Petrophysical analysis of well logs from Manitou Lake, Saskatchewan

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ABSTRACT

This report presents the log analysis results from three wells in the Manitou Lake area, in west central Saskatchewan. A 3C-3D survey was acquired in the area by CALROC Energy LTD. in February 2005, with the Colony sand and Sparky members as exploration targets. The log analysis indicates that the Colony and Sparky members have very high porosities, up to 37 % and very low water saturation. The water resistivities calculated from the 3 different water zones give consistent values, between 0.12 and 0.15 Ωm, which is consistent with resistivities from the catalog for that area. Extremely high permeabilities were obtained in the Colony interval, probably due to the lack of calibration of certain parameters in the formula with core data, especially for the CPERM parameter which can take on a wide range of values. Future work involves the calibration of the log analysis with core, test and production data from nearby wells.

INTRODUCTION

This paper shows the results from the interpretation of three sets of logs from the Manitou Lake area in west central Saskatchewan (Figure 1). The log analysis is intended to support reservoir evaluation; as well as help interpret a 3C-3D seismic survey acquired by Kinetec Inc. in the area in February 2005 for Calroc Energy Ltd. The Colony and Sparky members of the Mannville Group are currently producing oil in the area, and are the main exploration targets of the survey.

The general purpose of well log analysis is to convert the raw log data into estimated quantities of oil, gas and water in a formation (Asquith and Krygowski, 2004). A review of the general stratigraphy of the area is presented, focusing on the two target formations, followed by the petrophysical analysis of logs from three wells in the area. Permeabilities, productivity and reserves are calculated for several zones of interest.

STRATIGRAPHY OF THE AREA

Deposition in the Western Canada Sedimentary Basin can be divided into two successions, based on two different tectonic settings affecting sedimentation. The Paleozoic to Jurassic platformal succession, dominated by carbonate rocks, was deposited on the stable craton adjacent to the ancient margin of North America. The overlying mid-Jurassic to Paleocene foreland basin succession, dominated by clastic rocks, formed during active margin orogenic evolution of the Canadian Cordillera, with the emplacement of imbricate thrust slices progressively from east to west (Mossop and Shetsen, 1994).

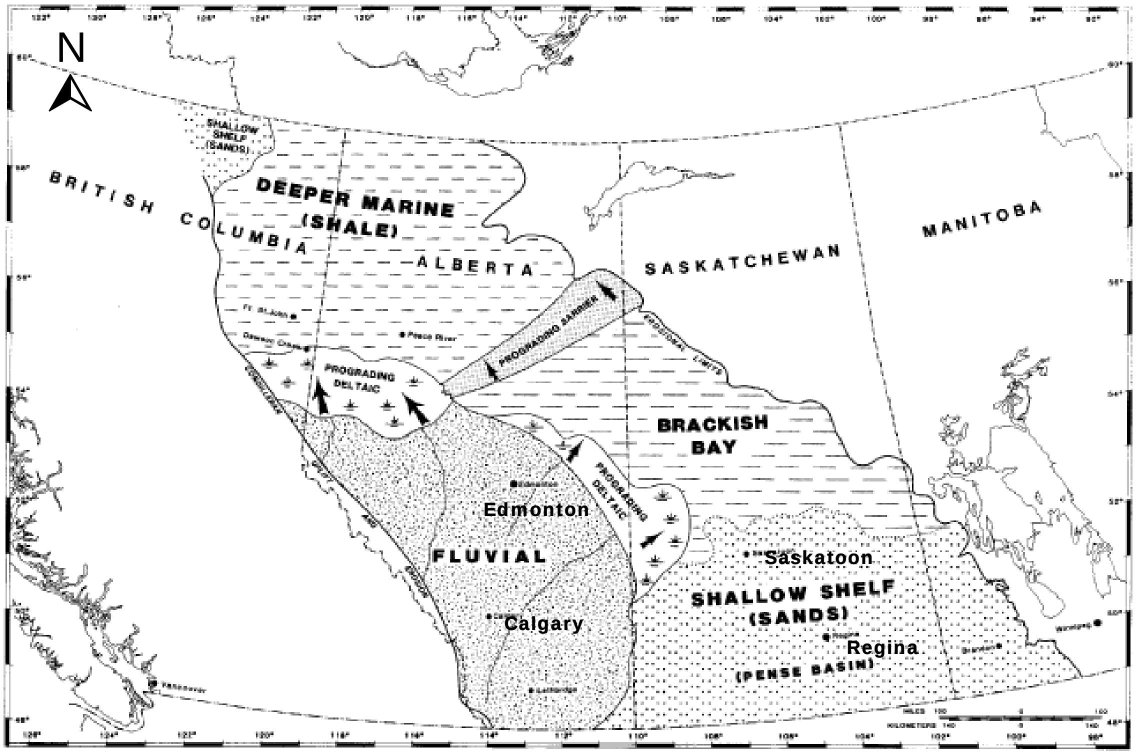

FIG. 1. Paleogeographic reconstruction of the Upper Mannville deposition. Red square shows location of the area of study (Modified from Leckie and Smith, 1992).

The exploration targets in the area are the Colony sand member of the Pense Formation, and the Sparky member of the Cantuar Formation, both part of the Cretaceous Mannville Group. In the area, the Mannville Group lies unconformably on Paleozoic strata, and its sedimentary pattern consists of an interplay of marine, estuarine and fluviatile agents acting in a setting controlled by paleo-topographic relief and eustatic and tectonic changes in relative sea-levels (Christopher, 1997).

