Petroleum geology and geochemistry of the Birrindudu Basin, greater McArthur Basin

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Summary

This study assesses the petroleum potential of the Palaeo–Mesoproterozoic Birrindudu Basin in the northwestern Northern Territory, which is one of several Proterozoic basins in northern Australia with the potential to host conventional and unconventional petroleum accumulations. Historical source rock geochemistry, porosity, and permeability data from the Birrindudu Basin are collated and interpreted; in addition, new fluid geochemistry is assessed within the context of the greater McArthur Basin. The limited data available indicate that at least four formations have good or excellent present-day organic richness (>2 wt% total organic carbon, TOC), and several sandstone and carbonate reservoirs have good porosity data. The calculated brittleness index of a number of organic-rich shales suggests that several are likely to be favourable for fracture stimulation and therefore might constitute good unconventional hydrocarbon targets. Four continent-scale petroleum supersystems are identified, two of which are described for the first time. These supersystems are an important tool in understanding the petroleum potential in frontier basins with limited data. Additionally, a number of basin-scale petroleum systems are potentially present within the basin successions; 14 possible conventional systems and nine possible unconventional systems are documented. Petroleum play concepts are also described to assist with assessing the potential for conventional and unconventional hydrocarbon resources. The ultimate aim is to identify areas that can be targeted for precompetitive geoscience data acquisition and assist in reducing the exploration search space.

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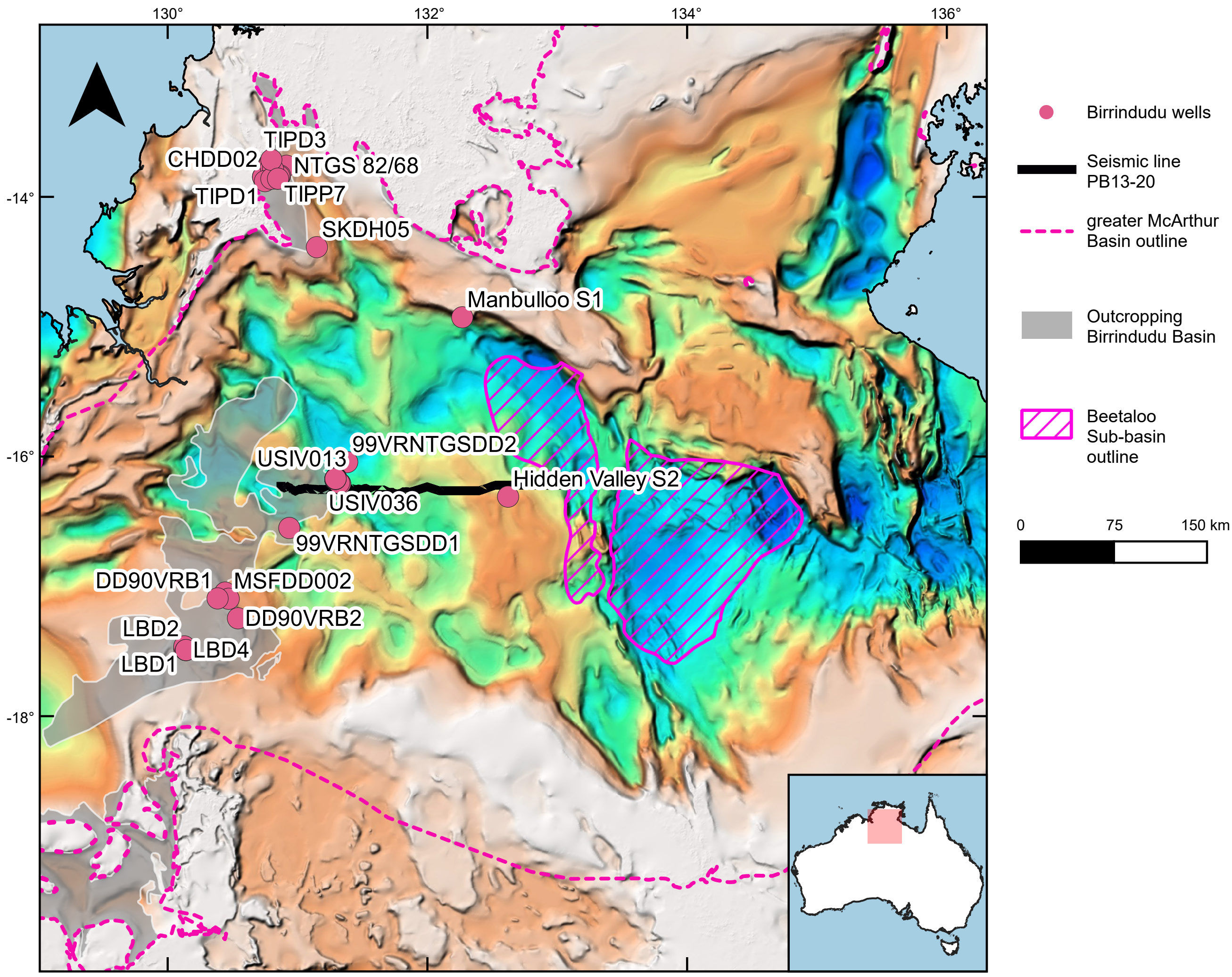

Figure 1. Regional map of the greater McArthur Basin, as defined by Close (2014), and the outcropping extent of the Birrindudu Basin. Subsurface extent of the Beetaloo Sub-basin from Williams (2019), with well and seismic data from STRIKE (http://strike.nt.gov.au/wss.html).

Introduction

The Birrindudu Basin straddles the Northern Territory–Western Australia border and is a component of the greater McArthur Basin (Close 2014), which also includes the McArthur Basin and Tomkinson Province. The outcropping extent of the Birrindudu Basin in the Northern Territory is >36 000 km^2; however, it extends over a much larger geographical area undercover to the northeast and east (Hoffman 2015, Williams 2019). Seismic exploration undertaken by Pangaea Resources has demonstrated that outcropping rocks of the Palaeoproterozoic Limbunya Group of the Birrindudu Basin can be traced ~200 km east towards the Beetaloo Sub-basin (Hoffman 2014, Hoffman 2015, Williams 2019; **Figure 1**). The Birrindudu Basin succession is comprised of six unconformably separated stratigraphic groups predominantly composed of fine to coarse siliciclastic, carbonate, and heterolithic clastic/carbonate rocks (Dunster and Ahmad 2013). These groups all contain potential petroleum systems elements, including black shales, sandstones, and mudstones (**Table 1; Figure 2**).

The Northern Territory Geological Survey (NTGS) has undertaken ongoing work to establish a robust stratigraphic framework across the greater McArthur Basin (Munson 2016, 2019, Munson *et al* 2020). The Tijunna Group has been demonstrated to be a correlative of the upper Roper

Table 1. Summary of continent-scale and basin-scale petroleum systems in Birrindudu Basin.

