowed sections coinciding with the deepest central regions of the sub-basin, and thinning toward the margins. The B shale has the most consistent thickness and petrophysical properties of the three organofacies, and the uppermost C shale has the greatest mineralogical variability through the siltstone. Basin centre source rock accumulation begins earlier and persists longer than in shelfward age-equivalent rocks; however, the peak organic content in a marine-TOC profile is most likely to be a time-synchronous marker, often correlating across much of a basin (Creaney and Passey 1993).

Pyrolysis yields

Pyrolysis S2 yields for the middle Velkerri Formation samples vary in the range 0.02–70.66 mg HC/g, whereas average values within individual wells vary in the range 0.15–29.27 mg HC/g rock or 3–641 bbl/a-ft. These values are indicative of 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 windows. There are three populations of middle Velkerri Formation samples that correspond to the different organic facies within this interval

Samples from Walton 2 and Atree 2 have variable, but generally elevated TOC and S2 values and plot in the region for oil-prone Type II kerogen (Figure 47). These samples are interpreted to be within the early oil window and have

not had TOC and S2 reduced much as a consequence of thermal maturity. They are interpreted as representing a population of samples dominated by well-preserved oil-prone Type II kerogen.

Most of the other middle Velkerri Formation samples have only moderate S2 values and plot below the lower border line for oil-prone Type II kerogen (Figure 47). These samples are highly variable and plot in regions consistent with Type II/III, Type III and Type IV kerogens; however, it is likely that these data represent partially converted (early/peak oil window) thermal maturity values and would have plotted in the Type II kerogen range when thermally immature.

A third group of samples have variable but occasionally elevated TOC and relatively low S2 values, and have been significantly altered through thermal maturation. These samples, from Sever 1, Tanumbirini 1 and Tarlee S3, plot along the line that separates Type III and Type IV kerogen, and also within the Type IV kerogen range (Figure 47). Although the plot locations are consistent with inert carbonaceous residue associated with Type IV kerogens, two of these wells have shown elevated levels of gas in the formations, and the samples are assumed to have contained oil-prone Type II original kerogen for the purposes of hydrocarbon yield estimations. It is possible that the samples could represent oxidised organic matter from a condensed marine section that was initially a mixture of Type II/IV kerogen.

Three wells with relatively high S2 content (Broadmere 1, Atree 2 and Walton 2) are located along the western and northern margins of the main Beetaloo Sub-basin and are all interpreted to be within the early oil window. A geographical trend can be observed with relatively higher S2 content in wells located along the margins of this area in the Beetaloo Sub-basin (Figure 48). In contrast, Shenandoah 1/1A, Tarlee S3 and Sever 1 are all interpreted to be within the dry gas window and have very low S2 yields. The 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 the regional geology and additional well data points will be needed to provide further insights into the origin of these S2 variations.

middle Velkerri Formation kerogen type and expelled product in Beetaloo Sub-basin

The most prospective samples, from wells interpreted to be in the early oil window, are characterised by relatively high TOC and S2 contents and are distinctive in having high HI values of ca 350 to 750 mg HC/g TOC. These samples contain particularly well preserved oil-prone marine Type I/II kerogen with filamentous algae and abundant framboidal pyrite, variable abundances of lamalginite, lens/layer amorphous organic matter (AOM), and inert AOM, along

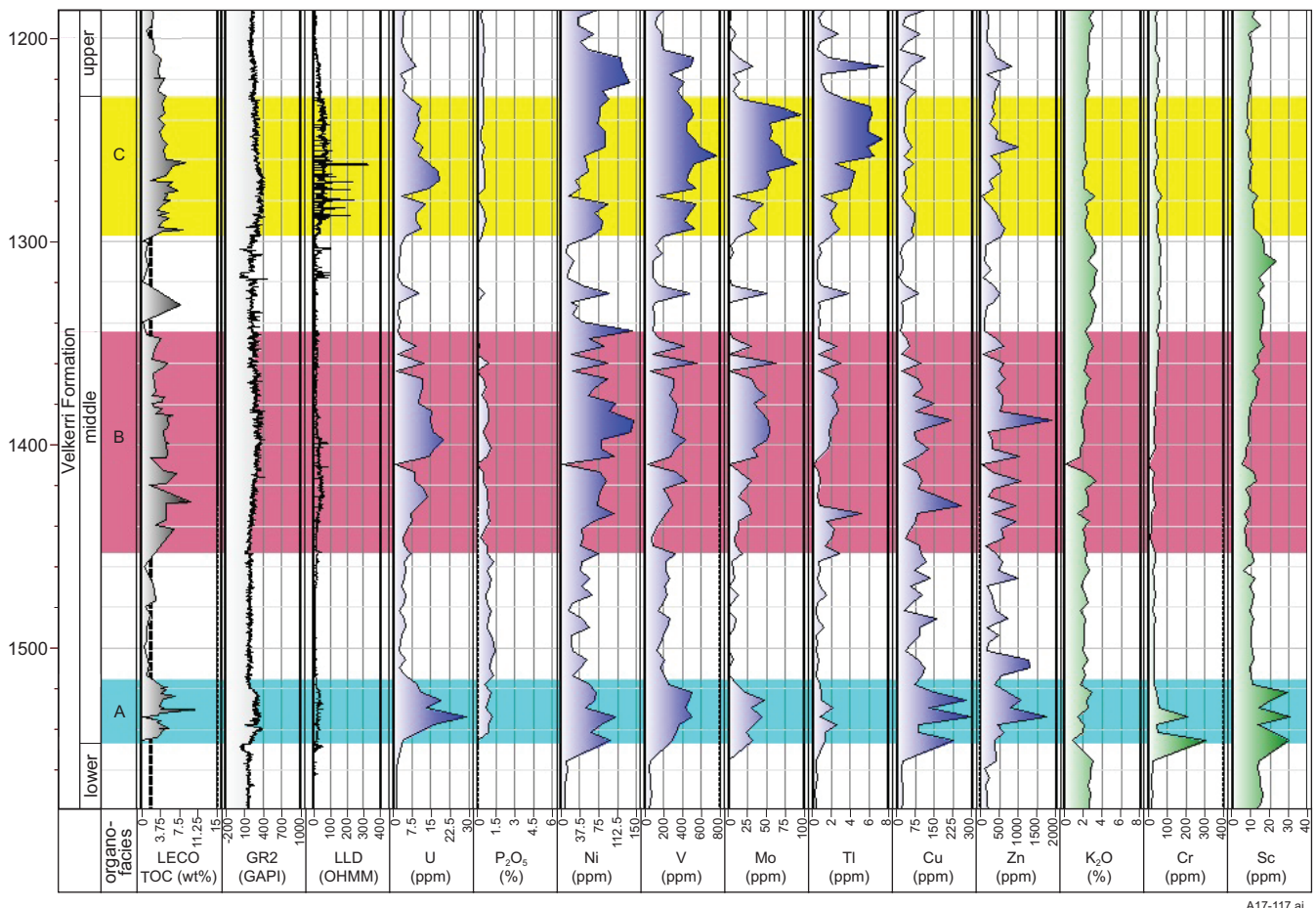


Figure 46. Gamma-ray and resistivity logs with chemostratigraphic and TOC measurements of organofacies A, B and C of middle Velkerri Formation lithofacies in McManus 1 (data from Revie 2017, Hess 2014). The A, B and C shales are highlighted, indicating the zones of increased concentrations of metals through the parasequences.

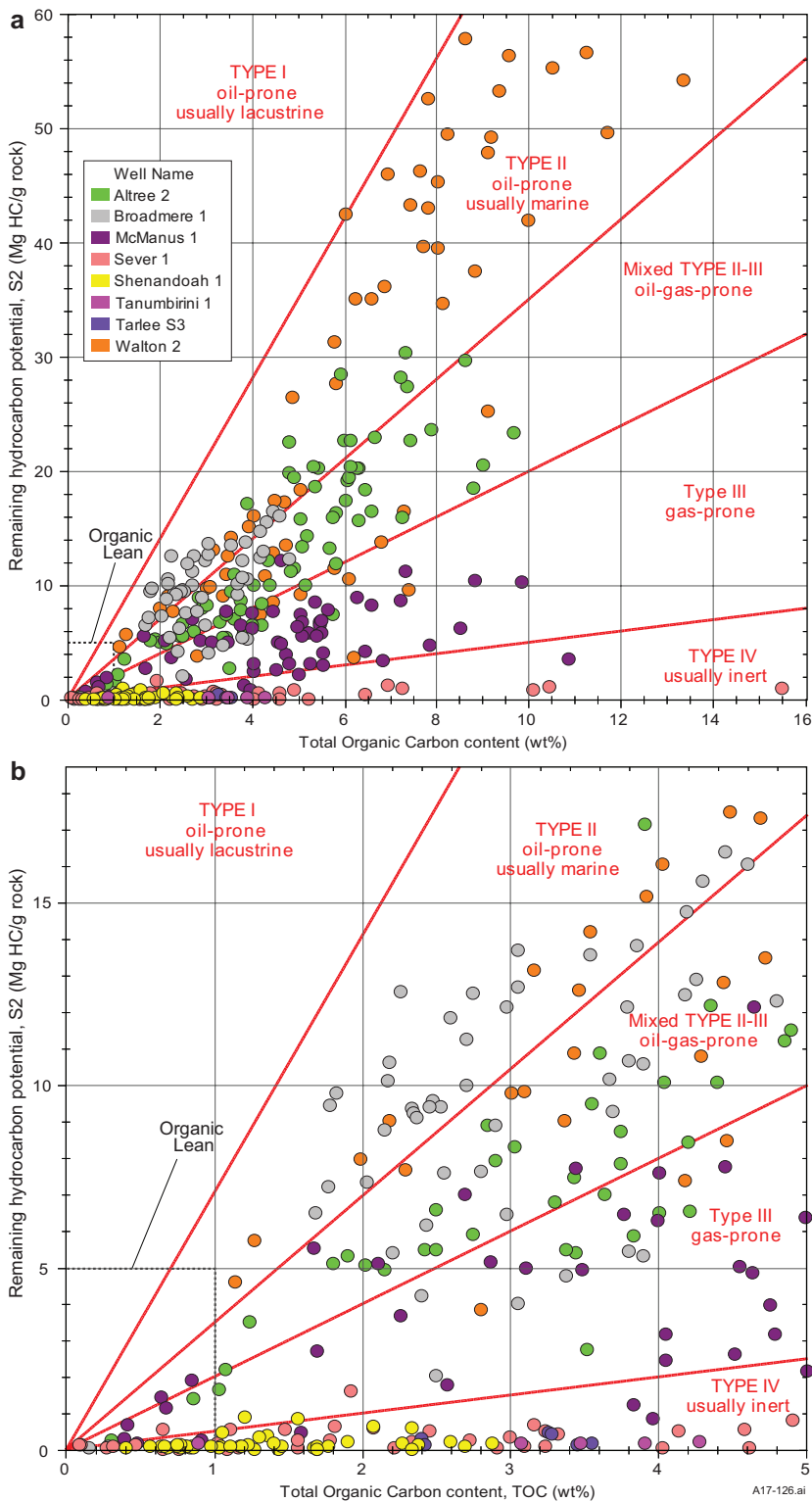


Figure 47. Total Organic Carbon (TOC) versus remaining hydrocarbon potential (S2) for middle Velkerri Formation samples in Beetaloo Sub-basin (data from Revie 2017): (a) shows range of up to 16 wt% TOC values; (b) shows expanded view of dataset up to 5 wt% TOC. Walton 2 (orange) is least thermally mature intersection and shows a correlation of values falling within Type II kerogen range.

with solid bitumens (**Figures 49, 50**). Organic petrology results from the middle Velkerri Formation document these types of samples (see Revie 2016a).