The Sparky member is informally grouped into the middle Mannville, which is dominated by sheet sandstone development, with narrow, channel sandstones and shales also present (Putnam, 1982). These units have been interpreted as a delta-front facies with associated tidal-flat, tidal-channel, and beach environments (Vigrass,1977). In the case of the Sparky member, the sheet sandstones are commonly 6-9 m thick, and can be traced laterally for several tens of kilometers; however, they are commonly broken by thick ribbon-shaped deposits or sandstone pinchouts (Putnam, 1982)

The Colony sand member consists of shales, siltstones, coals and sandstones. Deposition of this member occurred in an extensive complex of anastomosing channels sandstones, encased within siltstones, shales, coals and thin sheet sandstones (Putnam and Oliver, 1980). Figure 2 shows a schematic depositional model for the Colony sands, including the three distinct facies: channel, crevasse splay and interchannel wetlands. The Colony sand member is unconformably overlain by the Joli Fou marine shale, representing the basal unit of the Colorado Group, which is dominated by marine shales encasing generally thin but extensive sandstones, such as the Viking, Dunvengan and Cardium formations (Leckie et al., 1994).

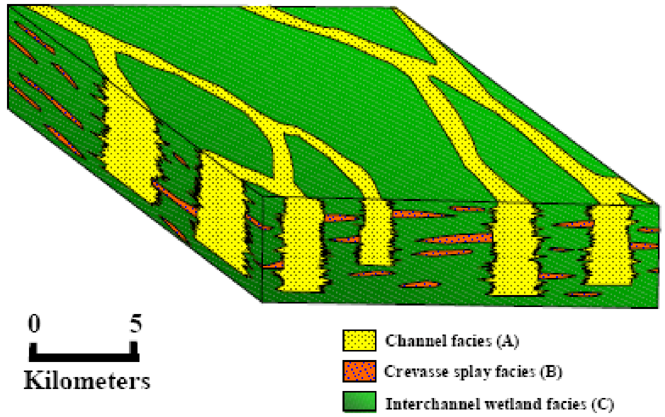

FIG. 2. Depositional model for the Colony sand member after Putnam and Oliver (1980) (From Royle, 2002).

WELL LOG DATA

A suite of logs from three wells in the area was provided by CALROC Energy Ltd. for this study. Three wells were available for this study (A11-17-44-27, C07-16-44-27 and C10-17-44-27) with a suite of logs, including gamma-ray (GR), spontaneous potential (SP), density (RHOZ), neutron and density porosity (PHIN and PHID), caliper, and resistivity, among others. A P-wave sonic log is available in wells C07-16 and A11-17, which also has an S-wave sonic. All wells are located within sand channels of the Colony, but only A11-17 is producing oil from this interval, while the other two produce oil from the Sparky B.

Figures 3-5 show the logs for each of the three wells, over the interval of interest. In all wells, there is a sharp decrease in the GR and SP curves at the top of the Mannville, indicating clean and permeable zones. The photoelectric factor is around 2 for most of the Mannville section (See Figure 4), indicating that sandstone is the dominant lithology.

At the top of the Colony there is some crossover between the neutron and density porosity, possibly indicating the presence of gas. This crossover is very thin in wells A11-17 and C10-17, but significantly more evident in well C07-16. This well also shows a much thicker Colony channel, saturated with gas, oil and water. The contacts between these fluids were interpreted based on the porosity cross-over (gas/oil) and the resistivity curve (oil/water). Another interesting effect is seen at the top of the Colony sand, where there is a sharp increase on the S-wave velocity but almost no change on the P-wave velocity (Figure 4), probably due to the lithologic change between sand and shale, which is seen by the S-wave but not the P-wave.

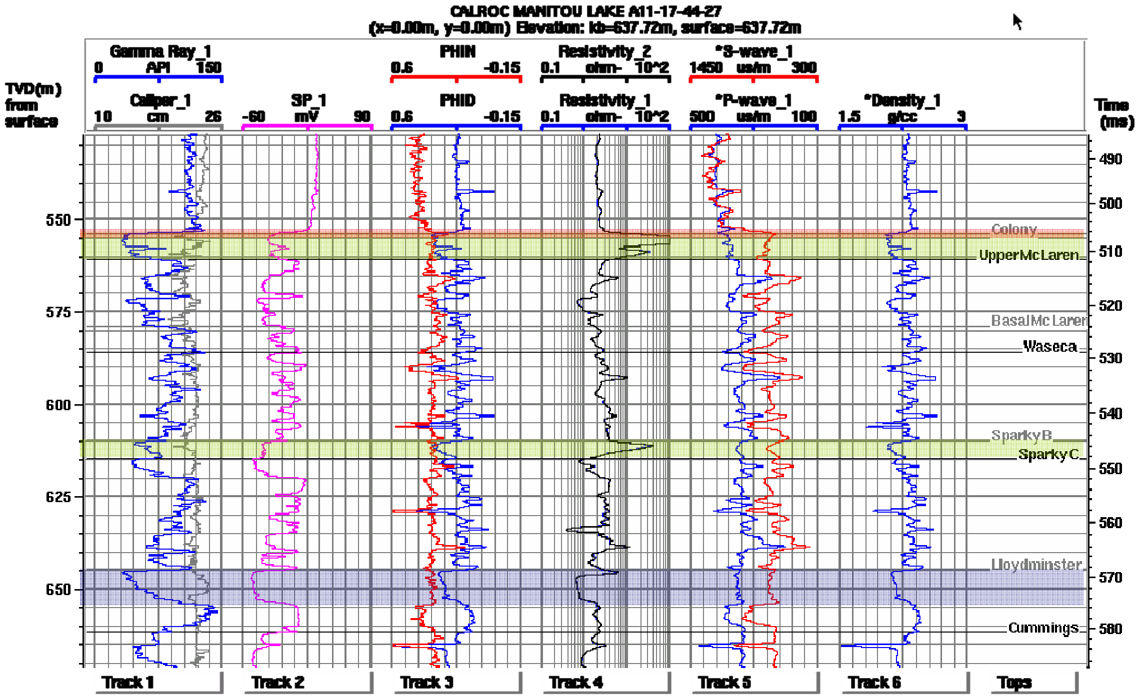

FIG. 3. Logs from well A11-17-44-27. Shaded areas indicate fluid present (red=gas, green=oil and blue=water).