Petroleum systems		Hypothetical petroleum system elements			Petroleum play
Continent-scale petroleum supersystem	Basin-scale petroleum system Magoon & Dow (1994)	Source	Reservoir	Seal	
	Birrindudu-Auvergne(?)	Proterozoic shales of Birrindudu	Auvergne Group	Auvergne Group	conventional oil/gas
Urapungan	Wondoan Hill/Stubb-Wondoan Hill/Stubb(?)	shales in Stubb and Wondoan Hill formations	sandy units in Stubb and Wondoan Hill formations	mudstones in upper Stubb Formation	conventional oil/gas
	Stubb-Stubb(?)	Stubb Formation	Stubb Formation	Stubb Formation	unconventional
Favenc*	Nero-Banyan/Mount Gordon/Weaner(?)	Nero Siltstone	Banyan Formation, Mount Gordon Sandstone and Weaner Sandstone	Banyan Formation and Battle Creek Formation	conventional oil/gas
	Nero-Nero(?)	Nero Siltstone	Nero Siltstone	Nero Siltstone	unconventional
	Timber Creek/Skull Creek- Timber Creek/Skull Creek(?)	Timber Creek and Skull Creek	Timber Creek and Skull Creek	Nero Siltstone	conventional oil/gas
	Timber-Timber(?)	Timber Creek Formation	Timber Creek Formation	Timber Creek Formation	unconventional
	Gibbie-Seale (?)	Gibbie Formation	Seale Sandstone	Nero Siltstone	conventional oil/gas
	Burtawurta/Hughie(?)	Burtawurta Formation	Hughie Sandstone	Mount Stanford Formation	conventional oil/gas
	Limbunya-Wattie/Bullita(?)	shales from Wattie Group (Kunja Siltstone/Fraynes Formation)	Seale Sandstone/Timber Creek Formation/Skull Creek Formation	Nero Siltstone	conventional oil/gas
McArthur	Fraynes/ Campbell Springs -Kilaloc/Wickham(?)	Campbell Springs Dolostone/Fraynes Formation	Kilaloc Formation/Wickham Formation	Burtawurta Formation	conventional oil/gas
	Fraynes-Fraynes(?)	Fraynes Formation	Fraynes Formation	Fraynes Formation	unconventional
	Kunja-Farquharson(?)	Kunja Siltstone	Farquharson Sandstone	Blue Hike Formation	conventional oil/gas
	Kunja-Kunja(?)	Kunja Siltstone	Kunja Siltstone	Kunja Siltstone	unconventional
	Mallabah-Mallabah(?)	Mallabah Dolostone	Mallabah Dolostone	Mallabah Dolostone	unconventional
	Amos Knob/Mallabah-Mallabah(?)	Amos Knob Formation/Mallabah Dolostone	Mallabah Dolostone	Kunja Siltstone	conventional oil/gas
	Mallabah-Mallabah(?)	Mallabah Dolostone	Mallabah Dolostone	Mallabah Dolostone	conventional oil/gas
	Pear Tree/Amos Knob-Amos Knob(?)	Pear Tree Dolostone/Amos Knob Formation	sandy units in Amos Knob Formation	shales in Amos Knob Formation	conventional oil/gas
Redbank*	undifferentiated Birrindudu Group (?)	undifferentiated Birrindudu Group (?)	undifferentiated Birrindudu Group (?)	undifferentiated Birrindudu Group (?)	unconventional
	Hinde-Waterbag Creek/Stirling(?)	Hinde Dolostone	Waterbag Creek Formation or Stirling Sandstone	shale in Waterbag Creek Formation or Margery Formation	conventional oil/gas
	Hinde-Hinde(?)	Hinde Dolostone	Hinde Dolostone	Hinde Dolostone	unconventional
	Talbot Well-Coomarie/Stirling(?)	Talbot Well Formation	Coomarie Sandstone or Stirling Sandstone	Coomarie SST (siltstone units) or Margery Formation	conventional oil/gas

* indicates petroleum supersystems currently undefined

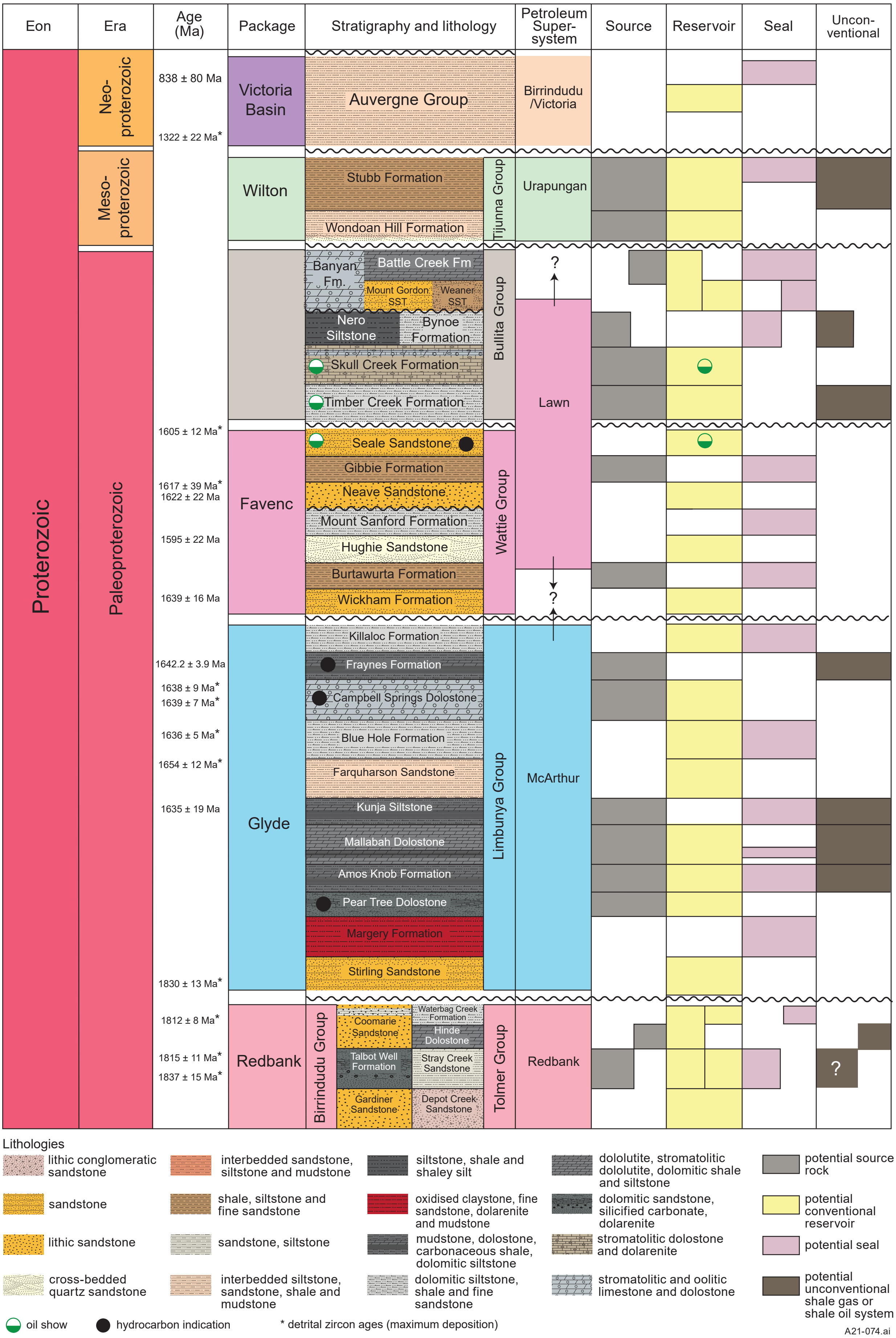

Figure 2. Stratigraphy and lithology of Birrindudu Basin and potential petroleum systems elements, including hypothetical source rocks, reservoirs, seals and shale gas plays. Geochronology of formations sourced from Dunster and Ahmad (2013), Munson (2019) and references therein.

Group, which hosts the shale gas plays currently being explored in the Beetaloo Sub-basin of the McArthur Basin (Munson 2014, 2016). Additionally, a chronostratigraphic link has been made between the Fraynes Formation within the Limbunya Group and the Barney Creek Formation of the southern McArthur Basin (Munson *et al* 2020). The Barney Creek Formation hosts the economic McArthur River Pb-Zn-Ag mine (Ahmad *et al* 2013) and is the source rock of the Barney–Coxco conventional gas play (eg, Munson 2014, Croon *et al* 2015), and potentially, an unconventional shale gas play (eg, Munson 2014, Johnston *et al* 2008, Baruch *et al* 2015).

The Birrindudu Basin has been poorly explored for petroleum despite the presence of relatively well-studied active petroleum systems in correlative units in the McArthur Basin. Minor hydrocarbon indications previously noted in the basin include stylolites and vugs containing solid bitumen in the Pear Tree Dolostone and Campbell Springs Dolostone (Simeone 1991, Pangaea Resources 2015); minor oil staining and fluorescence in the Fraynes Formation (Pangaea Resources 2015); and petroliferous odours from the Fraynes Formation recognised during mapping (Sweet *et al* 1974a). The first demonstrable hydrocarbon shows in the basin were identified in very fine to medium sandstones and silty sandstones of the Seale Sandstone, and the Timber Creek and Skull Creek formations in NTGS drillhole 99VRNTGSDD1. These hydrocarbon shows included live oil bleeds (light yellow to orange, high-viscosity and dark brown, low-viscosity degraded oils), solid bitumen, and fluorescing core (Dunster and Cutovinos 2002). This demonstrates the presence of a once-active petroleum system in the basin. At the time of discovery, it was speculated that the oil might have been sourced from the underlying Wattie or Limbunya groups, which contain several siltstone and shale units with petroleum source rock potential (Dunster and Cutovinos 2002).

