EVALUATION OF COALBED METHANE RESOURCE POTENTIAL

USING LIMITED DATA

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A

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ABSTRACT

This study presents the results of the evaluation of the Coalbed Methane (CBM) resource potential of the Cook Inlet Basin using a computer-aided well log analysis of the subsurface data. Coal seams were identified from the well logs. Formation and reservoir fluid properties including porosity, water saturation and net pay thickness of the coal seams were determined. The analysis revealed discontinuous coal seams interspaced largely by mudstone, silt, and sandstone formations within the depth of investigation. The CBM resource (Original Gas In Place) and recoverable reserves were estimated on per acre-foot basis. Monte Carlo simulation was run to refine the estimated CBM reserves and to allow for variations in the measured petrophysical input parameters used in the resource evaluation.

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CHAPTER 1

INTRODUCTION

The Cook Inlet Basin is the source of natural gas to meet power generation and utility needs in south-central Alaska. Gas supply from proven reserves in known fields is estimated to meet demand until 2012 (*Barker, 2003*). A shortage could occur by 2009 unless new reserves are found and developed, or industrial use is curtailed, or an alternative source of energy is discovered and developed. Coal is the most abundant energy source in the world. The coalification process, whereby plant material is gradually converted to coal, generates large volumes of methane-rich gas. In the United States, methane produced from coalbeds is an important energy source.

In the state of Alaska, collaborative research projects have been conducted since the middle 1990s to assess the coalbed methane resource potential of the state. These studies have shown that in the western Colville sub-basin of the North Slope Basin, the Cretaceous Nanushuk Formation, contains up to 150 coal seams ranging in thickness from 5 to 28 ft over a 40,000 mi^2 area. Near Wainwright, Nanushuk coals have a 0.4 to 0.5% mean random vitrinite reflectance (Rv-r) at the surface, which increases to about 0.6% Rv-r at 2000 ft depth. At this depth, adsorption isotherm analysis indicates a gas storage capacity of 80 scf/ton (as received basis) if the coal is gas-saturated. The North Slope Basin also contains Late Cretaceous to Tertiary Sagavanirktok Formation coals, with beds up to 30 ft thick and net coal thickness locally exceeding 150 ft. Geophysical logs indicate Sagavanirktok coals underlie about 2000 mi^2 between the Prudhoe Bay area and outcrops 70 miles to the south.

Sagavanirktok coals are about 0.3%Rv-r at the surface and increase to nearly 0.6% Rv-r at 6000 ft depth in the Prudhoe Bay area. Preliminary resource calculations indicate a geologic potential of about 800 TCF of CBM in the North Slope Basin (*Barker, 2003*). Thus, there appears to be enormous CBM resource potential in the state.

1.1 Statement of the Problem

Several studies have shown that Coalbed Methane gas is a major potential resource for south-central Alaska (*Barker, 2003*). However, the timing and economic viability of any contribution from this resource is highly uncertain because of the lack of sufficient data to predict gas productivity and the level of water disposal. There is therefore the need to obtain and analyze subsurface data to confirm the CBM resource potential in the area, and to evaluate its viability as an alternative source of energy.

1.2 Objectives and Scope of the Study

A well (AK94-CBM-1) was drilled in 1994 at a location about 4.2 km northwest of Wasilla on the northeast margin of the Cook Inlet Basin (Figure 1). A suite of geophysical logs (gamma ray, density, spontaneous potential, neutron, and resistivity) was run to evaluate the Tyonek rock. The objective of this study is to analyze the wireline logs from the AK94-CBM-1 well to identify coal seam intervals and evaluate the coalbed methane potential in the Basin.

The study objectives are achieved by carrying out the following tasks:

1. Analysis of well logs from AK94-CBM-1 to develop a database of rock properties
2. Evaluation of resource potential using information derived from the well log analysis
3. Risk-weighted analysis to estimate most probable CBM reserves in the Cook Inlet Basin.

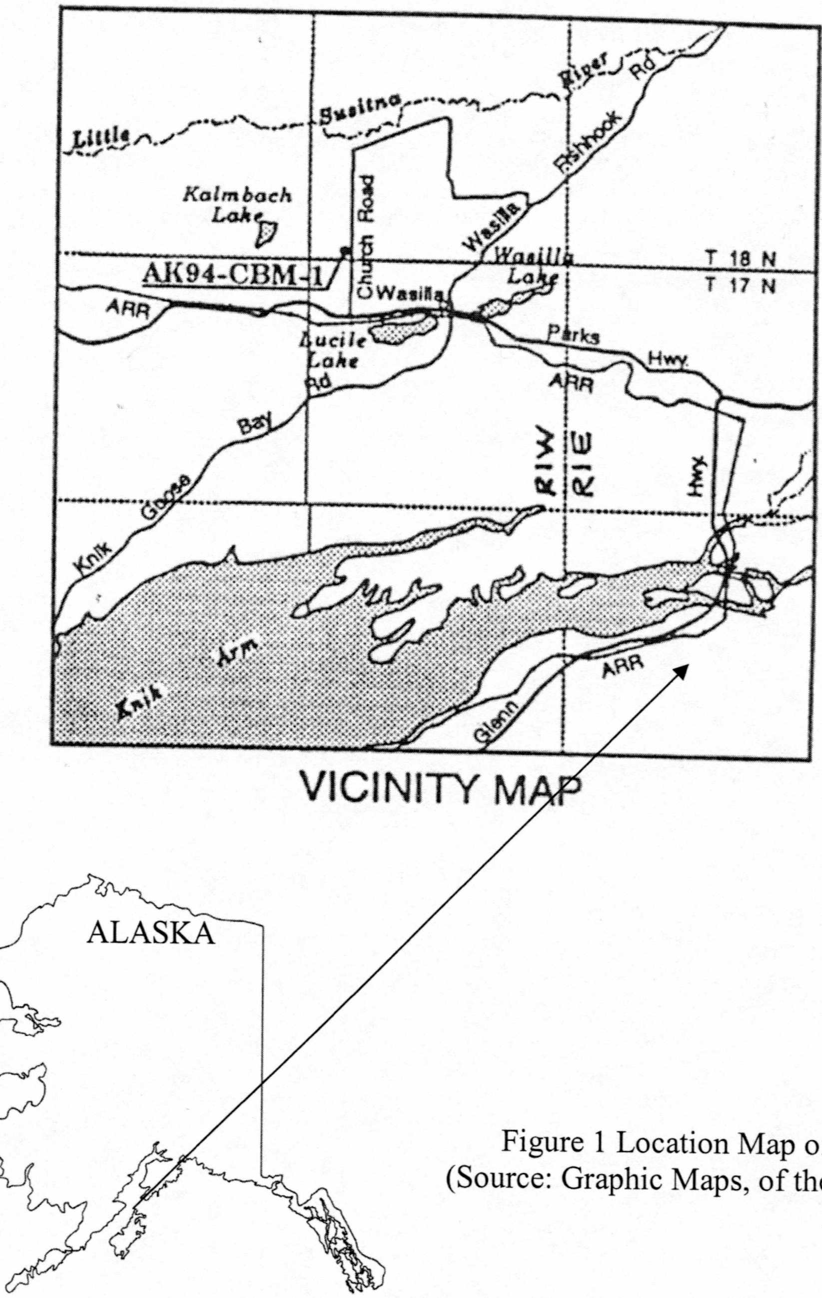

Figure 1 Location Map of Well AK94-CBM-1
(Source: Graphic Maps, of the Woolwine-Moen Group)

CHAPTER 2
OVERVIEW OF THE COOK INLET BASIN

In this chapter, a review of the geology and stratigraphy of the Cook Inlet Basin is presented.

2.1 Geologic Description of the Area

Geographically, Cook Inlet, located on Alaska's southern coast, is bounded to the northwest by the Alaska-Aleutian Range and Talkeetna Mountains; and on the southeast, the Kenai Peninsula Mountains. Folds in Cook Inlet are complex, discontinuous structures with variable shape that probably developed by right-transgressional deformation on oblique-slip faults extending downwards into the Mesozoic basement beneath the Tertiary basin (Figure 2). The basin is indicated by laterally discontinuous, inter-fingering beds of sandstone, siltstone, conglomerate and coal (*Barker, 2003*)

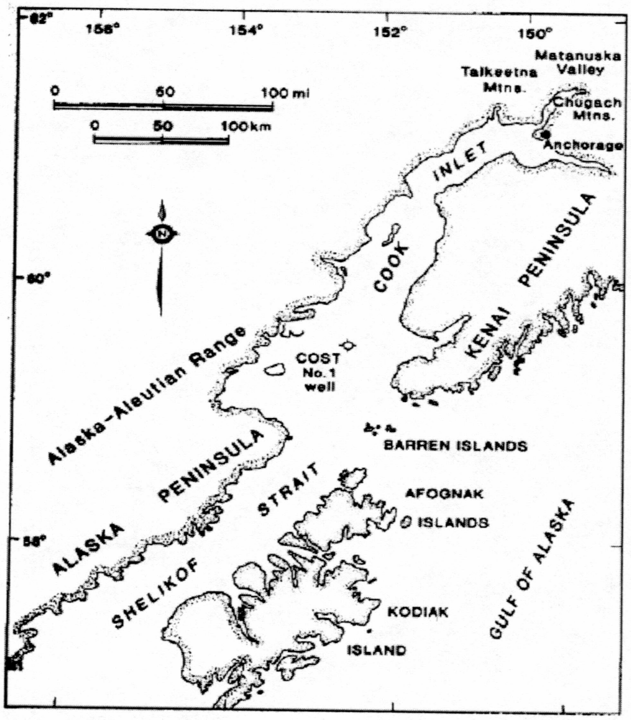

Figure 2 Location Map of Cook Inlet
(*Source: Whiticar, 2001*)

Major fault zones are close to the Margin of the Basin: the Castle Mountain fault to the north, the Bruin Bay fault to the northwest, and the Border Range fault along the southeast side (*Flores, 1997*)

2.2 Stratigraphy of the Area

The AK94-CBM-1 well is located south of the Castle Mountain Fault and it penetrated 50 to 200 ft of glacial-gravel and sand deposits. Below these recent deposits is the Tertiary Tyonek Formation, where drilling was done in competent sandstone, coal, and siltstone (Figure 3).