Measured present-day HI values in the middle Velkerri Formation samples range from 1 to 730 mg HC/g TOC; individual wells average 6 to 418 mg HC/g TOC, depending upon thermal maturity. On a plot of HI versus OI, most samples plot along the maturation pathway for either Type I or Type II kerogens (**Figure 51**). There is a trend line of samples with very low OI values that appear to follow the Type I maturation pathway, but the major group of samples is within the Type II kerogen envelope and follows that maturation

pathway. An overmature group of Type IV kerogen samples occurs along the x-axis of this plot. All of the middle Velkerri Formation source rocks are considered mature with regard to oil generation, and all kerogen HI values have been reduced as consequence of thermal maturity.

A plot of T_{max} values versus HI shows an association of diminishing hydrogen content with increasing thermal maturity (**Figure 52**) through the sampled intersections of the middle Velkerri Formation. The well with the least thermally mature intersections, Walton 2, has samples plotting along the immature–mature border, within the Type I/II oil-prone kerogen regions. With increasing

thermal maturity and hydrocarbon generation, HI decreases and the results indicate a change in kerogen type. Where values of $S_2 < 2$ mg HC/g rock, T_{max} is no longer a reliable measurement for kerogen type, as indicated by the blacked out samples in **Figure 52**. These samples are taken from wells with the highest level of thermal maturity in the dry gas window, Tanumbirini 1, Tarlee S3 and Shenandoah 1/1A. The results indicate that the samples have very little to no generative potential (oil) remaining. Any oil generated in these samples is likely to have been cracked to gas, and has the potential to still be undergoing this transformation.

Measured elemental H/C versus O/C ratios from isolated kerogen

A Van Krevelen plot of measured elemental H/C versus O/C ratios from isolated kerogen (**Figure 53**) represents kerogen quality in the middle Velkerri Formation source rock samples. The plotted data indicate that kerogen in the samples currently ranges between inert Type IV to oil-prone Type I. As previously discussed, thermal maturity effects tend to lower both H/C and O/C ratios from originally immature positions. The original position of the samples in the Van Krevelen diagram, prior to thermal maturation

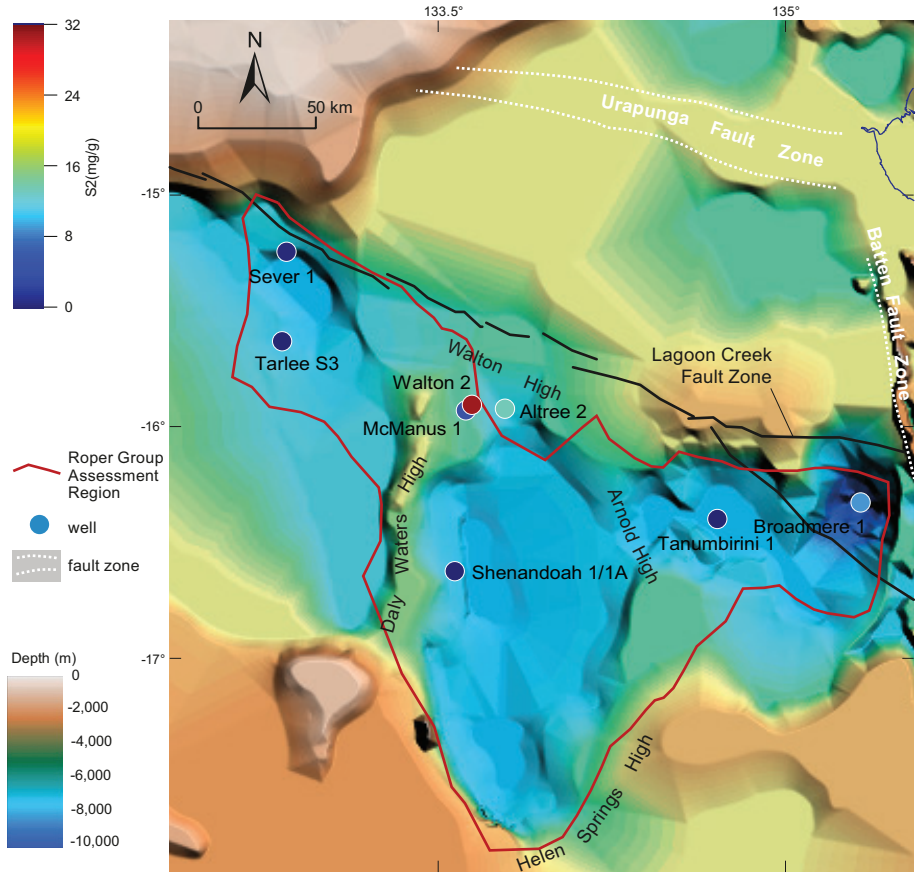


Figure 48. Spatial distribution of remaining hydrocarbon generation potential (S_2) for middle Velkerri Formation source rock samples in Beetaloo Sub-basin (data from Revie 2017). Mapped values are for average S_2 content and are reported as mg HC/g rock.

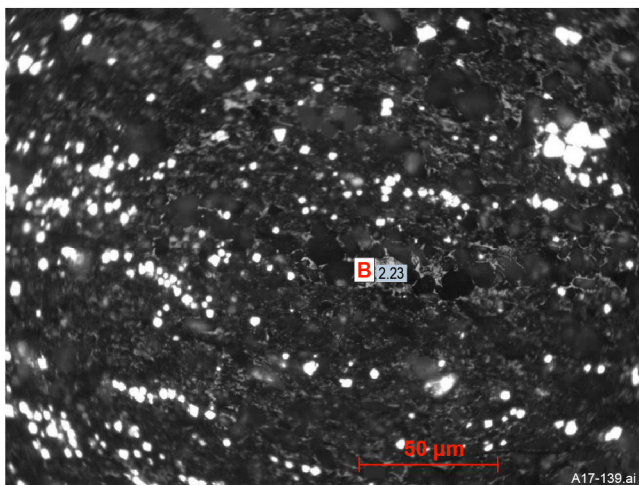


Figure 49. Photomicrograph of middle Velkerri Formation showing fine-grained bitumen (B) in mineral boundaries in pyrite-rich silty clay rock fragment; $VR_o = 2.23\%$, mean $VR_o = 2.39\%$ (sample TN16DJR185, Tanumbirini 1: 3259.80 m; reflected white light taken during reflectance measurement (Revie 2017).

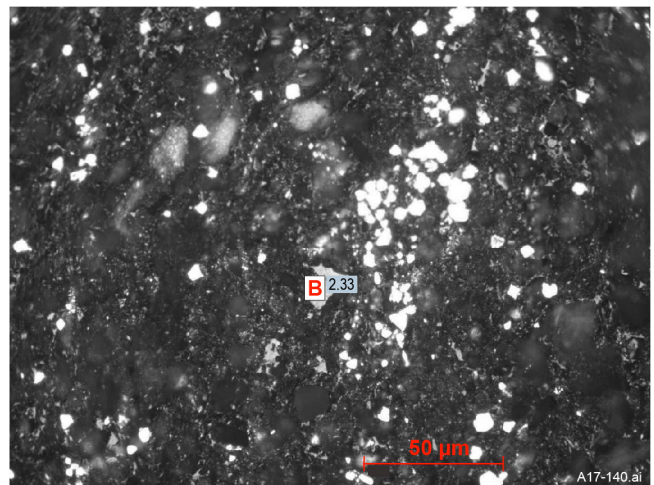


Figure 50. Photomicrograph of middle Velkerri Formation showing solid bitumen (B) in pyrite-rich silty clay fragment; $VR_o = 2.33\%$, mean $VR_o = 2.51\%$ (sample TN16DJR190, Shenandoah 1/1A: 2514.17 m; reflected white light taken during reflectance measurement (Revie 2017).

of the samples, is likely to have been within the oil-prone Type I/II regions. The least thermally mature samples, from Walton 2, plot within the Type I/II regions of the diagram, whereas highly thermally mature samples from Tarlee S3 and Sever 1 plot in the far lower left of the diagram where kerogen typing is less discernible.

The general trend of the samples shown in **Figure 53** appears to closely follow the maturation pathway that would be expected for a mixed oil-prone Type I/II kerogen suite, although the elevated O/C ratio for the samples with elevated H/C is more typical of Type II kerogen rather than Type I.

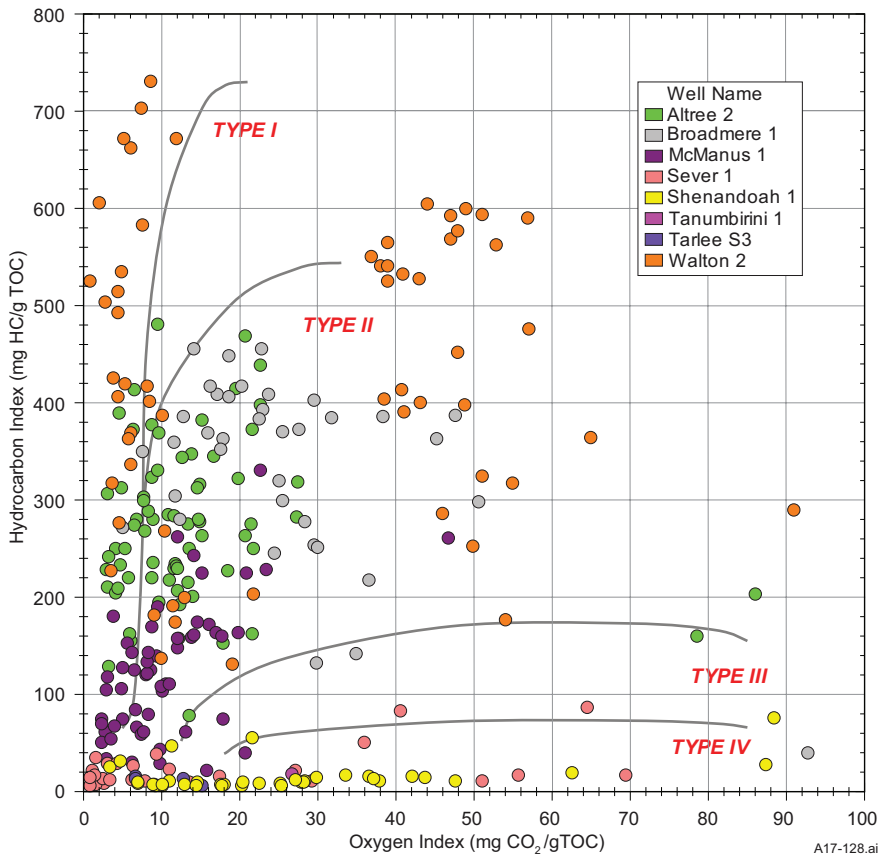


Figure 51. HI (hydrogen index) versus OI (oxygen index) for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Early oil mature samples from Walton 2 and Atree 2 are likely to best represent closest to original values of HI and OI. Tanumbirini 1, Shenandoah 1 and Tarlee S3 are dry gas mature, and kerogen HI values are greatly reduced through oil generation.

