REVIEW OF SOURCE ROCKS IN THE AMADEUS BASIN

TR Marshall

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ABSTRACT

Potential hydrocarbon source rocks in the Amadeus Basin are commonly considered to be absent below the Ordovician Horn Valley Siltstone. While it is true that this formation represents the most likely to produce oil (and gas) north of the Central Ridge, there is an earlier, relatively undocumented potential in the Neoproterozoic succession.

Using Total Organic Carbon (TOC) as a general guide to the potential that a given unit may have to act as an effective source rock, it is possible to garner some idea of the areas of the basin that should be targeted for hydrocarbon production from specific intervals.

In reality, the degradation of source rock potential over time should be considered when attempting to delineate areas that potentially hold both oil and gas at present. By using maturity trends coupled with existing knowledge, several aspects become clear.

The single most important factor when considering potential maturity of a given source, particularly north of the Central Ridge, is the thickness of the Pertnjara Group, which would have matured many formations well past the gas window.

Most importantly, oil could be sourced from Neoproterozoic units (Inindia beds, Aralka and Areyonga Formations, Gillen Member) in the southwestern Amadeus Basin, and some potential for liquids exists also in the central south. There are extensive source rocks for gas over almost the entire basin.

INTRODUCTION

The Neoproterozoic–Devonian Amadeus Basin is an asymmetric, east-trending intracratonic depression covering 155 000 km² of central Australia (Figure 1). The sedimentary succession reaches a maximum thickness of approximately 12 km (Figure 2). The basin is bounded to the north by the Precambrian Arunta Region, and to the south by the Musgrave Block. To the west and east, the present basin margins are obscured by a cover of Permian and younger sedimentary rocks.

Distribution of Neoproterozoic sediments was controlled by an east-trending hingeline (Central Ridge) across the north-central part of the basin, from which the thickness of the succession increases both northward and southward. The succession is thickest in the Carmichael Sub-basin along the present northern margin of the basin, and thins to 2 km near the southeastern margin.

The Amadeus Basin is a proven petroleum province containing initial recoverable proved, probable and possible reserves estimated at 37 million barrels of oil and 427 billion cubic feet of gas (Jackson et al 1984). Most hydrocarbon occurrences (by volume), including the oil and gas reserves at Mereenie and Palm Valley, have been found in Ordovician sandstones. Cambrian reservoirs, particularly the Arumbera Sandstone, have been the exploration objective in the eastern Amadeus Basin, where significant gas flows were recorded from this unit in the subeconomic Dingo and Orange fields. The sole penetration of the basal Heavitree Quartzite also yielded a small gas flow (1783 m³).

The aim of this review paper is to discuss the likely source potential of various Proterozoic to Ordovician lithofacies by comparing previously reported geochemical results with recently acquired Northern Territory Geological Survey (NTGS) data.

PALAEOGEOGRAPHY

The following palaeogeography is summarised from Jackson et al (1984).

Neoproterozoic

Sedimentation in the Amadeus Basin began during the early Neoproterozoic, with deposition of the Heavitree and Dean quartzites. These transgressive marine sands accumulated on a stable epicontinental shelf. The Bitter Springs Formation (including carbonate, evaporitic and siliciclastic rocks) was deposited in a restricted euxinic, locally hypersaline environment following shallowing of the basin. This formation contains source beds, reservoir rocks and seals. It is an exploration objective throughout the basin.

Consequent paralic deposition occurred in the north (Areyonga Formation), and paralic and possible continental deposition in the south (Inindia beds). Proglacial influx from a glaciated land mass to the north (Sturtian glaciation) may have influenced sedimentation in these areas, as may have a brief eustatic sea level change, leading to deposition of the Aralka Formation.

Renewed uplift of a southern provenance area during the Souths Range Movement resulted in deposition of shallow marine sandstone and shale (Winnall beds) in a southern trough, while fine marine siliciclastic (Pertatataka Formation) and carbonate sediments (Julie Formation) accumulated on a northern shelf. Figure 3 shows the east-trending hingeline that separated these two depocentres. By this time, the northern landmass had become a less significant sediment source, possibly due to peneplanation during the previous, Marinoan glaciation.

A period of mountain building, recumbent folding and northward overthrusting associated with the Petermann Orogeny terminated the Neoproterozoic depositional phase in the southwest. Previous authors have suggested that the detachment surface for the thrusting was the salt within the Bitter Springs Formation. Molasse sediments (Arumbera Sandstone) were shed to the north and northeast, in a predominantly deltaic depositional environment.
Figure 1. Locality map showing Amadeus Basin.

Figure 2. Lithostratigraphy of Amadeus Basin.
Early Palaeozoic

The framework of the Palaeozoic basin, which had an east-trending depocentre north of the present basin margin, was shaped by the Petermann Orogeny.

Arumbera Sandstone deposition continued into the earliest Cambrian. Locally, conglomerate (notably the Mount Currie Conglomerate) was deposited in the Mount Currie Sub-basin in the southwest during the later Petermann Orogeny. A relatively stable shelf developed thereafter in the northeastern Amadeus Basin, with initial deposition of the Todd River Dolostone. Shallow marine shale, evaporite and carbonate rocks followed in this northeastern area (Chandler Formation, Giles Creek Dolostone and Shannon Formation; Figure 4), while continental sedimentation (Tempe Formation and Cleland Sandstone)

Figure 3. Schematic map showing Neoproterozoic depositional model (after Jackson et al. 1984).

Figure 4. Schematic map showing Early Cambrian depositional model (after Jackson et al. 1984).
persisted in the west during much of the Cambrian. The Chandler Formation evaporites may seal the underlying Arumbera Sandstone in the eastern part of the basin. During the Late Cambrian, widespread transgressive phases deposited the sediments of the overlying Goyder Formation.

Marine transgression from the north followed during the latest Cambrian and Early Ordovician (Pacoota Sandstone). The Horn Valley Siltstone (euxinic marl, mud and silt) was deposited on an open shelf in well oxygenated waters which supported a rich fauna of trilobites, brachiopods, nautiloids, gastropods, pelecypods and graptolites. During subsequent transgressive and regressive cycles, the Stairway Sandstone and Stokes Siltstone (Middle Ordovician sediments) were deposited in similar environments (Figure 5). A final regression in the Middle Ordovician led to sedimentation in a dominantly estuarine environment (Carmichael Sandstone).

The Rodingan Movement caused a marine regression during the Late Ordovician to Early Silurian; some authors point to this as being responsible for the erosion of 1–3 km of Cambrian–Ordovician section from the eastern part of the basin. Arid climatic conditions became established over the emergent landmass. Aeolian and fluvial action transported, then deposited sediments (Mereenie Sandstone) in a shallow sea transgressing from the west during the ?Silurian–?Early Devonian.

**Late Palaeozoic to Recent**

Late Devonian uplift of the Arunta Region along the present northern margin of the Amadeus Basin marked the peak of the Alice Springs Orogeny. Thick molasse deposits (Pertnjara Group), accumulated in an adjacent foredeep as continental deposition continued. The Brewer Conglomerate formed a sedimentary wedge which depositionally thinned southward from some 3000 m to 1500 m over just 17 km. The Parke Siltstone was deposited under locally prevailing lacustrine conditions. The Central Ridge restricted deposition of the Pertnjara Group to the northern trough, whereas southern sedimentation was sourced from remnant highs of the Musgrave Block (Finke Group).

Since the mid-Carboniferous the Amadeus Basin has been relatively stable, although subsequent extensive erosion has led to the present exposure of Neoproterozoic rocks in the cores of some anticlines.

**TECTONIC HISTORY**

The two major episodes of tectonic deformation are the late Neoproterozoic Petermann Orogeny and the Ordovician to Late Devonian Alice Springs Orogeny. These two orogenies largely controlled structural development within the basin, and hence the formation of potential traps for hydrocarbon accumulation. The Alice Springs Orogeny is considered to define the timing of trap formation in the northern trough region, with diminishing effects southward of the Central Ridge. Structural features related to the earlier, Petermann Orogeny are evident throughout the basin, particularly in the southwest, but are less apparent in the northern trough due to significant overprinting and burial during the Alice Springs Orogeny.

**Figure 5.** Schematic map showing Ordovician depositional model (after Jackson et al 1984).
Structures resulting from Alice Springs Orogeny deformation are well expressed at the surface. In the eastern part of the basin, recumbent nappes and overthrusts formed in the Arltunga Nappe Complex as folds, strike-slip faults and thrust sheets deformed the overlying sedimentary succession.

The central and western parts of the basin are characterised by numerous large-scale folds, eg Mereenie Anticline. Fold axes trend east–west in the centre of the basin, but further west are aligned northwest–southeast. Folds are periclinal, commonly asymmetric, and in some cases have thrust-faulted cores. These latter are prevalent in the north, but uncommon in southern areas above the Neoproterozoic succession.

Halotectonics and halokinetonics have undoubtedly played a major role in basin development. It has been previously suggested that salt migration in the Bitter Springs Formation began in the Neoproterozoic and continued thereafter at different rates until the Devonian (Lindsay 1989). Structures induced by various halotectonic mechanisms were affected by subsequent overthrusting.

The tectonic history of the basin is not simple, as it embraces at least six diastrophic events. However, most of the structural features in the basin are, at least in part, related to the Petermann Orogeny.

SOURCE ROCKS

This study primarily utilises pyrolysis, the most common method of characterising the source potential of lithostratigraphic units. It is both relatively inexpensive and a direct method of measuring the conventional source potential of a rock sample. The NTGS geochemical data used to generate this report have been included in Appendix 1 and 2. Additional Geoscience Australia data are also appended (Appendix 3), but are not taken into consideration in calculating TOC averages and highs in the tables. The data encompass all known published values, together with those in reports available in the Minerals and Energy Information Centre, Darwin.

Several points need to be noted:

- Correlation between different data sources/laboratories is complicated, hence no strict cutoff values have been assumed.
- Cuttings samples from older (1960s) wells were generally oven dried except when dried with air. As both the length of storage and the drying method may have adversely affected the contained organic matter in the older samples, more credence should be given to open air-dried and recently collected material.
- Most samples are composited over a 10–15’ interval, and as such are average semiquantitative values.
- Pyrolysis works best on immature samples. The effect of maturity is to lower the Hydrogen Index as a result of migration of matured petroleum hydrocarbons. The amount that values are lowered depends on the original organic matter type.
- The data in Appendix 1 have been tied to the formation tops provided in Questa (1990).

CAMBRIAN–ORDOVICIAN SOURCE ROCKS

The low density of wells is a challenge to the definition of source richness trends in the Amadeus Basin. Petroleum wells, being the main source of samples, in some cases have been drilled on breached anticlines, so that a unit may not be represented in a well, even though present in the region.

The Ordovician includes the most prolific source rock known in the basin: the Horn Valley Siltstone. This unit has been subjected to a number of studies over the last 40 years, but much less time and research has been directed towards the delineation of other potential source intervals. In some respects, this has unnecessarily limited recognition of petroleum plays.

The Georgina Basin is host to a potential Middle Cambrian source rock in the basal Arthur Creek Formation (Ambrose et al 2001). Despite having a thickness of only 20–50 m, calculations have determined the total expulsion of liquid hydrocarbons at 11.7 billion tonnes (Dunster et al in prep).

Horn Valley Siltstone

This unit is of early Middle Ordovician age (472–468 Ma; Webby et al 1981, 2004). It is conformable between the Pacoota Sandstone below and the Stairway Sandstone above. It comprises thinly interbedded shale and siltstone with minor bedded and nodular limestone.

A basal dolomitic or glauconitic/dolomitic limestone is overlain by black shale rich in trilobites, nautiloids and brachiopods and with interbeds and nodules of calcimudstone. The upper part of the formation consists of interbedded marl and thin bioclastic limestone with occasional beds of shale and nodular limestone. The black shale grades upward through interbedded carbonate and siltstone into fine sandstone.

In the vicinity of the Central Ridge and in the western Amadeus Basin, the Horn Valley Siltstone tends to be more organic rich, particularly with regard to oil generative capacity (Gorter 1984).

