LOG INTERPRETATION REPORT

KINGFISHER-1

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Appendix 8

Log Interpretation Report

Kingfisher-1

by T. L. Gordon

1. Operations / Log Quality

Three suites of logs were run by Schlumberger using a CSU logging system. The following is a brief summary for each of the log suites. Refer to the table 1 for more details of the logs and log products, intervals and scales.

Suite 1 logs were run without operational difficulties in the 445mm (17 1/2") hole on reaching the 340mm (13 3/8") casing point within the Kuriyippi Formation. There were a total of two log runs. The well was logged from 1084m to 338m, with the GR logged in casing to the seabed. The mud system was gel/polymer. One of the SHDT pad buttons failed causing 0.7 hours lost time. However, good data was obtained without the button. The hole was mostly in gauge, but the average mud cake was 3/4 inch. Log quality was good apart from frequent cycle skipping on the long spaced sonic, making parts of the sonic log unusable. The total logging time was 9.1 hours.

Suite 2 logs were run in the 311mm (12 1/4") hole on reaching the 244mm (9 5/8") casing point in the Milligans Formation. There were five log runs with a hole condition trip after the first three runs. The well was logged from 1814m to 1083m. The mud system was seawater with gel slugs due to lost circulation problems. There were no operational or tool difficulties. The hole was extremely out of gauge in many zones and otherwise with a minimum out of gauge of 1 to 2 inches. Although the sonic and density logs were affected by the extreme out of gauge hole sections, the zones of interest were adequately in gauge to allow good log quality. The total logging time was 30.5 hours with no lost time.

Suite 3 logs were run in the 216mm (8 1/2") hole on reaching a total well depth of 3257m in the Bonaparte Formation (Ningbing Group). There were six log runs with a hole condition trip after the third run. The suite logged from 3255m to 1814m. The mud system was KCl/PHPA. Both borehole and tool problems were encountered with this log suite. On Run 1, the DLL-MSFL tool string became stuck while attempting a repeat log section near the casing shoe. Fishing of the tool string by drill pipe was required. Both Runs 2 (LDL-CNL tool string) and 3 (SHDT tool string) required wiper trips to enable getting to bottom. There were 30 misfired shots out of 60 on the CST run (Run 4) requiring an extra CST run. On Run 5, the RFT tool was unable to pass below 2553m. For Run 6, the Check Shot Survey results were invalid above 1393m due to casing ringing caused by the lack of cement behind the 244mm (9 5/8") casing. Although parts of the logged section, especially within claystone beds, were extremely out of gauge, the sandstone zones of interest were adequately in gauge to allow good log quality. The total logging time was 73.5 hours.

Table 1 Wireline Log Summary

Suite	Date	Logs	Additional Processed Logs	Interval (m)	Max. Temp. (°C)	SBHT (°C)	Scales/Remarks
1	30 May	DLL-SLS-CAL-GR-SP		1079.5 - 338.5, GR to 50	54.4		1:200, 1:500, 1:1000
		SHDT-GR		1084.0 - 338.3	54.7	55	1:200
			Cyberdip	1084.0 - 338.3			1:200, 1:000
2	17-18 Jun	DLL-MSFL-GR-AS-SP-AMS		1810.0 - 1083.0	54.5		1:200, 1:500, 1:1000
		LDL-CNL-NGS-AMS		1813.7 - 1083.0	54.5		1:200, 1:500
		SHDT-GR-AMS		1814.1 - 1083.0	58.0		1:200
		HP-RFT-GR-AMS		1795.5 - 1103.0	54.0		4 pressures
		CST-GR		1799.5 - 1151.0	54.0	***	21 samples
			Cyberlook	1800.0 - 1725.0			1:200
				1525.0 - 1400.0			1:200
			Cyberdip	1814.1 - 1083.0			1:200, 1:1000
			Directional Log	1814.1 - 338.3			
			Merge Log	1813.7 - 0.0			1:500
3	3-9 Aug	DLL-MSFL-GR-AS-SP-AMS		3255.0 - 1814.0	102.0		1:200, 1:500, 1:1000
		LDL-CNL-NGS-AMS		3153.0 - 1814.5	102.0		1:200,1:500
		SHDT-GR-AMS		3153.5 - 1814.5	106.0		1:200
		HP-RFT-GR-AMS		2535.0 - 1822.5	89.8		8 pressures, 1 sample
		CST-GR		3152.0 - 1841.0	106.0		65 samples
		Check Shot		3253.0 - 1393.0	107.0	110	16 levels
			Cyberlook	2625.0 - 2525.0			1:200
				2315.0 - 2275.0			1:200
				1915.0 - 1850.0			1:200
			Cyberdip	3153.5 - 814.5			1:200, 1:1000
			Directional Log	3153.5 - 814.5			
			Merge Log	3255.0 - 1814.5			1:500