Recent deposition has been by glacial and alluvial processes; most detritus was derived from erosion of the Alaska Range. As a result, the Sterling Formation of Pliocene and younger age and the overlying Quaternary sediments are more than 3050m thick in parts of the basin. The Sterling Formation consists of massive sandstones, conglomeratic sandstones, and interbedded claystones. The latest Oligocene-middle Miocene Tyonek formation consists of massive bedded sandstone and thick coalbeds; the late Miocene Beluga formations consist of thinly bedded sandstones, claystones and lignitic coal *(Haeussler, 2000).*

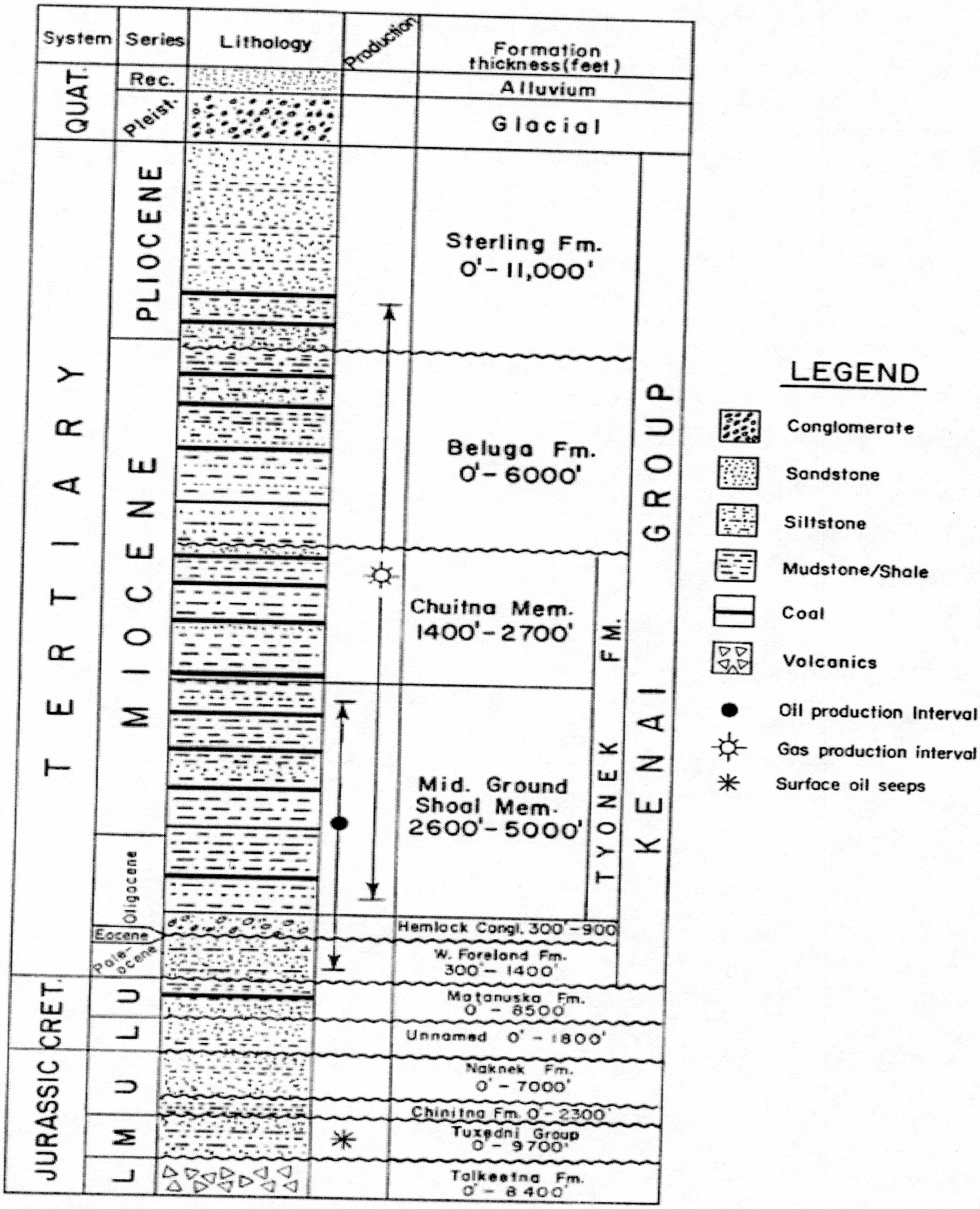

Figure 3 Generalized Stratigraphic Column in the Cook Inlet
(Source: *AOGCC, 2002*).

CHAPTER 3
FORMATION EVALUATION AND DEVELOPMENT OF PETROPHYSICAL PROPERTY DATABASE

This chapter details the approach and methodology used to carry out the objectives of the study. Analyses were done with the use of a number of computer programs including ***Interactive Petrophysics*** and ***Crystal Ball***.

3.1 Input Parameter Database

A database was developed for the AK94-CBM-1 well. The database consists of the log traces (curve data), general well information and the interpretation parameter sets associated with the well. The parameters used are listed on Table 1 below.

Table 1 Well Parameters Used in Log Analysis

Well Name:	AK94-CBM-1
Location	T18, R1W, Section 31
Township	Wasilla
Field and Pool	Tyonek Formation
Datum Elevation	Approx. 400 ft
Log Measured from:	350 ft
Rmf	63.5 ohm-m
Rw	0.651 ohm-m
Rm Temp:	60 F
Rmf Temp:	60 F
Rw Temp:	60 F

Approximately 1245 ft of log data was interpreted. Table 2 lists the curves that were loaded into ***Interactive Petrophysics*** along with depth intervals logged and the range of values recorded.

Table 2 Input Curves

Name	Description	Units	Type	Interval		Min.	Max
				Top (ft)	Bottom(ft)	Value	Value
CALI	Caliper	in.	Caliper	269.75	1218.75	4.90	6.51
SGR	Gamma Ray	GAPI	Gamma Ray	346.88	1247.88	20.72	135.31
SP	Spontaneous Potential	MV	SP	363.38	1244.88	-111.41	26.76
LLD	Deep Resistivity	Ohm-m	DeepRes	10.35	1247.35	1.05	93.75
LLS	Medium Resistivity	Ohm-m	MedRes	10.35	1247.35	1.10	331.76
MSFLC	Shallow Resistivity	Ohm-m	MicroRes	10.35	1247.35	30.55	209.98
RHOB	Density	g/cc	Density	349.73	1238.73	1.44	3.19
TNPH	Neutron	Dec	Neutron	13.85	1224.85	0.13	0.60

3.2 Well Log Analysis

Well log analysis is the process of determining reservoir rock and fluid properties by interpreting the responses of various logging tools designed to measure specific parameters from logged wells. The process involves handling large volumes of data. Necessarily, it is done using computer software. Computer software, *Interactive Petrophysics*™, developed by PGL (Production Geosciences Ltd) in Banchory, Scotland was used in this study.

The *Interactive Petrophysics*™ software is a tool for carrying out multi-zone, multi-well petrophysical field analyses. The functionalities include interpretation of well log and associated data in various formations, identification of lithology and hydrocarbon sequences, computation of clay volume, porosity, resistivity, water saturation, net pay, and determination of hydrocarbons' presence using crossplots and a lot more.

The software has modules addressing specific areas of well log interpretation. Notable among the modules and relevant to this work are the *clay volume module* for analyzing the curves (SGR, SP, LLD, LLS, MSFLC, RHOB, TNPH and TEMP) and calculating clay volume using multiple clay indicators (SGR, Resistivity and Neutron

Density). Results from the clay volume module are loaded onto the *Porosity Water Saturation module* for further interpretation. The cut-off and summation module is used to calculate and adjust the net pay and average petrophysical properties by zone.

3.2.1 Analyzing AK94-CBM-1 Geophysical Logs

The procedure for interpreting the AK94-CBM-1 well log data using the log analysis software is treated in this section

Generate Trace Plot

The digitized log data, provided in ASCII format, is loaded onto the database from which trace plots are generated. Figure 4 shows the initial trace plot of the logged data. The plot shows the various log responses (SP, gamma ray, resistivity, neutron and density porosity) as a function of depth. The next step in the log analysis is to calculate the clay volumes.

Calculate Clay Volume

The clay module is used to interactively analyze the trace plots for clay volumes using multiple clay indicators. Parameters were defined to determine how clay volume is calculated. Flags were set to use gamma ray, resistivity and neutron density as clay indicators in each zone. Values of the gamma ray in a clean (0% clay) and 100% clay zones were defined. Values of resistivity in a clean or zero clay zone as well as in a 100% clay zone, generally chosen as the highest resistivity in a hydrocarbon clean zone, were also defined. Neutron and density clay values were setup for the neutron density clay indicator.