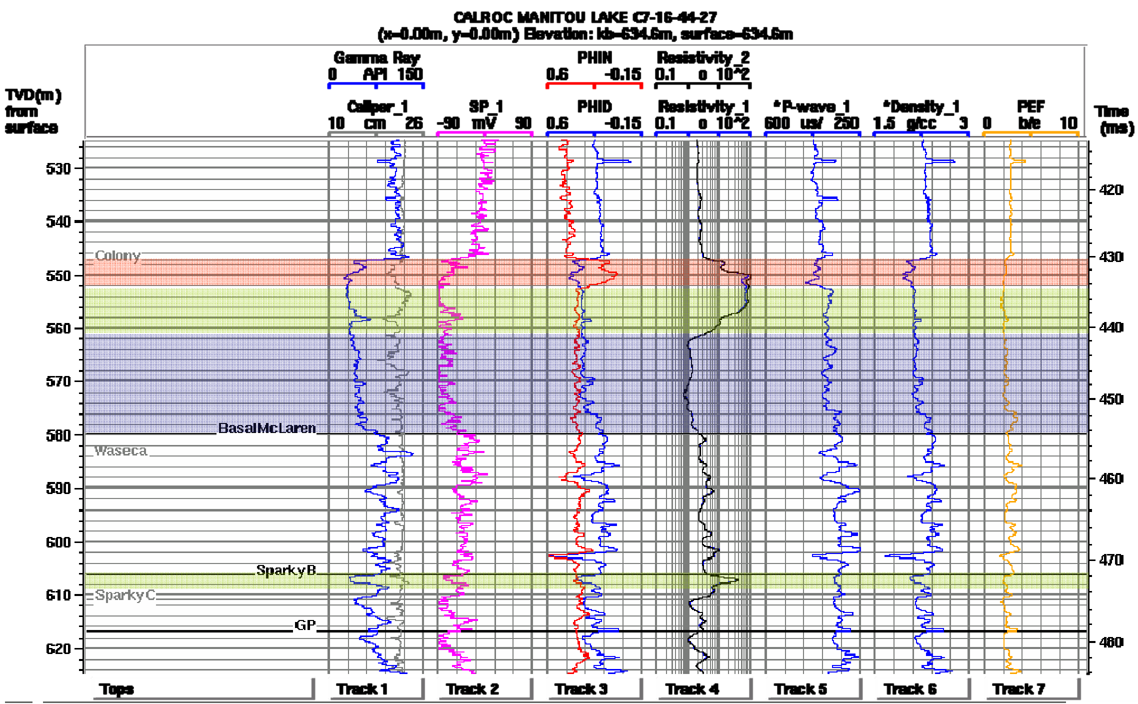

FIG. 4. Logs from well C07-16-44-27. Shaded areas indicate fluid present (red=gas, green=oil and blue=water).

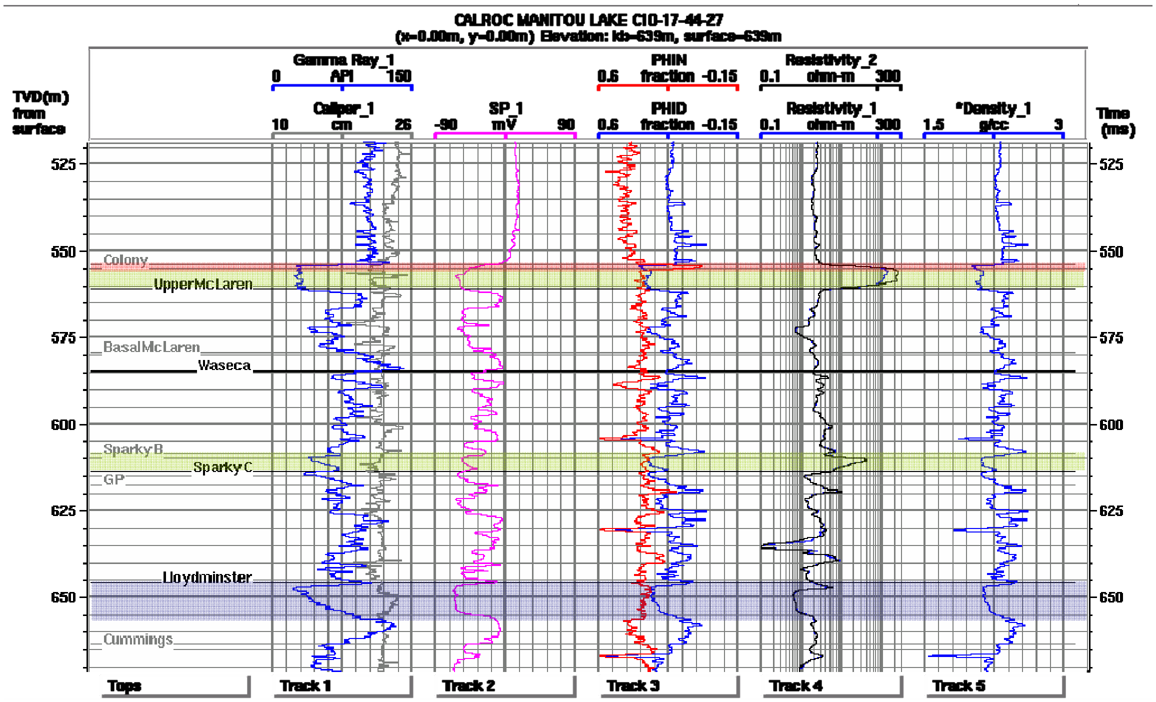

FIG. 5. Logs from well C10-17-44-27. Shaded areas indicate fluid present (red=gas, green=oil and blue=water).