Subsequent updates of the stratigraphy (Munson, 2016), seismic interpretations (Hoffman 2014, Williams 2019), and geochronology (Kositcin and Carson 2017, Munson 2019, Munson *et al* 2020), combined with new geochemistry (Jarrett *et al* 2020b, c, Revie and Normington 2020), has led to a need for NTGS to update the petroleum geology and potential for the Birrindudu Basin, last summarised in Munson (2014). Herein, the shale geochemistry of the Birrindudu Basin is used to determine the organic richness, kerogen type and thermal maturity of the basin rocks; and to compare the same with prospective source rocks in the McArthur Basin. Porosity and permeability data from sandstones and carbonate rocks is used to determine conventional reservoir quality. Furthermore, oil stains from the Timber Creek Formation of the Bullita Group are geochemically typed using biomarker and isotopic techniques and compared with the previously published fluid geochemistry of oils and oil stains from the McArthur Basin with the aim of typing the oil stains to a petroleum supersystem (Jarrett *et al* 2019c). Finally, several petroleum systems and plays are described to ascertain the potential for conventional and unconventional hydrocarbon resources in the Birrindudu Basin. This work is currently being undertaken as part of the four year (2018–2022) *Resourcing the Territory* initiative to promote and facilitate the development of resources and primary industries, as well as supporting industry exploration programs.

Source rocks

Abundant potential source rocks exist in the Birrindudu Basin, including a number of shales, mudstones and organic-rich carbonate rocks (**Figure 2**). Understanding the organic richness, kerogen type, and thermal maturity of these prospective source rocks can define areas with the potential to host a petroleum resource and allow the targeting of areas for future study. **Figure 3** plots open file Rock-Eval pyrolysis data from the Birrindudu Basin. The data used are a combination of previously published data available in DIP014 (Revie and Normington 2020) and new data generated at the Geoscience Australia through the *Exploring for the Future* program (Jarrett *et al* 2019a,b; 2020b).

Using the classification scheme of Peters and Cassa (1994), the Mallabah Dolostone and Fraynes Formation have ‘excellent’ organic richness (TOC >4 wt%; Revie and Normington 2020) with present-day TOC values up to 11.3 wt% and 8.1 wt% respectively. Two Palaeoproterozoic units from the Limbunya Group: (Pear Tree Dolostone and Kunja Siltstone) contain ‘good’ organic richness (TOC between 2 and 4 wt%), and several units, including the Timber Creek, Battle Creek and Wondoan Hills formations, contain ‘fair’ organic richness (TOC between 0.5 and 2.0 wt%; **Figure 3a**).

The hydrogen index (HI) can determine the expelled products at the time of peak maturity (eg Peters and Cassa 1994). Present day HI plotted in **Figure 3b** demonstrate a range of expelled products and kerogen types in the Birrindudu Basin. Shales from the Mallabah Dolostone, Kunja Siltstone, Fraynes Formation, and Timber Creek Formation appear to be oil prone (HI >300 mg HC/g TOC). The Pear Tree Dolostone is oil and gas prone (HI 200 to 300 mg HC/g TOC), and gas-prone kerogen (HI 50 to 200 mg HC/g TOC) occurs in the Wondoan Hill and Stubb formations. It should be noted that Rock-Eval indices including HI can be affected by oil staining and thermal maturity (Peters and Cassa 1994). **Figure 3c** plots the production index (PI; S1/[S1+S2]) against Tmax to show the generation history and maturation of potential source rocks. PI increases continuously through the oil window and many source rocks, including the Fraynes, Timber Creek and Battle Creek formations, and the Pear Tree and Mallabah dolostones, all appear to be affected by oil staining (**Figure 3c**). The results in **Figure 3** demonstrate that a significant amount of data have Tmax values >435°C and PI values >0.2 and therefore are thermally mature and may provide only a limited insight into the true petroleum potential of the region.

The results documented herein show that the source rock geochemistry for the Birrindudu Basin is still poorly understood. This is one of the major exploration risks or uncertainties when appraising a frontier basin (eg Binns and Corbett 2012). Although the petroleum supersystems framework of Bradshaw *et al* (1994) may provide regional analogues, additional basin-specific geochemistry, including Rock-Eval data and kerogen kinetics, is required from more thermally immature sedimentary rocks of the Birrindudu Basin to fully understand the expelled petroleum products. There are also many unsampled legacy drill cores still to be analysed for organic geochemistry, reflectance and mineralogy, including drill core containing black shales from the Mallabah Dolostone. Some shales are only known from field mapping, eg thick shales have been mapped in the Timber Creek Formation, Skull Creek Formation, and

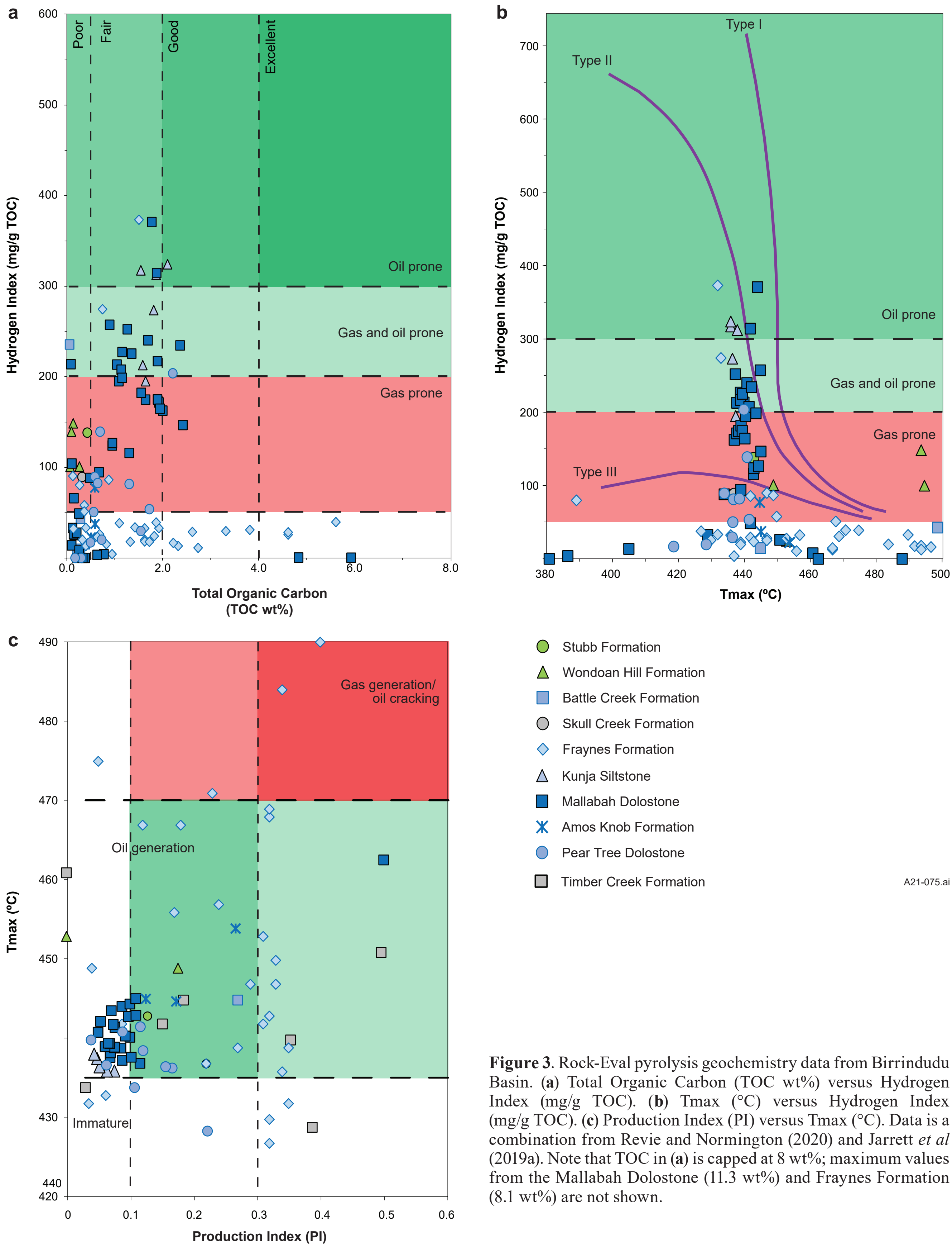

Figure 3. Rock-Eval pyrolysis geochemistry data from Birrindudu Basin. **(a)** Total Organic Carbon (TOC wt%) versus Hydrogen Index (mg/g TOC). **(b)** Tmax (°C) versus Hydrogen Index (mg/g TOC). **(c)** Production Index (PI) versus Tmax (°C). Data is a combination from Revie and Normington (2020) and Jarrett *et al* (2019a). Note that TOC in **(a)** is capped at 8 wt%; maximum values from the Mallabah Dolostone (11.3 wt%) and Fraynes Formation (8.1 wt%) are not shown.