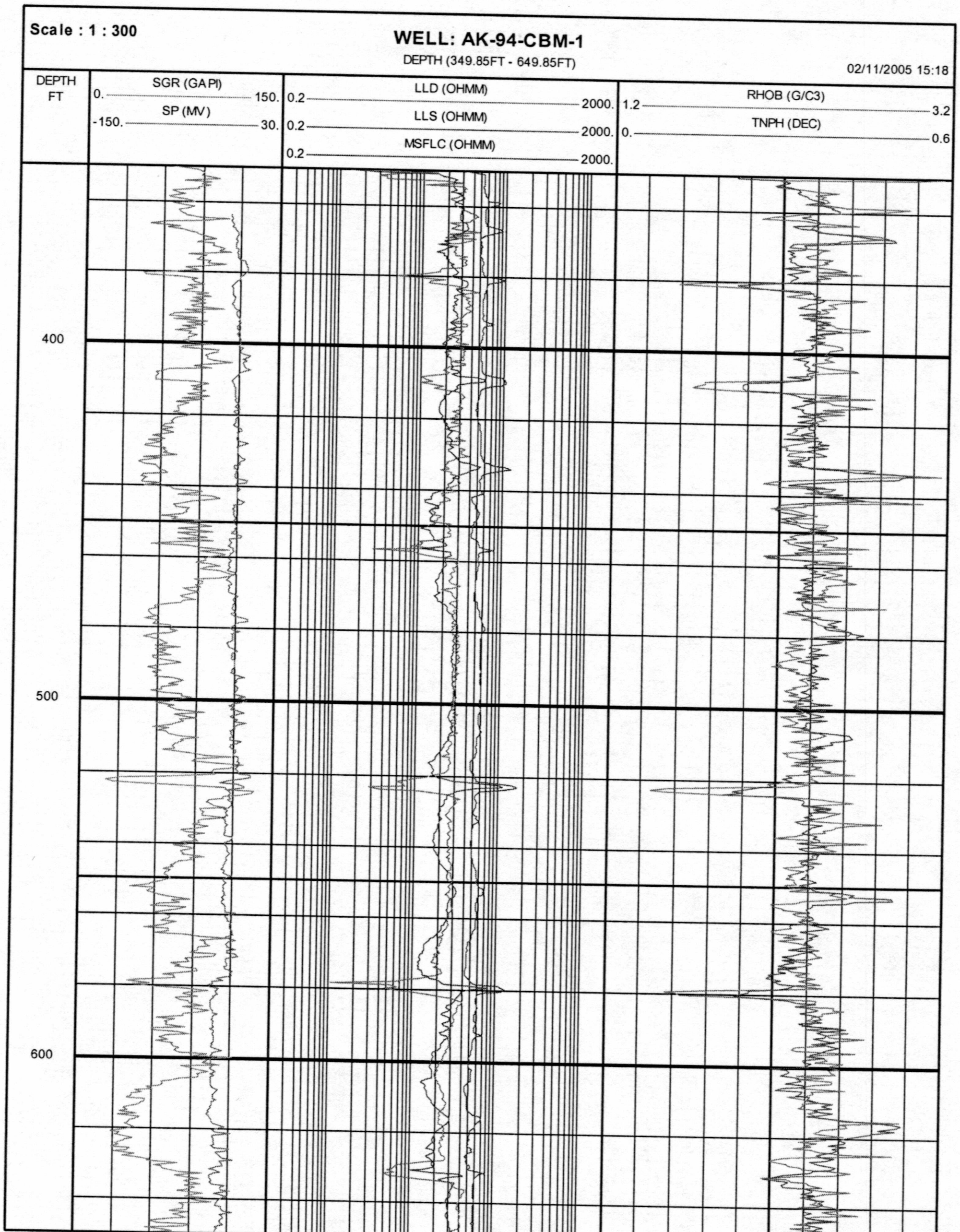

Figure 4 Trace plot of loaded curves

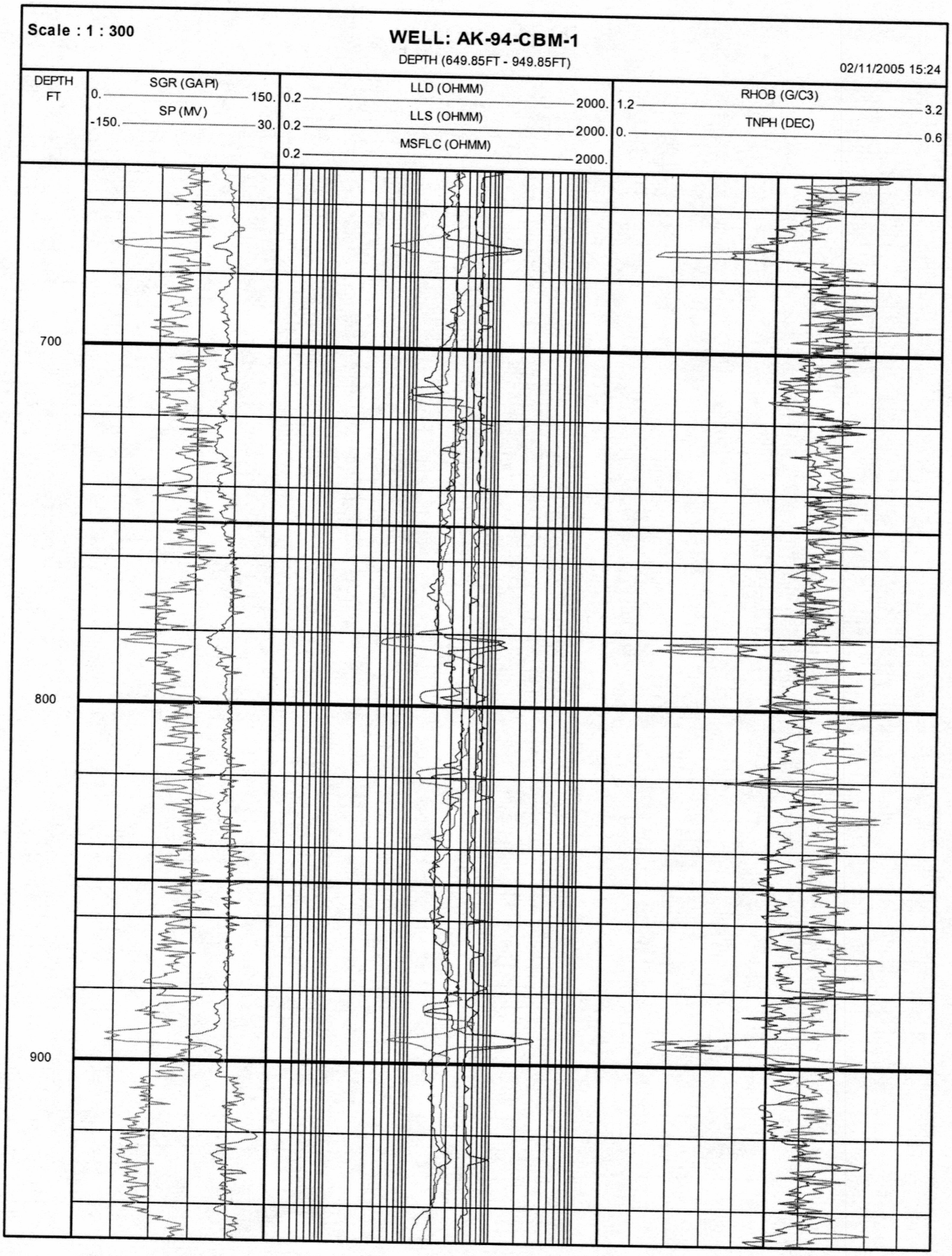

Figure 4 Trace plot of loaded curves, continued

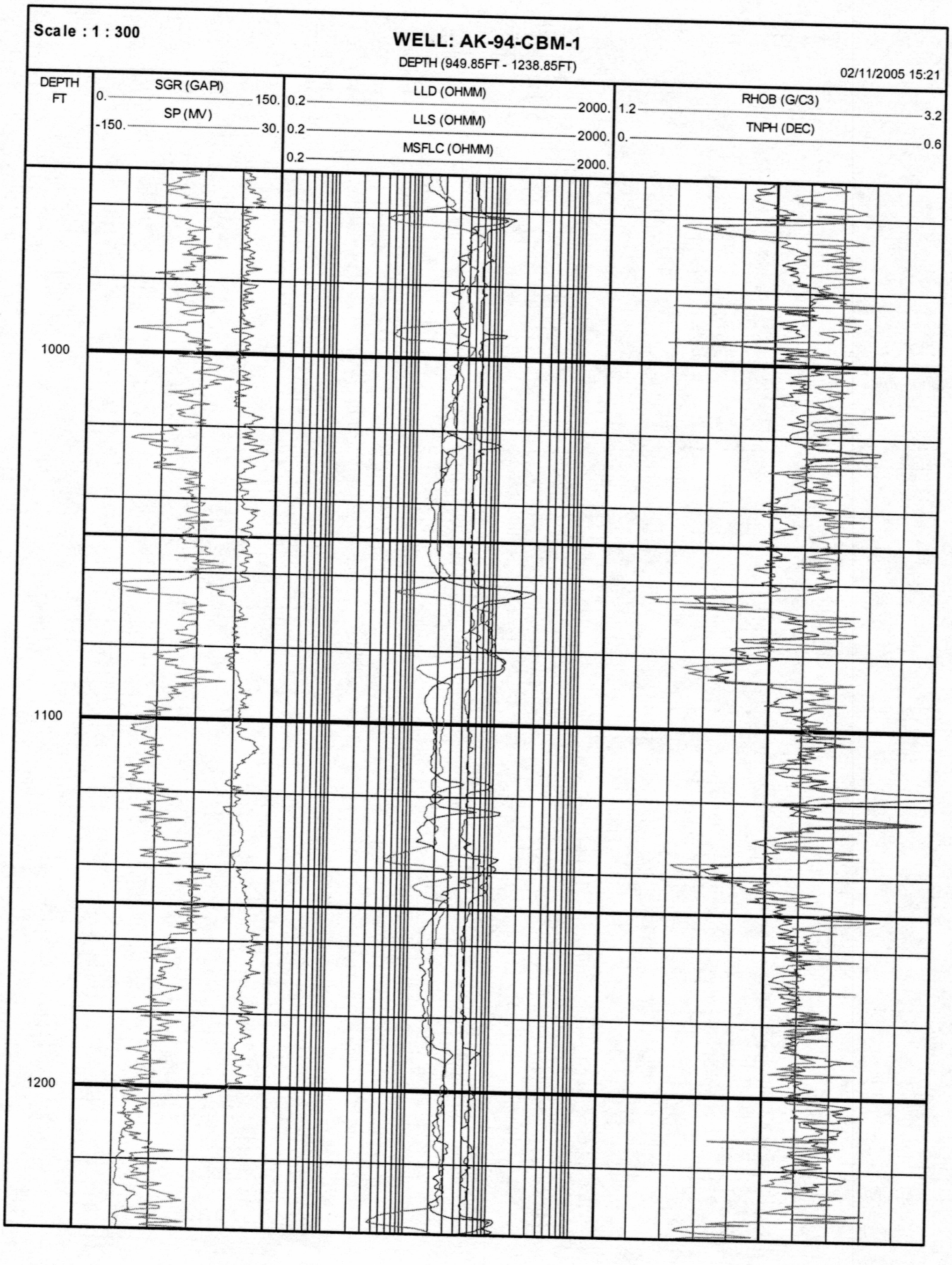

Figure 4 Trace plot of loaded curves, continued

Figure 5 shows the clay volume plot.