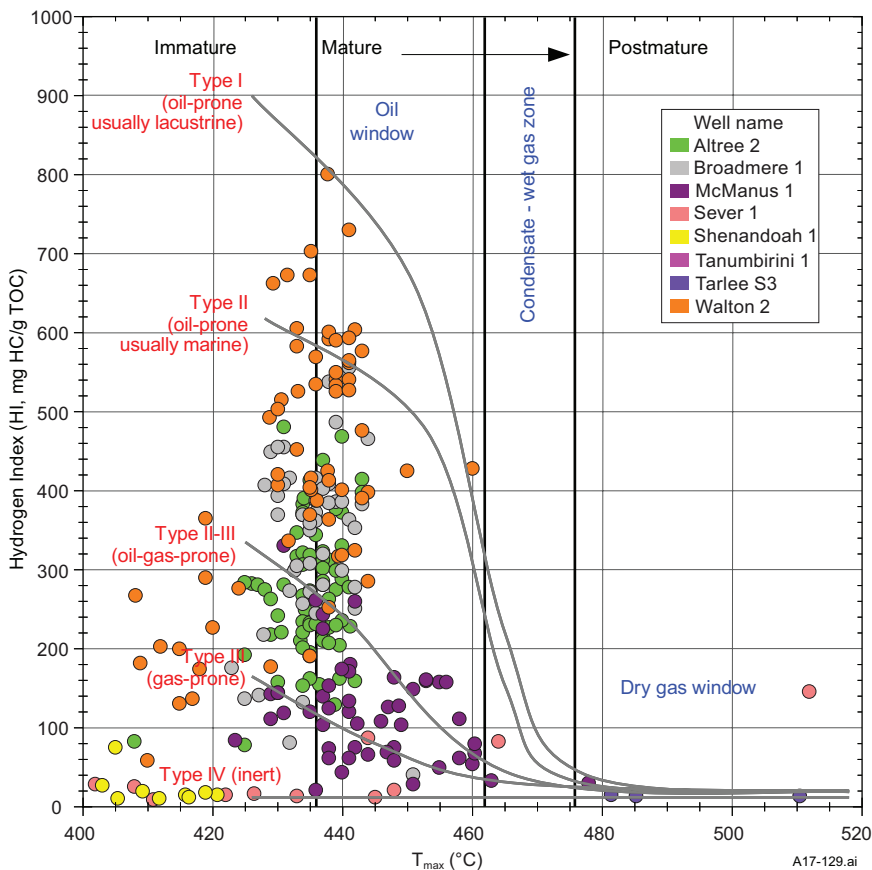


Figure 52. HI (hydrogen index) versus T_{max} for selected middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Samples with pyrolysis S2 values <2 mg HC/g rock have unreliable T_{max} values, and have been blacked out in figure; these represent samples with highest thermal maturation from Tanumbirini 1, Tarlee S3, Sever 1 and Shenandoah 1/1A.

middle Velkerri Formation generation and expulsion of hydrocarbons

Middle Velkerri Formation Production Index (PI) values from samples analysed in the Beetaloo Sub-basin vary between 0.03 and 0.78, and average between

0.13 and 0.50 within individual wells (**Figure 54**). Many of the samples fall within the zone designated for low-level conversion and are in the lower left of the main oil window region. Samples from those wells that are 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

Figure 53. Van Krevelen plot of elemental hydrogen/carbon (H/C) versus oxygen/carbon (O/C) ratios from isolated kerogen for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Thermal maturity increases toward bottom right of plot.

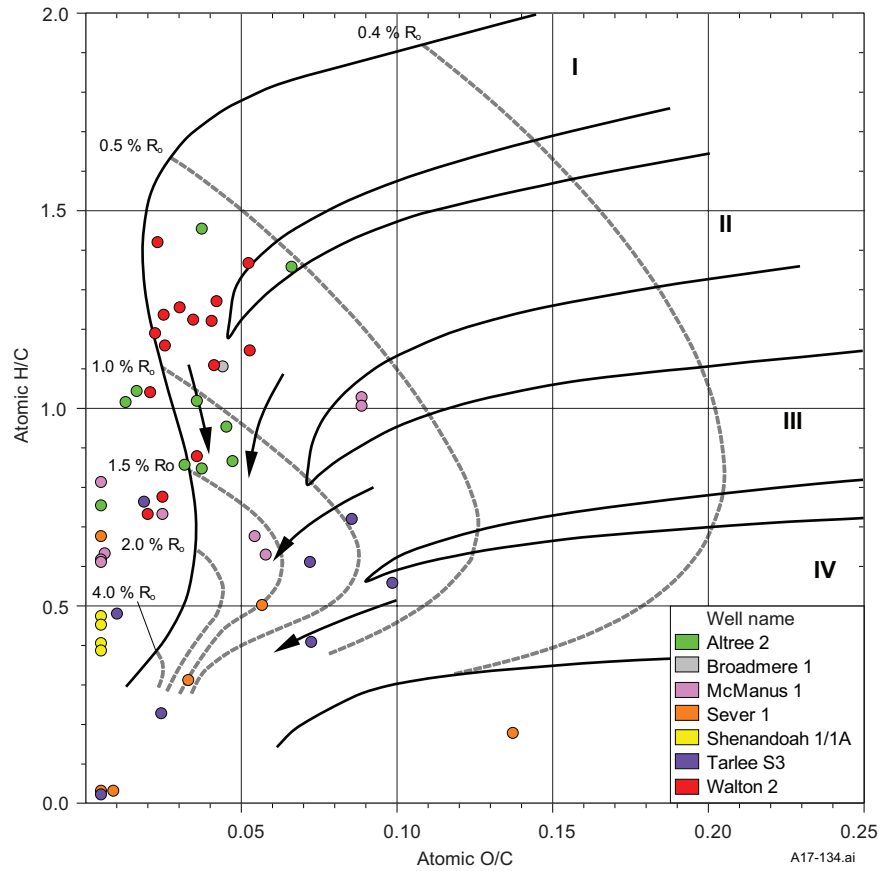
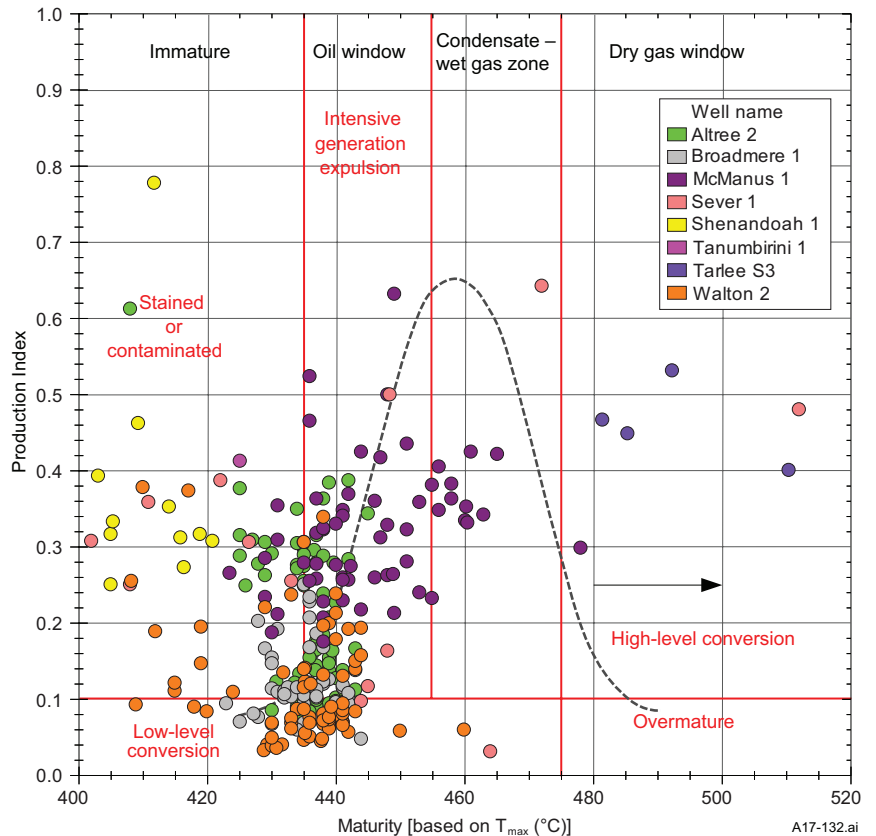


Figure 54. PI (production index) versus T_{max} for middle Velkerri Formation source rock samples in Beetaloo Sub-basin (data from Revie 2017). Dashed line trend envelope is based on Weatherford Laboratories analysis of over 5000 shale samples. Samples interpreted to be within dry gas window such as those from Tanumbirini 1 and Shenandoah 1/1A, generally plot in region for stained and contaminated samples and have anomalously low T_{max} values along with anomalously high PI values. Selected samples from Tarlee S3 plot in dry gas region and have anomalously high PI values, potentially indicating minor condensate saturation. Tarlee S3 was drilled using water-based muds, reducing the potential for oil-based mud contamination that may influence PI values.



with intensive generation and expulsion. These elevated PI values are consistent with source rocks that are interpreted to be within the main oil window. High PI values in many of the middle Velkerri Formation samples 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 wells interpreted to be thermally mature for the dry gas window generally plot in the stained or contaminated samples region and have anomalously low T_{max} values along with anomalously high PI. Selected samples from Tarlee S3 plot in the dry gas window of the T_{max} vs PI figure (Figure 54) and have anomalously high PI values, potentially indicating minor residual condensate saturation.

In situ hydrocarbon saturation (S1)

Measured *in situ* hydrocarbon saturation for middle Velkerri Formation source intervals, as determined by programmed pyrolysis S1 yields, is poor to very good [0.1 to 2.9 mg HC/g rock (2 to 64 bbl/acre-ft)]. This is generally consistent with the elevated TOC and generation potential (S2) observed in these oil-prone source rocks. All wells in the Beetaloo Sub-basin have sufficient thermal maturity to have generated oil (or in the case of the dry gas wells, retained minor residual oil from oil-to-gas cracking). Variable and in some cases quite elevated *in situ* hydrocarbon saturations are consistent with the interpreted thermal maturity. The S1 values are considered a minimum for *in situ* oil saturation, as they do not account for potential loss of volatile components during sample drill core storage, sample collection and analysis.

Estimated kerogen transformation ratios for the middle Velkerri Formation samples, based upon interpreted original and measured present-day HI, vary from 39 to 52% in wells interpreted to be within the early oil window, 80% for wells within the peak oil window, and 97 to 99% for wells within the gas window. These transformation ratios were calculated using limited measured kerogen maceral distributions combined with interpreted kerogen maceral distributions containing dominant oil-prone Type I and Type II kerogen. For the early oil window wells, these average transformation ratios are near, or below the recommended minimum threshold of 50% for shale oil systems. Wells that are within the peak oil window and gas window are above the 80% recommended minimum for thermogenic shale gas systems. The transformation ratios are generally consistent with the interpreted thermal maturity levels of these wells, and are complementary to the spatial distribution trends within other measured geochemical parameters of T_{max} , and maceral reflectance.