The maximum thickness of the unit is 120 m in the western MacDonnell Ranges near the present central-northern margin of the basin, thinning to the south and southwest. The thickest eastern intersection of this unit is 114 m in Palm Valley 2. It thins further eastward to 32 m in Dingo 2 and is thought to pinch out depositionally not far east of that well.

Type 2 kerogen from the oil-source rocks of the Horn Valley Siltstone in Tempe Vale 1 is characterised by an abundance of well preserved graptolites and other invertebrate fossils. This, together with a lack of benthic fauna, suggests well aerated, productive upper waters contrasted with anoxic conditions on the sea bottom – an ideal oil source rock development situation (Gorter 1984). Amorphous microbial sapropel is a major component of the Horn Valley Siltstone oil-source kerogen.
The unfossiliferous gas-source lithofacies of the unit (type 3 kerogen, with low H/C atomic ratios and Rock Eval hydrogen indices), typically contains much less organic carbon (TOC <0.5%) and has a different saturated hydrocarbon distribution (Gorter 1984).

Somewhat higher Rock Eval hydrogen indices (HI ~150) and organic carbon contents (TOC 0.6–0.8%) define an intermediate gas condensate source (Jackson et al. 1984).

In general, the quantity of organic matter in the source beds within the Horn Valley Siltstone, as defined by the TOC content, increases westward from low values in the south and east of the basin to maximum values in the Mount Winter and Mereenie areas. This westerly enrichment trend is paralleled by an improvement in source rock quality, as defined by the Hydrogen Index and T_max cross-plot of samples analysed by Rock Eval pyrolysis (Gorter 1984).

TOC, Rock Eval pyrolysis, Hydrogen Index, T_max, and microscopy demonstrate a clearly discernible westward change in the Horn Valley Siltstone (Gorter 1984). Specifically, they indicate an increase in the oil prone nature of the kerogen toward the central northwest. A northwesterly increase in the quantity of potential source rock kerogen (TOC) can also be seen (Figure 6).

McKirdy (1977) linked the Horn Valley Siltstone as the source for the oil and gas at Mereenie and the gas at Palm Valley. A controlling factor on its maturity, and the maturity of all possible sources in the northern trough of the basin is the thickness of overlying Pertnjara Group sediments.

The depositional controls on this unit are such that it is most likely to be found in significant thickness north of the Central Ridge (Figure 7).

Data from the westernmost well, Mount Winter 1, indicate that the same TOC and maturity profile is probably present further west in the basin (Figure 8).

The maturity profile through the basin (Figure 9) shows the likely present thermal state.

Figure 6. Schematic map showing generalised hydrocarbon lithofacies variation for Horn Valley Siltstone (after Gorter 1983).

Figure 7. Outcrop distribution of Horn Valley Siltstone (after Gorter 1983).
Figure 8. TOC trends of Horn Valley Siltstone (after Gorter 1983).

Figure 9. Schematic map showing maturity trends of Horn Valley Siltstone, based on conodont colour alteration index (after Gorter 1983).
Goyder Formation

The Goyder Formation in the eastern part of the basin consists of two shoaling-upward packages, from shale and siltstone to sandstone, limestone and dolostone. The upper package is more dolomitised than the lower (Gorter et al 1982a). The presence of ooid grainstone suggests oxidising, agitated deposition, further supported by the generally light colours of the rocks.

Total Organic Carbon (TOC) values are generally low, particularly in Wallaby 1, Dingo 1 and West Walker 1; this perhaps reflects the oxidising depositional environment. A general increase in TOC is evident toward the northeast of the basin (Figures 10, 11, Table 1).

As only one sample has been analysed from the Goyder Formation in East Johnnys Creek 1, it is best not to consider it at present as representative of local source characteristics; more data are needed.
The lower TOC content toward the southwest parallels an increasing coarse clastic content of the Goyder Formation, and the disappearance of shoaling parasequences from the section (Gorter 1982). At the Mereenie field, the Goyder is dominantly sandstone and minor limestone with virtually no source rock potential (Gorter 1982). Further west at Mount Winter 1, the formation is again predominantly sandstone, with only minor red-brown siltstone and shale (Gorter et al 1982b).

The Goyder Formation is not expected to be an effective source rock. It is clear from the maps that only the northeastern part of the basin, perhaps near Alice 1, retains any real possibility of an enhanced Goyder Formation source facies.

Considering that Wallaby 1 was drilled only 7 km from Alice 1 and had very low TOC values, the source potential must be considered at best to be average, and sporadically developed.

**Jay Creek Limestone**

This formation has only been reliably sampled at Alice 1 and Orange 1. It has a mean TOC at Alice 1 of 1.1% and at Orange 1 of 0.24%. The interval sampled in Alice 1 is most likely indicative of migrated hydrocarbons (Jackson et al 1984).

Although the formation is regionally extensive, the limited spatial distribution of samples makes current insight into the overall regional source potential questionable (Figure 12). When more information becomes available it will be clearer as to whether there is an increasing source potential, in particular, toward the south.

**Petermann Sandstone and Cleland Sandstone**

The Cleland Sandstone is not thought to have any source potential and there are no recorded geochemical values for this unit.

According to the NTGS database, the Petermann Sandstone has been sampled in Mount Winter 1, but this is by no means certain, due to poor recording.

Interestingly, the 11 samples analysed have a mean TOC of 0.46%. Although all the samples come from the same 5 m interval, this is positive evidence for potential within the formation (and Cambrian succession in general). However, lack of regional sampling

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**Table 1. Goyder Formation: mean drillhole TOC values.**

<table>
<thead>
<tr>
<th>Location</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.28</td>
<td>0.51</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.12</td>
<td>0.7</td>
</tr>
<tr>
<td>East Johnnys Creek 1</td>
<td>0.32</td>
<td>0.32</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.24</td>
<td>0.52</td>
</tr>
<tr>
<td>Wallaby 1</td>
<td>0.09</td>
<td>0.09</td>
</tr>
<tr>
<td>West Walker 1</td>
<td>0.06</td>
<td>0.07</td>
</tr>
</tbody>
</table>

---

**Figure 12. Jay Creek Limestone: TOC enrichment map.**
makes meaningful conclusions about level and distribution of enrichment trends difficult (Figure 13). The Petermann Sandstone is thought to have been deposited only in the western side of the basin, but was previously interpreted to be present in Dingo 1.

**Shannon Formation**

The Shannon Formation comprises siltstone, ooid limestone and stromatolite-bearing dolostone (Wells et al. 1970) (Figures 14, 15, Table 2). Gorter (1983) divided the formation into lower and upper Shannon units in the subsurface. The lower Shannon Formation contains a higher siliciclastic content than the upper, and generally has thinner carbonate beds.

**Upper Shannon Formation**

Total organic carbon content values in the upper Shannon Formation are generally less than 0.1%, but values of up to 0.39% have been recorded in Alice 1. The greatest value was from a sample from immediately below an oil and gas show (bleed) in core 11.

![Figure 13. Petermann Sandstone: TOC enrichment map.](image13.png)

![Figure 14. Shannon Formation: TOC enrichment map.](image14.png)
McKirdy (1977) linked the proportion of saturates and total hydrocarbons in the extractable organic matter (EOM) of core 11 to in situ oil generation.

Gorter (1982) cited elemental analysis of kerogens isolated from shales of the upper Shannon Formation (type 2–3, H/C = 0.99) at Alice 1, which suggest a reduced potential to generate liquid hydrocarbons; the indigenous origin of this asphaltic oil must remain speculative. Apart from McKirdy’s core sample, the highest TOC in the Shannon Formation is 2%.

**Lower Shannon Formation**

The lower Shannon Formation has been divided into two subunits, designated A and B by Gorter (1982). Subunit A generally has less than 0.1% TOC and therefore no source potential.

Richer pockets are present in subunit B: TOC locally approaches 0.24% (Orange 1). McKirdy (1977) showed that the kerogen in subunit B at Alice 1 is type 2, and as such must be regarded as both an oil, as well as a gas source, if areas of higher TOC can be located.

The highest TOC values at Alice 1 are associated with dolomitic siltstone and shale, whereas carbonate rock is deficient in organic carbon. The higher organic carbon content of the shale suggests that it, and not the carbonate rock, would be the major oil source in the formation (Gorter 1982a). This assessment is supported by the probably liptinic (type 2) composition and high volatile matter content (60.7%) of the kerogen (McKirdy 1977).

This variation in TOC between fine siliciclastic rocks and the ooid limestone and dolostone of the Shannon Formation probably reflects original depositional conditions. Shale was deposited in deeper water, probably below wave base, where organic matter had greater likelihood of preservation. Falling sea level and/or shoaling led to higher-energy carbonate deposition in a largely oxidising environment, where organic matter was preferentially removed (Gorter 1982b). The absence of an abundant or diverse biota throughout the Shannon Formation is a reflection of the virtual absence of benthic faunas and the scarcity of pelagic organisms (eg trilobites, acritarchs) preserved as fossils. Quite probably, the adverse environmental factors which prevented the development of an abundant biomass in the Shannon Formation contributed to the low TOC presently observed via geochemical analysis of the rocks.

In general, the Shannon Formation shows increasing TOC to the east, although a large discrepancy exists between the mean values at Wallaby 1 and Alice 1. Maturity trends show that the formation is immature where TOC is highest, and mature (VR equiv 1.44) where TOC is lowest (Dingo 1). The low TOC contents are below the minimum needed for laboratories to proceed to Rock Eval pyrolysis and therefore information is scant.

**Table 2. Shannon Formation: mean TOC.**

<table>
<thead>
<tr>
<th>Shannon Formation</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.41</td>
<td>2</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.06</td>
<td>0.1</td>
</tr>
<tr>
<td>Highway Anticline 1</td>
<td>0.29</td>
<td>0.29</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.1</td>
<td>0.24</td>
</tr>
<tr>
<td>Wallaby 1</td>
<td>0.07</td>
<td>0.21</td>
</tr>
</tbody>
</table>

**Figure 15. Shannon Formation: maturity map.**

McKirdy (1977) linked the proportion of saturates and total hydrocarbons in the extractable organic matter (EOM) of core 11 to in situ oil generation.
The current source potential of the Shannon Formation is assessed as poor.

**Hugh River Shale**

The Hugh River Shale is divisible into three units based on relative percentages of siliciclastic and carbonate constituents. The middle unit is dominantly reddish siltstone and shale, whereas the upper and lower units contain up to 40% carbonate rock.

Scattered results make the resolution any discernible enrichment trend difficult. Despite having TOC values in Alice 1 that are sufficient for the generation and expulsion of hydrocarbons, the formation would generally be considered to have a sporadic potential (Figure 16, Table 3).

There is only one maturity data point available: a vitrinite reflectance equivalent value of 0.8% at Highway Anticline 1, indicating that this formation is likely to be largely immature in the southern part of the basin.

**Deception Siltstone**

The Deception Siltstone is dominantly a fine siliciclastic unit which becomes increasingly sand-rich to the west. Component siltstone and shale are red-brown, purple-brown or grey-green – colours not normally associated with source rocks.

Only small amounts of information are available on this unit (Figure 17). It has been sampled in East Mereenie 4 (TOC 0.11%) and East Johnnys Creek 1 (TOC 0.13%). Dark grey shale from core in East Mereenie 4 is barren and contains rare, very thin graphite flakes. The dark colour of the shale is imparted by small flakes of detrital mica (Kantsler in Gorter 1982).

The redbed lithology and low TOC content would render this unit unlikely to have generated hydrocarbons. The more sand-rich lithofacies to the west could be a potential reservoir target.

**Illara Sandstone**

This unit is not present in the eastern part of the basin. It shows poor potential in all samples east of Mount Winter 1.

The anomalous nature of the T_max values for the Mount Winter 1 samples (457°C and 274°C from samples 1 m apart) would indicate caution. Work by Jackson et al (1984) shows that these samples are not in the present oil window, thereby indicating that this unit is immature at the Mount Winter location. The TOC average value is approaching that required to generate hydrocarbons (0.5%).