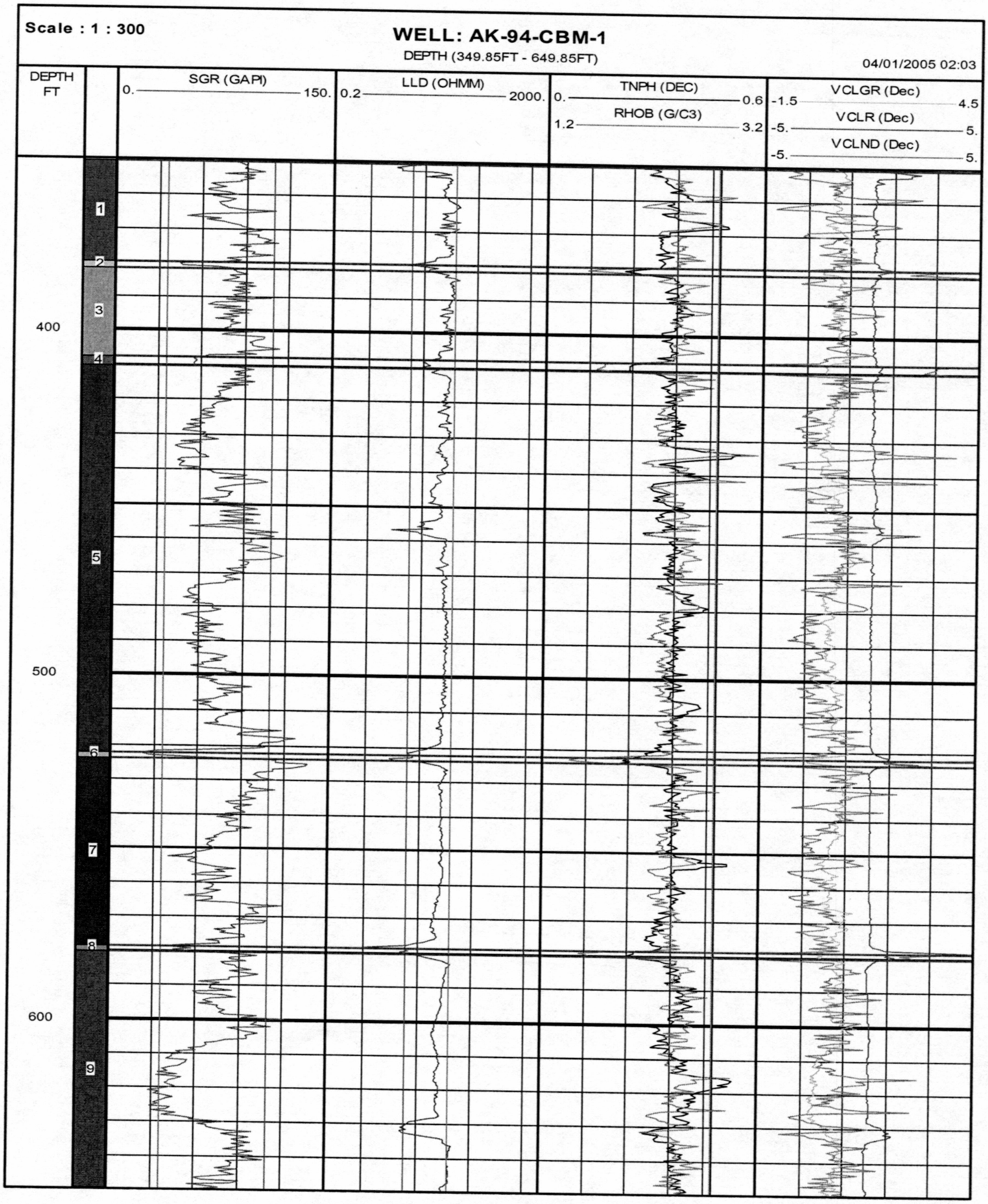

Figure 5 Clay Volume Plot

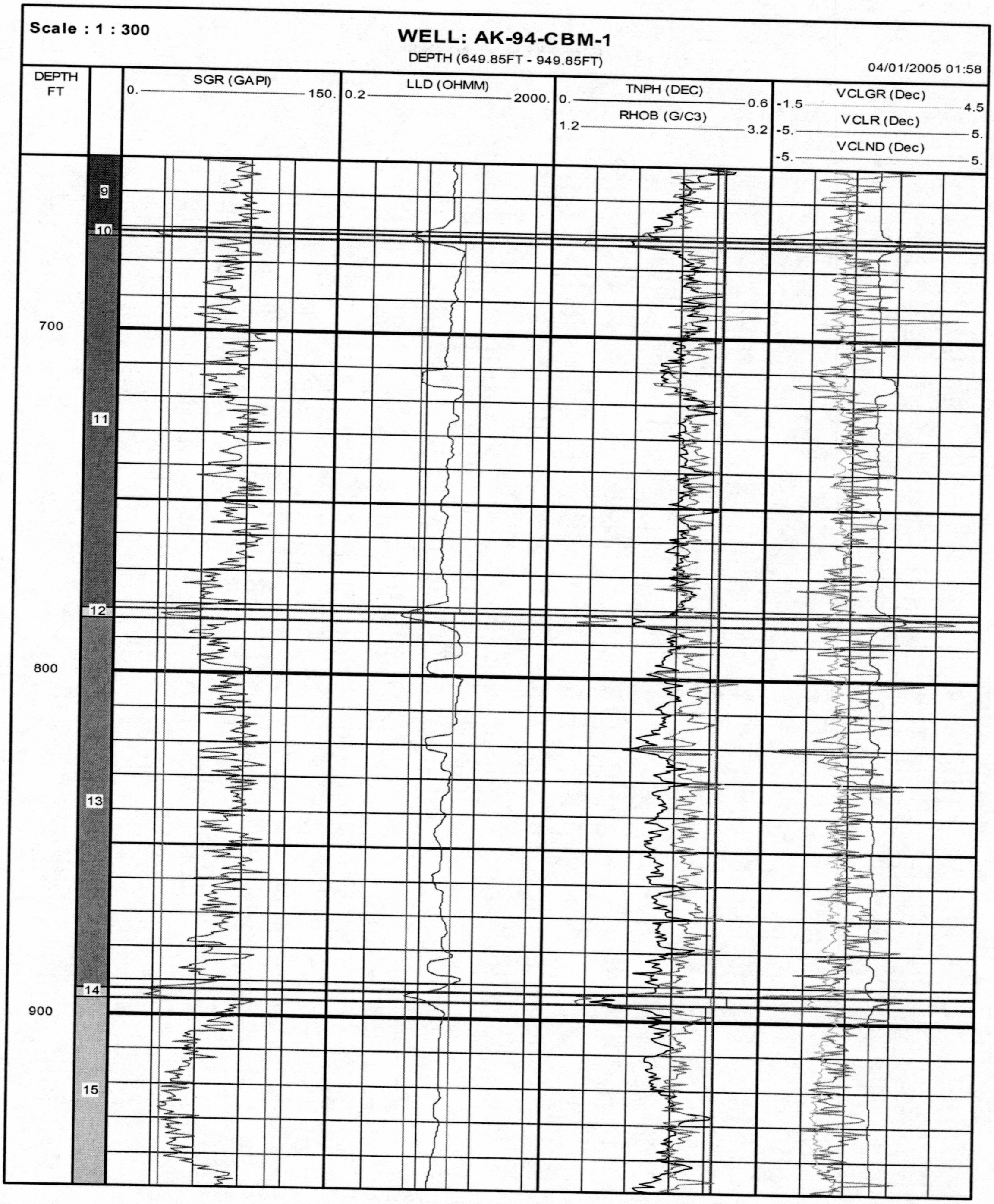

Figure 5 Clay Volume Plot continued

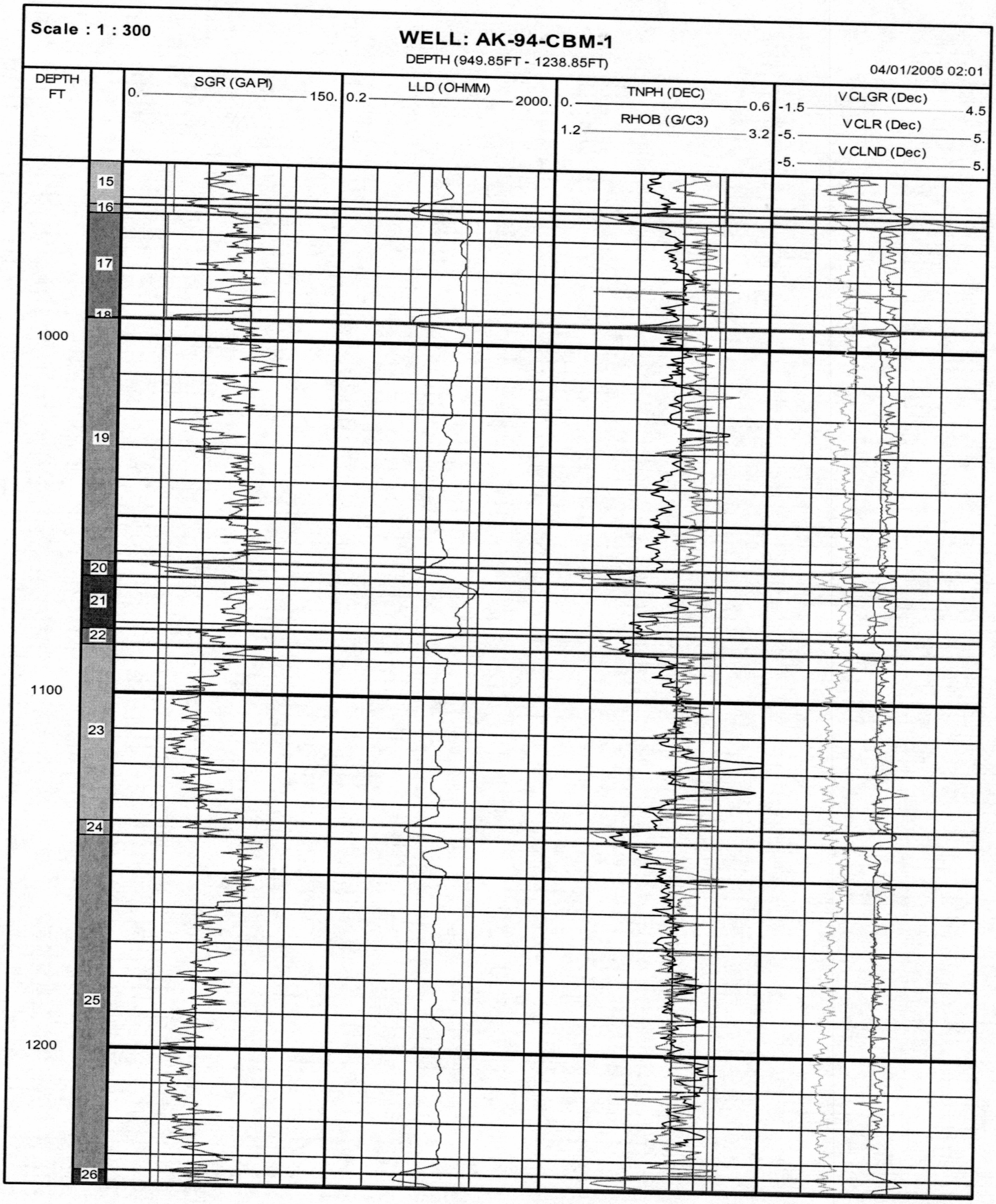

Figure 5 Clay Volume Plot continued

Calculate Porosity and Water Saturation

The next step in the log interpretation is the calculation of porosities and water saturations. The clay volume plot is loaded onto the porosity water saturation module, where the curves are further analyzed. Porosity, water saturation, matrix density, and hydrocarbon density values for various lithology sequences identified in the clay volume plot are calculated. Figure 6 shows the porosity and water saturation interactive plot, which indicates the lithology sequences penetrated by the AK94-CBM-1 well.

Calculate Net Pay and Average Petrophysical Properties

The final step in the log interpretation is the calculation of net pay and average petrophysical properties using the cutoff and summation module. The input curves used for the calculations are porosity, water saturation, clay, and coal volumes. Net pay and average petrophysical properties are adjusted interactively and then calculated for each zone. Models are defined at every stage of the interpretation to capture the characteristics of the reservoir parameters being measured. The results of the analysis are presented in the next section.

3.2.2 Results of Log Analysis

The results of the log analysis are presented in this section. It covers the various lithologies identified as well as a summary of the net reservoir rock parameters.

Lithostratigraphy

The analysis done in this study was based solely on the interpretation of the logged data. There was no physical observation or analysis of actual core samples for thickness, lithology, grain size and sorting, color, mineral composition and sedimentary structure.

The analysis revealed the logged depth as consisting of interbedded sandstone, mudstone, siltstone and coal. All the coal seams identified (see right-most track in Figure 6) are quite thin (less than 10ft). The Tyonek interval is comprised of various percentage

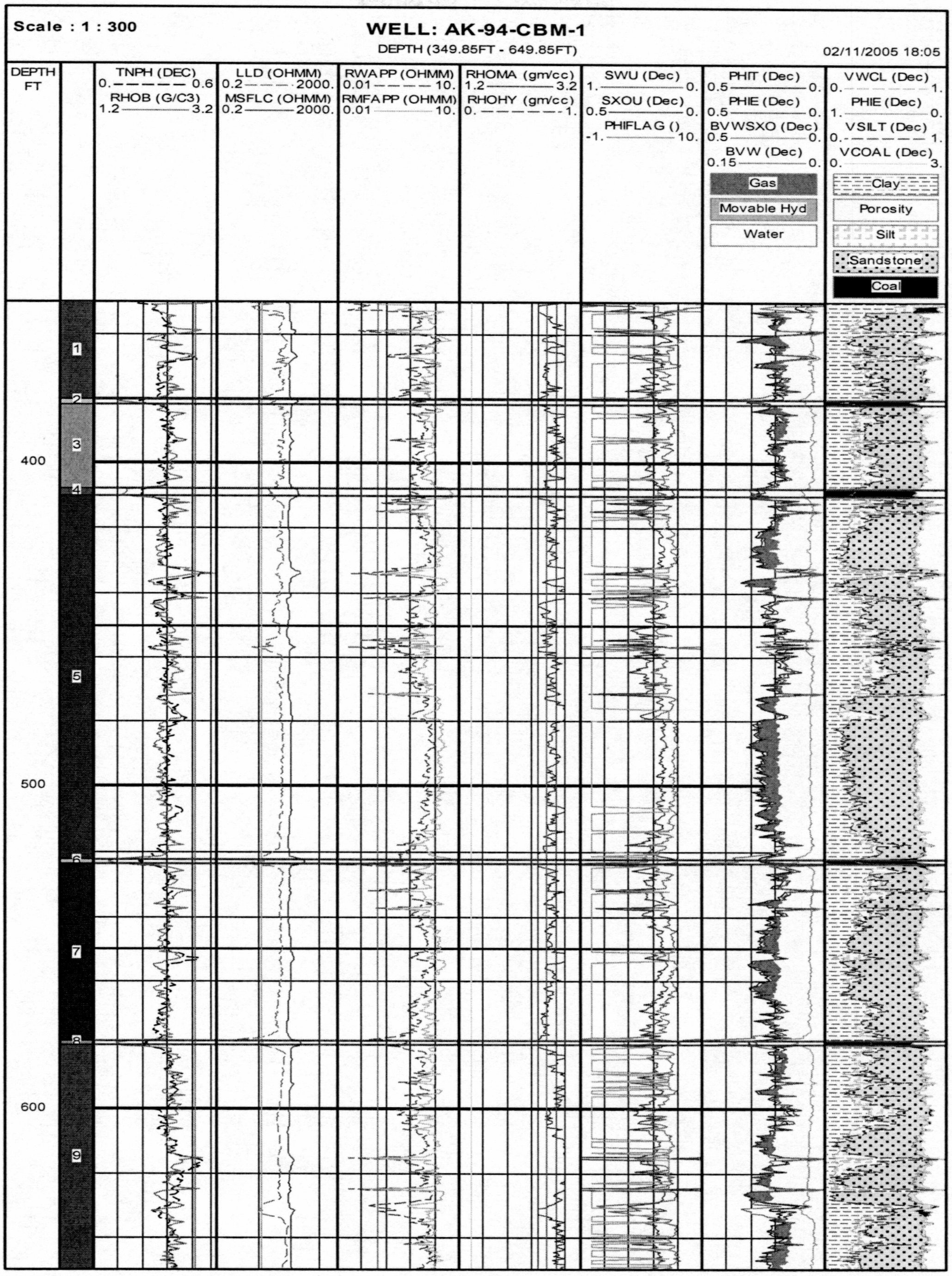

Figure 6 Porosity and Water Saturation Plot (Showing lithology sequences)

