LOG INTERPRETATION REPORT

SUNBIRD-1

Appendix 8

Log Interpretation Report

Sunbird-1

by T. L. Gordon

1. Operations / Log Quality

Four 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 on 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 1350 to 273m, with the GR logged in casing to the seabed. The mud system was gel/polymer. The hole was mostly in gauge except for the top 100m. Also, 57m of open hole below the 508mm (20") casing shoe was 660mm (26") due to the casing being set high. The total logging time was 8.5 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 eight log runs with a hole condition trip after the first four runs. The well was logged from 2560 to 1349m. The mud system was KCl/PHPA. There were 7.5 hours of lost time due to tool and operational problems. The hole was in gauge for most of the sandstone zones of interest. However, the upper sandstones and most of the shales were out of gauge, the shales to greater than 8" in places. The in gauge sandstones had no mudcake buildup. Thus, the log quality was good over zones of interest. The total logging time was 54.7 hours with 7.5 hours of this being lost time as mentioned above.

Suite 3 logs were run in the 216mm (8 1/2") hole at 3270m. Intermediate logs were run at this depth to determine the potential overpressure conditions in the underlying interval. A gas peak of 28.9% occurred from a silty and argillaceous sandstone at 3269.5m. It was decided that the precaution of running intermediate logs was necessary due to the lack of formation integrity (minor lost circulation was occurring) in the open hole section. Also, an increase in pore pressure was anticipated in the underlying section, based on correlations with area data. There were six log runs with a wiper trip after the third run. The interval logged was 3270m - 2543m. The mud system was KCl/PHPA/Glycol. The hole was nearly in gauge for most of the logged interval. The log quality was good. The total logging time was 37 hours. There was some down time for electrical problems associated with the SHDT.

Suite 4 logs were run in the 216mm (8 1/2") hole at the total depth of 3324m. There were only two log runs. The logged interval was 3324m - 3200m. The mud system was still KCl/PHPA/Glycol as with Suite 3. The log quality was good since the complete hole section was nearly in gauge. The total logging time was 9 hours.

Table 1 Wireline Log Summary

Suite	Date	Logs	Additional Processed Logs	Interval (m)	Max. Temp. (°C)	SBHT (°C)	Scales/Remarks
1	31 Aug	DLL-AS-CAL-GR-SP		1350 - 273, GR to 40	62.8		1:200, 1:500, 1:1000
		SHDT-GR		1354.0 - 273.0	63.3	64.5	1:200
			Cyberdip	1354.0 - 273.0			1:200, 1:000
			Merged Log	1350.0 - 40.0			1:500
2	23 - 26 Sep	DLL-MSFL-AS-GR-SP-AMS		2558.0 - 1349.5	80.0		1:200, 1:500, 1:1000
		LDL-CNL-NGS-AMS		2561.7 - 1349.5	85.0		1:200, 1:500
		EPT		2556.6 - 1800.0	85.0		1:200
		SHDT-GR-AMS		2562.0 - 1349.5	87.8	91.5	1:200
		RFT-GR		2165.0 - 1827.0	82.2		14 pressures 1 sample
		MSCT-GR		2552.0 - 1830.0	90		23 samples
		CST-GR		2507.5 - 1366.0	90		26 samples
			Cyberlook	2236.0 - 1825.0			1:200
			Cyberdip	2562.0 - 1349.5			1:200, 1:1000
			Directional Log	2562.0 - 1349.5			
			Merged Log	2561.7 - 1349.5			1:500
3	19 - 21 Oct	DLL-AS-MSFL-GR-SP-AMS		3269.0 - 2545.0	99		1:200, 1:500, 1:1000
		LDL-CNL-NGS-AMS		3272.8 - 2545.0	104		1:200,1:500
		SHDT-GR		3270.0 - 2545.0	109.4	114	1:200
		MSCT-GR		2992.5 - 2586.0	94		12 samples
		CHECK SHOT		3266.0 - 740.0	105		22 levels
		CST-GR		3265.0 - 2660.0	105		15 samples
			Cyberlook	3000.0 - 2920.0			1:200
			Cyberdip	3270.0 - 2545.0			1:200, 1:1000
			Directional Log	3270.0 - 2545.0			
			Merged Log	3272.8 - 2545.0			1:500
4	24 Oct	DLL-AS-MSFL-GR-SP		3322.9 - 3200.0	95.6		1:200, 1:500, 1:1000
		LDL-CNL-NGS-AMS		3326.7 - 3200.0	101	110***	1:200,1:500
			Cyberlook	3320.0 - 3200.0			1:200
			Merged Log	3326.7 - 3200.0			1:500