---

**Figure 16.** Hugh River Shale: TOC enrichment map.

<table>
<thead>
<tr>
<th>Hugh River Shale</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.33</td>
<td>0.76</td>
</tr>
<tr>
<td>Highway Anticline 1</td>
<td>0.24</td>
<td>0.29</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.05</td>
<td>0.07</td>
</tr>
<tr>
<td>Wallaby 1</td>
<td>0.07</td>
<td>0.07</td>
</tr>
</tbody>
</table>

**Table 3.** Hugh River Shale: mean TOC values in sampled wells.
It would seem that in the northwestern part of the basin this unit holds some limited potential as a source rock (Figures 18, 19, Table 4).

Giles Creek Dolostone

The Giles Creek Dolostone is readily divisible on downhole logs into four distinct units: the upper, middle and lower Giles Creek Dolostone and the basal Dingo Member. The lower unit is dominantly siliciclastic. Carbonate content in the upper two units decreases to the south, particularly in the upper Giles Creek Dolostone. The middle unit is the most consistently calcareous.

A basal, massive dolostone bed is easily correlated southward from Wallaby 1 to Dingo 1, but probably thins further southward to be absent at Highway Anticline 1. The Dingo Member, a thin, sandier unit at the base of the formation, may represent a basal transgressive sand (Gorter 1982).
In the northeastern Amadeus Basin, in Alice 1, the upper unit reaches 0.96% TOC in selected samples, but averages 0.2% (Figure 20, Table 5). The TOC content is lower in Orange 1, and at its most southerly data area, Mount Charlotte 1, is lower still at 0.11%. This could possibly reflect a more oxidising environment in the south. Oil and gas shows were encountered in the upper unit at Alice 1 and Wallaby 1, but there are no known shows at Orange 1, Dingo 1, Highway Anticline 1 or Mount Charlotte 1 (the most southerly).

McKirdy (1977) conducted extensive analyses on cores 19, 20, 22 and 23 from the upper unit in Alice 1. He concluded that the extremely low proportion of saturates in the EOM of shale from core 23 was only explicable if saturated hydrocarbons had preferentially migrated from the shale into interbedded dolostones. The dark brown, high-gravity (43° API) oil which bled from tight dolostone (core 23) over the interval 1864.2–1868.4 m (Planalp et al. 1963) is strong evidence that migration of hydrocarbons has occurred into this part of the section. Further evidence for migration is the comparatively high yield of extract from anhydritic dolostone in core 23, which had a high saturate/aromatic value (McKirdy 1977).

McKirdy (1977) reported that the pristane/phytane ratios of the anhydritic dolostone (0.5) and the dolomitic shale (0.7) of core 23 are significantly different to that obtained from the oil that bled from the core. This could suggest that the oil is migrated. However, a problem in using pristane/phytane ratios for correlation purposes is the uncertain effects of thermal maturation (Gorter 1982).

Carbon isotopes can also be used to correlate between oil and source rocks. In a genetically related series, kerogen source rock-hydrocarbon-crude oil, the carbon isotope values become increasingly negative from the kerogen through to the crude oil (Silverman 1964). The carbon isotope values of the shale (δ13C -30.8) and the oil (δ13C -28.8) in core 23 are sufficiently different to suggest that a separate source rock for the oil in core 23 is likely.

The kerogen in core 23 is presently type 3, and should have produced mainly gas rather than oil, especially at the low thermal maturity determined.

The evidence suggests that the oil in core 23 has migrated from oil-prone kerogens in mature source rocks deeper in the stratigraphic profile than the upper Giles Creek Dolostone.

Total organic carbon values in the middle and lower units average 0.15%, with one high value of 1.18% at Alice 1. This suggests that there are richer pockets of source potential in the lower part of the section.

Maturity trends in the basin (Figure 21) indicate that the Giles Creek Dolostone becomes more mature from south to north.

The Giles Creek Dolostone has a restricted deposition in the sense that it has not been picked on well logs from any of the western basin wells, limiting this discussion to the northeastern Amadeus Basin.
Figure 20. Giles Creek Dolostone: TOC enrichment map.

Table 5. Giles Creek Dolostone: mean source rock values.

<table>
<thead>
<tr>
<th>Giles Creek Dolostone</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.4</td>
<td>1.18</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td>Dingo 2</td>
<td>0.37</td>
<td>0.38</td>
</tr>
<tr>
<td>Finke 1</td>
<td>0.17</td>
<td>0.32</td>
</tr>
<tr>
<td>Highway Anticline 1</td>
<td>0.14</td>
<td>0.25</td>
</tr>
<tr>
<td>Mount Charlotte 1</td>
<td>0.11</td>
<td>0.31</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.14</td>
<td>0.88</td>
</tr>
<tr>
<td>Wallaby 1</td>
<td>0.11</td>
<td>0.41</td>
</tr>
</tbody>
</table>

Figure 21. Giles Creek Dolostone: maturity map.
$T_{Max}$ values at Mount Charlotte 1 are 430°, indicating that the formation is now in the low part of the oil window, but grades up to 475°C at Finke 1 in the James Range.

With a VR equivalent of 1.09% at Highway Anticline 1, the unit could be considered to be broadly in the oil window at most locations.

### Dingo Member

The Dingo Member was first recognised in Dingo 1 (Gorter et al. 1982a), where it is a coarsening-upward siliciclastic unit with good porosity in the upper part. The unit is also recognisable on log characteristics in other wells in the eastern Amadeus Basin. Gorter et al. (1982a) suggested that gas shows at Orange 1 may be from this unit.

Gorter et al. (1982a) also suggested that the Dingo Member may represent the transgression that spread over the eastern Amadeus Basin immediately following Chandler Formation evaporite deposition. The unit has no measured source rock characteristics, but could be a reservoir target.

### Tempe Formation

The Tempe Formation is limited to the western side of the Amadeus Basin, and has been sampled in five wells (Figure 22, Table 6).

In East Johnnys Creek 1, Undandita 1A and Mount Winter 1, the shale and siltstone are generally dark grey in colour, but have consistently low TOC content. The obvious exception is Undandita 1A, where there are two high TOC values, 1.43% and 5.45%, indicating excellent potential for hydrocarbon generation.

The dark colour of the fine siliciclastic sediment in this interval, and the foetid odour, could equally be explained by the presence of finely disseminated pyrite as by organic matter. The high TOC results represent thin, concentrated bands of organic matter, but there is insufficient information to indicate that these are regionally continuous.

Only the Undandita 1A area, in the northwestern part of the basin, would be a good target for Tempe Formation enrichment. There, the formation is in the oil window ($T_{Max}$ 443°C), and is a possible source for oil shows (live oil bleeds) in that well (Figure 23). South of this location, source rock characteristics remain poor.

Another location to obtain any form of maturity data is Mount Winter 1, which yielded VR equivalent values of 1.8 and 1.9.

The Tempe Formation could provide a good seal over porous sands in the Eninta Formation or over karst porosity in older carbonate rocks.

![Figure 22. Tempe Formation: TOC enrichment map.](image)

<table>
<thead>
<tr>
<th>Tempe Formation</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>East Mereenie 4</td>
<td>0.12</td>
<td>0.2</td>
</tr>
<tr>
<td>East Johnnys Creek 1</td>
<td>0.08</td>
<td>0.24</td>
</tr>
<tr>
<td>Mount Winter 1</td>
<td>0.08</td>
<td>0.08</td>
</tr>
<tr>
<td>Ochre Hills 1</td>
<td>0.07</td>
<td>0.09</td>
</tr>
<tr>
<td>Undandita 1A</td>
<td>2.15</td>
<td>5.45</td>
</tr>
</tbody>
</table>

**Table 6.** Tempe Formation: mean TOC values.
The Chandler Formation thickens southward away from the northeastern Amadeus Basin. Chandler Formation outcrop consists of limestone, dolostone and interlaminated chert. Evaporites and shale are present in the subsurface. In the subsurface the unit dominantly comprises halite and other evaporitic minerals (anhydrite, gypsum), but contains discrete carbonate and siliciclastic intervals. One such interval is correlatable from Wallaby 1 to Dingo 1 and has hydrocarbon shows (elevated gas readings, oil stains, some bitumen).

Total organic carbon values in the Chandler Formation are generally around 0.3%, but richer pockets are present (Figure 24, Table 7). The 3% TOC recorded in the Rodinga 1A core was measured by Felton (1981), and is evidence of the potential of discrete bands within the formation. These ‘hot shales’ are easily recognised on downhole logs.

Generally, the highest TOC values occur (particularly in Rodinga 1A), in bituminous dolostone, dark grey shale or dark brown shale (this latter the lithology of the 3% TOC measurement). This dark brown shale also had a very high potential
(S$_1$+S$_2$) of 686, indicating a tendency toward liquids. Extractable organic matter averaged 140 ppm, supporting the possibility that the unit could generate hydrocarbons.

Bituminous carbonate and siliciclastic rocks also occur in Dingo 1 (TOC 0.17%), and in outcrop. Similar bituminous rocks consistently produce a foetid odour when struck with a hammer.

McKirdy (1977) showed that hydrocarbons isolated from core 26 in the Chandler Formation of Alice 1 were probably allochthonous (migrated) because of the relatively high saturate/aromatic ratio of the EOM. The EOM yield was also very high in this core, which had a TOC value of less than 0.01%. The few measurements available from Alice 1 are from core (spatially restricted) and may not reflect the maximum TOC present.

At Highway Anticline 1, the average TOC is 0.21%. The high Oxygen Index and low Hydrogen Index indicate that any future hydrocarbons expelled would be gas.

However, at Hermannsburg 41, the higher Hydrogen Index relative to Oxygen Index would indicate that with additional maturation, it would produce some oil and (wet) gas.

The Chandler Formation must be considered to contain source rock intervals that are capable of generating hydrocarbons. The fine shale intervals can yield high values of TOC and extracted organic matter and high hydrogen indices. These together indicate the potential to generate amounts of hydrocarbons (eg S$_2$ of 1.02 in Hermannsburg 41).

At Hermannsburg 41, $T_{max}$ is in the range 286–472°C, at Orange 1 it is about 426°C, and at Finke 1 it is 475°C. Highway Anticline 1 has yielded a VR equivalent of 1.1. These results indicate a maturation trend that increases both northward and toward the centre of the basin (Figure 25). Considering the depth of burial of the Chandler Formation (in some places quite deep), it is surprising that the maturity of the unit is only in the low oil mature window.

The carbonate and anhydrite in this unit could have suppressed the maturation of intercalated shale units, sustaining the potential of the unit even where deeply buried beneath younger sediments.

Considering the regional extent of the unit, it is possible that northward it constitutes a potential source rock, and could also act as an important seal for hydrocarbon accumulations in the Arumbera Sandstone beneath.

<table>
<thead>
<tr>
<th>Chandler Formation</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.01</td>
<td>0.02</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.17</td>
<td>0.17</td>
</tr>
<tr>
<td>East Johnnys Creek 1</td>
<td>0.28</td>
<td>0.28</td>
</tr>
<tr>
<td>Finke 1</td>
<td>0.23</td>
<td>0.32</td>
</tr>
<tr>
<td>Hermannsburg 41</td>
<td>0.81</td>
<td>1.2</td>
</tr>
<tr>
<td>Highway Anticline 1</td>
<td>0.21</td>
<td>0.24</td>
</tr>
<tr>
<td>Ochre Hill 1</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.16</td>
<td>0.29</td>
</tr>
<tr>
<td>Rodinga 1A</td>
<td>0.82</td>
<td>3</td>
</tr>
<tr>
<td>Waterhouse 2</td>
<td>0.2</td>
<td>0.2</td>
</tr>
</tbody>
</table>

Table 7. Chandler Formation: mean TOC values.