Nero Siltstone of the Bullita Group, and in the Stubb and Wondoan Hill formations of the Tijunna Group (Beier *et al* 2002, Dunster and Ahmad 2013). Another opportunity for future work is defining the stratigraphy and ages of mudrocks and dolostones in legacy core. Up to 55 m of shale, termed 'Undifferentiated Birrindudu Group' (Hurrell 1993), has been reported in the drillholes LMDH8, LMDH10, and LMDH12. This unit has the potential to be a source rock, shale gas play or a basin-hosted base metals trap (eg Spinks *et al* 2016a, b). An understanding of the ages, relationships and extents of these systems is required to further de-risk exploration in the region.

Reservoirs

There is potential for both clastic and carbonate reservoirs in the Birrindudu Basin (**Figure 2**). Every group within the basin contains thick sandstones that may form potential reservoirs. The sandstones range in thickness from 5 m to 3000 m and are predominantly a mixture of fine to medium quartz sandstones (Dunster and Ahmad 2013). The Gardiner and Coomarie sandstones within the Birrindudu Group, as well as the Neave Sandstone in the Wattie Group, are lithic sandstones (**Figure 2**) that may have potential for secondary porosity through the breakdown of feldspars (Polito *et al* 2006). Additionally, several thick carbonate units are present in the basin; the presence of mouldic and vugular porosity within these formations (Dunster and Ahmad 2013) is evidence of chemical dissolution and secondary porosity. This is important as secondary porosity can often enhance permeability and production yields (Ghafoori *et al* 2009).

Fundamental controls on reservoir quality are determined by thickness, porosity, permeability, and fluid saturation (Magoon and Dow 1994, Worden *et al* 2018). To date, rock properties' data is minimal for the Birrindudu Basin: only 108 porosity and 13 permeability measurements are available (Hallett 2020; **Figure 4**). Measured sandstone porosity ranges from 1% to 16%; the porosity in carbonate rocks ranges from 0.1% to 14% (**Figure 4**). Data from the Seale Sandstone demonstrates low permeabilities ranging from 0.001 mD (millidarcies) to 1.73 mD (average 0.42 mD, stdev 0.59, n = 8). Permeability in the Stirling Sandstone is highly variable, with values ranging from 0.01 mD to 217 mD (average 75.8 mD, stdev 105.6, n = 5; Hallett 2020). There is a clear relationship between high porosity and high permeability, which is suggestive of microfracturing. Similar trends associated with micro-fracturing have also been identified in the Hayfield sandstone member of the McArthur Basin (Altmann *et al* 2020). Additional porosity and permeability testing of legacy drill core, in addition to calculations of porosity and permeability from available wireline logs (eg Helle *et al* 2001, Jennings and Lucia 2003), will greatly enhance the understanding of the reservoir qualities in the Birrindudu Basin. Other analyses and studies could be undertaken to improve knowledge of the quality of reservoirs in the region; these include Dean-Stark extraction to determine fluid saturations in potential reservoirs, and thin section and other mineralogical studies to understand grain size and arrangement, as well as determine evidence of diagenesis and pressure dissolution.

Fluid geochemistry

A key factor in reducing the petroleum exploration search space in a basin is defining the active petroleum systems present (eg Magoon and Dow 1994). Hydrocarbon shows and indications are direct evidence of an active petroleum system. The most significant shows in the Birrindudu Basin to date are live oils discovered during the stratigraphic drilling of NTGS 99VRNTGSDD1 (Dunster and Cutovinos 2002). The source of the live oil has not yet been determined but was speculated to be from shales within either the Wattie or Limbunya groups (Dunster and Cutovinos 2002).

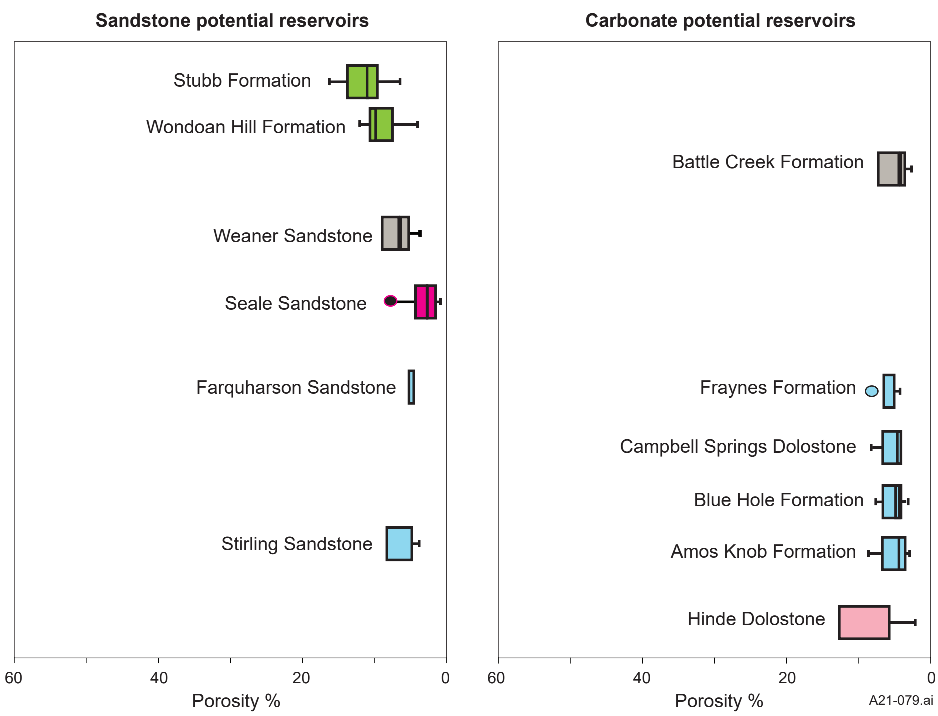

Figure 4. Box plots of porosity for potential sandstone and carbonate reservoirs in Birrindudu Basin. Data from Hallett (2020).

Traditional organic geochemical methods to type petroleum families typically rely on the combination of hydrocarbon biomarkers and isotopic analyses (eg, Peters *et al* 2005, Huc 2013). In this study, hydrocarbon biomarkers were extracted from drillholes NTGS 99VRNTGSDD1, NTGS 99VRNTGSDD2, and Pangaea Resources' Manbulloo S1, which is located in the northeast Birrindudu Basin (**Figure 1**). These were analysed by gas chromatography mass spectrometry (GC–MS) at Geoscience Australia, and metastable reaction monitoring (MRM aka GC–MS–MS). The results share qualities consistent with previously published biomarker data. Saturated triterpanes are below detection limits in sediments of the Fraynes Formation in drill core from Manbulloo S1. A study of the aromatic hydrocarbons reveals the presence of 2,3,4- and 2,3,6- trimethyl aryl isoprenoids, in addition to MPI-1 values that suggest thermal maturity within the peak oil window. Aryl isoprenoids were not present in extracts from 99VRNTGSDD1 and 99VRNTGSDD2. These sedimentary rocks from the Bullita and Tijunna groups are predominantly composed of *n*-alkanes, mono methyl alkanes, and large unresolved complex mixtures, with small concentrations of hopanes. These are broadly consistent with general features identified in Proterozoic sedimentary rocks globally (Pawlowska *et al* 2013). In the greater McArthur Basin and coeval Lawn Hill Platform, hydrocarbon biomarkers are generally very similar in the saturated fraction, reflecting a largely consistent dominant primary producer in the water column during the Proterozoic (Summons *et al* 1988, Flannery and George 2014, Jarrett *et al* 2019a, 2020a). Previous studies have reported differences between the Barney Creek Formation and the Velkerri Formation in the abundances of 2,3,4- and 2,3,6- trimethyl aryl isoprenoids (eg Summons *et al* 1988, Flannery and George 2014, Jarrett *et al* 2019b). These aryl isoprenoids are biomarkers of green and purple sulfur bacteria and are found in euxinic water columns (Brocks *et al* 2005). The Velkerri Formation is largely ferruginous with euxinic excursions in the organic-rich intervals of the Amungee Member (Cox *et al* 2016). Aryl isoprenoids are only identified in trace amounts in these euxinic zones, and are largely absent throughout the Velkerri Formation (Jarrett *et al* 2019b). Conversely, the Barney Creek Formation is predominantly euxinic and contains prolific aryl isoprenoids and other carotenoids (Brocks *et al* 2005). Higher resolution studies of the Barney Creek Formation have revealed large fluctuations in the abundance of these aryl isoprenoids, likely due to subtle changes in ocean biogeochemistry (Nettersheim 2017). Therefore, changes in the aromatic fractions are largely due to shifts in thermal maturity, as well as microbial assemblages in different water chemistries, and therefore these biomarkers cannot be used to effectively differentiate between different formations in the greater McArthur Basin.