LOG ANALYSIS

The first step in a log analysis is to identify the zones of interest (clean zones with hydrocarbons), and define clean and shale baselines on the logs. The top of the Colony sand is clearly identified in all wells by a significant deviation to the right in the GR, SP and porosity logs, as we pass from the marine shales of the Joli Fou formation to the channel sands of the Colony member. The depth of this top varies between 547.5 m and 554 m in the three wells. The Sparky B member is thinner and shalier than the Colony in these particular wells, with lower resistivities but similar porosities. The zones of interest for the petrophysical interpretation were defined in terms of clean zones with hydrocarbon saturation (low GR and high resistivity), as well as two water zones used to calculate water resistivity at formation temperature, which is necessary to calculate water saturation and permeability. Areas shaded in red in figures 3-5 indicate gas zones, interpreted from crossover of the porosity logs, green shaded areas correspond to oil zones, based on high resistivity values, and blue shaded areas correspond to water zones (very low resistivities).

After picking clean and shale lines on the logs, the next step is shale volume estimation. In this study, shale volume (V_{sh}) was calculated by the three common methods (Equations 1 to 3), which use values from the gamma ray (GR), spontaneous potential (SP), and neutron (PHIN) and density (PHID) porosity logs, with the minimum of the three being selected as the shale volume

$$V_{shg} = \frac{GR - GR_{clean}}{GR_{shale} - GR_{clean}} \quad (1)$$

$$V_{shs} = \frac{SP - SP_{clean}}{SP_{shale} - SP_{clean}}\text{, and} \quad (2)$$

$$V_{shhx} = \frac{PHIN - PHID}{PHIN_{shale} - PHID_{shale}} \quad (3)$$

GR, *SP*, *PHIN* and *PHID* are the picked log values, while *clean* and *shale* indicate values picked in the clean and shale base lines, respectively.

Porosity from logs is considered total porosity (*PHIt*), which includes the bound water in the shale; to obtain effective porosity (*PHIe*) it must be corrected for shale volume. When both the neutron and density porosity curves are available, as in this case, the best method for correcting porosity is the Complex Lithology Density Neutron crossplot. First, porosity is corrected for shale volume by $PHIxc = PHID - (V_{sh} \times PHI_{shale})$ (4), where *x* will be *n* for neutron or *d* for density porosity. Effective porosity is then calculated as:

$$PHI_e = \frac{PHI_{nc} + PHI_{dc}}{2} \quad (5)$$

This method works equally well in quartz sands as in mixtures, except in areas with bad hole conditions which affect the density reading (Crain, 2006).

The density and neutron porosity logs show cross-over at the top of the Mannville, suggesting the presence of gas. For this reason, the porosity in the uppermost interval was corrected using the equation for neutron-density porosity in a gas zone (Asquith and Krygowski, 2004)

$$PHIe_{NDgas} = \sqrt{\frac{PHI_{dc}^2 + PHI_{nc}^2}{2}} \quad (6)$$

To calculate water saturation, most methods require a water resistivity (R_w) value. In this case, an obvious clean water zone is present in two of the wells in the area and the water resistivity was calculated from the porosity and resistivity in this zone, using the *Ro* method, given by the following equation:

$$RW\ @\ FT = \frac{PHI_{wtr}{}^{m}\, Ro}{a} \quad (7)$$

RW@FT is the water resistivity at formation temperature, PHI_{wtr} and R_o are the total porosity and deep resistivity values in the water zone, *a* is the tortuosity factor and *m* is the cementation exponent.

Water saturation (S_{wa}) can then be calculated using Archie's method, given by:

$$S_{wa} = \left(\frac{RW@FT}{R_{wa}} \right)^{1/n} \tag{8}$$

where n is the saturation exponent and R_{wa} is water resistivity in the zone of interest, calculated in the same manner as $RW@FT$:

$$R_{wa} = \frac{PHI_t^{\,m} * RESD}{a} \tag{9}$$

Note that in the water zone, saturation should be equal to 1, as $RW@FT$ is equal to R_{wa}. The parameters a, m and n should be determined from core analysis if possible; however, in this case, a, m and n were set to 0.62, 2.15 and 2, respectively, based on usual values for unconsolidated sandstones (Asquith and Krygowski, 2004).

Permeability (*Perm*) is calculated using the Wyllie-Rose method considering Morris-Biggs parameters, which is generally used when no core data is available:

$$Perm_w = \frac{CPERM * (PHI_e)^{DPERM}}{(SW_{ir})^{EPERM}} \tag{10}$$

where SW_{ir} is the irreducible water saturation, and *CPERM*, *DPERM* and *EPERM* are constants, which should be adjusted by core calibration. In this case, they were set to Morris-Biggs values (65000, 6 and 2, respectively, for the oil-saturated zoned and 6500, 6 and 2 for the gas-saturated zones). SW_{ir} is assumed to be equivalent to the water saturation estimated from Archie's equation.