SBHT = Static Bottom Hole Temperature

*** SBHT not obtained due to the extreme cooling of the formation from continued additions of seawater while having lost circulation.

Suite	Hole		Casing		Mud		
	Size (mm)	TD (m)	Size (mm)	TD (m)	Type	Density (sg)	Rmf
1	445	1090	340	1083.1	Gel/Polymer	1.10	0.269 @ 20.0°C
2	311	1817	244	1814.3	Seawater	1.02	0.239 @ 20.0°C
3	216	3257	-	-	KCl/PHPA	1.57	0.038 @ 22.0°C

2. Interpretation Procedure

Due to the very variable formation water salinities as assessed in the Kingfisher-1 well and from area well data, it is concluded that hydrocarbon saturation determination from log analysis is suspect if there is no hydrocarbon/water contact within specific sands of interest. Nonetheless, Sw method was attempted in Kingfisher-1 by several methods including, Porosity vs Resistivity Crossplots, Cyberlook and Crocker's Quick Look 'Logs' program.

In formations above a regional claystone overpressure seal 50 m- 100m thick (140m thick in Kingfisher-1) within the upper Milligans Formation (1950m - 2090m interval in Kingfisher-1), there is considerable variations in the formation water salinities related to the degree of meteoric water flushing. Area data indicates that the hydrocarbon bearing zones have approximate connate water salinities, while the adjacent wet zones are flushed. Below this regional overpressure seal, the formation salinities within the lower Milligans Formation and Bonaparte Formation (Ningbing Group) are also variable, but all hypersaline (50,000 - 300,000 ppm total dissolved salts).

Although conventional wireline log analysis techniques were applied, due to the above mentioned variability in the formation water salinities, the following evaluation parameters and techniques were found more useful for assessing potential hydrocarbon zones in the Kingfisher-1 well.

1 Drill returns cuttings shows and gas readings.
2 Wireline log quicklook curve overlays of DT and Rt (hydrocarbon anomaly assessment for constant Rw and lithology) and Rxo and Rt (movable hydrocarbon assessment for zones of constant Rw, lithology and porosity).
3 Sidewall core show assessment, especially, odour, stain, and fluorescence distribution and brightness.
4 RFT pressure data.

In the Barnett and Turtle wells, all zones that produced oil, either from the Kuriyippi or Milligans Formations, had good shows in the sidewall cores, while nonproductive zones had trace to fair shows at most. Thus, sidewall cores were most effective in evaluating hydrocarbon bearing zones.

Also, all the oil productive zones within the Kuriyippi Formation (Turtle-1 and Barnett-2) above the Point Spring Sandstone were without gas due to flushing, biodegradation and/or leakage of the light hydrocarbons. Hence, the lack of gas associated with oil shows in the post Point Spring Sandstone section of Kingfisher-1 was expected. Thus, cuttings shows alone were significant and were best examined further by logs, sidewall cores and RFTs as appropriate. The Turtle and Barnett well data indicate that all the oil bearing zones in this shallow section had good shows in sidewall cores.