Figure 25. Chandler Formation: maturity map.
**Todd River Dolostone**

Neither the Todd River Dolostone, which is intersected in and outcrops eastward of Wallaby 1, nor its siliciclastic correlatives, which extend westward and southward from Wallaby 1, contain sufficient ‘dark matter’ to sample. The dolostone is generally light coloured or pink, reflecting an oxidising depositional environment. The equivalent siliciclastic rocks are of redbed lithology, also not likely to preserve organic matter. This leads to the conclusion that there are no source rocks in the Todd River Dolostone.

**Arumbera Sandstone**

The Arumbera Sandstone is predominantly thought to be a redbed, intertidal to deltaic formation. It straddles the Ediacaran–Cambrian boundary. Measurements from this formation prove that it contains very low TOC (Figures 26, 27, Table 8).

It has good potential to be a reservoir rock, and has had numerous gas shows throughout the eastern part of the basin (notably in the Orange and Dingo fields).

![Arumbera Sandstone: TOC enrichment map.](image1.png)

![Arumbera Sandstone: maturity map.](image2.png)
Arumbera Sandstone TOC peaks in the central-eastern Amadeus Basin, near Orange 1 (TOC 0.4%). Given the lithology and its propensity for acting as a reservoir, it is unlikely that this unit will produce hydrocarbons in sufficient quantities to be commercially accumulated.

**Eninta Formation**

Organic geochemical data for the Eninta Formation, which also straddles the Ediacaran–Cambrian boundary, are only available from one well. A sample from East Johnnys Creek 1 revealed a TOC of 0.12% from the interval 1479–1500 m. This is insufficient information to draw any conclusions regarding the source rock quality of this unit.

**Cryogenian–Ediacaran source rocks**

**Julie Formation**

The Julie Formation consists of dolostone, limestone, partially ooid limestone and siltstone with sandstone lenses. It outcrops as low ridges, which are light coloured on aerial photographs. At Ellery Creek, it consists of calcareous siltstone and coarsely crystalline limestone.

Generally, average TOC values for the Julie Formation are poor, but they peak toward the east at Ooraminna 1 (**Figure 28, Table 9**). It is possible that zones of better source rock potential are present further east of Ooraminna 1, but the available data

<table>
<thead>
<tr>
<th>Arumbera Sandstone</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Alice 1</td>
<td>0.11</td>
<td>0.13</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.03</td>
<td>0.04</td>
</tr>
<tr>
<td>Ooraminna 1</td>
<td>0.26</td>
<td>0.26</td>
</tr>
<tr>
<td>Orange 1</td>
<td>0.21</td>
<td>0.4</td>
</tr>
<tr>
<td>Wallaby 1</td>
<td>0.02</td>
<td>0.03</td>
</tr>
<tr>
<td>Waterhouse 2</td>
<td>0.2</td>
<td>0.2</td>
</tr>
</tbody>
</table>

**Table 8. Arumbera Sandstone: TOC average values.**

**Table 9. Julie Formation: mean TOC.**
to the west of this location do not suggest that there is a much potential overall. Gorter (1982) considered that the shoaling depositional environment would not support the development of any richer source within the Julie Formation elsewhere in the basin.

The application of a lower TOC requirement for effective generation from carbonate rocks indicates that some limited potential could be present in the vicinity of Ooraminna 1.

**Pertatataka Formation and Winnall beds**

The Pertatataka Formation is a thick (up to 600 m) black shale package which extends throughout the eastern Amadeus Basin from Ooraminna 1 to as far south as Erldunda 1. In the south and to the southwest of Gardiner Range, shale of the Pertatataka Formation passes laterally into shale, siltstone and sandstone of the Winnall beds. The Julie Formation was included by Preiss et al (1978) as a member of the Pertatataka Formation, but is now regarded as a distinct unit.

The top of this composite package is recognised throughout the Amadeus Basin by a pronounced unconformity caused by erosion and uplift accompanying the Late Neoproterozoic–Early Cambrian Petermann Orogeny. The effects of this orogeny are less obvious in the northeast, but in the central basin area onlap of younger sediments onto a regional anticlinorium is apparent.

There is a slight decrease in source rock potential from the middle of the formation toward its top in Ooraminna 1 (Figure 29, Table 10). This declining potential may be attributable to the progression from marine to less marine influence higher in the section. The Julie Formation is a carbonate shoaling unit, probably developed in oxidising conditions not conducive to source rock deposition, and represents the final marine phase of the regression (Gorter 1982).

Probable migrated hydrocarbons are present in core 9 at Ooraminna 1, where the Rock Eval $S_1$ peak is significantly higher than the $S_2$ peak. The EOM is also anomalously high. Quality Index ($S_2/S_3$) values in the Pertatataka Formation are always less than 4.

The Pertatataka Formation does show some hydrocarbon generation potential, which increases to the northeast of Ooraminna 1. In the lower half of the formation, TOC routinely reaches 0.9%, often having a high Hydrogen Index (eg 291 at 624.8 m in Ooraminna 1), indicating that it will yield oil as well as gas.

![Figure 29. Pertatataka Formation: TOC enrichment map.](image-url)

<table>
<thead>
<tr>
<th>Pertatataka Formation</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Unknown location</td>
<td>0.11</td>
<td>0.16</td>
</tr>
<tr>
<td>Dingo 1</td>
<td>0.15</td>
<td>0.21</td>
</tr>
<tr>
<td>Mount Charlotte 1</td>
<td>0.21</td>
<td>0.38</td>
</tr>
<tr>
<td>Ooraminna 1</td>
<td>0.3</td>
<td>1</td>
</tr>
<tr>
<td>Rodinga 4</td>
<td>0.18</td>
<td>0.31</td>
</tr>
<tr>
<td>Rodinga 4A</td>
<td>0.19</td>
<td>0.22</td>
</tr>
<tr>
<td>Waterhouse 2</td>
<td>0.14</td>
<td>0.19</td>
</tr>
</tbody>
</table>

*Table 10. Pertatataka Formation: mean TOC.*
At Ooraminna 1, the Pertatataka Formation is mature for oil generation, but tends to be slightly less mature higher in the section, most likely reflecting carbonate content and relative depth of burial (Figure 30). The maturity of the Pertatataka Formation mirrors the TOC enrichment in many respects, as it attains its maximum values in the Ooraminna 1 well (northeastern Amadeus Basin), yet is low at Rodinga 4 (T<sub>max</sub> 343°C) in the central part of the basin and at Mount Charlotte 1 (T<sub>max</sub> 331°C) in the south.

**Winnall beds**

The Winnall beds are included here as they are the lateral to the Pertatataka Formation. The Winnall beds were completely penetrated at Erldunda 1 and show some source potential (Figures 31, 32, Table 11).

As with the Pertatataka Formation, this unit shows a diminishing source rock potential trend from the formation base to its top. In the Erldunda 1 well it has a TOC of 0.61% at 1120 m, which falls to 0.08% at 412 m. It does show strong potential to
produce hydrocarbons. The higher Oxygen Index relative to Hydrogen Index is interpreted to mean that it more likely at present to generate gas than liquids.

The Winnall beds are mature at Erldunda 1, with a T_max of 464°C at 1120 m. Although the TOC is too low higher in the section to permit Rock Eval analysis, it is assumed that maturity will decrease in concert with TOC (again, mirroring the Pertatataka Formation).

From the spatially sparse available data coverage, it is difficult to draw firm conclusions regarding these units. It is suggested that, in terms of TOC, source rock quality in the Pertatataka Formation (particularly at its base) increases northward of the Erldunda 1 area.

Even less data are available on kerogen type. McKirdy’s (1977) analyses of type 3–4 kerogen in core 6 at Erldunda 1 (Winnall beds), type 3 in core 12 at Mount Charlotte 1 and type 3 at Ooraminna 1 suggests that quality improves to the north and northeast of Erldunda 1. It is important to note that original source characteristics are diminished.

There are marginally better source beds present in the deeper-water Pertatataka Formation than in the more paralic Winnall beds. The fact remains that this package shows strong source rock potential in the southern Amadeus Basin.

Inindia beds

The Inindia beds are a thick unit of sandstone and lesser siltstone, chert and jasper. Ranford et al (1966) defined the unit and estimated its thickness to be 2130 m. It disconformably overlies the Bitter Springs Formation and is in turn overlain, probably unconformably, by the Winnall beds. Outcrop and drillhole data indicate a basinal thickening of the Inindia beds to the southwest, where it eventually terminates abruptly against fault-controlled uplifted basement (Musgrave Block) in the south.

The Inindia beds have been divided into three informal units: a lower unit of possible tillite that is correlated with the Areyonga Formation, a middle unit correlated with the Aralka Formation and an upper unit correlated with the Pioneer Sandstone.

For the purposes of this document the Inindia beds are only considered to have been penetrated (well data) in the southern Amadeus Basin. The Areyonga and Aralka Formations are detailed separately.

In Erldunda 1, the average TOC of the Inindia beds is 1.44% with a high value of 3.4% (1251–1254 m), and with S_1+S_2 of 1.01 at the same depth (Figure 33). A higher Oxygen Index to Hydrogen Index ratio indicates a likelihood of gas generation in preference to liquids (in its present state). Samples from Murphy 1 indicate similar potential (mean TOC 2.29%), although these data have a distinct affinity for oil generation, with a Quality Index at 12.25 (999–1005 m). Within Murphy 1, the Hydrogen Index is, on average, higher than the Oxygen Index, confirming its ability to produce both oil and gas (at present).
Thickening of the unit to the southwest enhances the possibility that both of these rich intervals thicken and source characteristics improve toward the Musgrave Block. If the unit thickens as much as reported by Ranford et al. (1966), it has the potential to generate significant volumes of hydrocarbons. The Inindia beds have very good potential for oil and gas.

Modern Rock Eval results indicate that at Erldunda 1, the Inindia beds are mid-mature ($T_{\text{Max}}$, 450°C) for oil generation, whereas at Murphy 1, they are immature ($T_{\text{Max}}$, 360°C). Although this information is not geographically extensive, it could be interpreted to indicate an overall easterly increase in maturity (Figure 34).

**Aralka Formation**

The Aralka Formation is a succession of fresh black to dark grey, pyritic calcareous siltstone/shale overlain by black/green calcareous siltstone. Pyritic carbonate rocks of probable ‘algal’ (microbial) origin have been reported to occur sporadically in the Ringwood Member (Preiss et al. 1978).

![Figure 33](image-url). Inindia beds: TOC enrichment map.

![Figure 34](image-url). Inindia beds: maturity map.
This formation was the target of the BMR stratigraphic corehole Illogwa Creek 6. The average TOC of the formation in the Illogwa Creek 6 drillhole is 0.3%, with a maximum value of 0.46% (Figure 35).

West of Illogwa Creek, in the central Amadeus Basin (Wallara 1), the Aralka Formation shows heightened source potential, with an average TOC of 0.67% and a maximum value of 0.88%.

These results indicate that this formation contains strong source rock characteristics particularly in the central Amadeus Basin. It is geographically extensive and recognisable on electric logs.

The Aralka Formation appears to be immature at the location of Illogwa Creek 6, with a VR equivalent of 0.7% from shallow samples and a $T_{\text{max}}$ of 438°C at 73 m. Recently acquired maturity information from Wallara 1 shows the formation to be mature there, with a VR equivalent of 1.1% (derived from aromatic maturity methylphenanthrene index). This is significantly different to that reported by Burgess et al. (2002). To date the Rock Eval technique has failed to provide a reliable $T_{\text{max}}$ due to the presence of hydrocarbons in the sample.

The high EOM counts (up to 376 ppm) from the Aralka Formation in Illogwa Creek 6 are further evidence of its potential to generate hydrocarbons.

It is expected that this unit has (or could) generate gas with some oil

**Areyonga Formation**

The Areyonga Formation is a unit of coarse conglomerate (diamictite) with interbeds of sandstone, shale and siltstone. Its log character is distinctive on electric logs due to its conglomeratic nature.

Ooraminna 1 encountered a significant gas show in rocks assigned to the Areyonga Formation (Planalp and Pemberton 1963). The formation-top picks in this well and basinwide are currently under review by NTGS. The gas has been shown to be sourced from within the formation (McKirdy 1977). Migrated hydrocarbons appear to be present in shale from core 13 at 1195 m, given that the Rock Eval $S_2$ peak is significantly higher than the $S_1$ peak. Quality indices ($S_2/S_3$) are generally under 1, but some measurements approach 4. This indicates that the present kerogen is likely to be a source for dry gas, but has the potential to produce some associated liquids.