The four wells interpreted to be within the dry gas window (Tarlee S3, Tanumbirini 1, Sever 1 and Shenandoah 1/1A) have elevated TR values (Figure 55). Depth of burial is a significant factor in the maturity of these middle Velkerri Formation samples (Shenandoah 1/1A: >2500 m depth, Tanumbirini 1: >3100 m depth). However, depth is not the only factor controlling maturity, and there may be a spatial trend of more elevated thermal maturity along the northern and eastern margins of the Beetaloo Sub-basin. Localised heating by igneous intrusions and variable depths due to faulting may play significant roles in the thermal maturity of the middle Velkerri Formation in individual wells. An example of this is the variability between Walton 2, where

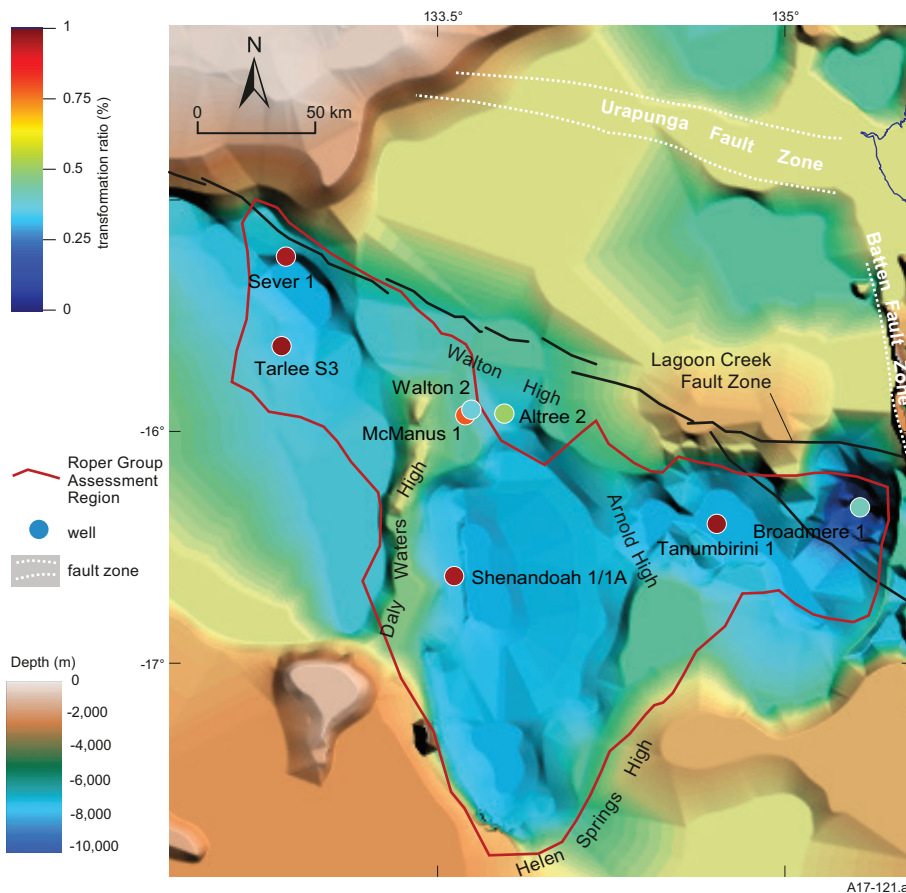


Figure 55. Spatial distribution of Transformation Ratios (TR %) of middle Velkerri Formation in Beetaloo Sub-basin (data interpreted from Revie 2017). Mapped values are for average TR and are reported as decimal percent conversion using calculated original HI_o values, based upon measured/interpreted original kerogen distributions.

the middle Velkerri Formation is early oil mature at a depth of ca 250 to 550 m, and the nearby (about 2 km) well McManus 1, where the formation is in the peak oil window at a depth of ca 1200 to 1550 m. The approximately 1000 m offset in depth between these two wells is unclear but is possibly due to faulting. Additional well data integrated with the current geochemical data and regional geology will potentially provide further insights into the origin of the variation in the transformation ratios between these two wells.

Maceral reflectance values of middle Velkerri Formation in Beetaloo Sub-basin

Measured maceral reflectance (% R_o) analyses were conducted on middle Velkerri Formation samples from six wells in the Beetaloo Sub-basin (Atree 2, Broadmere 1, McManus 1, Shenandoah 1/1A, Tarlee S3 and Walton 2). The macerals identified in the samples consist of non-fluorescing alginite, low-reflectance solid bitumen and high-reflectance solid bitumens. A range reflectance values are represented with each maceral found within each sample, relative to depth of burial and thermal maturation.

The low-reflectance solid bitumen populations in McManus 1 have reflectance values that average 0.90% R_o and are considered the most representative indigenous kerogen population for thermal maturity assessment in the sub-basin. These values support the interpreted peak oil window maturity level of the middle Velkerri Formation in McManus 1. Non-fluorescing alginite populations in Shenandoah 1/1A have reflectance values that average 2.18% R_o and appear consistent with the interpreted dry gas thermal maturity level. Likewise, a single high-reflectance solid bitumen measurement in Tarlee S3 gives a 1.81% equivalent R_o using the Jacob (1985) conversion formula,

and supports the interpreted dry gas thermal maturity level (late-stage catagenesis) in this well.

The thermal maturity of middle Velkerri 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, **Table 29**). Samples from selected source rocks within the dry gas window (average 30–40% clay content) have average measured Kübler Index values of 0.210–0.326, equivalent to a measured vitrinite reflectance ranging from ca 3% (mid-stage metagenesis) to >4% (late-stage metagenesis). The maturity interpretations are inconsistent with other geochemical maturity ratios evaluated in this study (see above) and suggest the Kübler Index should be used with caution to evaluate thermal maturity in Mesoproterozoic source rocks.

middle Velkerri Formation original generative potential and hydrocarbon yield calculations

The petroleum generative capacity of middle Velkerri Formation source rocks was calculated using **Equations 3–6** to determine the original petroleum generative potential and present-day hydrocarbon yields (**Table 30**).

The average maceral percentages in the various wells evaluated in the current study, and the resultant average original HI values (HI_o) were calculated using **Equation 3** (**Table 31**). The kerogen estimations are generally in agreement with other published values that suggest a Type II to mixed Type I/II kerogen assemblage (Crick *et al* 1988, Taylor *et al* 1994).

The expulsion efficiency (direct proportion of measured retained oil saturations and average generated hydrocarbon yields) of middle Velkerri Formation source rocks in wells

Table 29. Metapelitic zones showing associated lithologies and metamorphic facies (after Abad 2008). Illite Kübler index and other indicators of reaction progress in smectite-I/S-illite-muscovite series of clay minerals used to index the zones. KI = Kübler Index. $Rr\%$ = Random vitrinite reflectance.

Metapelitic zone (depth, km)	Temperature (°C)	KI ($\Delta 2\theta$)	% illite in I/S	TEM mean illite crystallite thickness (Å)	Illite-muscovite polytype	Typical pelitic lithologies	Characteristic microfabrics	Metamorphic facies	Fluid zone	Maturation stages	Vitrinite reflectance $Rr\%$
Shallow diagenetic zone										Diagenesis	
3.5–4	~100	~1.00	60–80		1M ₀ (IM?)	shale/mudstone		zeolite	HHC		0.50
Deep diagenetic zone							bedding-parallel (S_0)			Catagenesis	1.35
6.5–8	~200	0.42	~90	200			crenulated (S_0)				2.00
Low anchizone					2M ₁ (3T)	slate	slaty	prehnite-pumpellyite	CH ₄	Metagenesis	3.00
High anchizone							cleavage (S_1)				4.00
10–12	~300	0.25	>99	500	2M ₁ (3T)	slate					
Epizone						(phyllite)	(S_{1+})	greenschist	H ₂ O		

interpreted to be within the oil window varies between 75 and 89%, which is most consistent with late oil to early wet gas/condensate maturity. The four dry gas wells all have much higher expulsion efficiencies of 99%, consistent with the interpreted maturity levels.

Middle Velkerri Formation source rock samples in the various Beetaloo Sub-basin wells are interpreted to be in the early-to-peak oil window, through to the early-dry gas window. Hydrocarbon yield calculations suggest that significant generation has occurred, predominantly oil

with some associated gas in most wells, and cracked gas with minor residual oil in other wells. This is generally favourable from an exploration risk perspective.

It is useful to relate the hydrocarbon yields to producing unconventional USA shale plays (Table 32). The potential critical value is not only the generated oil and gas yields, but also the original (S_{2o}) generation potential of the source rocks. These values relate to the ultimate volumes of hydrocarbon that could be generated at depth. For the middle Velkerri Formation samples, S_{2o} averages between 171 to 898 bbl oil/

Well	%Type I 750 HI _o	%Type II 450 HI _o	%Type III 125 HI _o	%Type IV 50 HI _o	HI _o
Altree 2	2	98	0	0	456
Broadmere 1	9	91	0	0	478
McManus 1	0	100	0	0	450
Sever 1	0	100	0	0	450
Shenandoah 1/1A	0	100	0	0	450
Tanumbirini 1	0	100	0	0	450
Tarlee S3	0	100	0	0	450
Walton 2	33	67	0	0	550

Table 30. Average kerogen estimations for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Average maceral percentages determined by visual kerogen estimates where available. Due to absence of visual data, kerogen type was estimated by present-day TOC, HI and OI values.

Table 31. Hydrocarbon yields average data for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Original values estimated using Equation 1 – Equation 4.

Well	TOC _{pd}	HI _{pd}	S _{2pd} (bbl/a-ft)	HI _o	TR	TOC _o	S _{2o} (bbl/a-ft)	S1 free oil (bbl/a-ft)	Est. Oil (bbl/a-ft)	Cracked gas (Mcf/a-ft)
Altree 2	4.41	274	283	456	0.52	5.10	510	54	227	0
Broadmere 1	2.94	332	210	478	0.43	3.36	347	29	136	0
McManus 1	4.34	129	110	450	0.80	5.52	544	46	417	102
Sever 1	3.79	22	8	450	0.97	4.93	485	5	15	2771
Shenandoah 1/1A	1.29	21	6	450	0.97	1.74	171	2	0	993
Tanumbirini 1	3.13	8	4	450	0.99	4.20	414	3	0	2459
Tarlee S3	4.11	6	3	450	0.99	5.42	534	3	2	3174
Walton 2	6.48	418	641	550	0.39	7.15	898	64	257	0

Table 32. Geochemical properties and generation potential of middle Velkerri Formation (data from Revie 2017) compared with producing USA shale gas plays. Middle Velkerri Formation wells are colour coded for possible shale oil (green) and shale gas (red) prospect type.

Sample database Average TOC >1%	HI _o mg/g TOC	TR	TOC _o	S _{2o}	Remaining potential (bbl/a-ft)	Original potential (bbl/a-ft)	Oil cracked (%)	S1 Free Oil (bbl/a-ft)	Estimated oil (bbl/a-ft)	Cracked gas (Mcf/a-ft)
Barnett Shale, Fort Worth Basin	435	0.84	5.38	23.40	94	513	40	33	251	1005
Barnett Shale, Delaware Basin	435	0.91	5.25	22.84	52	500	80	32	90	2149
Woodford Shale, Delaware Basin	480	0.89	6.41	30.79	139	674	89	46	60	2854
Haynesville Shale, East Texas Basin	400	0.98	3.93	15.73	7	344	100	3	0	2022
Fayetteville Shale, Arkoma Basin	435	0.95	3.34	14.53	15	318	100	10	0	1820
Woodford Shale, Arkoma Basin	520	0.87	5.15	26.80	12	587	70	87	170	2431
Eagle Ford Shale, Gulf Coast Basin	520	0.85	3.19	16.61	61	364	47	22	161	848
Marcellus Shale, Appalachian Basin	600	0.97	6.44	38.66	34	847	100	24	0	4875
Utica Shale, Appalachian Basin	450	0.98	2.74	12.32	6	270	100	12	0	1585
Barnett Shale Oil	450	0.47	5.47	24.64	326	540	0	79	308	0
Barnett Shale Gas	450	0.96	5.58	25.13	23	550	87	7	68	3657
Altree 2	456	0.52	5.10	23.30	283	510	0	54	227	0
Broadmere 1	478	0.43	3.36	15.83	210	347	0	29	136	0
McManus 1	450	0.80	5.52	24.85	110	544	3	46	417	102
Sever 1	450	0.97	4.93	22.17	8	485	95	5	15	2771
Shenandoah 1/1A	450	0.97	1.74	7.82	6	171	100	2	0	993
Tanumbirini 1	450	0.99	4.20	18.89	4	414	100	3	0	2459
Tarlee S3	450	0.99	5.42	24.38	3	534	100	3	2	3174
Walton 2	550	0.39	7.15	40.99	641	898	0	64	257	0

acre-ft (Table 32). With the exception of Shenandoah 1/1A, all other wells are >340 bbl oil/acre-ft and generally fall within the range of producing unconventional USA shale plays. The least thermally mature well, Walton 2, exceeds the average values for the producing unconventional USA shale plays. This suggests that middle Velkerri Formation source rocks in the Beetaloo Sub-basin, particularly along the northern margins, have excellent prospectivity from a geochemical hydrocarbon generation perspective. Although this is encouraging, it is only one component of the unconventional shale play risk assessment; other factors such as *in situ* hydrocarbon saturations and source rock mineralogy must be considered during evaluation.

middle Velkerri Formation unconventional oil and gas risk assessment

Middle Velkerri Formation source rocks in the Beetaloo Sub-Basin were evaluated by Weatherford Laboratories on behalf of the NTGS for unconventional oil and gas potential. Figure 56 is a modified geochemical risk assessment diagram for these source rock samples, based upon published results from the Barnett Shale in the Fort Worth Basin, USA.