Oil productive zones within the Milligans Formation (Turtle-2 and Barnett-2) had both cuttings shows and significant gas peaks, besides good shows in sidewall cores.

Also, oil productive zones in the Barnett and Turtle wells have Rt/DT curve separations in the oil zones on log curve overlays matched in adjacent wet zones.

3. Evaluation of Rw

There are four distinct salinity zones within the well. Refer to the table 2. The formation water in the sandstones in the interval 357m - 460m is saline. (The interbedded claystones are more resistive than the sandstones). From 460m to 1300m the formation water is variable, but brackish to fresh. (The interbedded claystones are less resistive than the sandstones). In the interval 1300m to 2090m, the water is also variable, but brackish to saline. (The interbedded claystones are again more resistive than the sandstones). Below 2090m to 3257m (TD) the formation water is hypersaline. (Some interbedded claystones are more resistive than the sandstones while others are less resistive).

The following method was used to determine the formation salinity. Formation water resistivities (Rws) were calculated from formation resistivity (Ro) and porosity, assuming the zones to be wet, i.e., water saturation (Sw) = 1. For porosities (ϕ) < 20%, Rw was considered to equal ϕ^2 Ro and for ϕ > 20%, Rw was considered to equal ϕ^2 Ro / 0.81.

SP was not useful for determining Rw in the well. The SP response was subdued throughout the logged intervals. The cause of this subdued response is probably due to the shaliness of the sandstones. These often have a kaolinite clay matrix, thus the shaliness is not apparent on GR due to the lack of potassium.

The main Kuriyippi reservoir at 965m - 1033m is fresh water flushed. Zones 1325m - 1363m, 1374m - 1387m and 1458m - 1575m show increasing salinity with depth profiles. Shale permeability barriers separate these zones. The 482m - 508m zone shows the transition from saline to brackish, again with a shale permeability barrier overlying.
It is noted that the Barnett and Turtle wells had similar variations in formation water salinities as Kingfisher-1. With such variable formation water salinities, thus, formation water resistivities, the use of water saturation (Sw) in evaluating zones for productive hydrocarbons is questionable. Sw and Rw determinations in these wells were additionally complicated by the hydrocarbon zones having a higher salinity than the adjacent wet beds. Thus, in conclusion, Sw calculations based on Rw values are usually not reliable in the Southern Bonaparte Basin. Nonetheless, for completeness, the

parameters used for such calculations and the resulting Sw values are listed in the table 3.

The depositional environment for all of the formations is marginal marine to marine. Thus, the brackish to fresh water has been introduced by flushing from meteoric waters. The lower Kuriyippi and older formations cropout in the onshore portion of the Southern Bonaparte Basin, while offshore the upper Kuriyippi and post Kuriyippi formations either cropout or have only a veneer of young sediments covering them. These younger horizons were probably also exposed to meteoric waters at times of lower sea levels during the ice ages.

Table 2 Formation Water Salinities

Zone	Interval (m)	Rw Range (ohm-m)	Salinity Range (ppm x 1000)	Rt Sh vs Rt Sdst	Formation	Depth (m)
	357.5				Keyling	357.5
Saline	I	0.2 - 0.4	26 -12	Sh > Sdst		
	460					
Brackish	I				Treachery	649.5
- Fresh	I	0.5 - 3.2	8.5 - 1	Sh < Sdst		
	I				Kuriyippi	911
	1300					
	I				Point Spring	1470.5
	I	0.2 - 1	15 - 3	Sh > Sdst		
Brackish	I				Tanmurra	1575
- Saline	I					
	I				Milligans	1743.5
	2090					
Hyper-	I	0.01 - 0.03	400 -90	Sh > & < Sdst	Bonaparte	
saline	I				(Ningbing	2612.5
	I				Group)	
	3257				TD	3257

Relative Salinity (ppm TDS)