SBHT = Static Bottom Hole Temperature

*** This SBHT is anomalously low compared with the SBHT of 114°C obtained at 3270m. This anomaly is probably due to both the limitations of the Horner SBHT method and to operational factors.

Suite	------Hole------		------Casing------		------------------------Mud------------------------		
	Size (mm)	TD (m)	Size (mm)	TD (m)	Type	Density (sg)	Rmf
1	445	1354	340	1349	Gel/Polymer	1.10	0.265 @ 21.0°C
2	311	2560	244	2543	KCl/PHPA	1.08	0.155 @ 24.5°C
3	216	3270	-	-	KCl/PHPA/ Glycol	1.25	0.072 @ 25.0°C
4	216	3324	-	-	KCl/PHPA/ Glycol	1.25	0.077 @ 21.9°C

2. Interpretation Procedure

Due to the variable formation water salinities (as assessed in the Sunbird-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 Sunbird-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 50m - 150m thick (60m thick in Sunbird-1) within the upper Milligans Formation (2655m - 2716.5m interval in Sunbird-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 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 Sunbird-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 MSCT and 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 Sunbird-1 was expected. Thus, cuttings shows alone were significant and were best examined further by logs, MSCT and 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 had Rt/DT curve separations in the oil zones on log curve overlays matched in adjacent wet zones.

3. Evaluation of Rw

The formation water salinity varies considerably in the well (Table 2). The salinity fluctuates between brackish and saline in the interval 275m to 2715m. Within these major fluctuations, there are also minor variances. Below 2715m the formation water is variable, but hypersaline.

For the interval 275m - 1300m, there is a fluctuation in salinity from brackish to saline. The following list gives more detail about this fluctuation.

Depth (m)	**Relative Salinity**
275	
	Brackish
370	
	Transition
500	
	Near saline
700	
	Saline
1020	
	Transition
1150	
	Brackish
1215	
	Near saline
1240	
	Saline
1300	

This salinity variation is common within the Southern Bonaparte Basin for this interval. Being of a marine depositional environment, the brackish to fresh formation water indicates meteoric water flushing.

There is an apparent trend of increasing formation water salinity with depth over the interval 1375m - 2127m. This is indicated both from calculated Rws and the SP magnitude. While the salinity at the top of the interval is about 12,000 - 15,000 ppm total dissolved salts(TDS), it is about 23,000 ppm (the same as the mud filtrate) at the base of the Point Spring Sandstone. The Table 3 shows Rw, salinity and SP data from the most porous sandstones:

Table 3 Variation of Rw, Salinty and SP

Depth (m)	Rw	TDS(ppmx1000)	SP
1375	-	-	27
1560	-	-	25
1688	0.21	13.3	40
1842	0.17	16.7	30
1884	0.23	12.5	20
2022	0.19	14.8	15
2065	0.14	19.7	10
2127	0.12	23.3	0

Also, within this interval there is some indication of hypersalinity over thin intervals at 1955m - 1965m and 2155m - 2185m within the Point Spring Sandstone.

An Rw of 0.03 - 0.04 ohm-m was calculated ($Rw = \Phi$^2.15 / 0.62 x Rt) for the most porous sand at 2992m - 2994m. This Rw is equivalent to a Total Dissolved Salts(TDS) of 87,000 - 61,000 ppm. The TDS of the mud filtrate is 123,000 ppm (Rmf 0.072 @ 25°C and 0.026 ohm-m at 107°C at the zone of interest). A slight positive SP verifies that the formation water salinity is slightly fresher than the mud filtrate.

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, that is, the 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.