Middle Velkerri Formation source rocks in most of the Beetaloo Sub-basin wells are interpreted to represent a low to moderate geochemical risk for *in situ* shale oil/gas production, although Shenandoah 1/1A is considered to be a high risk for shale gas. The average measured TOC contents of all wells are above the generally accepted minimum value of 1% TOC necessary to be considered an *effective* source rock for hydrocarbon generation/expulsion, which is also the minimum threshold for prospective shale oil systems.

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 Shenandoah 1A, which has an average TOC of 1.32 wt%, below the recommended minimum shale gas threshold. The original organic matter type in these source rock intervals is interpreted to have been 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, whereas others are interpreted to be in the dry gas window. The average T_{max} values of 433–444°C for wells within the early to peak oil window are generally above the recommended minimum value of 435°C for shale oil, although Walton 2 values are slightly below this threshold. The level of thermal maturity would probably be sufficient to generate/expel significant amounts of hydrocarbons from this organic-rich source facies. Average T_{max} values of 499°C and 530°C for the wells Tanumbirini 1 and Shenandoah 1/1A are within the gas window and are far above the minimum of 455°C for shale gas, although no reliable T_{max} values are available from Shenandoah 1A. Transformation ratios (TR), the least constrained risk parameter, average between 39 and 80% for wells interpreted to be in the oil window, with two wells (Broadmere 1 and Walton 2) falling below recommended minimum of 50% for shale oil.

The four 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. Measured maceral reflectance values are only available for three of these wells. The value of 0.90% R_o for low-reflectance solid bitumens in McManus 1 are above the recommended minimum threshold of 0.6% R_o for shale oil systems but below the minimum threshold of 1.0% R_o for shale gas systems. Measured and equivalent R_o values for the dry gas wells are

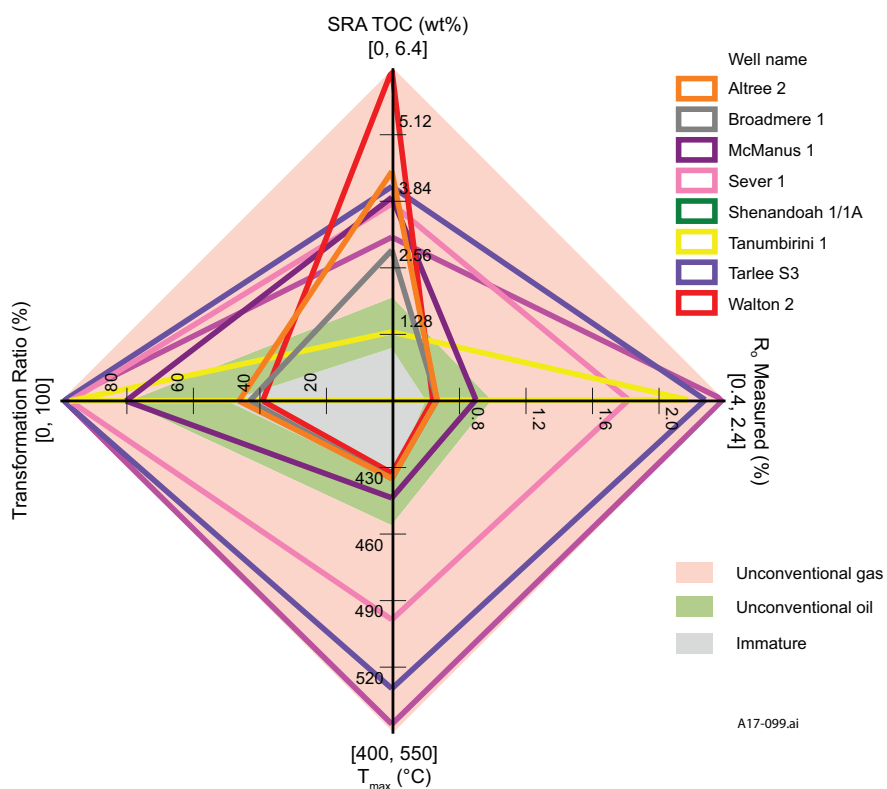


Figure 56. Geochemical risk assessment diagram for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). These results are based upon published results from Barnett Shale in Fort Worth Basin, USA. Data illustrated in star plot represents average values for all four diagnostic ratios, where available.

1.81, 1.99 and 2.18% R_o and are well above the minimum threshold for shale gas.

For the middle Velkerri Formation source intervals interpreted to be in the oil window, measured *in situ* oil saturation (S1) yields are good to very good (average 29–64 bbl oil/acre-ft), which is a positive factor regarding risk assessment for unconventional oil (Figure 57).

Estimated yields for wells interpreted to be in the oil window average 136–417 bbl oil/acre-ft. In comparison, a representative sample from the core area of the Barnett Shale in the Fort Worth Basin, USA, has an estimated generation yield of 213 bbl/acre-ft with a measured S1 oil saturation of 79 bbl/acre-ft. With the exception of Broadmere 1, these values are comparable to most of the middle Velkerri Formation intersections in the Beetaloo Sub-basin.

Four of the middle Velkerri Formation well intersections are interpreted to be in the dry gas window; measured S1 yields are low (average 2–5 bbl/oil/acre-ft) as expected for this level of thermal conversion. Average generated oil estimations from these intervals are 0–15 bbl oil/acre-ft; oil cracking is estimated to have been 95 to 100%, resulting in cracked gas yields of 993 to 3174 Mcf/acre-ft (Figure 57). In comparison, the Barnett Shale in the Fort Worth Basin has an estimated cracked gas yield of 2751 Mcf/acre-ft, with 68 bbl/acre-ft of residual oil/condensate and a measured *in situ* oil saturation of 7 bbl/acre-ft. Both Sever 1 and Tarlee S3 have cracked gas yields that exceed the Barnett Shale values, and are considered low risk for shale gas.

As noted above, the quantity of oil generated from a potential source rock is only one geochemical factor to consider in a risk assessment. Equally important is the quality of the oil generated, since this factor can be a critical element in assessing hydrocarbon mobility and ultimate recovery. Middle Velkerri Formation samples interpreted to be within the early oil window are likely to have heavy and immobile hydrocarbon saturations. Wells with middle Velkerri Formation intercepts within the peak oil window are likely to have fairly light and mobile *in situ* oil saturations.

Spatial distributions of measured *in situ* S1 free oil saturations (Figure 58), estimated generated oil yields (Figure 59), and estimated cracked gas yields (Figure 60)

were evaluated in the context of trends within other geochemical parameters.

Measured *in situ* S1 oil saturations are generally good (29 to 64 bbl oil/acre-ft) in most of the middle Velkerri Formation wells interpreted to be within the main oil window. The three wells in the north-central margins of the sub-basin (McManus 1, Altree 2 and Walton 2), have the highest S1 free oil saturations, correlate favourably with the TOC in the wells, and are interpreted to be within the oil window. The expected very low S1 values found in Tanumbirini 1, Shenandoah 1/1A, Tarlee S3 and Sever 1 are interpreted as indicating the dry gas thermal maturity window and having undergone extensive (95 to 100%) oil to gas cracking.

Spatial trends for estimated secondary cracked gas yields (Figure 60) closely follow the thermal maturity patterns established above for transformation ratios and calculated R_o . Tanumbirini 1, Sever 1, Shenandoah 1/1A and Tarlee S3 are the only wells in this study interpreted to be in the dry gas window and to have generated significant amounts of estimated cracked gas from the middle Velkerri Formation. The Tarlee S3 cracked gas yield is higher due to its higher TOC content, and the other three wells follow this trend.

middle Velkerri Formation mineralogy

XRD analyses of middle Velkerri Formation source rocks (Table 33) indicate that clays are very abundant (37 wt%). Quartz is the dominant mineral present (46%). Based on mineralogy, the Velkerri Formation source rocks would be mostly classified as clay-rich siliceous mudstones, with some silica-rich argillaceous mudstones, argillaceous-siliceous mudstones, mixed carbonate mudstones and carbonate dominated lithologies.

The source rock samples have abundant clays, which presents a risk for potential fracture stimulation because this is often a fairly ductile mineral assemblage. The types of clays present are also important and present another potential risk factor; the samples contain abundant ordered interstratified mixed-layer illite/smectite (12% of mineral assemblage and 39% of total clays). On the other hand,

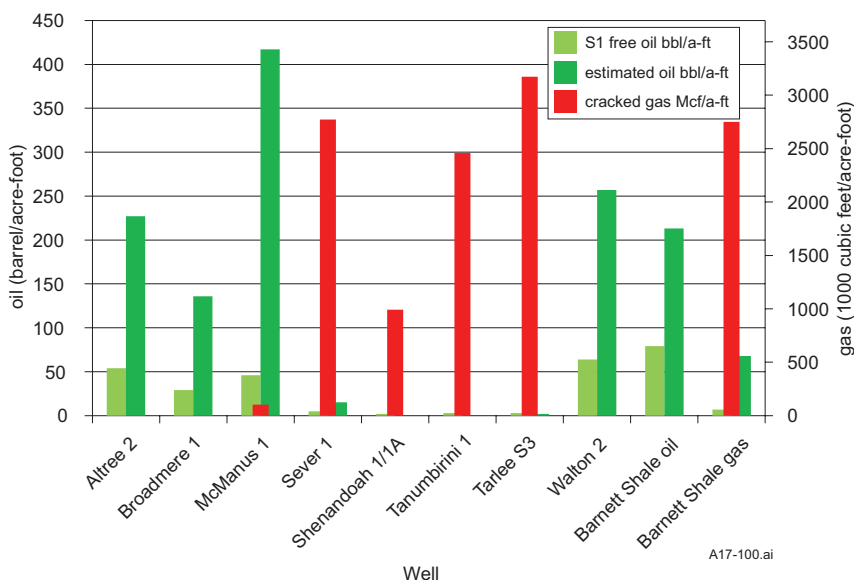


Figure 57. Hydrocarbon yield estimates for middle Velkerri Formation source rock samples from Beetaloo Sub-basin, compared to Barnett Shale (USA) in oil and gas windows.

the dominant quartz content, a relatively brittle mineral, is conducive to fracture stimulation. Pyrite is present in minor amounts (3%) and is associated with kerogen that is a minor component of the overall mineral assemblage. Pyrite is usually a positive component with regards to fracture

stimulation for organic-rich shales at elevated thermal maturity.