A clear isotopic differentiation between source rocks is required to type 'vagrant oils' with no known petroleum system. Jarrett *et al* (2019c) reported a divergence in *n*-alkane $\delta^{13}C$ values between the Roper and McArthur Groups (**Figure 5a**). Source rocks from the Velkerri and Kyalla formations have *n*-alkanes ranging from -35.0‰ to -28.7‰, whereas the Barney Creek Formation appears to be more isotopically enriched, with values between -24‰ and -29‰ (Jarrett *et al* 2019c). However, Vinnichenko *et al* (2021) have demonstrated that thermal maturity plays a large role in the isotopic profiles of *n*-alkane $\delta^{13}C$ values by up to 6.8‰. Barney Creek Formation *n*-alkane $\delta^{13}C$ data from Vinnichenko *et al* (2012) range from -24.1‰ to -32.4‰, overlapping the envelope of Kyalla Formation values; however, a clear differentiation between the Barney Creek and Velkerri formations remains (**Figure 5a**). These values are consistent with isotopic data from oil stains and source rocks from the correlative Palaeoproterozoic Lawn Hill Platform (Jarrett *et al* 2020c). The *n*-alkane $\delta^{13}C$ values are wide ranging from -24.0‰ to -31.8‰, demonstrating broad similarities in the biological sources of *n*-alkanes and geological processes within the Palaeoproterozoic McArthur petroleum supersystem (Jarrett *et al* 2020a). The results from Jarrett *et al* (2019c) were used to type many oil stains extracted from intraformational sandstones within the Kyalla and Velkerri formations; the results successively typed back to primary source rocks, demonstrating the reliability of the carbon specific isotope analysis (CSIA) technique. Additionally, oil from Jamison-1 was matched to the Kyalla Formation, and subsequent work has demonstrated that the live oil discovered in BMR Urapunga-4 (Jackson *et al* 1986) can be typed to its host rock, the Velkerri Formation (**Figure 5a**). The dataset from Jarrett *et al* (2019) has subsequently also typed an oil stain from the Hayfield sandstone member from the Amungee NW1 well to the Kyalla Formation (Altmann *et al* 2020).

In the present study, two oil stains from 99VRNTGSDD1 within the Timber Creek Formation yielded enough saturated hydrocarbons for *n*-alkane $\delta^{13}C$ analysis (out of the 16 oil stains from 99VRNTGSDD1 and 99VRNTGSDD2 extracted). The isotopic values are fairly well constrained between -27.1‰ and -29.7‰ (**Figure 5b**). These values sit within the range of source rocks from both the Kyalla and Barney Creek formations. The lighter <C20 *n*-alkanes of the shallowest oil stain are isotopically enriched and sit within the zone of the Barney Creek Formation (**Figure 5a**). This tentatively suggests a Palaeoproterozoic source; however, the other isotopes appear more consistent with a Mesoproterozoic source. Future work in obtaining *n*-alkane CSIA values for Birrindudu Basin source rocks in the Birrindudu Basin will make a significant contribution to understanding the correlation between the preserved live-oil and potential source rocks in the region, a crucial step in defining the active petroleum systems in the basin. Furthermore, this data will allow for a more comprehensive correlation between Proterozoic-aged petroleum systems in northern Australia.

Stable carbon isotopic signatures ($\delta^{13}C$) of individual hydrocarbons, and the bulk saturated ($\delta^{13}C_{sat}$) and aromatic ($\delta^{13}C_{arom}$) hydrocarbon fractions, have been successfully used to differentiate between petroleum families in the McArthur Basin (Jarrett *et al* 2019c). Within the Roper Group, $\delta^{13}C_{sat}$ and $\delta^{13}C_{arom}$ have been used for oil-source rock correlations (Jarrett *et al* 2019c; Altmann *et al* 2020; **Figure 6**) similar to *n*-alkane $\delta^{13}C$ work described above. As the concentration threshold is an order of magnitude higher than CSIA of *n*-alkanes, this type of analysis can be conducted more routinely with organically lean oil stains and still provide useful information on oil source correlations.

Herein we present new bulk $\delta^{13}C_{sat}$ and $\delta^{13}C_{arom}$ from the Birrindudu and McArthur basins to complement previously published McArthur Basin isotopic data. The material analysed comprises one oil stain from the Timber Creek Formation in 99VRNTGSDD1, six samples of extracted bitumen from the Fraynes Formation in Manbulloo S1, and nine oil stains from the Lynott Formation in Armour Energy Lamont Pass-3 (**Figure 6**). Velkerri Formation extracts are the most isotopically depleted and have $\delta^{13}C_{sat}$ and $\delta^{13}C_{arom}$ values that range between -35‰ and -31‰, whereas the Kyalla Formation extracts are slightly more enriched in $\delta^{13}C_{sat}$ with values between -32‰ to -29‰. The Lynott