It is difficult to draw consistent conclusions from the sparse well intersections, but from the map (Figure 36, Table 12), it is evident that the potential of this unit is greatest toward the northeastern corner of the Amadeus Basin. It is lower in the central portion of the basin around the Angas Downs locality (Wallara 1).

The maturity of this formation (in terms of $T_{\text{max}}$) in Ooraminna 1 is in the upper mature oil window ($T_{\text{max}}$ 460°C), although some VR equivalent measurements indicate a much higher maturation state (1.7%) (Figure 37). Because of the very low TOC within East Johnnys Creek 1 and Wallara 1, no $T_{\text{max}}$ data are available to evaluate maturation of this unit westward (although of VR equiv 1–1.2% at Wallara 1).

Gorter (1982) suggested that the gas-prone nature of the Areyonga Formation is not an artifact of maturation but an original character of the kerogen composition. Elemental analyses of kerogen from the Areyonga Formation by McKirdy (1977) support the presently gas-prone nature (type 3) of the potential source rocks at Ooraminna 1. Recent analyses indicate that there is not a strict low Hydrogen Index-low Quality Index relationship. In some samples, there are high Hydrogen Index values together with Quality Index values an order of magnitude higher. This would suggest that the kerogen is most likely to have been type 2 and retains some liquid-generation potential.
The Bitter Springs Formation has been divided into intervals to facilitate description. The intervals represent periods of high deposition rate and their boundaries approximate to periods of little or no deposition. The interval boundaries are chosen to reflect timelines, lithological boundaries or basinwide diachronous breaks in sedimentation; often marked by erosion of older rocks or by orogenic activity.

Table 12. Areyonga Formation: mean TOC measured in well intersections.

<table>
<thead>
<tr>
<th>Areyonga Formation</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Ooraminna 1</td>
<td>0.51</td>
<td>1.06</td>
</tr>
<tr>
<td>East Johnnys Creek 1</td>
<td>0.08</td>
<td>0.12</td>
</tr>
<tr>
<td>Wallara 1</td>
<td>0.06</td>
<td>0.06</td>
</tr>
</tbody>
</table>

Figure 36. Areyonga Formation: TOC enrichment map

Figure 37. Areyonga Formation: maturity map.

**Bitter Springs Formation**

The Bitter Springs Formation has been divided into intervals to facilitate description. The intervals represent periods of high deposition rate and their boundaries approximate to periods of little or no deposition. The interval boundaries are chosen to reflect timelines, lithological boundaries or basinwide diachronous breaks in sedimentation; often marked by erosion of older rocks or by orogenic activity.
**Johnnys Creek beds**

This unit was first recognised and defined by Gorter (1982). The Johnnys Creek beds have been recognised in Mount Winter 1, East Johnnys Creek 1 and, tentatively, in Ochre Hill 1, based on lithological similarity and wireline log characteristics (Gorter 1983). The beds may also be represented in the top 130 m of the reference section at Ellery Creek (Wells et al 1967), and in other wells in the Amadeus Basin that penetrated the Bitter Springs Formation (Erldunda 1, Mount Charlotte 1).

The Johnnys Creek beds appear to be a consistently petroliferous unit, with oil shows (staining, bitumen) in Mount Winter 1, asphaltic sandstone and fluorescence in East Johnnys Creek 1, fluorescence in Ochre Hill 1 and cuttings gas in Erldunda 1. The correlative section at Ooraminna 1 underlies the gas-bearing Areyonga Formation.

Geochemical analyses of the unit are scant, despite the several shows within or closely associated with it. Total organic carbon in samples is not particularly high (Figure 38, Table 13).

No elemental analyses of the kerogen type have been carried out to date, of which the author is aware. The Quality Index ($S_i/S_j$) from a sidewall core at 1705 m in Mount Winter 1 is less than 1, indicating the gas-prone nature of the present kerogen state; however, at 329 m in Finke 1, a Quality Index of 3.5 has been recorded. This again points to the potential to generate some liquids with gas, leaving the possibility of an original type 2 kerogen. Gorter (1982) reported that a higher Oxygen Index compared to the Hydrogen Index from the same sidewall core in Mount Winter 1 suggests that the kerogens are type 3. However, results in the NTGS database contend that the Hydrogen Index is higher than the Oxygen Index, indicating a likelihood of type 2 oil/gas-prone kerogen.

The high maturation state indicated by some $T_{Max}$ values is a little unreliable because of the extremely low $S_i$ peak obtained during pyrolysis (Gorter 1982). However, the presence of oil in the Johnnys Creek beds at Mount Winter 1 suggests that the level of maturity attained is unlikely to be much more advanced than the late oil to early catagenetic stage. The ranking could be supported by the lack of fluorescent organic matter in the sidewall core, but this may be due as much to the absence of any biological remains as to an advanced maturation state. Palynological examinations of the sidewall core proved it to be barren of identifiable organic remains (Gorter 1982).

A sidewall core from 1747.5 m in the 'oil zone' at Mount Winter 1 was considered by Amdel (in Gorter 1982) to be oil stained. Amdel (in Gorter 1982) also reported that the ‘whole oil’ chromatogram is typical of a mature marine crude derived from algal/bacterial remains, and commented that the $C_{15+}$ alkane distribution is very similar to that obtained from shale in the Gillen Member of the Bitter Springs Formation at Mount Charlotte 1. Gorter (1982) reported that the $S_i$ peak from the Rock Eval pyrolysis of the sidewall core at 1705 m is about 30% more than the $S_j$ peak and may indicate the presence of migrated hydrocarbons higher in the unit.

The source rock characteristics and chromatograph results reported by Amdel (in Gorter 1982) indicate that it is unlikely that the oil show at Mount Winter 1 was derived from within this unit, but had instead migrated from another (lower) level in the succession.

![Figure 38. Johnnys Creek beds: TOC enrichment map.](attachment:03-158.dgn)

**Table 13.** Johnnys Creek beds: average TOC concentration in well intersections.

<table>
<thead>
<tr>
<th></th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Finke 1</td>
<td>0.19</td>
<td>0.24</td>
</tr>
<tr>
<td>Ooraminna 1</td>
<td>0.34</td>
<td>1.1</td>
</tr>
</tbody>
</table>
It would be more helpful to await future studies on the elemental composition of kerogens in the Johnnys Creek beds and then to offer further comment on the source rock quality or quantity present.

**Loves Creek Member**

Earlier measurements of the source potential of the Loves Creek Member of the Bitter Springs Formation were reviewed by McKirdy (1977). McKirdy additionally analysed core material from the unit in Mount Charlotte 1, Erldunda 1, Highway Anticline 1 and Ooraminna 1.

Generally, TOC values for the Loves Creek Member are low in the central and western parts of the basin, but toward the east they are more consistent (Figure 39, Table 14). McKirdy’s (1977) analyses were completed from cores, which may not be representative of the best source intervals in the well.

The lean source rock samples in the central and western parts of the basin could be a result of the evaporitic and probably oxidising depositional environment, which would not be conducive to the preservation of organic matter.

The extremely high Oxygen Index to Hydrogen Index at Mount Charlotte 1 and Ooraminna 1 potentially indicates that the Loves Creek Member is gas prone at these locations. The best results are from Bluebush 1 in the eastern Amadeus Basin. In this well, the unit shows exceptional oil generative potential as its Hydrogen Index is over 700, with an accompanying Oxygen Index of over 300. Additionally, the Quality Index (S2/S3) is almost 3, indicating the likelihood of generating oil and gas. This infers that, barring contamination, the Loves Creek Member has excellent hydrocarbon potential in the eastern part of the basin. CJ Boreham (Geoscience Australia, pers comm, 2004) noted that some TOC measurements on laminations within the unit in Wallara 1 have measured TOC up to 12%.

The highest maturity occurs at Ooraminna 1, where a VR equivalent of 1.7% was measured (Figure 40). This value decreases southwestward, to 0.86% at Highway Anticline 1, reaching a minimum at Bluebush 1 (Tmax, 410°C). Elevated Tmax results of 450°C are found at Mount Charlotte 1, which could be a result of the deeper burial that the Loves Creek Member has undergone at this location in comparison to the nearby Bluebush 1 well.

![Bitter Springs Formation Loves Creek Member TOC enrichment map](image)

Figure 39. Loves Creek Member: TOC enrichment map.

<table>
<thead>
<tr>
<th>Loves Creek Member</th>
<th>Average</th>
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</tr>
</thead>
<tbody>
<tr>
<td>Bluebush 1</td>
<td>0.52</td>
<td>0.52</td>
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<tr>
<td>Erldunda 1</td>
<td>0.33</td>
<td>0.42</td>
</tr>
<tr>
<td>Mount Charlotte 1</td>
<td>0.32</td>
<td>1.14</td>
</tr>
<tr>
<td>Murphy 1</td>
<td>0.13</td>
<td>0.13</td>
</tr>
<tr>
<td>Ochre Hills 1</td>
<td>0.04</td>
<td>0.04</td>
</tr>
<tr>
<td>Ooraminna 1</td>
<td>0.27</td>
<td>1</td>
</tr>
<tr>
<td>Wallara 1</td>
<td>0.27</td>
<td>1.01</td>
</tr>
</tbody>
</table>

Table 14. Loves Creek Member: average TOC content of well intersections.
**Gillen Member**

This unit has been heavily sampled and analysed since the discovery of sub-commercial gas at Magee 1. The gas is thought to be sourced from the lower Gillen Member, which conformably overlies the Heavitree Quartzite.

In the past, the Gillen Member has been separated into upper, middle (sometimes referred to as ‘Gillen salt’) and lower units, but for the purposes of this discussion, it will be treated as a whole.

Measured TOC in the wells generally averages less than 0.5%, but there is some increase in TOC enrichment towards the south of the basin (Erdunda 1, Murphy 1, Magee 1; **Figure 41**).

Kerogen types reported by McKirdy (1977) are consistently gas prone, except for a sample at 2057.1 m in Mount Charlotte 1. The type 4 kerogens reported from BMR Alice Springs 3 are likely to be a result of the high maturation level (R_o 1.95%, low H/C ratio) (Gorter 1982b). As type 4 kerogen is largely amorphous material, the high maturation may have converted the more sapropelic kerogens to petroleum hydrocarbons, which subsequently migrated to leave the inert kerogen fraction behind.

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**Figure 40.** Loves Creek Member: maturity map.

**Figure 41.** Gillen Member: TOC enrichment map.
Gorter (1982a) reported that a Quality Index from core at 2191 m in Mount Winter 1 is less than 1, indicating that this sample is likely to be a source for gas in its present form. He also reported a high T\text{\textsubscript{Max}}, of 499°C, indicating that the formation at Mount Winter 1 was post-oil mature.

McKirdy (1977), also recorded some type 2 kerogen, notably in Mount Charlotte 1 (2057.1 m). He reported anomalously high EOM:TOC values from cores in the Gillen Member, suggesting that migration of hydrocarbons had taken place. Younger source rocks cannot be invoked (eg by overthrusting), therefore the conclusion must be that the hydrocarbon source is intraformational.

The data indicate some distinct trends in the Gillen Member. In the northeastern Amadeus Basin at Ooraminna 1, the interval is well sampled but has yielded only one good value (TOC 0.95%); TOC content is generally low. However, TOC increases markedly to the south of Ooraminna 1, to 0.37% at Erldunda 1, 0.35% at Mount Charlotte 1, 0.4% at Magee 1 and 0.99% at Murphy 1 (all compute average values; see Table 15).