Mineralogy data can potentially be used to further assess rock mechanical properties, including brittleness. Brittleness Index (BI) values were calculated using

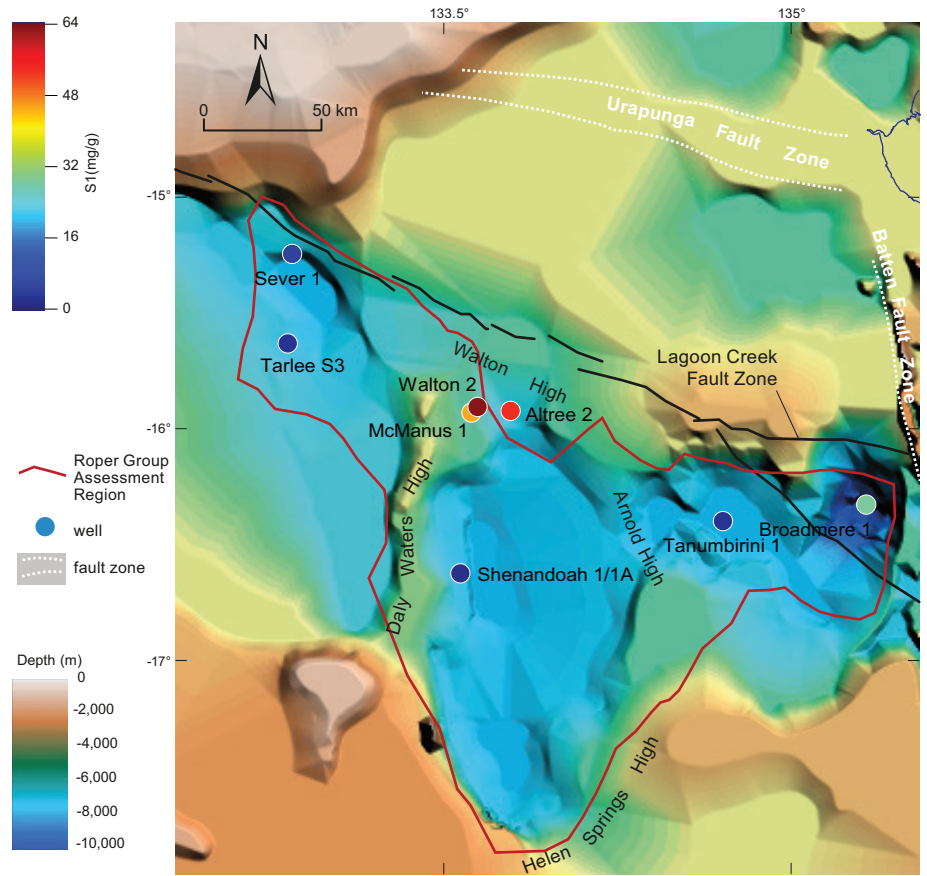


Figure 58. Spatial distribution of S1 free oil saturation for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Mapped values are for average S1 and are reported in bbl oil/acre-ft.

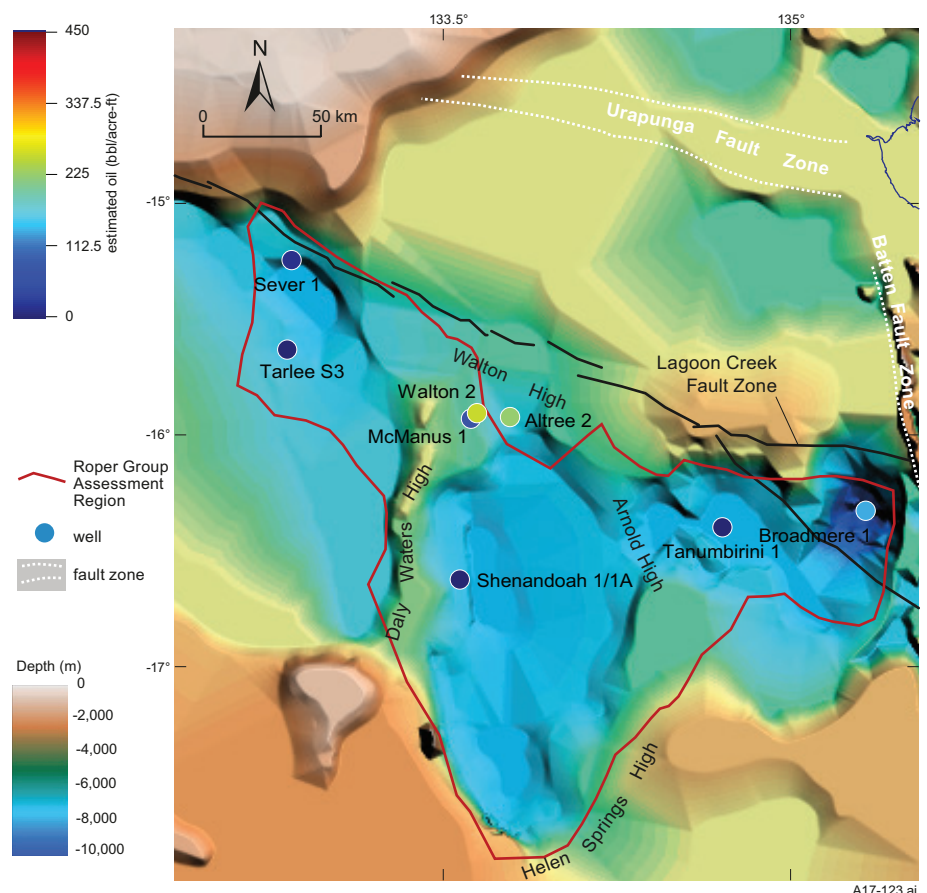


Figure 59. Spatial distribution of estimated generated oil yields for middle Velkerri Formation source rocks from Beetaloo Sub-basin (data from Revie 2017). Mapped values are for average generated oil and are reported in bbl oil/acre-ft.

Equation 9. The range of BI values vary in the range 24–76 and average 52, with higher values supposedly indicating more brittle rock (in comparison, the Kyalla Formation in the Beetaloo Sub-basin averages 41). The highest BI values were found in samples with the lowest overall clay content. Both carbonates and quartz have a strong influence on the brittleness calculation. For the middle Velkerri Formation source rock samples, carbonate is generally very low in abundance, and the variability in the quartz and clay content has the greatest influence in the BI.

Static Young’s Moduli yields of 23–34 GPa for two middle Velkerri Formation samples (Table 34) indicate values typical of a high cohesive and unconfined compressive strength in the material. Prospective shales, based on historical data, have a static Young’s modulus in excess of 24.1 GPa (Britt and Schoeffler 2009). This is a moderate risk for the middle Velkerri Formation in the Beetaloo Sub-basin, where both samples tested at, or

slightly above, this threshold (Atree 2: 34.5 GPa; Sever 1: 24.1 GPa).

The static Poisson’s Ratios of the two samples analysed (0.10–0.31) show that there is variability within the middle Velkerri Formation, but there are insufficient samples to make a comment on the overall character of the unit. Typical values for Poisson’s ratio for shales range from 0.28 to 0.43 (Bair *et al* 2010). Shales typically fracture under tensile stress well before failing under compression. Although the Atree 2 sample falls within this range, the Sever 1 sample is lower than the range for shale, and is more typical of a hard, compacted or cemented sandstone (0.10–0.22 Poisson’s Ratio). It is worth noting that the presence of gas and increased TOC content can lower the measured Poisson’s Ratio, and this must be taken into consideration for the carbonaceous shale of the middle Velkerri Formation.

Mineralogy data can be used to compare the middle Velkerri Formation source rock samples against those

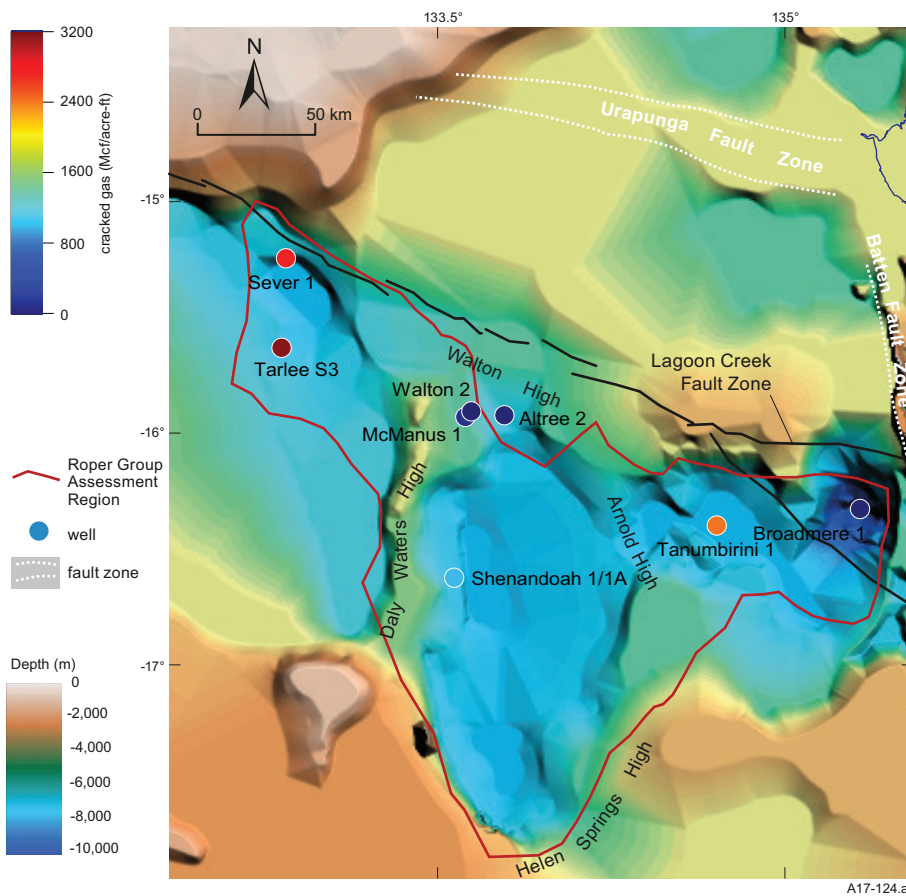


Figure 60. Spatial distribution of estimated cracked gas yields for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). Mapped values are for average secondary cracked gas and are reported as Mcf gas/acre-ft.

Table 33. TOC and X-ray diffraction average data (wt%) for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017). * ordered interstratified mixed-layer illite/smectite.

Formation	Clays	Carbonate minerals	Quartz	K-spar	Other	Mixed I/S*	TOC	Brittleness Index
middle Velkerri	32	5	46	3	15	12	3.6	52

Table 34. Rock mechanics for selected samples of middle Velkerri Formation taken from two wells within the Beetaloo Sub-basin (data from Revie 2017).

Well	Depth (m)	Formation	Confining pressure (MPa)	Compressive strength (MPa)	Static Young’s Modulus MPa (psi)	Static Poisson’s Ratio
Altree 2	850.03	middle Velkerri	6.62	194.26	34291	0.31
Sever 1	756.62	middle Velkerri	5.93	124.88	23766	0.10

of producing USA shale formations. A ternary plot (**Figure 61**) shows the relative weight percentages of carbonate minerals, clays and quartz, as determined by XRD, for middle Velkerri Formation source rock samples compared to published data for USA shale plays. The middle Velkerri Formation samples generally have elevated silica (46%), and moderate clay content (32%), which may present as a risk for fracture stimulation. Samples from Atree 2 and McManus 1 that have a high carbonate mineral content were taken from the base of the middle Velkerri Formation where there is a distinctive carbonate-rich marker horizon.