It is noted that the Kingfisher, Barnett and Turtle wells had similar variations in formation water salinities as Sunbird-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 the Barnett and Turtle 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

Table 2 Formation WaterSalinities

Zone	Interval (m)	Rw Range (ohm-m)	Salinity Range (ppm x 1000)	Rt Sh vs Rt Sdst	Formation	Depth (m)
					Keyling	234
	275					
Brackish	I	3	1.5	Sh = Sdst		
	370					
Brackish	I	0.1 - 3	36 - 1.5	Sh > Sdst		
-Saline	I					
	700					
Saline	I	0.12	33	Sh > Sdst		
	I				Treachery	967
	1050					
Brackish	I	0.36 - 0.75	9 - 4	Sh > & < Sdst		
	I				Kuriyippi	1143.5
	1240					
	I				Point Spring	1920
Saline #	I	0.12 - 0.2	24 -13	Sh > Sdst		
	I				Tanmurra	2236.5
	I					
	I				Milligans	2498.5
	2715					
	I					
Hyper-	I	0.03 - 0.04	90 - 60	Sh < Sdst	Bonaparte	
saline *	I				(Langfield	3057
					Group)	
	3324				TD	3324

Relative Salinity (ppm TDS)

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

Tabel 4 Log Interpretation Parameters

Suite No.	Depth (m)	Zone	Formation	Rw	GR clean	GR shale	Rt shale	DT shale	DT matrix	a	m	n
1	1144 - 1150	A	top Kuriyippi	0.75	40	120	4	105	55.5	0.62	2.15	2
	1155 - 1159	B	top Kuriyippi	0.6	40	120	4	105	55.5	0.62	2.15	2
2	1826 - 1842	4	lower Kuriyippi	0.17	30	160	25	75	51	0.62	2.15	2
	1884 - 1915	4	lowermost Kuriyippi	0.23?	30	160	25	75	51	0.62	2.15	2
	1955 - 1974.5	3	upper Point Spring Sst.	0.07? - 0.13	30	130	20	75	51	0.62	2.15	2
	2000 - 2043	2	Point Spring Sst.	0.20	30	140	10	85	55.5	0.62	2.15	2
	2050 - 2097	2	Point Spring Sst.	0.14	30	140	10	85	55.5	0.62	2.15	2
	2100 - 2118	2	Point Spring Sst.	0.11	30	140	10	85	55.5	0.62	2.15	2
	2125 - 2147	2	Point Spring Sst.	0.12	30	140	10	85	55.5	0.62	2.15	2
	2153 - 2171	1	lower Point Spring Sst.	0.06?	30	160	15	75	51	0.62	2.15	2
	2201 - 2212	1	lowermost Point Spring Sst.	0.29?	30	160	15	75	51	0.62	2.15	2
3	2935 - 2947	-	lower Milligans	0.03	40	170	10	80	55.5	0.62	2.15	2
	2992 - 2994	-	lower Milligans	0.03	40	170	10	80	55.5	0.62	2.15	2
4	3272 - 3285	-	lower Milligans	0.03	60	170	20	70	55.5	0.62	2.15	2

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 following Table 4.

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.

4. Log Interpretation Results

4-1. Suite 1 (445mm / 17 1/2" Hole, 1350m - 273m)

No productive hydrocarbons were apparent in this upper Keyling to upper Kuriyippi Formation interval of the well. The top of the Kuriyippi is at 1143.5m. Although there were trace shows in cuttings over the interval 1140m - 1157m at the top Kuriyippi contact, there is no hydrocarbon anomaly indicated on logs. There is a sonic anomaly in the interval 1154m - 1158m, with sonic values 110 msec/ft versus the values above and below this interval being about 90 msec/ft. There are no apparent associated GR, SP or Rt anomalies.

Table 5 Suite 1 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
1144 - 1150	A	top Kuriyippi	0.26	-	* 0.8 - 1	Trace	-
1155 - 1159	B	top Kuriyippi	0.35	-	* 0.6 - .7	Trace	-
* The Rw and matrix composition are variable for the this data set, thus making the Sw value questionable.							