Finally, the productivity and reserves of the intervals of interest are estimated, along with an estimated flow rate. These values are a useful way of comparing the quality of wells from similar reservoirs, even when results are not calibrated (Crain, 2006).

RESULTS

The previous methodology was applied to the 4 zones of interest defined in each well (See Table 1). The first zone in all wells corresponds to gas saturated sands in the Colony member, while the second zone corresponds to oil saturated sands within the same formation. A water zone was also interpreted in each well, and was used to calculate water resistivity.

Table 1. Summary of analyzed zones in each well (Formation/Fluid).

	Well A11-17	Well C10-17	Well C07-16
Zone 1	Colony/Gas	Colony/Gas	Colony/Gas
Zone 2	Colony/Oil	Colony/Oil	Colony/Oil
Zone 3	Sparky/Oil	Sparky/Oil	Colony/Water
Zone 4	Lloydminster/Water	Lloydminster/Water	Sparky/Oil

Tables 2-4 summarize the results from the log analysis from all three wells in the area. The picked values for each zone in every well and all intermediate calculations are shown in appendix A. The productivity calculations are expressed by the values *HPV* (Hydrocarbon volume per unit area), *NetH* (net pay thickness), R_{oil} (recoverable reserves of oil), Q_o (Calculated oil productivity), R_{gas} (recoverable reserves of gas) and Q_g (Calculated gas productivity).

Wells A11-17 and C10-17 are located very close to each other within the same sand channel (Figure 6), and the log analysis results in very similar values for the different parameters in both wells. The Colony channel has a thickness of approximately 8 m in both wells, with a gas cap of 2 m, and the remaining 6 m being saturated with oil. The Sparky B member shows a thickness of 3 m. Porosities are very high in all the interpreted zones, ranging from 0.3 to 0.38. The difference between neutron and density porosity is small in all zones, except where there is gas present and significant cross-over occurs. This, coupled with the low shale volumes, results in effective porosities very similar to the total, except in the gas bearing zones, where a corrected equation for effective porosity is used and results in lower porosity values.

The three water zones used to calculate water resistivities at formation temperature give consistent results, between 0.13 and 0.15 Ωm. Permeabilities calculated within the oil zone in the Colony sand are extremely high (between 8000 and 30000 mD) due to the very high resistivities and porosities of the interval. This probably implies that the default values of CPERM, EPERM and DPERM used are not appropriate for this area, and calibration with core is necessary to obtain better parameters. However, other studies in the Pikes Peak heavy oil field (Zoue et al., 2006) show similar results for the Waseca channel facies, with oil saturation of 80 %, porosities around 34 % and permeabilities of 5000 md.

The productivity parameters calculated are significantly affected by the permeability calculation, so they will only be considered comparatively between one well to another. Note that results for wells C10-17 and A11-17 are very similar, both for the Colony and the Sparky members, although there is significant variation in the flow rate for the Colony. This interval shows higher reserves and productivity than the Sparky, due to the higher permeability and thickness. However, the reservoir within the Colony is limited to channel facies which are more difficult to map accurately, making the Sparky a more widespread target in the area.

The results for well C07-16 are consistent with those of the other two wells, even though it is located in a distant part of the interpreted channel.

Table 2. Summary of results from log analysis in well A11-17-44-27.

Zone	Top (m)	Bottom (m)	Vsh (frac)	PHIe (frac)	Sw (frac)	Perm (md)
1	553.5	555	0.0476	0.23	0.11	80.97
2	555	561	0.0761	0.33	0.06	20516
3	610	613	0.12	0.32	0.14	3795.07
4	646	654	0.0	0.35	1	119.48
Zone	**HPV (m)**	**NetH (m)**	**Roil (10^3m^3)**	**Qo (m^3/day)**	**Rgas (10^3m3)**	**Qg (m^3/day)**
1	0.30	1.5	N/A	N/A	5869	81.28
2	1.86	6	476.488	167.87	N/A	N/A
3	0.77	3	213.768	23.43	N/A	N/A
4	N/A	N/A	N/A	N/A	N/A	N/A

Table 3. Summary of results from log analysis in well C10-17-44-27.

Zone	Top (m)	Bottom (m)	Vsh (frac)	PHIe (frac)	Sw (frac)	Perm (md)
1	554	556	0.0442	0.18	0.21	5.46
2	556	561	0.0619	0.34	0.05	33847
3	609	612.5	0.1428	0.29	0.14	1964.47
4	648	655	0.0595	0.30	1	52.23
Zone	**HPV (m)**	**NetH (m)**	**Roil (10^3m^3)**	**Qo (m^3/day)**	**Rgas (10^3m^3)**	**Qg (m^3/day)**
1	0.28	2	N/A	N/A	5449	7.27
2	1.62	5	414.074	319.14	N/A	N/A
3	0.87	3.5	222.976	19.40	N/A	N/A
4	N/A	N/A	N/A	N/A	N/A	N/A

Table 4. Summary of results from log analysis in well C7-16-44-27.