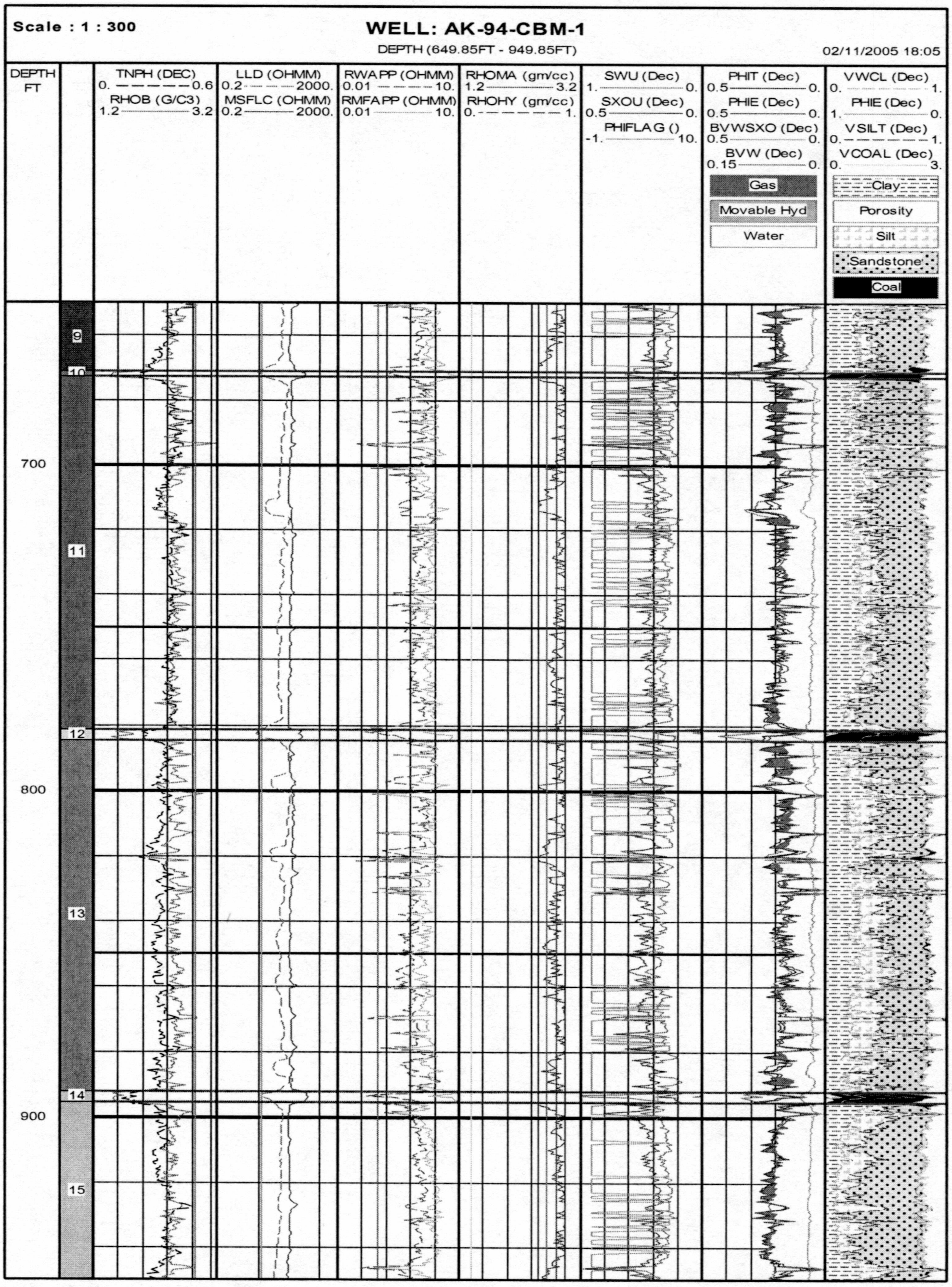

Figure 6 Porosity and Water Saturation Plot (Showing lithology sequences) continued

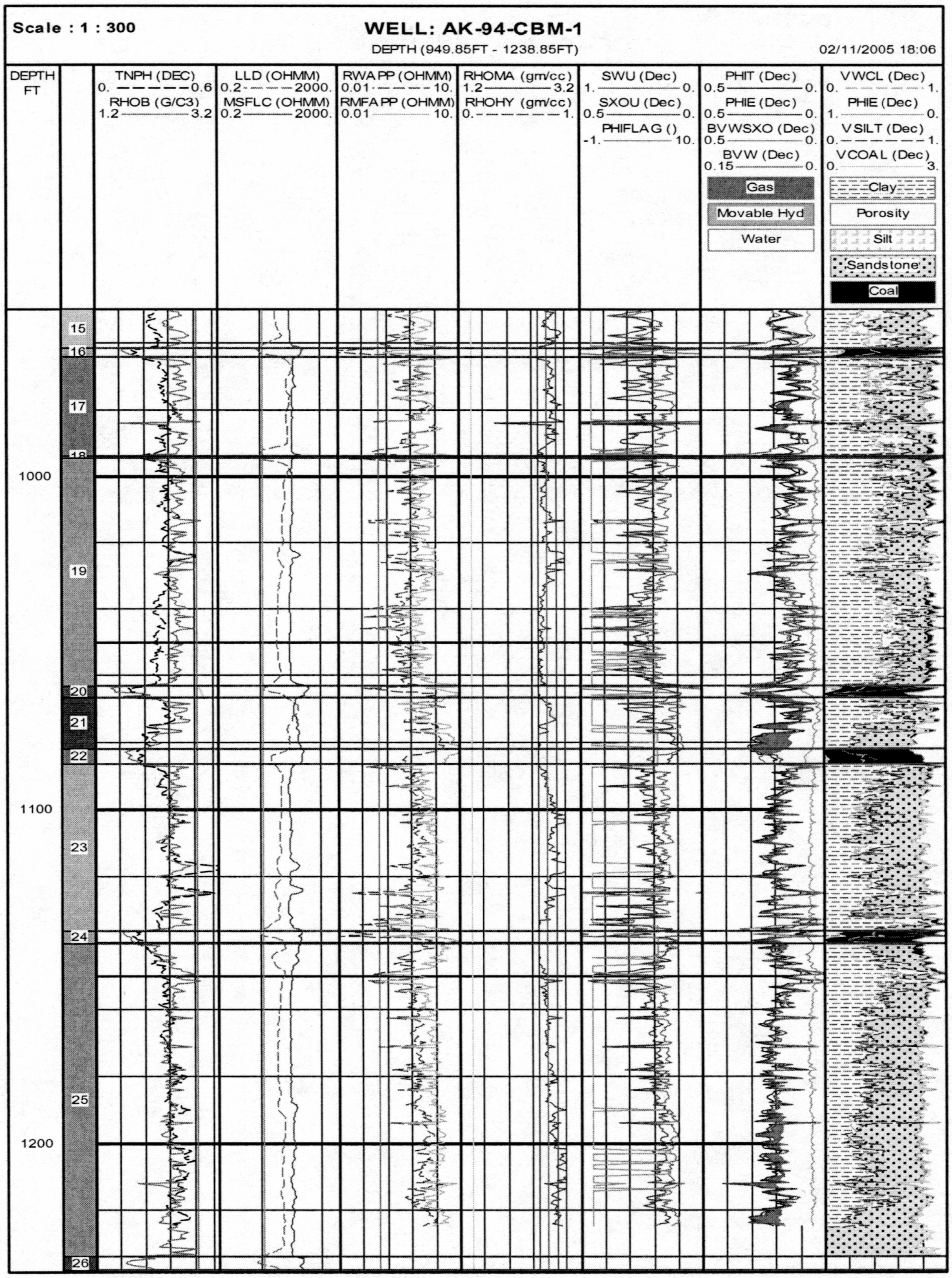

Figure 6 Porosity and Water Saturation Plot (Showing lithology sequences) continued

mixes of mudstone, siltstone, sandstone and coal seams. The thickest coal seam is found at the lower part of the formation, measuring 5.75 ft. The thinnest coal seam occurs at the upper part of the formation and it measures around 2.25 ft.

The total rock volume is comprised of roughly 3.6% coal, 34.2% mudstone, 13.3% siltstone and 48.7% fine-grained and conglomeratic sandstones.

Summary of Petrophysical Properties

The gross pay, net pay, average porosity, average water saturation, average clay and coal volumes for the AK 94 CBM-1 Well are listed on Table 3.

Table 3 Summary of Petrophysical Properties from Log Analysis

Zone	Top	Bottom	Gross Pay	Net Pay	N/G	ρ	Avg. Phi	Avg. Sw	Avg. Vcl	Coal Vol.
#	(ft)	(ft)	(ft)	(ft)		gm/cc				
1	379.90	382.85	3.00	3.00	1.00	1.58	0.234	0.341	0.284	0.775
2	407.40	410.85	3.50	3.50	1.00	1.60	0.265	0.315	0.237	0.317
3	521.40	524.85	3.50	3.00	0.86	1.45	0.201	0.507	0.350	1.133
4	577.90	580.85	3.00	2.75	0.92	1.55	0.236	0.547	0.379	0.619
5	670.40	673.35	3.00	3.00	1.00	1.47	0.208	0.510	0.323	0.721
6	780.40	785.35	5.00	4.00	0.80	1.49	0.194	0.468	0.326	0.648
7	891.90	896.35	4.50	3.50	0.78	1.51	0.218	0.388	0.209	0.417
8	961.40	965.85	4.50	2.25	0.50	1.62	0.208	0.354	0.290	0.815
9	1063.00	1067.40	4.00	3.50	0.88	1.44	0.230	0.285	0.216	0.237
10	1081.00	1086.90	6.00	5.75	0.96	1.68	0.228	0.282	0.253	0.309
11	1135.00	1140.90	5.50	3.25	0.59	1.63	0.211	0.304	0.292	0.565

The net pay thickness of the coal seams ranged from 2.25 to 5.75 ft. The coal seams are quite thin when compared to coal seams from producing CBM wells in the continental U.S. (San Juan Basin) where coal thickness average 70 ft (*Young, 2004*). The density of the coal seams ranged from 1.44 to 1.68 g/cc. The low density of coal as compared to other rock matrix makes it readily identifiable by the density tool. The actual value of the density is an indication of the ash content. Average water saturation levels ranged from a low of 28 to a high of 55% with an average of 39%.

Estimated average porosities of the coal seams ranged from 19 to about 27% and averaged 22%. While the porosities appear to be good enough for coal seams, considering that they are relatively tight as compared to sandstone and other formations, it is the permeability in the form of in-situ natural fractures or cleats that count towards ultimate recovery. However, the permeability is best obtained from laboratory tests using core samples.

CHAPTER 4
EVALUATION OF RESOURCE POTENTIAL

In this Chapter the data obtained from the interpretation of the wireline logs of AK94-CBM-1 are used to evaluate the CBM potential of the Basin. A discussion of coal as both source rock and reservoir rock is also presented.