Maturity trends mirror the TOC enrichment trends in the southern Amadeus Basin from Ooraminna 1 (VR 1.2%, T\text{\textsubscript{Max}} 277°C) to Mount Charlotte 1 (VR 1.1%, T\text{\textsubscript{Max}} 430°C), Magee 1 (VR 1.4%, T\text{\textsubscript{Max}} 445°C) and Murphy 1 (VR 1.5%). It is difficult to place much emphasis on the maturity of this unit toward the west as there is only one sample, from Mount Winter 1, in the NTGS database (Figure 42).

The data indicate that the Gillen Member is mid-mature for oil generation in the southern Amadeus Basin, but shows little generation potential in the north (likely due to excessive burial by Alice Springs Orogeny sediments). The NTGS database indicates that a T\text{\textsubscript{Max}} of 457°C was measured for a sample in Mount Winter 1, giving hope of potential remaining in the vicinity of that prospect and further west.

As previously stated, McKirdy (1977) did analyse for, and find type 2 and 3 kerogen in this unit. It is more than likely that the maturation state did downgrade the kerogen type over time, and as hydrocarbons were expelled.

The Hydrogen Index to Oxygen Index ratio at Mount Winter 1 is indicative of a source that will generate some oil and gas, whereas at Mount Charlotte 1 it is distinctly gas prone at present (HI 68, OI 461 at 1654.5 m). Magee 1 is more likely to generate gas with some associated oil in its present state, with a Hydrogen Index of 159 and Oxygen Index of 122 (2217 m).

Where available, the Quality Index (S\textsubscript{2}/S\textsubscript{3}), between 1 and 2, infers an affinity to generate gas with some liquids across the basin.

Moving stratigraphically down a well, there appears to be a trend of oil-prone to gas-prone strata, leading one to believe that there are discrete lithofacies present that will generate a specific hydrocarbon type.

<table>
<thead>
<tr>
<th>Gillen Member</th>
<th>Average</th>
<th>High</th>
</tr>
</thead>
<tbody>
<tr>
<td>Erldunda 1</td>
<td>0.37</td>
<td>0.6</td>
</tr>
<tr>
<td>Magee 1</td>
<td>0.4</td>
<td>0.81</td>
</tr>
<tr>
<td>Mount Charlotte 1</td>
<td>0.35</td>
<td>1.37</td>
</tr>
<tr>
<td>Mount Winter 1</td>
<td>0.45</td>
<td>0.45</td>
</tr>
<tr>
<td>Murphy 1</td>
<td>0.99</td>
<td>1.17</td>
</tr>
<tr>
<td>Ooraminna 1</td>
<td>0.2</td>
<td>0.95</td>
</tr>
</tbody>
</table>

Table 15. Gillen Member: TOC potential from well intersections.

![Figure 42. Gillen Member: maturity map.](image-url)
Because gas was found reservoired in the underlying Heavitree Quartzite in Magee 1, it is very likely that the Gillen Member is the source rock for a functioning Neoproterozoic petroleum system in the basin.

The high maturation state and results from Mount Winter 1 (McKirdy 1977) show that the Gillen Member has, and retains the potential to generate intraformational hydrocarbons, and that these are likely to be found in the southern parts of the basin.

The abundant shows (poor to fair) of oil above and within the Bitter Springs Formation demonstrate that it has the potential to be an effective source rock in the Amadeus Basin.

Maturity

The following is a discussion on the determination of maturity of source rocks, particularly with respect to the Neoproterozoic succession of the Amadeus Basin.

Reflectance

One of the most commonly used parameters for measuring the thermal maturity of kerogen is vitrinite reflectance (R_o). The method is invalid in pre-Late Devonian rocks because vitrinite is absent in rocks older than this. However, several reflectance studies on vitrinite-like phytoclasts (eg coalified graptolites, algae, thucholites and other grains) have been attempted in the Amadeus Basin. Because of the difficulties in comparing reflectivities of kerogen of differing and unknown composition, these results are sometimes questionable.

Kurylowicz et al (1976) successfully equated reflectivities of coalified graptolites in the Horn Valley Siltstone at Mereenie and Palm Valley fields to thermal maturation of the enclosing source rocks. However, graptolites are not known in rocks older than Middle Cambrian.

Gorter (1982a) compiled a diagram that illustrated the problem of comparing R_o values from pre-Cambrian rocks in the same well that have been analysed by different methods. Gorter (1982) reported, in reference to analyses done over the same interval in Ooraminna 1 that ‘CSIRO derived values are very much lower than those cited by McKirdy. The scatter apparent in the R_o measured on cuttings may be due as much to caving as to the uncertainty of the R_o technique when applied to non-vitrinite phytoclasts’. He further stated that the comparison of R_o values with other measures of maturity often show that the R_o values are inaccurate. For example, core 9 at Ooraminna 1 contains oil character hydrocarbons (McKirdy 1977), but has a reported R_o of 1.4%. At this reflectivity, most of these ‘oil-like’ hydrocarbons should have undergone thermal breakdown to lighter carbon analogues. Similarly, core 5 at Erldunda 1, which appears to be immature on other parameters, has reflectivities ranging from 2.18% to 3.15% and should be extremely mature. Only dry gas should be expected at this core depth (1113.7 m), and yet wet gas (23.5% C_2+ ; Gorter 1982), was recovered from cuttings from the interval 1261–1274 m (McKirdy 1977).

Reflectance-equivalent values should be used with caution in pre-Cambrian strata and only in conjunction with other measurements.

Hydrogen/carbon (H/C) atomic ratio

McKirdy (1977) used H/C atomic ratios in kerogens to determine the stage of thermal maturity reached in a source rock interval. Tissot and Welsie (1978) stated that knowledge of this ratio alone is not a sufficient measure of thermal maturity because it is also dependent on the original kerogen composition.

The H/C ratio should decrease with depth in a particular well due to increasing thermal maturity. However, this was not apparent when Gorter (1982) plotted all the available H/C ratios against depth for the Amadeus Basin. Mount Charlotte 1 showed that there was no marked decrease in H/C ratio with depth, and in fact BMR Alice Springs 1 showed an increase with depth.

The H/C ratio is not a good maturity measure in the Amadeus Basin.

Methylphenanthrene Index (MPI)

In sediment extracts from rocks containing hydrogen-poor kerogen, the concentrations of 2- and 3-methylphenanthrenes are seen to increase as a result of increasing maturation. It is believed that this occurs as a result of rearrangement of 1- and 9-methylphenanthrenes, as the 2- and 3- forms are thermodynamically favoured at higher temperatures. Two indices, known as MPI 1 and MPI 2, have been proposed. The MPI is dependent on both lithofacies and kerogen type. In conventional theory the MPIs reach maximums at vitrinite reflectances of 1.3%, then decrease thereafter, so that there are two values of R_o for one of each MPI. An MPI of 0.45 (0.6 R_o ) to 1.5 (1.3 R_o ) defines the oil window. These values have also been recalculated as methylphenanthrene distribution factor (or MPDF), which is 2+3-methylphenanthrenes/1+2+3+9-methylphenanthrenes, which yields a linear correlation with vitrinite reflectance.

Recent advances have also derived the methylphenanthrene ratio (MPR) and dimethylnaphthalene ratio (DNR).

As these techniques are based on aromatic hydrocarbons, they are quite robust where hydrogen yields in samples are low. In the Amadeus Basin, unpublished NTGS comparative geochemical studies have shown a strong association between true vitrinite reflectance calculations and MPI-derived values.

In the case of the Neoproterozoic rocks, MPI is apt in providing an accurate estimate of maturity where Rock Eval fails. Recent application of MPI has shown that Wallara 1 (at Aralka Formation level), previously thought to have a VR equivalent value of 1.6 (Burgess et al 2002), actually has a value of 1–1.2.

Aromatic maturity techniques are the most useful measurement of maturity in the Amadeus Basin.
Spore reflectance

Fluorescence of organic matter under ultraviolet light can be valuable in maturity analyses of vitrinite-poor samples. This is the case particularly for kerogen of microbial origin, and should be well suited for the determination of maturation in Neoproterozoic rocks in which spores are rare or absent.

Fluorescent organic matter has only been observed in three wells (Gorter 1982) from the Neoproterozoic succession of the Amadeus Basin, although several dozen samples have been examined. Gorter (1982) reported rare, very small fluorescent bodies in samples from Ooraminna 1 which fluoresced deep yellow at 625 m in the Pertatataka Formation, through to deep reddish orange in the Areyonga Formation beneath. He suggested a maturity gradient equivalent to the lower portion of the oil window, with VR equivalent in the range 0.9–1.3%.

Felton and West (1982) reported moderate to bright orange fluorescence in a possible acritarch fragment from core 28 in BMR Rodina 4. These fluorescence colours probably correspond to mid-oil maturity.

Small fluorescing bodies have been reported (Gorter 1982) in Illogwa Creek 6, but were thought to be non-organic. If they were organic, it would indicate that maturity in this well is above R0 1.35% (ie overmature).

Transformation Ratio

The Transformation Ratio (TR) is a measure of the rank kerogen attains during thermal evolution. It can be determined by the S1/(S1+S2) of the Rock Eval pyrolysis, or from the ratio of EOM:TOC. As the Transformation Ratio is ‘fairly independent’ of the kerogen type during catagenesis (Tissot and Welte 1978), the progressive increase in the Transformation Ratio with depth for a particular well should show the maturation window.

Tissot and Welte (1978) stressed the need to plot the variations in Transformation Ratio versus depth in order to identify minute accumulations of migrated hydrocarbons by their anomalously high values compared to the average curve. Such small accumulations may also be suspected if the S1 peak is 10% or more, greater than the S2 peak.

The plot of Transformation Ratio versus depth for Ooraminna 1 (Figure 43) is a good discussion point, as this well has both EOM and pyrolysis data available. Anomalously high departures from the ‘average curve’ occur in the Pertatataka Formation, Areyonga Formation and Loves Creek Member of the Bitter Springs Formation. The first two are associated with oil-like hydrocarbons in core 9 and dry gas in the Areyonga Formation. No hydrocarbon shows were encountered in the Bitter Springs Formation, except for minor gas near the top of the Loves Creek Member, but the extremely high TR values below 1590 m strongly suggest the presence of migrated hydrocarbons. The high EOM (138 ppm) and low TOC (0.04%) in core 20 also suggest that migrated hydrocarbons are present.

In Mount Charlotte 1, the TR values are readily divisible into those derived from dolomitic samples and those from shale samples (Figure 44).

The dolostones show consistently lower maturation than the shale samples. Core 10 is also anomalous as it was reported by Gorter (1982) to come from a silty shale rather than a ‘pure’ shale sample.

Figure 43. Transformation Ratio versus depth for Ooraminna 1; pyrol = pyrolysis (adapted from Gorter 1982).

Figure 44. Transformation Ratio versus depth for Mount Charlotte 1 (adapted from Gorter 1982).
However, recent pyrolysis data on some shales from the Bitter Springs Formation, indicate that they are presently in the oil-mature window (1500–1700 m) at this locality. Obviously, the surrounding region is therefore prone to present accumulations.

Anomalous TR readings are seen in Erldunda 1 (Figure 45), core 5 (Areyonga Formation) and core 10 (Loves Creek Member). McKirdy (1977) suggested the presence of migrated hydrocarbons in core 5. Most other values indicate immaturity.

Again, recent data would indicate that the Inindia and Winnall beds are within the oil window at this locality. The succession is actually quite ‘dark’ in colour, with significant thicknesses of shale (200 m).

Interestingly, when the one sample from the Pertatataka Formation in Rodinga 4 is included on the same graphs, the suggestion is that the section is presently in the post-oil generative stage. This is a very different perspective from the VR equivalent of 0.9 on a vitrinite-like maceral from core 36. Moderate to bright orange fluorescence from a possible acritarch in the same core indicates that both the TR and R, are anomalously high.

Illogwa Creek 6 poses an interesting interpretational dilemma. All the samples are from black pyritic and calcareous siltstone of the Areyonga Formation. The TR scatter (Figure 46) would indicate, on face value, that the unit varies from extremely overmature to undermature. This could possibly be an effect of variation in the calcareous component, where more calcitic sediments have a lower TR and less calcitic, higher.