Zone	Top (m)	Bottom (m)	Vsh (frac)	PHIe (frac)	Sw (frac)	Perm (md)
1	547.5	553	0.0462	0.19	0.14	13.94
2	553	561	0.0462	0.34	0.10	8136
3	561	580	0.1667	0.28	1	3.21
4	606.5	608.5	0.0462	0.36	0.14	742.86
Zone	**HPV (m)**	**NetH (m)**	**Roil (10^3m3)**	**Qo (m^3/day)**	**Rgas ($10^3 m^3$)**	**Qg (m^3/day)**
1	0.88	5.5	N/A	N/A	16593	50.28
2	2.4	8	613.33	114.04	N/A	N/A
3	N/A	N/A	N/A	N/A	N/A	N/A
4	0.62	2	158.58	3.85	N/A	N/A

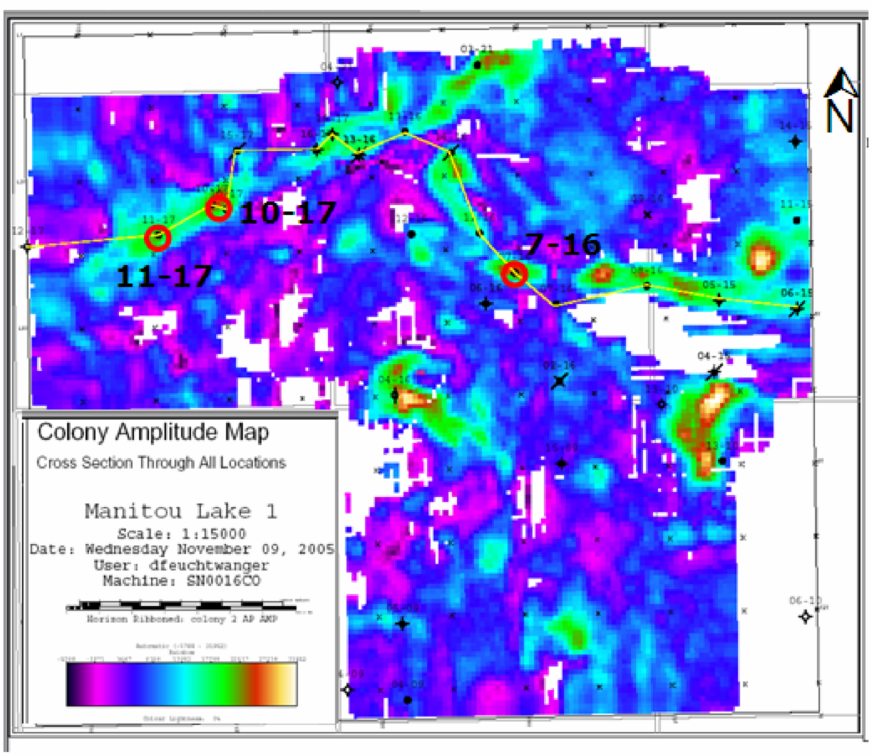

FIG. 6. Amplitude map of the top of the Colony from a 3D seismic data volume, showing amplitude anomaly related to a sand channel. Red circles show location of the wells (Calroc, 2006).

CONCLUSIONS

The log analysis performed shows that Colony sand contains significant accumulations of oil. The sand channel has an average thickness of 7 m, and effective porosity in the order or 0.35. The Sparky interval in these wells is very thin, with an average thickness of 3 m, it has a higher shale volume and lower resistivities, as well. However, the wells used are specifically located within the interpreted trend of a Colony channel, which doesn't coincide with interpreted channels in the Sparky member. Further calibration of the log analysis parameters with core, test and production data is necessary to verify the calculated values, as the permeabilities for the Colony member are extremely high.

Logs from wells A11-17 and C10-17 provide very similar results, which are expected due to their proximity and their location within the same interpreted sand channel. However, well C07-16 shows a Colony interval which is considerably thicker than in the other wells, with a log character which is different from the other wells, suggesting the well could be located on a different channel. This well shows higher reserves; however, the reservoir appears to be of lower quality, as the permeabilities and flow rates are lower than the other wells.

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APPENDIX A

Appendix A	A11-17			
PARAMETERS:	Colony gas	Colony Oil	Sparky oil	Lloyd Water
GR clean line (GR0)	30	30	30	30
GR shale line (GR100)	135	135	135	135
SP clean line (SP0)	-50	-50	-50	-50
SP shale line (SP100)	27	27	27	27
DPHI shale line (PHIDSH)	0.2	0.2	0.2	0.2
NPHI shale line (PHINSH)	0.45	0.45	0.45	0.45
Sonic shale line (DELTSH)				
Resisitivity shale line (RSH)	2.5	2.5	2.5	2.5
Resisitivity of water zone (R0)	0.9	0.9	0.9	0.9
Bottom hole temperature (BHT)	22	22	22	22
Surface temperature (SUFT)	10	10	10	10
Bottom hole depth (BHTDEP)	707	707	707	707
	Zone 1	Zone 2	Zone 3	Zone 4
Layer top	553.5	555	610	646
Layer bottom	555	561	613	654
Deep Resistivity (RESD)	77	200	40	0.9
Neutron porosity (PHIN)	0.3	0.375	0.38	0.4
Density porosity (PHID)	0.38	0.34	0.35	0.3
Sonic travel time (DELT)				
Gamma Ray (GR)	35	38	50	53
Spontaneous potential (SP)	-24	-30	-38	-50
Photo-electric effect (PE)	1.9	2.1	1.9	1.9
Caliper (CAL)	234	234	234	234
Shale Volume				
Vshg	0.047619048	0.07619048	0.19047619	0.219047619
Vshs	0.337662338	0.25974026	0.155844156	0
Vshx	-0.32	0.14	0.12	0.4
Vsh	0.047619048	0.07619048	0.12	0
Porosity				
PHIdc	0.37047619	0.3247619	0.326	0.3
PHInc	0.278571429	0.34071429	0.326	0.4
PHIxdn	0.231762081	0.3327381	0.326	0.35
PHIsc	0	0	0	0
PHIe=PHIxdn	0.231762081	0.3327381	0.326	0.35
Water Resistivity				
PHIwtr	0.35	0.35	0.35	0.35
RW@FT	0.151913761	0.15191376	0.151913761	0.151913761
Water Saturation				
PHIt	0.34	0.3575	0.365	0.35
Rwa	12.21177257	35.3331051	7.389209168	0.151913761
Swa	0.111534495	0.06557037	0.143383632	1