Hypersaline	>35,000
Saline	10,000 - 35,000
Brackish	1,000 - 10,000
Fresh	<1,000

Table 3 Log Interpretation Parameters

Suite No.	Depth (m)	Zone	Formation	Rw	GR clean	GR shale	Rt shale	DT shale	DT matrix	a	m	n
1	495 - 642	1	Keyling	2.4	40	110	5	125	55.5	1	2	2
	694 - 727	2	Treachery	2	40	120	7	115	55.5	1	2	2
	917 - 967	3	top Kuriyippi	2.4	30	130	4	130	55.5	1	2	2
2	1112 - 1327	3	Kuriyippi	1.4	20	140	12	90	55.5	0.81 & 0.62	2 & 2.15	2
	1362 - 1552	2	base Kuriyippi & top Point Spring Sst.	0.22	18	140	30	80	55.5	0.81 & 0.62	2 & 2.15	2
	1757 - 1786	1	top Milligans	0.27	15	120	30	80	55.5	0.81 & 0.62	2 & 2.15	2
3	1852 - 1871.5	A	upper Milligans	0.43	75	190	10	90	50	0.81 & 0.62	2 & 2.15	2
	1893 - 1906	B	upper Milligans	0.43	75	190	10	90	50	0.81 & 0.62	2 & 2.15	2
	2288 - 2298	C	lower Milligans	0.03	75	160	10	75	50	0.81 & 0.62	2 & 2.15	2
	2532 - 2539	D	lowermost Milligans	0.03	75	160	10	75	50	0.81 & 0.62	2 & 2.15	2
	2613 - 2622	E	Ningbing Group	0.03	75	160	10	75	50	0.81 & 0.62	2 & 2.15	2

* GR is anomalously high due to the abundance of potassium ions from the 15% KCL concentration in the KCl/PHPA mud system.
For Cyberlook and Crocker's Quick Look 'Logs', a = 0.81 and m = 2.
For Porosity vs Resistivity Crossplots, a = 0.62 and m = 2.15.

4. Log Interpretation Results

4-1. Suite 1 (445mm / 17 1/2" Hole, 1084m - 338m)

No productive hydrocarbons were apparent in this Keyling Formation to upper Kuriyippi Formation interval of the well. Although a trace show was recorded at the top of the Kuriyippi Formation, over the interval 911m - 950m, no hydrocarbon response is apparent on the wireline logs. The maximum gas reading for this interval was less than 0.1% with only C1 and C2.

The sonic log has excessive cycle skipping over the logged interval. However, the sonic 'down log' is far less effected. Unfortunately, even the 'down log' sonic response is suspect in the only zone with shows (911m - 950m). By an interpolation of the sonic curve through this cycle skipped zone, a sonic porosity of 20% is obtained.

The upper sandstone (911m - 1035m) of the Kuriyippi Formation is more than 120m thick with the interval 926m - 965m being shaly. There is no log hydrocarbon anomaly at the top of this sand in the interval with shows (911m - 950m), compared to the interval below this zone. The complete sand is interpreted as being wet. The sharp increase in resistivity on entering the top of the Kuriyippi sandstone is considered to be due to the near fresh formation water as encountered in the Barnett and Turtle wells 27km to the north. The SP does not reflect the calculated Rw. (This is also the case for the Barnett and Turtle wells).

The DT / Rt quicklook log overlay method indicates an anomaly for the 582.5m - 593m interval within the Keyling Formation. (An overlay of the DT and Rt log curves indicates any non-porosity related Rt hydrocarbon response. To obtain valid results, this method requires overlay curve matching in adjacent wet sands that have the same lithology and water salinity). Since no hydrocarbons were indicated from the drill returns for this interval, it is concluded that the anomaly is probably a function of variable lithologies and/or water salinities between the interval of the matched curve overlay and the interval with the curve separation. A possible alternative explanation is the presence of a non combustible gas such as carbon dioxide.

Table 4 Suite 1 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
495 - 642	1	Keyling	0.34	-	* 1	-	-
694 - 727	2	Treachery	0.30	-	1	-	-
917 - 967	3	top Kuriyippi	0.19	-	# 0.9 - 1	Trace	-

* The Rw and matrix composition are variable for the this data set, thus making the Sw value questionable.