The clay content of the middle Velkerri Formation contains an abundance of mixed layer illite/smectite (12%). Illite/smectite content is a critical factor in determination of the effect of clay content on the response of a formation to stimulation and completion. There is considerable variability in the middle Velkerri Formation, shown within the ternary diagram (**Figure 61**), and each of the A, B and C organofacies should be considered on its own mineralogy and petrophysical attributes for potential responses to stimulation and completion practices.

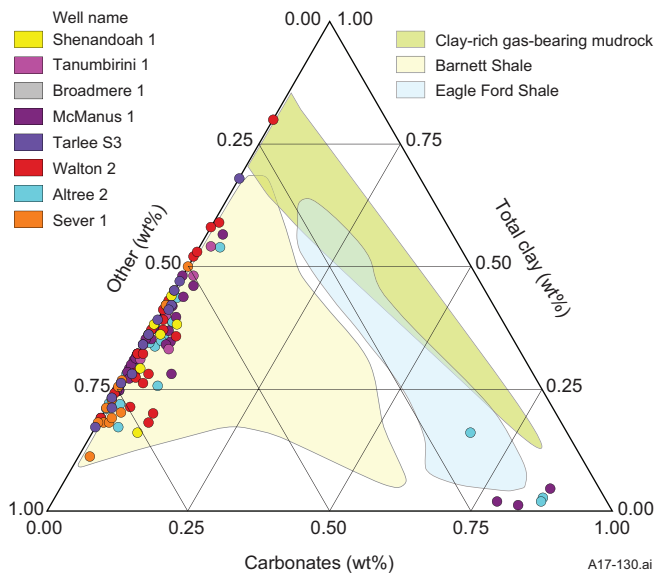


Figure 61. XRD mineralogy ternary diagrams for middle Velkerri Formation source rock samples from Beetaloo Sub-basin (data from Revie 2017) compared with producing USA shale plays (data from Passey *et al* 2010). Middle Velkerri Formation results plot within region covered by Barnett Shale.

Table 35. Integrated contaminant-corrected gas composition of Kyalla Formation and middle Velkerri Formation B shale. Concentration is presented in mol fraction of total gas component. C₁=methane, C₂=propane, C₃=ethane. Data sourced and adapted from Falcon Oil & Gas (2010).

Sample ID	Midpoint depth (m)	C ₁ (mol frac)	C ₂ (mol frac)	C ₃ (mol frac)	O ₂ (mol frac)	N ₂ (mol frac)	CO ₂ (mol frac)	H ₂ (mol frac)	Total (mol frac)
lower Kyalla Formation									
44569-2	1589.8	0.4042	0.2123	0.3414	0.0	0.0	0.0421	0.0	1.0
44569-3	1592.8	0.4860	0.1802	0.3029	0.0	0.0	0.0308	0.0	1.0
Average	-	0.4451	0.1963	0.3222	0.0	0.0	0.0365	0.0	1.0
middle Velkerri Formation B shale									
44569-5	2513.6	0.8834	0.0638	0.0052	0.0	0.0	0.0476	0.0	1.0
44569-6	2515.6	0.9232	0.0315	0.0022	0.0	0.0	0.0431	0.0	1.0
Average	-	0.9033	0.0477	0.0037	0.0	0.0	0.0454	0.0	1.0

GAS SHOWS AND COMPOSITION

GAS SHOWS AND FLOWS

Gas shows have been recorded in the middle Velkerri Formation in Shenandoah 1 (and re-entry Shenandoah 1A) (Falcon 2012), and Kalala-S1 and Amungee NW 1 (Close *et al* 2016); these shows indicate that gas generation has occurred, and is likely to still be generating through oil to gas cracking within the dry gas window. Tanumbirini 1 also encountered significant mud gas shows, with elevated gas readings over a total gross interval in excess of 500 m through the middle Velkerri Formation (Santos 2014, Tamboran 2017).

Amungee NW-H1 (horizontal extension to Amungee NW 1) successfully flowed gas to surface after a multi-stage hydraulic fracture stimulation program. The well underwent a successful extended production test, and was announced as a discovery in December 2016 (Origin Energy 2016). Initial production rate (30 days) was 1.11 million standard cubic feet per day (MMscfd), and the final rate was 1.07 MMscfd (57 days), with a total of 63 MMscf being produced from the well (Origin Energy 2016).

GAS COMPOSITION

The announcement of basic gas compositions from the Amungee NW-H1 well production test (Origin Energy 2016) are complementary to the gas composition analyses of the Kyalla and middle Velkerri formations performed on gas canister samples taken from Shenandoah 1/1A by Falcon Oil & Gas Ltd (Falcon 2010). The integrated gas composition data for gas at each of four sampled intervals are summarised in **Table 35**. Note that the integrated gas compositions have greater amounts of gases that are more strongly adsorbed than methane at the expense of the methane content.

The lower Kyalla Formation has an integrated gas composition of 44.5% methane, 32.2% propane and heavier hydrocarbons, 19.6% ethane and 3.6% carbon dioxide. For the middle Velkerri Formation B shale, the average integrated gas composition is 90.3% methane, 4.8% ethane, 4.5% carbon dioxide, and 0.4% propane and heavier hydrocarbons (Falcon 2010).

The presence of wet-gas components (C₂-C₇, propane and heavier fractions) up to 32.2% in the lower Kyalla

Formation of Shenandoah 1/1A is consistent with geochemical indicators that in this well the formation is currently within the late-oil to wet gas/condensate window.

The dominant presence of dry-gas (predominantly methane and ethane, C₁-C₂) with relatively low levels of heavier hydrocarbon fractions is typical of oil-to-gas cracking within shales that are thermally mature within the dry gas window. This is consistent with the interpretation of other geochemical indicators that middle Velkerri Formation B shale in Shenandoah 1/1A is currently within the dry gas window.

MODELLED HYDROCARBON CONTENT

NTGS commissioned Weatherford Laboratories during 2017 to conduct a resource assessment to evaluate the hydrocarbon prospectivity of the Kyalla and middle Velkerri formations across the Gorrie, Beetaloo, OT Downs and Broadmere sub-basins (Weatherford 2017). Core-based stock tank oil-initially-in-place (STOIIP) estimates were calculated using the open-file data collated and referenced within this report. Three methods of calculation were used for comparison. Firstly STOIIP was calculated using oils saturations from shale rock property (SRP) data. Secondly, S1 values were determined from pyrolysis data. The third method used estimated oil yields and assumed a 37% retained oil volume, based upon geochemical hydrocarbon yield data. A map-based volume calculation approach was employed to calculate the original hydrocarbons in place for both the Kyalla and middle Velkerri formation intervals. Using cumulative probability functions, 90, 50 and 10% probability values (P90, P50 and P10 values) were determined for each formation respectively. Original hydrocarbons in place (OHIP) values, as determined through the resource assessment, are shown in **Table 36**. The assessment is comprehensive across the sub-basins where the formations are likely to be present within the oil window and gas window of thermal maturity, and uses all available open file data across multiple tenements. The

Table 36. Original hydrocarbons in place comparisons between different methods of volumetric resource assessment for Kyalla and middle Velkerri formations. Further details of estimation methodology are detailed in Weatherford (2017). MMbbl = millions of barrels, TCF=trillions of cubic feet.

	P10	P50	P90
Kyalla Formation	Oil (MMbbl)		
Map Based Volumetric	1164	772	414
SRP Based Volumetric		143	
S1 Based Volumetric		94	
HC Yield Based Volumetric		293	
middle Velkerri Formation	Oil (MMbbl)		
Map Based Volumetric	113	83	62
SRP Based Volumetric		9	
S1 Based Volumetric		13	
HC Yield Based Volumetric		24	
middle Velkerri Formation	Gas (TCF)		
Map Based Volumetric	293	202	118
S1 Based Volumetric		752	

report estimates that there is a risked recoverable resource in the range 118–293 TCF in place within the middle Velkerri Formation. This is highly dependent on future recovery efficiencies and availability of infrastructure in this frontier basin. The P10–P90 forecasts will change with time, as forecasting is dependent on information beyond reservoir characterisation, engineering and management.

Risk in estimation of hydrocarbons in place

There are several sources of uncertainty associated with the modelling of these data. Most of the samples taken were from drill core that has been exposed to atmospheric conditions for prolonged periods of time. Fluids in the core, both hydrocarbons and water, may have changed composition as a result of this exposure. Estimated hydrocarbons could be higher or lower, depending on how the core was affected. SRP data are sparse considering the size of the basin: within a total modelled area of 36 600 km², there were only 14 Kyalla Formation samples from three wells and 36 middle Velkerri Formation samples from seven wells. SRP values measured/calculated from the core have been assumed to be representative of the whole area modelled. The siltstones of the formations do display some heterogeneity in rock properties, and assumptions of homogeneity in SRP values can also affect the final outcome.

Core data may also have been high-graded in some instances where sampling targeted the intervals with the best potential for hydrocarbons. Any hydrocarbon-in-place estimates therefore could have been overestimated and may not be representative of the overall reservoir characteristics for the volume of reservoir used in the calculations. Geochemistry-based hydrocarbon yield volumetric calculations had an arbitrary retention factor applied to all of the data. If this assumed retention factor was too high compared to present-day conditions, the hydrocarbon yields would be overestimated. Core sample data alone may not capture the true variability needed to accurately estimate hydrocarbons in place on a basin scale. A complete reservoir model, rather than a core-based approach, would better serve this purpose.

POROSITY AND OVERPRESSURE:

An abnormal pressure includes both under- and overpressures relative to the hydrostatic and confining pressure at any given depth. Some unconventional plays can be highly overpressured, eg Bossier and Haynesville shales in the USA. Abnormal overpressures (>12 kPa/m, or >0.53 psi/ft) are created and maintained by the inability of pore fluids to migrate within a reasonable geologic time period when subjected to stresses that cause increased fluid pressure (Hunt 1995).

Overpressures can be generated through various processes, but the most influential are compaction disequilibrium due to rapid burial of fine-grained sediments, and hydrocarbon generation through cracking (Peters *et al* 2015). Compaction disequilibrium, thermal expansion of fluids and tectonic compression would all have contributed in part to the generation of abnormal pressures in the Beetaloo Sub-basin.

The effect of mechanical compaction reduces with depth, and this can be modelled in the form of a negative exponential (Athys 1930, Hedberg 1936) that produces an asymptotic low porosity with increasing depth (Allen and Allen 2013). Compaction frequently has no further effects at depths where porosity <10%, which is common in measured samples taken within the Roper Group shale succession. Further changes in porosity at depth come from diagenetic effects such as cementation, pressure solution, and hydraulic and tectonic fracturing.

The depth below which there is no further compaction tends to vary based on the clay mineral content (Hunt 1995). Shale composed of very fine-grained quartz, carbonate minerals or kaolinite, will compact to lower porosities than those composed of mixed-layer water-absorbing clays. The clay mineral content of the Kyalla and Velkerri formations have a variable content of non-water adsorbing clay minerals, with porosities in the range 3–7%.

DIFFERENTIAL FLUID PRESSURE WITHIN THE ROPER GROUP

The alternating sandstone–shale succession of the Roper Group allows for potentially unrestricted lateral flow of fluids through the sandstone formations, but the vertical flow of fluids through the shales would probably be restricted, enabling differential compaction to occur within the shale

units. Differential, greater-than-hydrostatic fluid pressures were potentially generated within the medial portions of thick Roper Group shale formations. These overpressures are related to the formation of pressure barriers that prevent vertical fluid movement through the entire section. Fluids escape upward and downward to sandstone beds that are in contact with the shale, so that the center of the shale is undercompacted and has a higher porosity relative to its margins (Figure 62).