Sw	0.111534495	0.06557037	0.143383632	1
Irreducible water saturation				
KBUCKL	0.025849467	0.02181776	0.046743064	0.35
Swir	0.111534495	0.06557037	0.143383632	1
Permeability				
PERMw=perm	80.97467951	20516.9691	3795.070099	119.4872656
Fluid Properties				
PF	5764.2	5803.2	6359.6	6760
PF in psi	835.809	841.464	922.142	980.2
PS	100.21	100.21	100.21	100.21
FT	19.40735502	19.4710042	20.37906648	21.03253182
FT in Fahrenheit	66.93323904	67.0478076	68.68231966	69.85855728
DENShy	982.6388889	982.638889	982.6388889	982.6388889
GOR	1307.820833	1317.32683	1453.323663	1551.591875
Bo	1.002214569	1.00227698	1.003278408	1.004135231
VISd	34050.97493	33352.1525	25013.58796	20519.45793
VISo	32.37300036	31.6154036	22.98926982	18.64819914
Reserves				
NetH=THICK	1.5	6	3	8
PV	0.347643121	1.99642857	0.978	2.8
HPV	0.308868921	1.86552201	0.837770808	0
Kh	121.4620193	123101.814	11385.2103	955.898125
Roil	78895.72386	476488.679	213768.5064	0
Bg	74.22750428	74.713457	81.62342013	86.56960231
Rgas	5869201.712	35681177.1	17505719.97	0
Productivity				
Qo	0.160657801	167.876586	23.43525517	2.580815997
Qg	81.28810425	83505.81	9274.826474	879.5633632
Reserves:				
RF	0.4	0.4	0.4	0.4
KV3 (metric)	1	1	1	1
AREA	640000	640000	640000	640000
Productivity:				
KV1	0.00000756	0.00000756	0.00000756	0.00000756
KV2	0.0000061	0.0000061	0.0000061	0.0000061
KT2	273	273	273	273
ZF	0.75	0.75	0.75	0.75

	C10-17			
PARAMETERS:	Colony gas	Colony Oil	Sparky oil	Lloyd Water
GR clean line (GR0)	22	22	22	22
GR shale line (GR100)	135	135	135	135
SP clean line (SP0)	-70	-70	-70	-70
SP shale line (SP100)	14	14	14	14
DPHI shale line (PHIDSH)	0.225	0.225	0.225	0.225
NPHI shale line (PHINSH)	0.45	0.45	0.45	0.45
Sonic shale line (DELTSH)				
Resisitivity shale line (RSH)	3	3	3	3
Resisitivity of water zone (R0)	0.9	0.9	0.9	0.9
Bottom hole temperature (BHT)	25	25	25	25
Surface temperature (SUFT)	10	10	10	10
Bottom hole depth (BHTDEP)	709	709	709	709
	Zone 1	Zone 2	Zone 3	Zone 4
Layer top	554	556	609	648
Layer bottom	556	561	612.5	655
Deep Resistivity (RESD)	50	220	40	0.9
Neutron porosity (PHIN)	0.05	0.38	0.36	0.35
Density porosity (PHID)	0.375	0.35	0.32	0.3
Sonic travel time (DELT)				
Gamma Ray (GR)	27	29	40	40
Spontaneous potential (SP)	-40	-60	-58	-65
Photo-electric effect (PE)	1.8	1.8	2	1.9
Caliper (CAL)	222	222	222	222
Shale Volume				
Vshg	0.044247788	0.061946903	0.159292035	0.159292035
Vshs	0.357142857	0.119047619	0.142857143	0.05952381
Vshx	-1.444444444	0.133333333	0.177777778	0.222222222
Vsh	0.044247788	0.061946903	0.142857143	0.05952381
Porosity				
PHIdc	0.365044248	0.336061947	0.287857143	0.286607143
PHInc	0.030088496	0.352123894	0.295714286	0.323214286
PHIxdn	0.18314108	0.34409292	0.291785714	0.304910714
PHIsc	0	0	0	0
PHIe=PHIxdn	0.18314108	0.34409292	0.291785714	0.304910714
Water Resistivity				
PHIwtr	0.325	0.325	0.325	0.325
RW@FT	0.129538853	0.129538853	0.129538853	0.129538853
Water Saturation				
PHIt	0.2125	0.365	0.34	0.325
Rwa	2.886689176	40.64065042	6.343777956	0.129538853
Swa	0.211836119	0.056457247	0.142897962	1
Sw	0.211836119	0.056457247	0.142897962	1