4.1 Coal: Source Rock and Reservoir Rock

The coal formation process is by the biochemical decay and metamorphic transformation of vegetable matter, thereby generating large quantities of gases. There is not one set amount of gas that can be produced from a coalbed. The amount produced from a coalbed depends on a few important factors:

- The thickness, lateral continuity and rank of the coal
- Moderate to high permeability that is controlled by the amount of fracturing or cleats
- Depth of burial and other barriers, such as impermeable layers, or structures, as faults and folds, that keep the gas trapped within the coal seam.

The amount of gas generated from the coalification process as well as the ability of the coal to retain gas increases with rank. Coal rank is a measure of maturity and organic matter. During the burial and metamorphosis of the decaying material, a large fraction of this gas escapes to the atmosphere. The gas retained in coal ranges from very low quantities to as high as 800 standard cubic ft per tonne (scf/ton) and increases with rank and depth (*Thakur*, *1977*). Methane is the major component of the gases in coal and it accounts for between 80 to 95% of the volume. The balance is made up of ethane, propane, butane, carbon dioxide, hydrogen, oxygen, nitrogen and helium.

The heating value of coalbed methane drained from virgin coal is generally higher than 33.5 Megajoules per cubic meter. Thus, undiluted coalbed methane is very similar to natural gas in composition and calorific value, and as such can be used interchangeably with natural gas in most applications.

A coalbed methane reservoir is considered an unconventional reservoir in that methane gas is stored in micropores and bedding planes, as well as free gas within natural fractures or cleats. The reservoir acts both as the source rock and storage reservoir for methane gas. Coalbed methane is peculiar in that methane and carbon dioxide are predominantly stored in a molecular adsorbed phase within micropores of the coal.

The quantity of methane in a specific coalbed, estimated in the laboratory by the direct determination method, indicates that the methane contents of bituminous coalbeds range from nearly zero to 600 Scf/ton. However, data for all types of coals are limited. Most of the data that are available have been derived only from bituminous coalbeds; very few data are available for anthracite and subbituminous coals (*Satriana, 1980*).

The total volume of methane in a coal seam may be determined from the product of the estimated quantity of coal in-place and the gas content measured directly in a core of the specific coal. The gas content may also be estimated indirectly by using the relationship established by *Kim (1976)*, where core is not available to make a laboratory analysis. The relationship, based on the fixed carbon and volatile matter content of coal, the depth of the coal, and constants determined experimentally is illustrated in Figure 7. However, the indirect method overestimates gas content.

4.2 Evaluation of Resource Potential Using Scf/Ton Model

Estimates of the original gas in place (OGIP) is made using the desorbed gas content obtained from the AK94-CBM-1 Well desorption data (Figure 8) and the net pay thickness data derived from the log analysis. The data is digitized and the following relationship (equation 4.1) between the gas content and depth was derived.

$$G_c = 3\times 10(D)^3 - 0.0073(D)^2 + 6.0107(D) - 1450 \qquad (4.1)$$

Where D is Depth (ft) and G_c is Gas content (Scf/Ton)

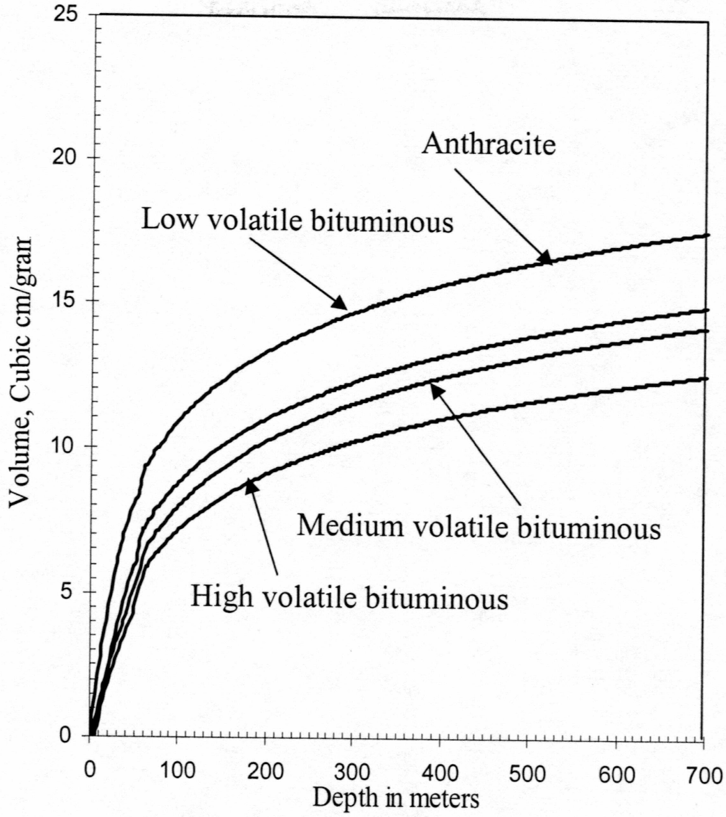

Figure 7 Estimated Methane Content with Depth and Rank (*After: Kim,1976*)

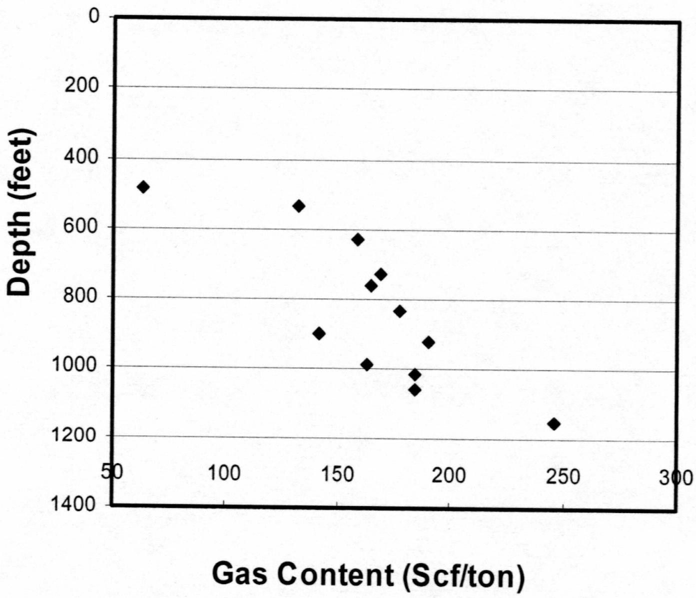

Figure 8 AK94-CBM-1 Well Desorption Data (*Source: Smith, 1995*)

This relationship was used to calculate gas content at unrepresented depths (Table 4). The values obtained from the relationship compared very well with values in the chart (Figure 9).

An estimate of coal mass for each individual coal seam is first determined by using equation 4.2

$$C_m = C_{a-f} \times T_{a-f} \quad (4.2)$$

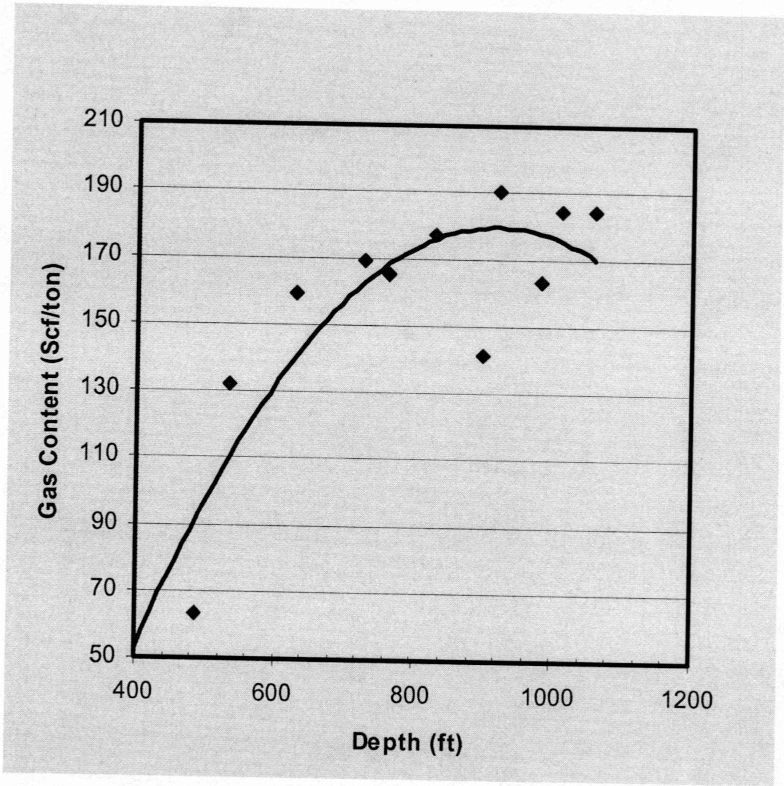

Figure 9 AK94-CBM-1 Well Desorption Data (With fitted relationship)

where C_m is coal mass (short tons); C_{a-f} is the volume of coal (acre-ft); and T_{a-f} is tons per acre-ft.

The specific gravity of bituminous coal ranges between 1.15 and 1.7 depending on rank, moisture content, and ash content, and averages 1.35. The coal densities from log analysis of AK94-CBM-1 well are listed on Table 5. The data show that the specific gravities of the coal seams range between 1.4 and 1.7 in this case.

Equation 4.3 is the regulatory equation for the determination of tons per acre-ft, $T_{a\text{-}f}$, and was used in this study.

Table 4 Gas Content Calculated at Equivalent Depths for Coal Seams Identified from Log Analysis

Depth	Gas Content
(ft)	(Scf/Ton)
382.85	38
410.85	43
524.85	131
580.85	143
673.35	159
785.35	174
896.35	139
965.85	159
1067.35	196
1086.85	204
1140.85	236

$$tons.per.acre.ft = \frac{\left(62.4SG_{Coal}\right)\frac{lbs}{ft^3} \times \frac{43{,}560\,ft^3}{acre - ft}}{2000lbs/ton} \tag{4.3}$$

where SG_{coal} is the specific gravity of the coal.

Estimates of the original gas in place were then derived using equation 4.4.

where G_c is the gas content (scf/ton), and C_m (short tons) is the total coal mass.

Table 5 Volumes of CBM Gas in Place in Scf/Ton

Zone	Top of	Bottom of	Gross Pay	Net Pay	Coal Volume	Coal Density	Tons/Acre-ft	Coal Mass	Gas content	OGIP
	Interval	Interval			C_{A-F}	ρ	T_{A-F}	C_m	G_c	
	(ft)	(ft)	(ft)	(ft)	(acre-ft)	gm/cc		(short-tons/acre-ft)	(scf/ton/acre-ft)	(MMcf/acre-ft)
#				(a)	(a) x 1 acre-ft)		(By Eqn. 4.1)	(By Eqn. 4.2)		
1	379.90	382.85	3.00	3.00	3	1.58	2147	6442	38	0.25
2	407.40	410.85	3.50	3.50	3.5	1.60	2175	7611	43	0.33
3	521.40	524.85	3.50	3.00	3	1.45	1971	5912	131	0.77
4	577.90	580.85	3.00	2.75	2.75	1.55	2107	5793	143	0.83
5	670.40	673.35	3.00	3.00	3	1.47	1998	5994	159	0.95
6	780.40	785.35	5.00	4.00	4	1.49	2025	8100	174	1.41
7	891.90	896.35	4.50	3.50	3.5	1.51	2052	7183	139	1.00
8	961.40	965.85	4.50	2.25	2.25	1.62	2202	4954	159	0.79
9	1063.00	1067.40	4.00	3.50	3.5	1.44	1957	6850	196	1.34
10	1081.00	1086.90	6.00	5.75	5.75	1.68	2283	13129	204	2.68
11	1135.00	1140.90	5.50	3.25	3.25	1.63	2215	7200	236	1.70
All	379.85	1140.90	45.5	37.5	37.5			79166		12.05

$$OGIP = G_c \times C_m \tag{4.4}$$

The Original Gas in Place (OGIP) for the coal seams identified from the log analysis was calculated using equation 4.4. The calculations and the results are presented on Table 5. The results indicate 37.5 net ft of coal at less than 1,300 ft depth, averaging about 148 scf/ton, on a dry, ash-free basis. The total amount of original gas in place (OGIP) is 12.05 MMcf per acre-ft.