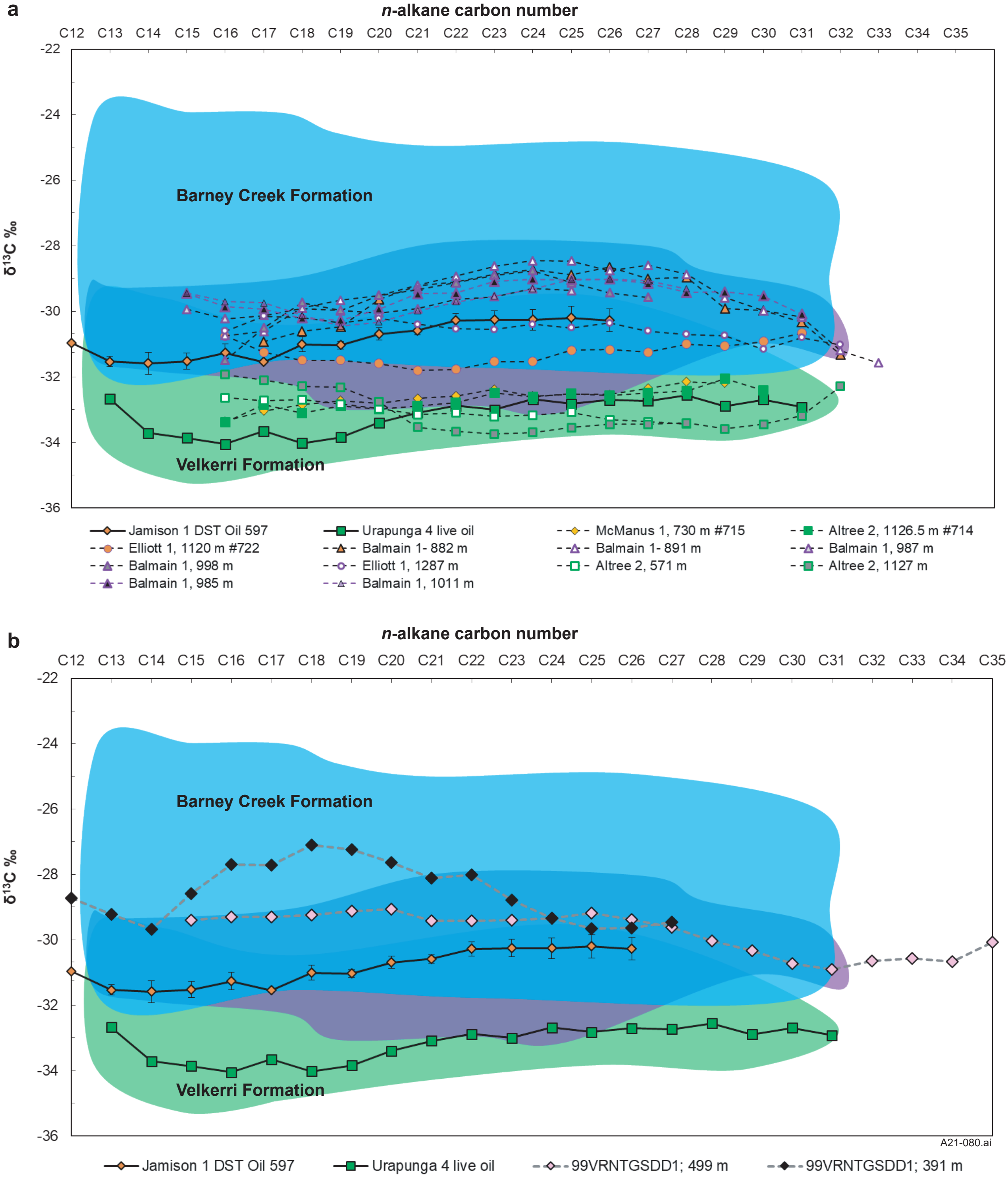

Figure 5. Carbon specific isotope analysis (CSIA) of individual *n*-alkanes for oil source rock correlations in greater McArthur Basin. (**a**) Data published for McArthur Basin in Jarrett *et al* (2019) demonstrating good oil source correlations between Roper Group oils, oil stains and source rocks. (**b**) New oil stain CSIA data from Birrindudu Basin overlain with oils and source rocks of McArthur Basin. Solid lines indicate oils, including Jamison-1 oil and live oil from BMR Urapunga-4. Dashed lines indicate oil stains with colours corresponding to their host formation, including Kyalla Formation (purple), Velkerri Formation (green), Moroak Sandstone (orange), and Jamison sandstone (yellow). Shaded polygons demonstrate ranges of source rocks from Kyalla Formation (purple), Velkerri Formation (green) and Barney Creek Formation (blue). Data for Barney Creek Formation is a combination of those from Jarrett *et al* (2019) and Vinnichenko *et al* (2021).

Formation oil stains plot between the Velkerri and Kyalla formations with $\delta^{13}C_{sat}$ values between -30.8‰ and -32.4‰ (**Figure 6**). In the Birrindudu Basin, the Fraynes Formation has similar aromatic profiles to the Kyalla Formation; however, $\delta^{13}C_{sat}$ values are significantly more isotopically enriched compared to the Kyalla Formation and range from -30‰ to -27‰ (**Figure 6**). This demonstrates a clear differentiation of the formations into clusters that can be used to potentially type oils. The Timber Creek Formation oil stain (99VRNTGSDD1) plots within the cluster of Lynott Formation oil stains (**Figure 6**). However, the isotopic differences between Kyalla Formation and Lynott Formation values overlap; thus typing the oil stain to an exact source does not appear to be well-defined. Future work should include obtaining sufficient bulk $\delta^{13}C_{sat}$ and $\delta^{13}C_{arom}$ of other source rocks in the Birrindudu Basin to provide a statistical significance and determine the robustness of this technique.

Unconventional hydrocarbon potential

Mineralogy and shale brittleness are key factors that influence the hydrocarbon reservoir property of a shale in addition to the efficiency of hydrocarbon extraction. Generally, minerals such as quartz and carbonate can increase the brittleness of a shale; such shales may readily fracture and release hydrocarbons. Shales with higher clay contents are generally more ductile and reduce the effectiveness of stimulation (Sone and Zoback 2013, Perez Altamar and Marfurt 2014). Revie (2017b) identified mineralogy and the brittleness index as factors influencing the unconventional petroleum resource potential of the Velkerri and Kyalla formations, where favourable shale contains >40% of brittle minerals and <40% clays. It should be noted that the average clay content of the Kyalla Formation is 55% and of the Velkerri Formation is 37%; recent industry activity has demonstrated stimulation effectiveness in both reservoirs (Close *et al* 2017, Bein *et al* 2020).

Mineralogy and brittleness data is limited for the Birrindudu Basin with only 17 data points published by NTGS (Revie and Normington 2020) and 53 data points generated by Geoscience Australia (Jarrett *et al* 2020b). **Figure 7** plots these results in a ternary diagram of quartz, carbonates and clays with overlaying polygons reflecting the composition of successful shale plays (polygons superimposed from Passey *et al* 2010). The formations in **Figure 7** with potential unconventional hydrocarbon potential are the Mallabah Dolostone (n = 12), Kunja Siltstone (n = 1), Fraynes Formation (n = 14) and Timber Creek Formation (n = 14). All of these formations contain a relatively high quartz and carbonate content, and a low clay content; they all sit within the polygons of known successful shale gas plays. The results also demonstrate large variabilities in the mineralogy within formations. The Fraynes Formation, for example, contains carbonate contents ranging from 0% to 93% (**Figure 7**). These variabilities demonstrate the need for higher-resolution mineral studies to define the sweet spots of brittle minerals. **Figure 8** plots the brittleness index (BI) of Li *et al* (2013), defined as the concentration of quartz and carbonates over total minerals. Shales are characterised as brittle when BI >0.48, less brittle when BI = 0.48 to 0.32, less ductile when BI = 0.32 to 0.16, and ductile when BI <0.16 (Perez Altamar and Marfurt 2014). The results demonstrate that the Kunja Siltstone is characterised as being 'less brittle', the Fraynes Formation and Mallabah Dolostone are 'less

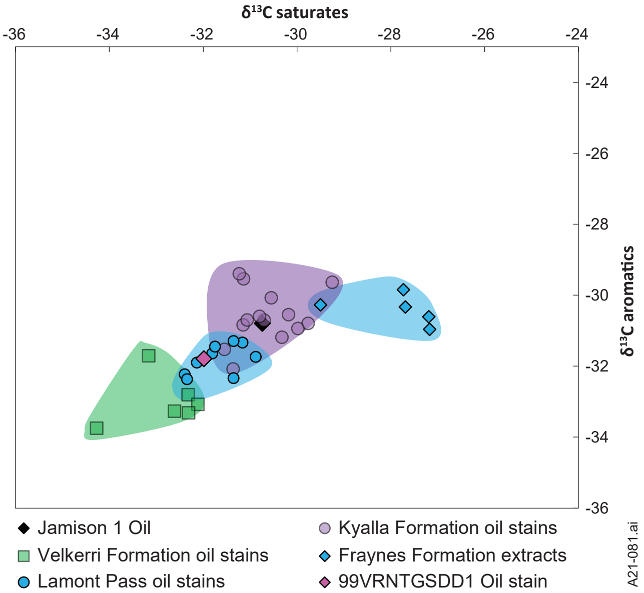

Figure 6. Cross plot of extracted δ13C saturated hydrocarbon fraction (δ13Csat) versus δ13C aromatic hydrocarbon fraction (δ13Carom) of Jamison-1 oil (black diamond) and source rocks in greater McArthur Basin, including new data from Fraynes Formation (blue triangles) and Lynott Formation (blue circles) compared with previously published values (Jarrett *et al* 2019) from Velkerri Formation (green squares), and Kyalla Formation (purple circles).

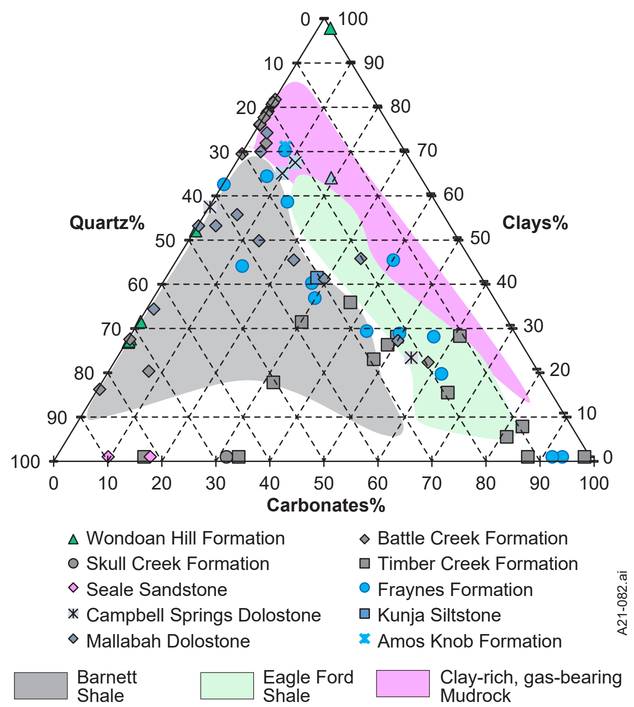

Figure 7. Ternary plot of carbonate (wt%), quartz (wt%) and total clay (wt%) compositions of sedimentary rocks in Birrindudu Basin. Polygons represent zones of successful shale gas plays based on XRD data from Passey *et al* (2010) for Barnett Shale (grey), Eagle Ford Shale (green) and a clay-rich, gas-bearing mudrock (purple). Data is a combination from Revie and Normington (2020) and Jarrett *et al* (2019a).

brittle to brittle', and the Timber Creek Formation is 'brittle' (**Figure 8**, **Table 2**). It should be noted that BI is not a universal proxy. There are examples of basins where BI is highly effective in predicting sweet spots, for example in the Barnett Shale (Sone and Zoback 2013); and other basins where BI does not correlate to rock strength or hydraulic stimulation effectiveness (Mathia *et al* 2016). Geomechanics and rock strength testing is one methodology that can be used to obtain a detailed understanding of the rock strength of legacy drill core where direct drilling and hydraulic stimulation is otherwise not planned (eg Chang *et al* 2006, Dewhurst *et al* 2008, Bailey *et al* 2021).