The TR values for Tempe Vale 1 are derived from Rock Eval results (Figure 47, Table 16). The TR does show an increase with depth in this well. At 362 m (Horn Valley Siltstone) the ratio is 0.13, but at 417 m in the same unit it is 0.42. This indicates that the unit is mature for oil generation. A more likely interpretation is that at its maximum burial, it was in the oil generation window, and that subsequent uplift has brought it to its present state.

Gorter (1982) compiled a table listing the depths at which the oil window is present in some of the wells. It was a comparison of the results from several different methods. It graphically illustrates the computational maturity effects, as the present oil window in some wells is above ground level.

**Elemental analysis of kerogen**

Tissot and Welte (1978) stated that the elemental analysis of kerogen, in terms of the H/C and O/C ratios plotted on a modified Van Krevelen diagram, should give a fairly good indication of maturity. The hydrogen to carbon ratio should decrease, due to the catagenetic loss of the hydrogen fraction as maturity increases. This relationship could also be expressed as the Hydrogen Index/Oxygen Index ratio.

Gorter plotted all Hydrogen Index and Oxygen Index data available to him on a modified Van Krevelen diagram (for Neoproterozoic sedimentary rocks in Ooraminna 1; Figure 48). He found that all values plot on or just below the type 3 kerogen line, and all except for just two readings plot as immature. Values from core in the Pertatataka Formation of Ooraminna 1 plot as overmature, which is difficult to equate with reported oil hydrocarbons in the core (McKirdy 1977).

As Tissot and Welte (1978) stated, the Hydrogen Index to Oxygen Index ratio decrease is directly related to the kerogen type, but it is also related to the TOC in a given sample. High TOC can reflect both an increase in the amount of TOC as well as the quality (kerogen type, etc) and so the ratio should be normalised by dividing it by TOC. This gives a much smoother representation of the degradation of hydrogen with increasing maturity.

Temple Vale 1 shows this well, as there are continuous pyrolysis samples, so that $T_{\text{Max}}$ and TR can be used to compare the new ratio ($\text{HI/OI}$) / TOC (Figure 49).

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*Figure 45. Transformation Ratio versus depth diagram for Erldunda 1 (adapted from Gorter 1982).*

*Figure 46. Transformation Ratio versus depth diagram for Rodinga 4, Illogwa Creek 5 and Illogwa Creek 6 (adapted from Gorter 1982).*
Table 16. Rock Eval data for Tempe Vale 1. HI = Hydrogen Index, OI = Oxygen Index, TOC = total organic carbon.

<table>
<thead>
<tr>
<th>Depth (m)</th>
<th>Tmax</th>
<th>HI</th>
<th>OI</th>
<th>HI/OI</th>
<th>(HI/OI)/TOC</th>
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</thead>
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<tr>
<td>362.6</td>
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<td>260</td>
<td>133</td>
<td>1.95</td>
<td>2.06</td>
</tr>
</tbody>
</table>

**Figure 47.** Transformation Ratio versus depth diagram for Tempe Vale 1; pyrol = pyrolysis (adapted from Gorter 1982).

**Figure 48.** Van Krevelen diagram for Ooraminna 1 (adapted from Gorter 1982).

**Pristane/n-C<sub>17</sub>** versus **phytane/n-C<sub>18</sub>**

Gorter (1982) plotted the pristane/phytane ratios for Mount Charlotte 1 and Ooraminna 1 (Figure 50). The plot shows that maturity increases with depth (expressed in increasing core number), for the Pertatataka Formation and probably the Areyonga Formation, but is random for the Bitter Springs samples from both wells. The abrupt change may be due to a difference in the original kerogen type, or a variation in maturity between the shales of the Pertatataka and Areyonga Formations and the carbonate/evaporite portion of the Bitter Springs Formation. Core 6, from limestone of the Julie Formation, also plots off-scale on the diagram.

Gorter (1982) produced another figure including only shale-bearing samples (Figure 51). A consistent maturity trend is evident for all cores except core 21 in Mount Charlotte 1. This core contains dolostone bands and anhydrite, suppressing values.
These plots confirm that the Pertatataka Formation at Ooraminna 1 is less mature than in Mount Charlotte 1. Two shale samples from Erldunda 1 were also included and indicate that they too are more mature than at Ooraminna 1, but slightly less mature than at Mount Charlotte 1.

Gorter (1982) regarded interpretation of the ratios as geologically valid because the Pertatataka Formation, with oil source potential, occupied the measured intervals in Ooraminna 1. He suggested that the less mature values below that unit may not indicate that significant generation has occurred, but merely record a return to the more gas-prone kerogens, which are still relatively immature.

However, this is more probably a suppressed artifact of low TOC and kerogen in the strata. It is unlikely to be an effect of immaturity.

Gorter (1982) reported that the pristane/phytane plot of samples from BMR Alice Springs 3 indicated a trend toward less maturity with increasing depth in the evaporitic samples, the deepest sample (252.1 m) being the least mature. There is evidence of migrated hydrocarbons in this well, especially in core 54 at 252.1 m, where a high EOM (143 ppm) is associated with a very low TOC (0.04%) and a very high TR ratio (suggesting migrated hydrocarbons).

**Figure 49.** Tempe Vale degradation in HI/OI ratio.

**Figure 50.** Pristane/phytane ratio for all samples from Mount Charlotte 1 and Ooraminna 1 (Gorter 1982).

**Figure 51.** Pristane/phytane ratio for Mount Charlotte 1, Ooraminna 1 and Erldunda 1 shale-bearing samples (adapted from Gorter 1982).
T_max

This is by far the most common and readily available parameter for estimating maximum maturity of a sample.

In the Rock Eval pyrolysis method, the T_max parameter is recorded at the maximum point of hydrocarbon generation during pyrolysis. While T_max is influenced by the type of organic matter in the early stage of hydrocarbon maturation, there is little influence of kerogen type in the peak oil generation or gas zones. T_max in the early state is lowest for humic (type 3) kerogens. A T_max range of 440–475°C appears to be compatible with the oil-mature zone for all kerogen types, although chemical variants enable higher and lower values.

To obtain a T_max, a minimum TOC of 0.5% is generally required by laboratories, or Rock Eval will not be performed. Because generally few samples reach this minimum requirement, there are not abundant values available from Neoproterozoic rocks in the Amadeus Basin.

The plot of T_max for all formations (Figure 52) shows that across nearly all units, the maturity is in the oil-mature to late oil-mature window. This indicates that the source rocks, where found, are likely to be generative, or have generated hydrocarbons. Obviously, areas of lower maturity have the potential to thicken in source kitchens, and generate at a different locality.

Maturity data for the Pertatataka and Areyonga Formations in Ooraminna 1 (Appendix 1) shows that the interval that flowed gas (consisting of 84.2% methane and only 3.6% ethane to butane, plus 11.6% nitrogen) was in the late stage oil-mature window. This gas composition is particularly dry for a source unit that is not significantly past the oil generation window. The high nitrogen content has not been explained, other than considering that this is a feature of the type of kerogen originally present.

Likewise, dry gas composition is not necessarily a feature of overmaturity, but is possibly associated with the original kerogen composition.

T_max values indicate that the Pertatataka Formation is presently in the oil-mature zone. The highest recorded TOC values occur at this depth, hence the Rock Eval results, so that hydrocarbons should therefore probably be present.

McKirdy (1977) found that core 9 (823 m) contained 73% of saturates in the EOM (412 ppm) and stated that the total alkane pattern in the gas chromatogram obtained from a sample of this core ‘is distinctly crude oil like in appearance’. A plot of Hydrogen Index to Oxygen Index values indicates that the Pertatataka Formation kerogens are type 3 (therefore theoretically more gas prone than would be expected of marine rocks). The most oil-prone value (in terms of HI/OI) comes from core 9, which also plots as the most mature.

Discussion

McKirdy’s (1977) thesis concluded that ‘Kerogen H/C atomic ratio and reflectivity of vitrinite like phytoclasts and or zoo-clasts were found to be the most useful indicators of diagenetic rank’.

This statement is probably an oversimplification, as the maturation history of rocks that are so old is complicated by kerogen type.

Application of several other techniques in addition to these two is likely to provide a more reliable assessment of the stage of hydrocarbon generation. These additional techniques include spore fluorescence of organic matter (including vitrinite), Rock Eval-derived Oxygen Index and Hydrogen Index values, T_max, and Transformation Ratio. Gorter (1982) was of the opinion that pristane/phytane cross-plots only provide qualitative assessments of maturity in a particular well.

One of the most important deductions from these graphical representations is that the thickness of the Pertnjara Group, to the north of the Central Ridge, is likely to be the single biggest factor in consideration of maturity. This is not such a problem
in the southern part of the basin where the thickness of these units is substantially less. The northern limits of the oil-mature Neoproterozoic rocks will be severely hampered by this, resulting in probable overmaturity. However, the Ordovician (Horn Valley Siltstone) will most likely be found in the oil window today.

The southern reaches of the basin still have the possibility of producing and/or trapping Neoproterozoic oil. Maturity results indicate that formations such as the Inindia beds are significantly less mature at Erldunda 1 and Mount Charlotte 1 than they would be, if located in the northern Amadeus Basin.

Drilling in the Amadeus Basin is quite sparse and generally limited to its northern area. The last big thermal pulse probably occurred during the Alice Springs Orogeny, which in turn precipitated the deposition of the Pertnjara Group. The area to the south was largely protected from this event, and this is reflected in Magee 1, Murphy 1, Mount Charlotte 1 and Erldunda 1.

Magee 1 penetrated through to basement, and recoverable (subeconomic) gas was found in the Heavitree Quartzite, exemplifying that the maturity at this location was still not high enough to crack all hydrocarbons to bitumen.

Because of this shielding, it is likely that a lower-maturity corridor extends to the western side of the basin, preserving the potential to produce from Cambrian (?) and pre-Cambrian strata (Figure 53). Unfortunately, at this time, there is no well information to confirm any potential south of Mount Winter 1.

Using the Inindia beds as an example, it is possible to theorise that the maturity gradient continues to the west, but also that it could be in the oil-mature window today. Other parts of the stratigraphic succession may prove to have a better maturity profile toward the west. Drilling in that area of the basin, integrated with maturity studies such as those discussed above, will most likely delineate a positive profile.

**Notes on organic source units**

The categorisation of kerogen quality in source rocks of Neoproterozoic age, or even of younger source rocks, is generally difficult in any case. The true potential of a unit can be masked by a variety of diagenetic processes or weathering, either during deposition, immediately afterwards, or subsequently, via uplift and erosion, or even *in situ* biodegradation. These effects are likely to be even more strongly represented in such ancient rocks.

The first and most obvious point of contention is the assumption that Proterozoic kerogens behave similarly to much younger organic matter, particularly the well understood Permian to Recent kerogen. Proterozoic kerogens are clearly different from their younger counterparts in that the more advanced forms of animals and land plants did not exist during pre-Cambrian time. Consequently, many of the conclusions drawn about the prospectiveness of Proterozoic source beds may be invalid.

Theoretically, Proterozoic source beds should contain organic matter of dominantly algal, bacterial or archaeal origin, although more advanced organisms did exist during late Neoproterozoic (Ediacaran) time. Higher plant life did not exist until at least Siluro–Devonian time and therefore ‘humic’-type kerogen should not exist.

Algal/microbial kerogens are thought to be the precursor to type 1 kerogens, which are the most prolific in terms of hydrocarbon (particularly oil) generation. Yet none of the kerogens examined by authors over the years has actually plotted as a type 1 on a Van Krevelen diagram.

Gorter (1982) suggested that this could be because Proterozoic kerogens do not react to increasing thermal gradient as do younger Phanerozoic kerogens. Theoretically, though, they should behave in a similar fashion, as it would be the increased

![Figure 53. Schematic maturity map extrapolated to western Amadeus Basin, relative to Murphy 1 and Magee 1.](image-url)
hydrogen content of the kerogen over the carbon content that determines whether oil or gas will be the primary hydrocarbon produced during advancing maturation. As can be seen from McKirdy’s (1977) H/C values and the Rock Eval-derived hydrogen and oxygen indices, nearly all Proterozoic kerogens have low- to mid-range hydrogen contents (100–350). Generally, it can be seen that it is rocks of the Gillen Member, Inindia beds, Areyonga Formation and Aralka Formation which approach a traditional type 2 kerogen.