4.3 Risk-Weighted Analysis of CBM Resource Potential

This section discusses the risk-weighted analysis that was done to estimate the recoverable reserves from the estimated CBM original gas in place. Probability distributions describing the reservoir rock properties (net pay thickness, tons per acre-ft, gas content and recovery factor) were defined. A model to forecast recoverable reserves by applying a recovery factor to the OGIP was also defined. Monte Carlo Simulation was then run to forecast recoverable reserves, accounting for all the uncertainties in the reservoir properties. The simulations were conducted using 1000, 2000, and 5000 trials. The results of the Monte Carlo simulations (i.e., the recoverable reserves) were analyzed to determine the sensitivity of the estimated reserves to the recovery factor and the input reservoir rock properties.

4.3.1 Probability Distribution of Input Parameters

The Monte Carlo Simulation method requires the definition of probability distributions for the input parameters. In exploration risk analysis, lognormal distribution can be used to describe the probability distribution of the thickness of sedimentary beds, the recovery factor in a given formation producing by a common reservoir mechanism, as well as tons per acre-ft. Uncertainties in gas content can be specified by triangular or uniform distribution (*Thanh, 2002*).

In this study, the net pay thickness and recovery factor are assumed to be lognormally distributed, while tons per acre-ft and gas content are assumed to be normally distributed (Table 6). The net pay thickness for each zone (taken as the mean value) and the standard deviation for thickness in all zones are used to describe the data of net pay thickness. The calculated tons per acre-ft for each zone (taken as the mean value) and the standard deviation for tons per acre-ft in all zones are used to describe the data of tons per acre-ft. The minimum value specified for the recovery factor was 10%. This is consistent with recovery factors reported by other investigators (see *Montgomery, 2003* and *Barker, 2003).* A more optimistic recovery factor of 15% was specified as the maximum value. Table 7 gives detail of the input parameters to the Monte Carlo simulation run.

Table 6 Probability Distribution of Input Parameters for Monte Carlo Simulation

Parameter	Minimum	Maximum	Mean	Standard Deviation	Input Distribution
Net Pay Thickness	2.75	5.75	3.386	0.276	Lognormal
Tons Per Acre-Ft	1957	2283	2103	33	Normal
Gas Content	38	236	147.45	18.49	Normal
Recovery Factor (percent)	10	15	12.5	3.54	Lognormal

4.3.2 Monte Carlo Simulation

The objective of the simulation is to forecast reserves for the acreage surrounding the AK94-CBM-1 Well, taking into account all the uncertainties in the reservoir properties of the coal seams. The software used for the Monte Carlo simulation runs is ***Crystal Ball***. Probability distributions referred to as "assumptions" in ***Crystal Ball*** are defined to describe the uncertainties in the four input parameters (net pay thickness, tons per acre-ft, gas content; and recovery factor). Table 7 lists the input values.

The simulation model also includes a forecast, *total recoverable reserves per acre-ft*. The forecasts are basically equations relating the recoverable reserves (i.e., output) to the input parameters or assumptions.

Table 7 Monte Carlo Simulation Input Values

Recovery Factor	10%							
Zone	Top of	Bottom of	Gross	Net	Coal Volume	Tons/Acre-ft	Coal Mass	Gas content	OGIP
	Interval	Interval	Pay	Pay	C_{A-F}	T_{A-F}	C_m	G_c	
	(ft)	(ft)	(ft)	(ft)	(acre-ft)	(tons/acre-ft)	(short-tons)	(scf/ton)	(MMcf/acre-ft)
#									
1	379.85	382.85	3	2.75	3	2147	6442	38	0.24
2	407.35	410.85	3.5	3.5	3.5	2175	7611	43	0.33
3	521.35	524.85	3.5	3	3	1971	5912	131	0.77
4	577.85	580.85	3	2.75	2.75	2107	5793	143	0.83
5	670.35	673.35	3	3	3	1998	5994	159	0.95
6	780.35	785.35	5	4	4	2025	8100	174	1.41
7	891.85	896.35	4.5	3.5	3.5	2052	7183	139	1.00
8	961.35	965.85	4.5	2.25	2.25	2202	4954	159	0.79
9	1063.35	1067.35	4	3.5	3.5	1957	6850	196	1.34
10	1080.85	1086.85	6	5.75	5.75	2283	13129	204	2.68
11	1135.35	1140.85	5.5	3.25	3.25	2215	7200	236	1.70
All	379.85	1140.85	45.5	37.5	37.5				12.05
								Recoverable reserves per acre-ft	1.20

4.3.3 Results of Risk-Weighted Analysis

The simulation was run using 1000, 2000 and 5000 trials. Results from the simulations include cumulative probability charts of the simulated values (total recoverable reserves) shown in Figures 10, 11 and 12.

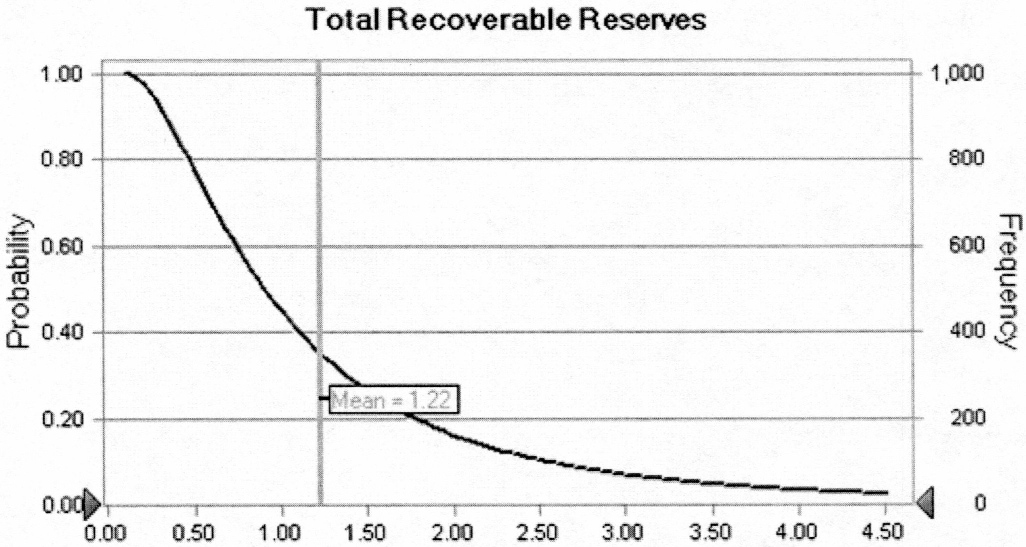

Figure 10 Cumulative Probability Chart of Total Recoverable Reserves per Acre-ft (1000-Trials)

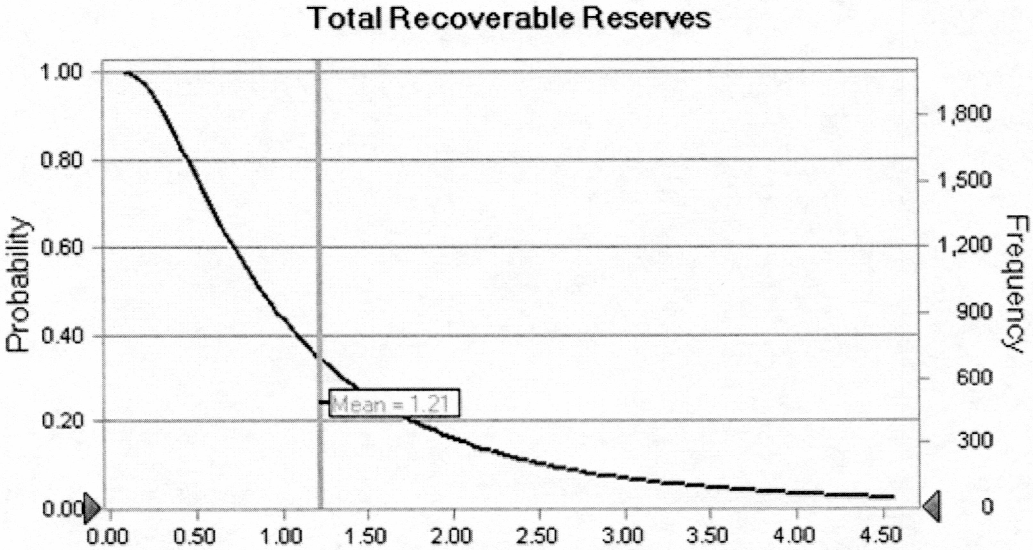

Figure 11 Cumulative Probability Chart of Total Recoverable Reserves per Acre-ft (2000-Trials)

There were no significant differences between results from the three (1000-, 2000-, and 5000-trial) runs. The results are also presented as probability plots in Figures 13, 14, and 15.

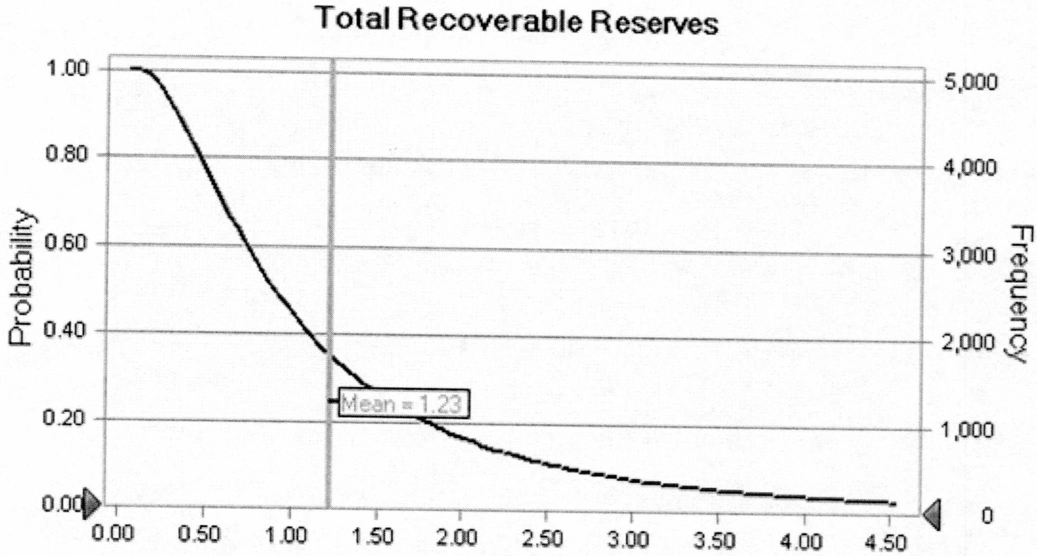

Figure 12 Cumulative Probability Chart of Total Recoverable Reserves per Acre-ft (5000-Trials)