Petroleum play concepts

The petroleum supersystem framework is used in Australia to link basins of similar age, structural history, depositional history, and petroleum potential; it may include a family of similar source rocks instead of one source–reservoir–seal system (Bradshaw *et al* 1994). The petroleum supersystem approach can be a powerful way to predict the potential for petroleum resources in data-poor frontier basins through comparison with data of known petroleum systems elements in roughly time equivalent and structurally similar depositional settings.

Petroleum systems in the Birrindudu Basin are likely comparable to those within the McArthur Basin to the east. The McArthur Basin hosts the formally defined McArthur and Urapunga petroleum supersystems. An older petroleum supersystem hosted in the ca 1850 Ma Redbank package has also been hypothesised (Munson, 2014). This petroleum supersystem hosts two prospective shale packages: the McDermott and Wollogorang formations (Munson 2014, Jarrett *et al* 2019). However, other petroleum supersystems have been recognised but not yet formally described. The oldest known petroleum supersystem in the McArthur Basin is hosted in the ca 1850 Ma-aged Redbank package and herein termed the Redbank Supersystem (**Figure 2**, **Table 1**). It includes the McDermott and Wollogorang formations, which contain organic-rich shales and hydrocarbon indications (Munson 2014, Jarrett *et al* 2019). In the Birrindudu Basin, shales in the Talbot Well Formation and Hinde Dolostone are Redbank Petroleum Supersystem equivalents. Additionally, another petroleum supersystem is identified in the Palaeoproterozoic Favenc Package (**Figure 2**) and in the correlative Lawn Supersequence in the Lawn Hill Platform (Gorton and Troup 2018, Bailey *et al* 2019). The Lower Pmh_4 interval within the Lawn Hill Formation hosts a shale gas discovery at the Egilabria structure in NW Queensland (Longdon 2014, Gorton and Troup 2018). Therefore, this petroleum supersystem is named the Lawn Supersystem. In the Birrindudu Basin, potential shale packages in the Lawn Supersystem include the Timber Creek Formation and the Nero Siltstone (**Figure 2**, **Table 1**). Better age constraints are needed on Birrindudu Basin shales for appropriate petroleum supersystem sub-divisions.

Potential petroleum systems and plays can be identified in each of the major packages of the McArthur Group (eg, Munson 2014, Jarrett *et al* 2019c), and it is possible that a similar number might be present in correlative Birrindudu Basin successions. In this study, petroleum systems and plays are established for the Birrindudu Basin using the source reservoir nomenclature of Magoon and Dow (1994)

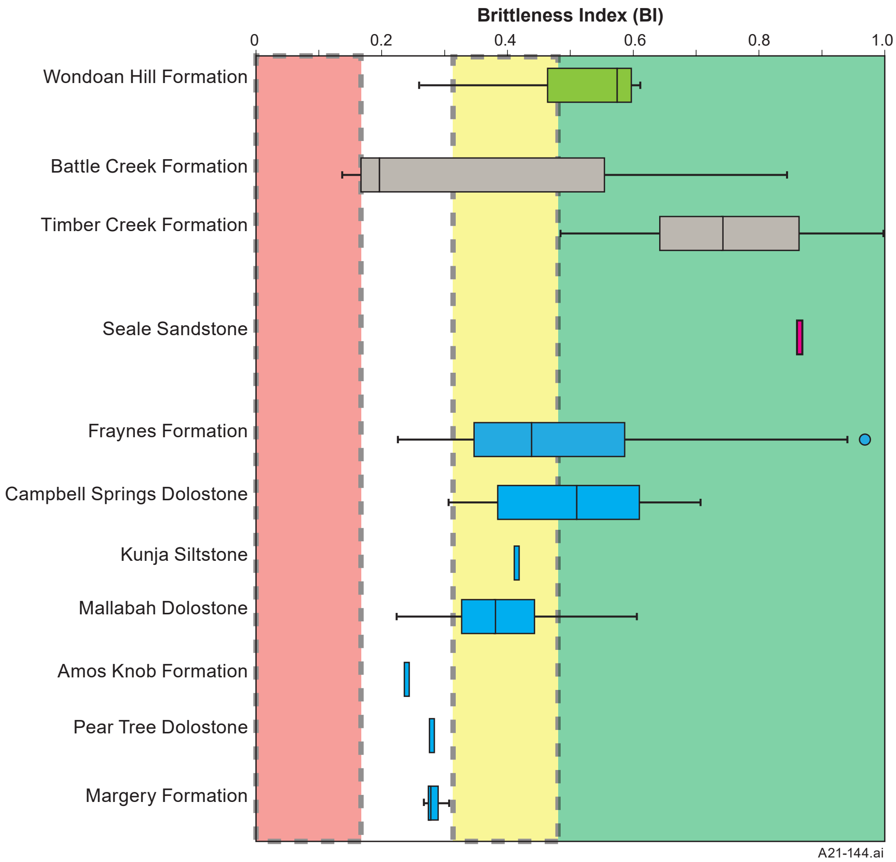

Figure 8. Box and whisker plots for Brittleness Index (calculated as total quartz and carbonates over all minerals) for sedimentary units in Birrindudu Basin.

as presented in **Table 1**. Although hypothetical, this high-level summary demonstrates the potential for many source–reservoir pairs within the basin, which might contain up to 14 conventional systems and 9 unconventional systems. This is in line with detailed petroleum play analysis in the data-rich, coeval Beetaloo Sub-basin, for which Côté *et al* (2018) described five different petroleum play types: the Velkerri shale dry gas play, Velkerri liquids-rich gas play, the Kyalla shale gas play, Kyalla hybrid liquids-rich gas play, and the conventional Kyalla–Hayfield sandstone oil/condensate play. Individual play types have different levels of risk and require different technical information for appraisal; however, Coté *et al* (2018) made the point that an economically sound and efficient assessment of a region should attempt to holistically appraise multiple play types.

There are several hypothetical conventional trap styles for the Birrindudu Basin. Mapping in the region (eg Beier *et al* 2002) has identified favourable conditions for stratigraphic pinch-out traps, and gently folded anticlinal and fault-bounded structural traps. Faulting in the southwestern part of the basin was likely synchronous with deposition of the Limbunya Group (Beier *et al* 2002). This could have resulted in brecciated traps in carbonate rocks, with hydrocarbons sourced from organic-rich shales and carbonate rocks of the Limbunya and Bullita groups. In a hydrothermal dolostone play, low-temperature hydrothermal events could have generated and migrated hydrocarbons, forming secondary vugular pores for accumulation and preservation (Davies and Smith 2006). This is analogous to the Coxco Dolostone hydrothermal play in the McArthur Basin (Croon *et al* 2015). The presence of galena and pyrite pseudomorphs in several formations in the Limbunya Group (Dunster and Ahmad, 2013) is potential evidence of hydrothermal fluid flow through the basin.

There is also potential for unconventional shale oil and shale gas plays, and for basin-centred tight oil and gas plays. Unconventional hydrocarbon resources can be broadly defined as a resource requiring additional methods and technologies for extraction from reservoirs characterised by low porosity and permeability (Schmoker *et al* 1995). Unlike conventional reservoirs that have a physical separation between source rock and reservoir, a shale in an unconventional hydrocarbon resource can often be the source, reservoir and seal (Revie 2017a). Common unconventional resources are tight sands and shale oil or shale gas plays. Due to a paucity of data on porosity, permeability and mineralogy for sandstone units in the Birrindudu Basin, tight sandstone plays cannot be evaluated in any detail; however, low permeability values in the Stirling and Seale sandstones (Hallett 2020) show that there might be some potential for this play type. As the Beetaloo Sub-basin is actively being explored for shale gas, we also focus on analogous shale gas plays here.

Table 2. A summary of potential unconventional plays, and a summary of favourable characteristics.