The DT (and corresponding porosity) used in the Sw determination was obtained by an interpolation of DT over this zone of sonic cycle skipping.

4-2. Suite 2 (311mm / 12 1/4" Hole, 1814m - 1084m)

As with Suite 1, no productive hydrocarbons were recognised in this upper Kuriyippi to upper Milligans Formation interval of the well. Trace to poor cuttings shows were present in the 1400m - 1500m interval of the Kuriyippi Formation. The 1750m - 1800m interval of the Milligans Formation had poor shows in cuttings and trace to good shows (patchy moderately bright fluorescence with no stain or odour) in sidewall cores. A slight hydrocarbon log response is present for the 1782m - 1784m interval of the Milligans Formation. The Tanmurra limestone is very tight and without oil shows or gas peaks.

Log interpretation suggests that the Milligans' zone 1753m- 1814m may be partly fractured as indicated by the high delta bulk density with a corresponding low bulk density and high neutron porosity. It appears that the gas peak (1.67%) recorded at 1790m may have come from a fracture indicated at 1791m by the bulk density/neutron porosity response. Waveform analysis of the array sonic gives some indication of fracturing in the intervals 1774m - 1782.5m and 1784m - 1793m.

The logged interval has been divided into 3 zones of different averaged formation water salinities for purposes of log analysis. Even within these zones the salinities are somewhat variable. The Kuriyippi zone 1083m - 1350m appears to be relatively fresh while the lowermost Kuriyippi zone is more saline. The upper Milligans zone is brackish.

Quicklook log overlay methods indicate some anomalies within the logged interval. (As mentioned before, an overlay of the DT and Rt log curves gives non-porosity hydrocarbon related Rt responses. An overlay of the Rxo and Rt log curves gives an indication of movable hydrocarbons. To obtain valid results, these methods require overlay curve matching in adjacent wet sands that have the same lithology and water salinity).

Three anomalous DT/Rt and Rxo/Rt zones are apparent. These are as follow:

Formation	**Interval**(m)	**Remarks**
Kuriyippi	1234 - 1241	No hydrocarbons indicated from drill returns
Kuriyippi	1322 - 1334.5	No hydrocarbons indicated from drill returns
Milligans	1782 - 1784	Poor shows but no gas peaks indicated from drill returns

Since no hydrocarbons were indicated from the drill returns for the anomalies in the Kuriyippi Formation, it is concluded that the anomalies are probably a function of variable lithologies and/or water salinities between the interval of the matched curve overlay and the interval with the curve separations. A possible alternative explanation is the presence of a non combustible gas such as carbon dioxide.

The only anomalous zone on logs in which hydrocarbons were observed in the drill returns is in the Milligans Formation at 1782m - 1784m. Unfortunately, this zone is both thin and shaly with a volume of shale (Vsh) calculated at about 24%. The total porosity from sonic is calculated to be about 11%. The effective porosity is about 7%. The calculated Sw is about 50 - 55%.

RFT pressure data supports the log interpreted results and the drill returns data by indicating a water gradient over the 1758.4m - 1769.5m interval in the uppermost Milligans Formation.

Tabel 5 Suite 2 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
1112 - 1327	3	Kuriyippi	0.18	-	1	-	-
1362 - 1552	2	base Kuriyippi & top Pt. Sprg Sst.	0.13	-	* 0.9 - 1	Trace - Poor	-
1757 - 1786	1	top Milligans	0.09	-	0.5 - 1	Trace - Good #	1.67%

* The Rw and matrix composition are variable for the this data set, thus making the Sw value questionable.

Good shows in sandstone sidewall cores, but no stain or odour and no bright uniform fluorescence.