4-2. Suite 2 (311mm / 12 1/4" Hole, 2560m - 1349m)

As with Suite 1, no productive hydrocarbons were apparent in this upper Kuriyippi to upper Milligans Formation interval of the well. The top of the Point Spring Sandstone, Tanmurra and Milligans Formations are at 1920m, 2236.5m and 2498.5m respectively. There were scattered trace shows in the cuttings (without associated gas) in the lowermost Kuriyippi Formation, throughout the Point Spring Sandstone, near the top of the Tanmurra and at the top of the Milligans Formations. There were no gas peaks associated with any of these shows. However, there were two gas peaks of 5.7% and 4.92% from fractures near the top of the Point Springs Sandstone. At 2556m, 57.5m into the Milligans Formation, a gas peak of 4.48% occurred from siltstone without any shows in the cuttings. Oil was observed in the mud and a gas peak of 11.3% occurred on bottoms up on the hole condition trip before running the casing following the Suite 2 logs.

DT/Rt and Rxo/Rt quicklook log curve overlays indicated that the complete depth interval of each of the major sandstones are without any hydrocarbon/water contacts.

A normal pressure gradient (0.44psi/ft) was obtained from a plot of all the RFT pressure points for the interval 1832m - 2145m. A reliable pressure gradient was obtained for the sandstone interval 2050m - 2097m. Within this sandstone package, four pressure points gave a pressure gradient of 0.46 psi/ft, a near normal water gradient within the accuracy of the RFT strain gauge. The pressure gradients of 0.51 and 0.50 psi/ft obtained in the sandstone packages for the intervals 1826m - 1843m and 2121m - 2147m respectively are questionable, probably due to pressure variances caused by the low formation permeability (supercharging) and the limited accuracy of the strain gauge. (The HP gauge was not operative). However, the interval 2050m - 2147m is probably a single hydraulic fluid column (due to only minor shale breaks) and the pressure points for this interval gave a water gradient.

The segregated samples obtained at 2091.2m are mud filtrate, with the NaCl and KCl concentrations matching those of the mud filtrate. The formation water lacks KCl salt.

The best shows from both the MSCT cores and sidewall cores were good shows at 2085m and 2093.5m. However, the good shows had no hydrocarbon ordour and were without uniform bright fluorescence. A minor number of cores had trace to poor shows, but most of the cores were without shows.

MSCT core descriptions indicate that the sandstone bed from 2061m to 2070m (with 16% apparent log porosity) has an abundant kaolin clay matrix. The sandstone beds from 2080m to 2097m have abundant silica cement. These abundant clay matrices and silica cements cause the low permeabilities as indicated by the RFT pretests.

Table 6 Suite 2 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
1826 - 1842	4	lower Kuriyippi	-	0.08	0.9 - 1	Trace	-
1884 - 1915	4	lowermost Kuriyippi	0.21	-	*0.7 - 1	Trace	-
1955 - 1974.5	3	upper Point Spring Sst.	-	0.08	* ~1	Trace	-
2000 - 2043	2	Pt. Sprg. Sst.	0.12	-	*0.8 - 1	Trace	4.92%
2050 - 2097	2	Pt. Sprg. Sst.	-	0.16	*0.7 - 1	Poor-Good#	-
2100 - 2118	2	Pt. Sprg. Sst.	-	0.17	*0.8 - 1	-	-
2125 - 2147	2	Pt. Sprg. Sst	-	0.20	*0.75 - 1	-	-
2153 - 2171	1	lower Pt. Sprg. Sst.	-	0.05	*0.8 - 1	-	-
2201 - 2212	1	lowermost Pt. Sprg. Sst.	0.12	-	*0.9 - 1	Trace	-

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

Good shows in sandstone MSCT cores, but no odour or bright uniform fluorescence.

4-3. Suite 3 (216mm / 8 1/2" Hole, 3270m - 2543m)

No productive hydrocarbons were apparent in the all interval of the Milligans Formation of the well.

Only one significant sandstone is present in this logged section. It is a 12m sandstone at 2935m to 2947m. However, its porosity is 2% only. This zone had trace shows but no associated gas. Another 2m sandstone at 2992m - 2994m has 7% porosity. It also had trace shows but no associated gas.

No hydrocarbon anomaly was indicated for the 2935m- 2947m sandstone from a DT/Rt log curve overlay.

Cyberlook analysis was conducted over the interval 3010m - 2920m. Neither residual nor movable hydrocarbons were indicated.