Petroleum systems							
Continent-scale petroleum supersystem Bradshaw *et al* (1994)	**Basin-scale petroleum system Magoon & Dow (1994)**	**Shale thickness (m)+**	**Depth below surface (m)**	**Total organic carbon (TOC wt%)**	**Thermal maturity**	**Mineralogy**	**Brittleness**
Urapungan	Stubb-Stubb(?)	210	0 to 170	0.4% (n = 1)	mature 443°C (n = 1)		
Favenc*	Nero-Nero(?)	80					
	Timber-Timber(?)	>300	245 to 552	max 0.87% (average 0.2%, stdev 0.2%, n = 16)	immature to overmature (average 466°C, stdev 50°C, n = 11)	average brittle minerals 75%, average clays 13%	brittle
McArthur	Fraynes-Fraynes(?)	<100	29 to 992	max 8.1% (average 1.5%, stdev 1.7%, n = 43)	immature to overmature (average 457°C, stdev 27°C, n = 35)	average brittle minerals 50%, average clays 28%	less brittle to brittle
	Kunja-Kunja(?)	60	0 to 1538	max 2.1 wt% (average 1.5%, stdev 0.2%, n = 7)	early oil generation (average 437°C, stdev 1°C, n = 6)	brittle minerals 42%, clays 29%	less brittle
	Mallabah-Mallabah(?)	20	0 to 1554	max 11.3% (average 2.3%, stdev 2.2%, n = 56)	immature to overmature (average 444°C, stdev 31°C, n = 28)	average brittle minerals 40%, average clays 40%	less brittle to brittle
	Amos Knob-Amos Knob(?)	50	47 to 1609	max 0.60% (average 0.3%, stdev 0.2%, n = 8)	peak oil mature (average 448°C, stdev 5°C, n = 3)	average brittle minerals 22%, average clays 77% (n = 1)	less ductile (n = 1)
Redbank*	Hinde-Hinde(?)	55	0 to 465				
	undifferentiated Birrindudu						

Coloured green for favourable, yellow for potentially favourable, red as unfavourable, and grey for unknown (insufficient or no data).
* indicates petroleum supersystems currently undefined
\+ a combination of field and drill core measurements

There are a number of different workflows available to test shale oil and shale gas potential. Bailey *et al* (2019) summarised six broad factors influencing shale gas prospectivity assessments:

1. geology, including shale thickness and depth
2. organic geochemistry, including organic richness (TOC), kerogen type and thermal maturity
3. mineralogy and brittleness
4. an understanding of the regional stress fields and pressure regimes
5. petrophysical factors, including characterising fractures, porosity and permeability
6. gas composition (thermogenic source).

The frontier Birrindudu Basin has limited datasets, so only the first few factors can be tested and compared to analogues from other more data-rich regions, eg the Beetaloo Sub-basin (Revie 2017a). Nine shales have been identified as having unconventional shale gas or shale oil potential as summarised and classified in **Table 2**.

The main geological factors influencing unconventional hydrocarbon prospectivity are shale thicknesses and depth below surface (Charpentier and Cook 2011, Jarvie 2012). Net shale thicknesses of >45 m (Jarvie 2012) or >100 m (Ahmeed and Ghori 2013) have been estimated as having potential as economically favourable pay zones. Deeper shales typically have higher reservoir pressures and thermal maturities. Depths of >1000 m are considered most favourable for shale gas, although shale gas from ~500 m is known in the Fayatteville shale play in the Arkoma basin of northern Arkansas (Ikonnikova *et al* 2015). As there are only limited seismic datasets and few deep drill cores in the Birrindudu Basin, the extent, thicknesses and depths of shale units are largely unknown. The results in **Table 2** are likely skewed by shallow drilling in the region and reliance on thicknesses from outcrop mapping (eg, Dunster and Ahmad 2013). Regardless, shale thicknesses appear to be generally favourable within the basin. Additionally, three out of the nine shales (Amos Knob Formation, Mallabah Dolostone and Kunja Siltstone) are at economically favourable depths; with two more (Fraynes and Timber Creek formations) at potentially favourable depths (**Table 2**). Future seismic acquisition and isochore mapping would greatly assist in determining the known thicknesses and depths of shales within the basin.

Shale geochemistry data plotted in **Figure 3** identified several shales with measured TOC between 1 and 2 wt%, the likely minimum requirements for an unconventional petroleum play (Charpentier and Cook 2011). Successions intersected in many of the legacy wells in the Birrindudu Basin are thermally overmature, and the original TOC would therefore have been higher (Huc 2013). Many of the shales are also thermally mature in the zone of oil and gas generation and may be potential sweet spots for shale oil or shale gas (Jarvie 2012). Geochemistry is not available for all potential unconventional systems. However, black shales in the Mallabah Dolostone, drilled by Peko Wallsend Operations, are described as having anomalous Pb-Zn values (Hurrell 1993). This could also suggest high TOC values due to the intimate association between redox sensitive trace metals and TOC (eg, Tribovillard *et al* 2006, Emsbo 2009, Spinks *et al* 2016b, Jarrett *et al* 2020c).

The results in **Table 2** are very preliminary due to the low data coverage in the region. Extensive work is needed to understand the petroleum potential of the Birrindudu Basin. Large scale deep crustal seismic would be beneficial to understand basin architecture and relationships between depocentres within the greater McArthur Basin. Additionally, increased diamond drilling will provide further opportunities for a raft of new analyses. Detailed geochemical, petrological and geomechanical studies of legacy wells will provide the best possible characterisation of intersected units and ultimately assist in determining the potential for unconventional resources. This work would be undertaken in conjunction with a reinterpretation of seismic data, solid geology mapping, and relogging of legacy holes in order to define the extent of units across the Birrindudu Basin and spatially map exploration fairways and possible sweet spots.

Hydrocarbons sourced from the Birrindudu Basin could also potentially migrate upwards through faults and fractures into sedimentary successions of the unconformably overlying Neoproterozoic Victoria Basin. The Victoria Basin is interpreted to be part of the large polyphase Centralian Superbasin that covered extensive areas of Australia (Walter *et al* 1995, Munson *et al* 2013). The Auvergne Group of the Victoria Basin is composed of seven formations broadly composed of sandstones, siltstones, dolostones shales; it reaches a maximum thickness of about 950 m (Sweet *et al* 1974a, Dunster and Ahmad 2013). Sandstones of the Jasper Gorge and Spencer sandstones are hypothetical reservoirs, with the Angalarri Siltstone and mudstones within the Shoal Reach Formation potentially forming regional seals. Oil seepage was identified in an unidentified borehole near Bullo River in close proximity to the Bubble Springs Fault (Laing and Webby 1982); the source for this oil is currently unknown. Minor gas shows are known in the Victoria Basin in drill core from Bullo River-1 (Queensland Petroleum 1984); however, in this well, the Auvergne Group unconformably overlies granitic basement, possibly analogous to the Gillen sub-salt play in the Amadeus Basin (eg Palmer and Ambrose 2012, DeBacker *et al* 2016). Understanding the source of these hydrocarbons would also greatly assist in constraining petroleum systems in the region.

Conclusions

The Birrindudu Basin in the northwestern Northern Territory is a frontier greenfields basin and an underexplored component of the resource-rich greater McArthur Basin. While industry exploration is currently focused on the Beetaloo Sub-basin and southern McArthur Basin, this ongoing Birrindudu Basin study by NTGS is aimed at expanding the prospective plays in the region as part of the *Resourcing the Territory* initiative. The Birrindudu Basin contains four continent-scale petroleum supersystems; within this supersystem framework, basin-scale petroleum systems have been defined comprising

14 conventional systems and nine unconventional systems. New and existing legacy geochemistry and rock properties data have been collated and interpreted for conventional hydrocarbon quality. Although data are limited, four formations have good to excellent present-day organic richness (>2 wt% TOC), and several sandstone and carbonate reservoirs have good porosity data. Mineralogy was used to calculate the brittleness index of a number of organic-rich shales and the results suggest that several of these would constitute good unconventional hydrocarbon targets and are likely to be favourable for fracture stimulation. Fluids from the Seale Sandstone, Timber Creek Formation, and Skull Creek Formation were geochemically analysed for an oil-source rock correlation. However, geochemical differentiation of the oil in comparison to McArthur Basin source rocks is difficult due to the ubiquitous nature of hydrocarbon biomarkers and an overlap in carbon-specific isotopic analyses. Future work is recommended to analyse a wider range of potential source rocks in the region. A larger foundational dataset of geochronology, geochemistry, and reservoir properties is also needed to test many of the play concepts described herein and thus reduce exploration search space for conventional and unconventional hydrocarbons.

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