4-3. Suite 3 (216mm / 8 1/2" Hole, 3255m - 1814m)

As with the first two suites, no significant productive hydrocarbons were apparent in this upper Milligans to Bonaparte (Ningbing Group) interval of the well. Although some poor to good shows (patchy fluorescence with no stain or odour) were present in the sidewall core samples in the interval 1890m - 1930m, logs and a RFT pressure gradient indicate that the sandstones are wet with residual hydrocarbons at most. In addition, the RFT pretest pressure data indicate that this zone is tight. Log analysis also indicates that the zones 2290m - 2300m and 2530 m- 2538m are wet. Although gas peaks of 38.9% (79% C1) and 10.4 % (94% C1) respectively occurred, there were no cuttings shows and only trace shows in some of the sidewall cores in these intervals.

The formation salinity is brackish to saline in the upper Milligans Formation logged interval to 2090m. Below the base of an overpressure seal at this depth, the salinity is hypersaline. The mud salinity was increased from below the bit trip at 2574m from 8% to 15 - 16% KCl and 50,000 to 110,000 - 120,000 ppm NaCl to stabilise the hypersaline sloughing and swelling clays.

Six RFT pressure measurements were obtained in the interval 1838m - 1900.5m. A water gradient was indicated from a plot of the data. Twenty attempted measurements were made in the interval 1822.5m - 2535m, with only the above successes due to the poor permeability of the formations. Even the measured points indicated low permeability. One segregated sample (2000cc and 2250cc) was taken at 1900.5m which consisted of mud filtrate.

In general, the gas peaks in this interval are associated with thin (maximum 10m at 2295m) sandstone beds. A major gas peak (39.4%) at 2375m appears to be from a fracture. Only gas peaks at 1894m and 1928m have associated oil shows, these being poor at most. A dry gas composition is indicated for all peaks except from the suspected fracture at 2375m.

Thin fractured gas sands are indicated on logs at 2122m and 2126m. The sands are 0.5 and 1m thick respectively. Following a gas peak of 1.65% at 2124m, the well flowed due to underbalance. Gas may be indicated on logs from a 6pu and 6 - 9pu crossover of the LDL/CNL curves in the 2122m and 2126m sands respectively. Fracturing is indicated by the MSFL curve lows within the tight, low porosity (5 -7%) sands.

Table 6 Suite 3 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
1852 - 1871.5	A	upper Milligans	-	0.09	* 0.8 - 1	-	-
1893 - 1906	B	upper Milligans	-	0.10	* 0.8 - 1	Trace - Good #	2.20%
2288 - 2298	C	lower Milligans	-	0.08	* 0.8 - 1	Trace	38.90%
2532 - 2539	D	lowermost Milligans	-	0.06	* 0.8 - 1	-	10.40%
2613 - 2622	E	Ningbing Group	-	0.06	* 0.8 - 1	-	-

* The Rw and matrix composition are variable for the this data set, thus making the Sw value questionable.

Good shows in sandstone sidewall cores, but no stain or odour and no bright uniform fluorescence.

5. RFT and Sidewall Core Results

Limited pressure gradients were obtained from the RFT pressure plots due to hole gauge and low permeabilities. Those that were obtained indicated water gradients.

Sidewall cores were obtained in all zones of interest except in the upper Kuriyippi Formation. The lack of good shows with odour and/or stain and uniform bright fluorescence is interpreted as indicating residual hydrocarbons at most.

6. Conclusion

For the Kingfisher-1 exploration well, the primary objective in log interpretation was to determine if any drillstem testing for producible hydrocarbons was justified. Thus, even though an accurate determination of Sw was not feasible, it was also not necessary. The primary concern was to determine if there were adequate movable hydrocarbons. A combination of sidewall core shows, RFT pressure profiles, quicklook log curve overlay techniques and drill returns cuttings shows and gas peaks allowed adequate assessment of the potential producibility of the zones of interest. In all cases these parameters indicated the zones of interest were non productive. In many cases the zones of interest were also of poor reservoir quality and/or very thin. In conclusion, all zones within the Kingfisher-1 well were considered nonproductive, thus, no drillstem testing was undertaken.