The intervals 2550m - 2655m, 2715m - 2765m, 2815m - 2842m, 3150m - 3175 and 3220m - 3240m are shaly (as indicated by both the GR and neuron/density) and non reservoir. Zones 2550m - 2655m and 2715m - 2765m are also very calcareous and dolomitic as indicated by calcimetry.

Fractures are indicated at 2959m, 3022m, 3073m, 3136m and 3230m by the neutron/density, MSFL and caliper spiked responses. The diameter tadpole plot also indicates 30 - 40° dip anomalies at these depths. Partial lost returns was encountered at 2959m and continued intermittently to the bottom of the logged interval.

The intervals 2500m - 2655m and 2715m - 2765m were described from drill cuttings as dominantly calcareous and/or dolomitic claystone and siltstone with minor sandstone. The GR log response is consistent with this description having with an average value of 70 API units. Area data indicates that typical clean sandstones in the Milligans Formation have a GR reading of 30 and typical shales a GR reading of 120-150. The GR reading of about 70 for these intervals is indicative the carbonate content rather than sandstone. Calcimetry gave values of 20 - 60% for calcite and 5 - 40% for dolomite in these intervals.

Only trace shows were indicated in six sandstone MSCT cores within this logged interval.

Table 7Suite 3 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
2935 - 2947	-	lower Milligans	-	0.02	~1	Trace - Poor	-
2992 - 2994	-	lower Milligans	-	0.07	~1	Trace	-

4-4. Suite 4 (216mm / 8 1/2" Hole, 3324m - 3200m)

Five gas peaks with a magnitude of greater than 1% occurred within this Milligans Formation interval of the well. There were no associated shows. These peaks ranged from 1.42% to 28.9%. The gas was dry with the methane concentration being greater than 95%. The high gas peak of 28.9% at 3269.5m was probably due in part to a slightly underbalanced drilling condition. The mud density was increased from 1.18sg to 1.25sg following this gas peak. A near balanced hydrostatic to formation pressure condition contributed to the high magnitude of the other gas peaks.

A shaly sandstone is indicated by GR and neutron/density for the 13m interval 3272.5m - 3285.5m. A 20% shale volume is indicated by GR. With this much shale volume, a neutron/density curve crossover of 2 - 3pu indicates a gas effect. However, minimal permeability is indicated by both the lack of any SP response (Rw 0.03 vs Rmf 0.025 ohm-m at formation temperature) and the lack of any mud filtrate invasion as indicated by the overlay of the dual laterlog deep and shallow curves. The neutron/density porosity is 2%. The cause of the anomalous 200+ ohm-m resistivity over the interval 3272.5m - 3274m is uncertain, but may be due to either bed boundary affect or resistive accessory minerals. This high resistivity does not appear to be due to gas since there is no corresponding marked neutron/density crossover.

Cyberlook analysis was conducted over the interval 3010m - 2920m. Only a trace of hydrocarbons is indicated.

An Rw of 0.03 ohm-m was used. This value was calculated ($Rw = \Phi^{2.15} / 0.62 \times Rt$) for the only porous sand at 2992m - 2994m in the Suite 3 logged interval.

Tabel 8 Suite 4 Results Summary

Depth (m)	Zone	Formation	Porosity		Sw	Shows	Gas peaks
			DT	N/D			
3270 - 3285	-	lower Milligans	-	0.02	0.9 - 1	-	28.9%

5. RFT and MSCT/Sidewall Core Results

RFT pressure measurements were taken with only the Suite 2 logs over the interval 2168.5m - 1827m. The reliable pressure gradients that were obtained indicated water as the formation fluid. The sandstones within the Suite 3 and 4 logged intervals were considered either too tight or thin for RFT measurements.

MSCT and/or sidewall cores were obtained in all zones of interest. The lack of good shows with odour and uniform bright fluorescence is interpreted as indicating residual hydrocarbons at most.

6. Conclusion

For the Sunbird-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 nonproductive. In many cases the zones of interest were also of poor reservoir quality and/or very thin. In conclusion, all zones within the Sunbird-1 well were considered non productive, thus, no drillstem testing was undertaken.