There are several possible solutions to this conundrum. It could be that the discrepancy lies in processes operating during original burial and subsequent diagenesis. Most of the Bitter Springs Formation was deposited under evaporitic conditions which may have led to the oxidation of much of the organic matter. However, evaporitic conditions cannot be invoked for the deposits of glacial origin (Areyonga Formation, Aralka Formation, Inindia beds). The Pertatataka Formation has been discussed as having been deposited in an offshore environment, in which reducing conditions, indicated by the presence of pyrite, were present.

A second possibility could be that the original kerogens were indeed type 1 or 2, and that high maturation has driven off the hydrogen component leaving the residual kerogens rich in carbon and other inert kerogens. Gorter (1982) showed that many of the kerogens were in what he considered to be the late stage of oil generation, and was doubtful that it was sufficiently high to deplete the hydrogen component to such an extent.

There is no debate that what is measured by TOC, Rock Eval pyrolysis and other techniques is characteristic of an interval in its present state. As such, two basic processes affect the ability of a source rock to produce oil or gas. The first of these is increasing temperature (such as orogenies or intrusions). The second is time. In the case of rocks that are older than 545 Ma, slow hydrogen-depleting processes, such as those due to temperature, will leach away potential to almost nothing. The kerogen type is most likely to have been type 2, and the organisms extant within this time period would have been so simple as to experience maturity at a lower temperature gradient.

A third possibility is bacterial biodegradation of the original kerogen soon after deposition. It has been suggested by (Lambert and Knutson in Gorter 1982), that bacterial sulfate reduction in the 750 Ma Tapley Hill Formation of the Adelaide Rift is positively correlated with organic carbon content. It could be that much of the pyrite in the Pertatataka Formation was produced by bacterial reduction and that these bacteria may also have degraded original organic matter.

The best source potential in the Neoproterozoic section is probably in the Gillen Member of the Bitter Springs Formation, Inindia beds and the Aralka, Areyonga and Pertatataka Formations (Figure 54). The type and quality of Cambrian source rocks are low in the eastern Amadeus Basin, and there is insufficient information to comment on the potential in the western portion (Figure 55). As previously noted, the Cambrian of the nearby Georgina Basin is home to a prodigious source rock, and a correlative could be present in the Amadeus Basin. The best source rock in the Amadeus Basin is the Horn Valley Siltstone, and this has been discussed by many authors (Figure 56).

CONCLUSIONS

Irrespective of the reasons for the degradation of source potential in some Amadeus Basin strata, oil is present in the Neoproterozoic succession at Mount Winter 1 and possibly at Ooraminna 1, and minor bituminous shows are abundant in intersections of the Johnnys Creek beds. The very presence of these liquid hydrocarbon indicators strongly suggests that oil-prone kerogens are present somewhere in the Neoproterozoic succession.

![Areas of Potential Neoproterozoic Hydrocarbon Source Units](m03-206.dgn)

Figure 54. Areas of potential for Neoproterozoic sediment-sourced hydrocarbons.
The most likely candidates for oil-prone source rocks are the Horn Valley Siltstone in the north, Pertatataka Formation in the east, Inindia beds/Areyonga Formation in the south and Gillen Member throughout the basin. Gas-prone source rocks are likely to be present in the same formations, depending on maturity, and also in the Winnall beds.

In considering the low TOC of many of the samples, it is pertinent to examine, where available, the rock interval sampled. In many Amadeus Basin cases, the sample analysed was a 50' (15 m) composite cuttings sample. This would severely dilute the results of any thick source rock that may or may not be present at a location. A 10' (3 m) thick shale that would otherwise reveal 5% TOC will not be distinguished. (Alternatively, where TOC results are high (eg 1%) in such a sampled section, this would represent a particularly rich interval of heightened potential). The lack of recently drilled wells compounds the sampling problem: Rock Eval readings are complicated where old samples, drilled with mud, were oven dried (according to the oven temperature, etc). A good potential example of this is the Tempe Formation, from where a TOC of 5.45% was recorded in core at Undandita 1A, but elsewhere in the basin, reported TOC was closer to 0.1% in composite cuttings samples from older wells (eg 7850–7900' [239–241 m] in East Mereenie 4).

Figure 55. Areas of potential for Cambrian sediment-sourced hydrocarbons.

Figure 56. Areas of potential for Ordovician sediment-sourced hydrocarbons.
The long periods of burial of the Amadeus Basin succession have contributed to the slow degradation of hydrogen from potential source rocks. High EOMs, in cores from wells in the northeast and south, indicate that these rocks have had, and in some cases retain the ability to produce both oil and gas. It could be that most rocks are largely gas prone today, but we should turn our attention to what happened to the oil that was expelled from formations in the past. Recent unpublished fluid inclusion studies by NTGS indicate the presence of palaeo-oil columns in the sections of ‘lean’ potential.

The presence of subeconomic gas in Magee 1, Dingo field, Ooraminna 1, West Walker 1 and Orange 1 and 2, which are sourced from different parts of the stratigraphic succession, indicates that there is still plenty of scope for commercial discoveries throughout the basin.

The nature of the kerogen in the Neoproterozoic succession of the Amadeus Basin is of great interest. Little recent research has been directed into the properties of the simple organisms of this era. Because of the dominantly microbial nature of these organisms, it follows that under our current interpretation of kerogen formation, they would form type 1 and type 2 kerogens originally. This indicates a distinct ability to produce both oil and gas.

The maturation of these potential rocks is also the subject of debate. The degradation in Hydrogen Index is probably a result of the duration of maturation at low temperature, as much as other possible organic destruction processes (like generation and expulsion). Measurements of the present oil window as defined by TR, pristane/phytane ratio, T₄₄₄, and other techniques all fail to take into account the fact that this is the maximum rank attained by the rock. They do not give a good indication of what has happened previously.

Incorporation of unpublished NTGS AFTA data into basin modelling indicates that the prospects in the basin experienced sufficient generation conditions to reservoir hydrocarbons elsewhere in the basin.

There is also some evidence that carbonate rocks and possibly evaporites may retard the maturation of organic matter long beyond the traditionally overmature oil limit. Such retardation of source maturation or retention of matured hydrocarbons in these rocks has profound implications for further oil provinces south and east of the thick Pertnjara Group deposits in the Amadeus Basin.

In conclusion, the southern, and southwestern Amadeus Basin hold the greatest potential for discovery of liquids sourced from below the Ordovician. Gas can be found through multiple sources throughout the basin, and oil produced from the Horn Valley Siltstone is likely to be restricted to north of the Central Ridge.

REFERENCES


APPENDIX 1 – NTGS GEOCHEMICAL DATABASE

Appendix 1 (MS Excel format) includes:
1. TOC and $T_{\text{Max}}$ plots by formation/well
2. Summary tables
3. Charts of applicable data discussed in text.

APPENDIX 2 – VAN KREVELEN DIAGRAMS BY FORMATION

Aralka Formation – HI versus OI
Areyonga Formation – HI versus $T_{\text{Max}}$
Areyonga – HI versus OI
Arumbera Sandstone – HI versus $T_{\text{Max}}$
Bitter Springs Formation – HI versus OI
Bitter Springs Formation – HI versus $T_{\text{Max}}$
Chandler Formation – HI versus OI
Chandler Formation – HI versus $T_{\text{Max}}$
Finke beds – HI versus OI
Finke beds – HI versus $T_{\text{Max}}$
Giles Creek Dolostone – HI versus OI
Giles Creek Dolostone – HI versus $T_{\text{Max}}$
Gillen Member – HI versus OI
Gillen Member – HI versus $T_{\text{Max}}$
Illara Sandstone – HI versus $T_{\text{Max}}$
Inindia beds – HI versus OI
Inindia beds – HI versus $T_{\text{Max}}$
Johnnys Creek beds – HI versus OI
Johnnys Creek beds – HI versus $T_{\text{Max}}$
Loves Creek Member – HI versus OI
Loves Creek Member – HI versus $T_{\text{Max}}$
Pacoota Sandstone – HI versus OI
Pacoota Sandstone – HI versus $T_{\text{Max}}$
Pertatataka Formation – HI versus OI
Pertatataka Formation – HI versus $T_{\text{Max}}$
Stairway Sandstone – HI versus OI
Stairway Sandstone – HI versus $T_{\text{Max}}$
Tempe Formation – HI versus OI
Tempe Formation – HI versus $T_{\text{Max}}$
Winnall beds – HI versus OI
Winnall beds – HI versus $T_{\text{Max}}$

APPENDIX 3 – GEOSCIENCE AUSTRALIA GEOCHEMICAL DATABASE

Appendix 3 (MS Excel format) includes all Geoscience Australia geochemical data from the Amadeus Basin, as of December 2003.
Appendix 2. Aralka Formation – Hydrogen Index versus Oxygen Index.
Appendix 2. Areyonga Formation – Hydrogen Index versus $T_{\text{max}}$. 
Appendix 2. Areyonga Formation – Hydrogen Index versus Oxygen Index.
Appendix 2. Arumbera Sandstone – Hydrogen Index versus \( T_{\text{max}} \).
Appendix 2. Bitter Springs Formation – Hydrogen Index versus Oxygen Index.
Appendix 2. Bitter Springs Formation – Hydrogen Index versus $T_{\text{max}}$. 

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Appendix 2. Chandler Formation – Hydrogen Index versus Oxygen Index.
Appendix 2. Chandler Formation – Hydrogen Index versus T_max.
Appendix 2. Finke beds – Hydrogen versus Oxygen Index.
Appendix 2. Finke beds – Hydrogen versus $T_{\text{max}}$.

Appendix 2 – p 10
Appendix 2. Giles Creek Dolostone – Hydrogen Index versus Oxygen Index.
Appendix 2. Giles Creek Dolostone – Hydrogen Index versus Tmax.
Appendix 2. Gillen Member – Hydrogen Index versus Oxygen Index.
Appendix 2. Gillen Member – Hydrogen Index versus $T_{\text{max}}$. 

Appendix 2 – p 14
Appendix 2. Illara Sandstone – Hydrogen Index versus $T_{\text{max}}$.
Appendix 2. Inindia beds – Hydrogen Index versus Oxygen Index.
Appendix 2. Inindia beds – Hydrogen Index versus \( T_{\text{max}} \).
Appendix 2. Johnnys Creek beds – Hydrogen Index versus Oxygen Index.
Appendix 2. Johnny's Creek beds – Hydrogen Index versus $T_{max}$. 

VR = 1.35%
Appendix 2. Loves Creek Member – Hydrogen Index versus Oxygen Index.
Appendix 2. Loves Creek – Hydrogen Index versus $T_{\text{max}}$. 
Appendix 2. Pacoota Sandstone – Hydrogen Index versus Oxygen Index.
Appendix 2. Pacoota Sandstone – Hydrogen Index versus $T_{\text{max}}$.

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Appendix 2. Pertatataka Formation – Hydrogen Index versus Oxygen Index.

* Note high reported HI often have no S₃ documents therefore no OI = theoretical OI value of 75.
Appendix 2 – Pertatataka Formation – Hydrogen Index versus Tmax

Hydrogen Index

Tmax°C

VR=1.35%
VR=0.5%

Pertatataka Formation
(All wells)
Appendix 2. Stairway Sandstone – Hydrogen Index versus Oxygen Index.
Appendix 2. Stairway Sandstone – Hydrogen Index versus $T_{\text{max}}$. 
Appendix 2. Tempe Formation – Hydrogen Index versus Oxygen Index.
Appendix 2. Tempe Formation – Hydrogen Index versus $T_{\text{max}}$. 

Appendix 2 – p 29
Appendix 2. Winnall beds – Hydrogen Index versus Oxygen Index.
Appendix 2. Winnall beds – Hydrogen Index versus $T_{max}$. 