An increased geothermal gradient is commonly associated with some overpressured formations. This is attributed to the shales acting as heat insulators, causing abnormal temperatures to exist laterally across them (Hunt 1995). The higher temperature enhances the primary generation of bitumen from organic matter, can facilitate the expulsion of hydrocarbons, and can cause an increase in fluid pressure.

Pressure compartments of organic-rich rocks often show a highly localised pressure regime that is limited to the hydrocarbon-generating interval of the organic-rich source rock. The Bazhenov Formation of western Siberia and the Bakken Formation of the Williston Basin are oil-prone source rocks that share common characteristics with the Kyalla and Velkerri formations of the Roper Group. These source rocks are only overpressured within the limits of the present-day hydrocarbon-generating temperature windows (Hunt 1995).

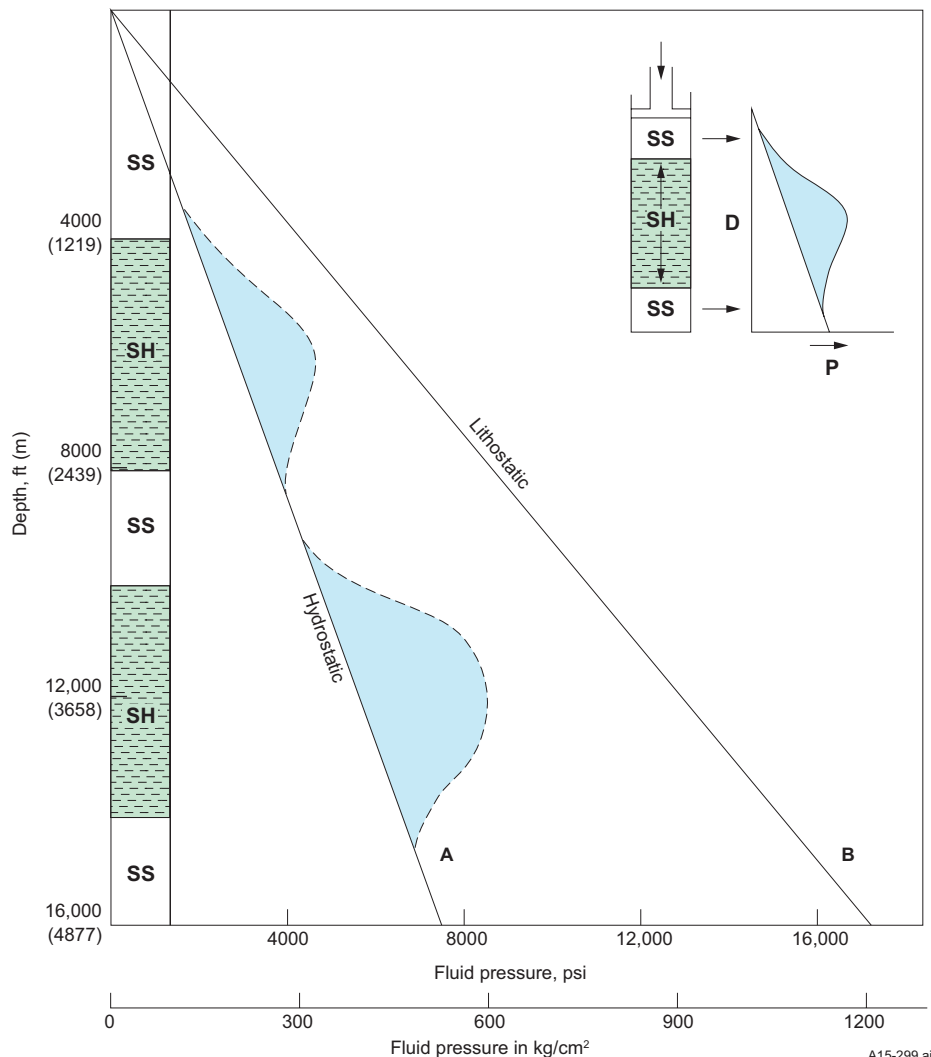


Figure 62. Chart showing increase in fluid pressure with depth (after Hunt 1995). Line A is hydrostatic gradient for most petroleum basins, 0.46 psi/ft (10.4 kPa/m). Line B is lithostatic gradient, 1.08 psi/ft (24.4 kPa/m). Dashed line shows fluid pressures in sandstone-shale succession to left. Inset (upper right) shows change in fluid pressure when pressure is applied to layers of sand and clay mud. Centre of shale is a pressure barrier to fluid movement; fluids are escaping upward and downward to sandstone beds that are in contact with shale surface.

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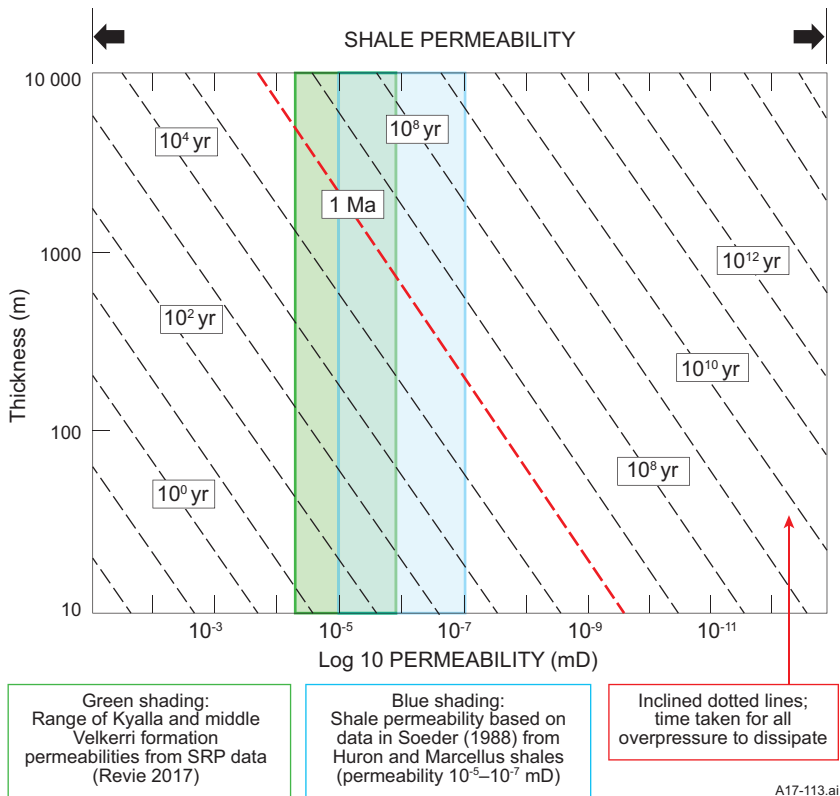


Figure 63. Chart showing pressure dissipation over geological time, dependent on shale thickness and permeability (adapted from O'Connor *et al* 2014). Superimposed in green are data from Revie (2017) from Kyalla and Velkerri formations. The implication is that even at the low permeability present in these accumulations, pressure will revert to hydrostatic in 1 million years, unless gas generation or expansion is occurring (or seals are very thick).

Pore pressure characterisation, based on Diagnostic Fracture Injection Tests (DFIT) undertaken on the Kalala S 1 and Amungee NW 1 wells, has enabled a pressure gradient of 0.53 psi/ft (11.9 kPa/m, overpressured) to be estimated for the middle Velkerri Formation (Close *et al* 2016). This figure is relatively consistent with fracture closure pressures measured in Shenandoah 1A, through a hydraulic stimulation test of the middle Velkerri Formation, which was interpreted to contain a reservoir pressure range of 0.662–0.567 psi/ft (14.97–12.83 kPa/m; Falcon 2012). All three wells intersected the targeted middle Velkerri Formation within the present-day dry-gas thermal maturity window. The Velkerri Formation in these locations is currently overpressured through the generation, expulsion and subsequent thermal cracking of hydrocarbons.

Seal thickness, permeability and time affect how shales can maintain pressure. In **Figure 63**, permeability data for Roper Group shales is superimposed on a model of pressure escape relative to shale thickness over time. This figure shows that even at the low permeabilities present in these accumulations, pressure will generally revert to the hydrostatic pressure gradient (0.48 psi/ft) in just one million years, unless gas generation or expansion is occurring, or seals are very thick (O'Connor *et al* 2014). The exceptional thickness of the Roper Group shales would potentially slow the rate of loss of overpressure, but the greatest contributing factor to maintaining overpressure within the Roper Group shales is gas generation through the cracking of oil produced through maturation and expulsion from organic matter.

The dissipation of any pressure differentials present within the shale units of the Roper Group poses a significant risk for petroleum exploration in the McArthur Basin. Any targeting of sweet-spots would be within the limits of hydrocarbon-generating kitchens. Economical production of gas shales would require enhancement of the inherently

low matrix permeability (<0.001 D or 1 mD) of these shale reservoirs (Hill and Nelson 2000).

CONCLUSIONS

Of the eight Mesoproterozoic Roper Group formations examined for their potential as unconventional shale-oil and shale-gas resources, the Kyalla Formation and the Velkerri Formation are ranked as the most prospective and lowest-risk targets within the McArthur Basin. Investigations of the two formations have resulted in the compilation of all available lithological, geochemical and volumetric data for these two intervals.

The Kyalla Formation is in the early to late oil window and contains ‘fair’ to ‘very-good’ geochemical parameters as a productive source rock. The formation is assessed as generally having a moderate to high shale oil production risk. It was originally composed of Type II marine oil-prone kerogens that have thermally matured to Type II/III kerogens, with indications that petroleum generation and expulsion has occurred.

The Velkerri Formation is comprised of three lithofacies (upper, middle and lower), with the middle being the most prospective for petroleum production potential. Three parasequences through the middle Velkerri Formation, informally named the A, B and C shales, are organic-rich facies with ‘very-good’ to ‘excellent’ geochemical parameters and mineralogical composition. The middle Velkerri Formation was originally composed of Type II marine oil-prone kerogens which have thermally matured and undergone petroleum generation and expulsion. The middle Velkerri Formation is within the dry-gas window in several wells that intersect the formation at greater depths in the deeper sub-basin regions of the McArthur Basin. Although data taken from both the Kyalla and Velkerri

formations indicate the presence of oil-mature and gas-mature rock, thermal maturity may be a limiting factor in shallower parts of the basin. Retention of overpressure of generated gas within the shales is also at higher risk in the shallower parts of the basin, where thermal conversion of oil to gas is limited.

The public announcement of a shale-gas discovery within the middle Velkerri Formation B shale (Origin Energy 2016) is highly encouraging for the future identification of an economic shale-gas play within the Mesoproterozoic shale formations of the McArthur Basin. The middle Velkerri Formation is estimated to contain gas-in-place volumes in the range 118–293 TCF (Weatherford 2017). This risked recoverable resource is highly dependent on both future recovery efficiencies and on the multiple risks of a frontier basin with little supporting infrastructure in place.

ACKNOWLEDGEMENTS

Acknowledgement must be given to Tim Munson for technical review and editing advice on this project, as well as Steen Nielsen, Ai Sariman, Ben Orr and Darryl Stacey at the NTGS core facility for their assistance moving kilometres of core for sampling. Acknowledgement is also given to Jamie Lankford at the Geoscience Australia core repository for his assistance whilst sampling in Canberra. Thank you to Iris Kovacli, Jan Twomey and Coleen Harris for assistance with the historical records search for compiling the data. I would also like to thank Kathy Johnston and Marianne Fuller for their assistance with preparation of figures and layout of the report, and Greg MacDonald for his editorial efforts. Finally I would like to thank Christine Edgoose and Dorothy Close from NTGS for the opportunity to undertake and understand the project.

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