Irreducible water saturation				
KBUCKL	0.038795896	0.019426539	0.041695584	0.304910714
Sw	0.211836119	0.056457247	0.142897962	1
Permeability				
PERMw=perm	5.465475563	33847.63925	1964.470155	52.23354104
PF	5772	5808.4	6351.8	6775.6
PF in psi	836.94	842.218	921.011	982.462
PS	100.21	100.21	100.21	100.21
FT	21.74188999	21.81593794	22.92136812	23.78349788
FT in Fahrenheit	71.13540197	71.26868829	73.25846262	74.81029619
DENShy	982.6388889	982.6388889	982.6388889	982.6388889
GOR	1303.448279	1312.241757	1443.818727	1546.792688
Bo	1.003538108	1.003618537	1.004954113	1.006181278
VISd	16683.04495	16333.99827	12030.80659	9594.356638
VISo	23.39798366	22.88418889	16.74315068	13.41703174
Reserves				
NetH=THICK	2	5	3.5	7
PV	0.36628216	1.720464602	1.02125	2.134375
HPV	0.288690368	1.623331907	0.875315456	0
Kh	10.93095113	169238.1963	6875.645542	365.6347873
Roil	73644.17331	414074.6235	222976.1078	0
Bg	73.73922492	74.18560942	80.82293154	85.96508961
Rgas	5449677.827	30829533.9	18110863.66	0
Productivity				
Qo	0.020031868	319.1413517	19.40834829	1.37527485
Qg	7.277566936	114096.9685	5539.211706	334.8812887
Reserves:				
RF	0.4	0.4	0.4	0.4
KV3 (metric)	1	1	1	1
AREA	640000	640000	640000	640000
Productivity:				
KV1	0.00000756	0.00000756	0.00000756	0.00000756
KV2	0.0000061	0.0000061	0.0000061	0.0000061
KT3	273	273	273	273
ZF	0.75	0.75	0.75	0.75

	C07-16			
PARAMETERS:	Colony Gas	Colony Oil	Colony water	Sparky Oil
GR clean line (GR0)	27	27	27	27
GR shale line (GR100)	135	135	135	135
SP clean line (SP0)	-90	-90	-90	-90
SP shale line (SP100)	0	0	0	0
DPHI shale line (PHIDSH)	0.225	0.225	0.225	0.225
NPHI shale line (PHINSH)	0.45	0.45	0.45	0.45
Sonic shale line (DELTSH)	420	420	420	420
Resisitivity shale line (RSH)	2.5	2.5	2.5	2.5
Resisitivity of water zone (R0)	1	1	1	1
Bottom hole temperature (BHT)	23	23	23	23
Surface temperature (SUFT)	10	10	10	10
Bottom hole depth (BHTDEP)	640	640	640	640
	Zone 1	Zone3	Zone 2	
Layer top	547.5	553	561	606.5
Layer bottom	553	561	580	608.5
Deep Resistivity (RESD)	100	78	1	40
Neutron porosity (PHIN)	0.11	0.375	0.375	0.38
Density porosity (PHID)	0.375	0.33	0.3	0.375
Sonic travel time (DELT)	364	364	364	364
Gamma Ray (GR)	32	32	45	32
Spontaneous potential (SP)	-77	-77	-85	-80
Photo-electric effect (PE)	1.9	1.9	1.9	1.9
Caliper (CAL)	217	217	217	217
Shale Volume				
Vshg	0.046296296	0.046296296	0.166667	0.0462963
Vshs	0.144444444	0.144444444	0.055556	0.1111111
Vshx	-1.177777778	0.2	0.333333	0.0222222
Vsh	0.046296296	0.046296296	0.166667	0.0462963
Porosity				
PHIdc	0.364583333	0.319583333	0.2625	0.3645833
PHInc	0.089166667	0.354166667	0.3	0.3591667
PHIxdn	0.187664396	0.336875	0.28125	0.361875
PHIsc	0.58451897	0.58451897	0.661585	0.584519
PHIe=PHIxdn	0.187664396	0.336875	0.28125	0.361875
Water Resistivity				
	0.3375	0.3375	0.3375	0.3375
#VALUE!	0.156097854	0.156097854	0.156098	0.1560979
Water Saturation				
PHIt	0.2425	0.3525	0.3375	0.3775
Rwa	7.668996822	13.36887997	0.156098	7.9440095
Swa	0.142668859	0.108056514	1	0.1401776

Sw	0.142668859	0.108056514	1	0.1401776
Irreducible water saturation				
KBUCKL	0.026773865	0.036401538	0.28125	0.0507268
Sw	0.142668859	0.108056514	1	0.1401776
Permeability				
PERMw=perm	13.94910324	8136.247376	3.21713	742.86119
PF	5722.6	5792.8	5933.2	6318
PF in psi	829.777	839.956	860.314	916.11
PS	100.21	100.21	100.21	100.21
FT	21.17695313	21.3140625	21.58828	22.339844
FT in Fahrenheit	70.11851563	70.3653125	70.85891	72.211719
DENShy	982.6388889	982.6388889	982.6389	982.63889
GOR	1292.752671	1309.737192	1343.737	1437.1213
Bo	1.003173643	1.003318457	1.00362	1.0045292
VISd	19659.73366	18882.86356	17435.87	14098.347
VISo	25.6430756	24.56147662	22.57533	18.13256
Reserves				
NetH=THICK	5.5	8	19	2
PV	1.032154175	2.695	5.34375	0.72375
HPV	0.884897917	2.403787694	0	0.6222965
Kh	76.72006783	65089.979	61.12546	1485.7224
Roil	225817.2036	613334.3264	0	158589.61
Bg	73.24852015	74.11252861	75.83813	80.55114
Rgas	16593270.51	45606600.77	0	12832433
Productivity				
Qo	0.127169109	114.048968	0.119399	3.8515575
Qg	50.28889609	43717.24285	43.06446	1186.3629
Reserves:				
RF	0.4	0.4	0.4	0.4
KV3 (metric)	1	1	1	1
AREA	640000	640000	640000	640000
Productivity:				
KV1	0.00000756	0.00000756	7.56E-06	7.56E-06
KV2	0.0000061	0.0000061	6.1E-06	0.0000061
KT4	273	273	273	273
ZF	0.75	0.75	0.75	0.75