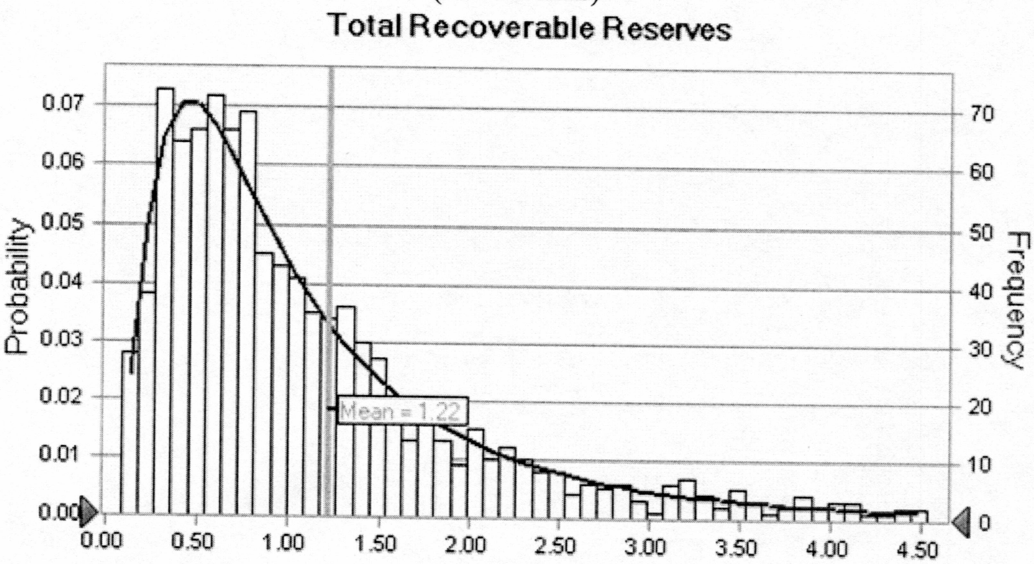

Figure 13 Probability Chart of Total Recoverable Reserves per Acre-ft (1000-Trials)

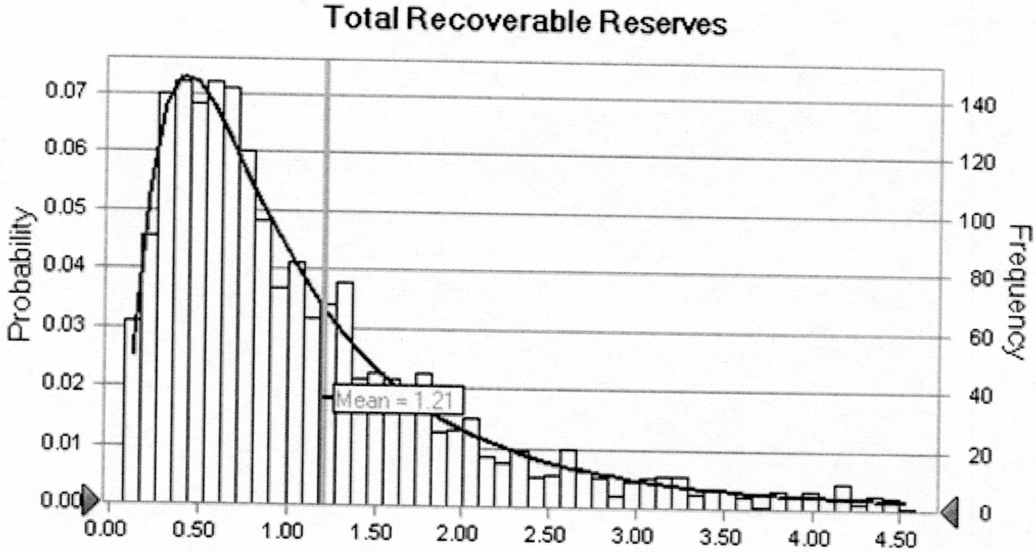

Figure 14 Probability Chart of Total Recoverable Reserves per Acre-ft (2000-Trials)

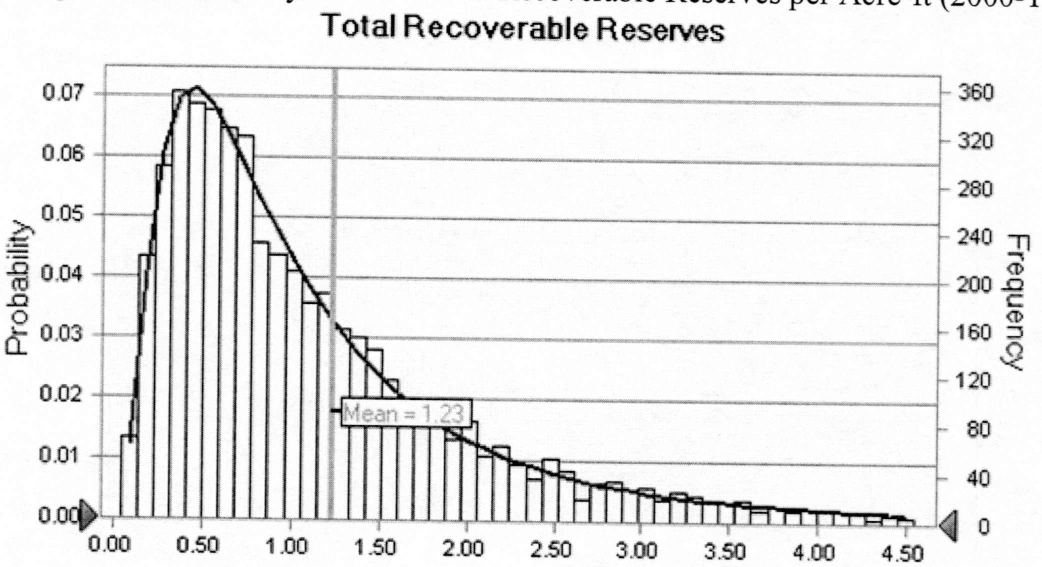

Figure 15 Probability Chart of Total Recoverable Reserves per Acre-ft (5000-Trials)

Table 8 is a summary of the results. The minimum recoverable reserves of CBM were 0.03 MMcf per acre-ft. The mean and median were 1.2 and 0.86 MMcf per acre-ft, respectively. The maximum recoverable reserves stood at 4.5 MMcf per acre-ft.

The results of the risk-weighted analysis paint a very pessimistic future for CBM development in Cook Inlet. Geologic factors such as coal thickness and gas content, among others, do not indicate sufficient quantity of gas within the depth of investigation.

This finding corroborates the disappointment expressed by Evergreen Resources when initial production results indicated that the first two pilot wells drilled by the company in the Matanuska-Susitna Valley were probably not capable of commercial production (*Thomas*, *2004*).

Table 8 Summary of Results of Monte Carlo Simulation

Statistics	Number of Trials		
	1000	2000	5000
	(MMcf/acre-ft)	(MMcf/acre-ft)	(MMcf/acre-ft)
Minimum	0.03	0.03	0.03
Mean	1.22	1.21	1.23
Median	0.90	0.86	0.85
P10	0.32	0.29	0.29
P90	2.44	2.52	2.35

Table 9 Best Fit Distribution of Forecast Recoverable Reserves

		Parameters	
Run	Probability Distribution	Mean	Standard Deviation
1000 Trials	Lognormal	1.22	1.28
2000 Trials	Lognormal	1.21	1.19
5000 Trials	Lognormal	1.23	1.25

4.3.4 Sensitivity Analysis

In this section, the sensitivity of the recoverable reserves with respect to the input parameters (log-derived petrophysical properties) is analyzed. As suggested by Hoye (2004), it is important to account for the dependencies that often occur between reservoir rock and fluid properties on a zone-by-zone basis when estimating reserves for wells with multiple pay zones. Also there is a need to quantify input parameter dependencies from one zone to another that may be the result of the geologic structural or stratigraphic framework associated with the pay zones (*Hoye, 2004*).

The Monte Carlo model forecasts CBM reserves per acre-foot, taking into account all the uncertainties in the reservoir properties of all the prospective pay zones. The input parameters with various levels of uncertainties used in the model are the tons per acre-ft, net pay thickness, gas content per ton and the recovery factor.

The results of the sensitivity analysis shown in Figures 16 to 18 indicate that the recovery factor has the greatest impact on the recoverable reserves. The second parameter which has some impact on the reserves is the gas content. This is expected as the adsorbed gas in coal depends largely on thermal maturity and volume of the coal or coal mass.

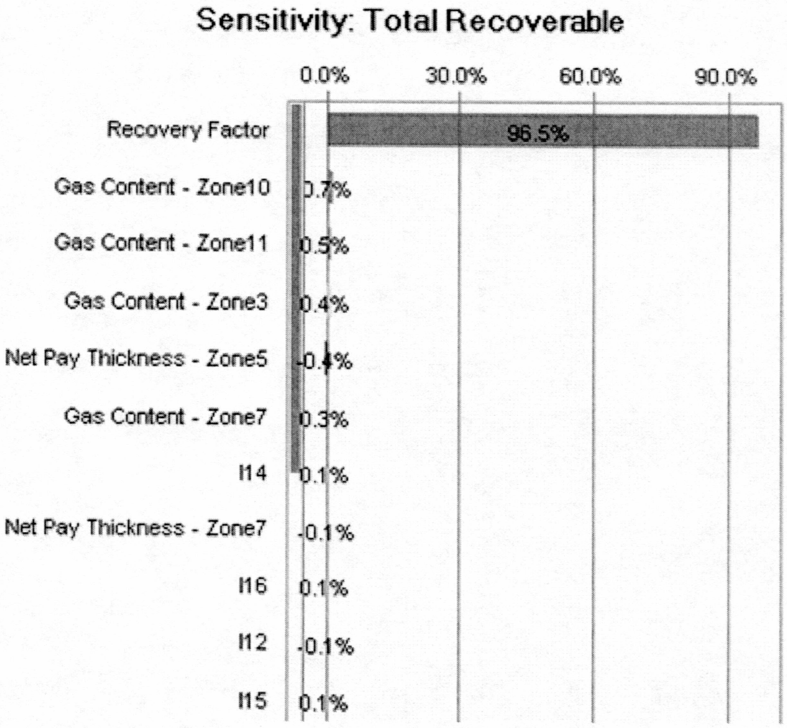

Figure 16 Sensitivity Chart (1000-Trials)

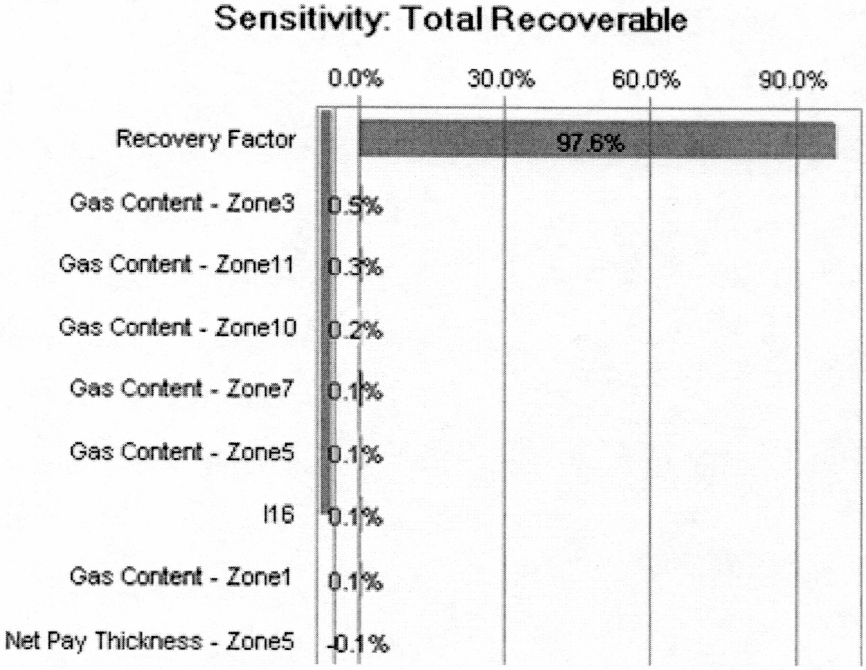

Figure 17 Sensitivity Chart (2000-Trials)

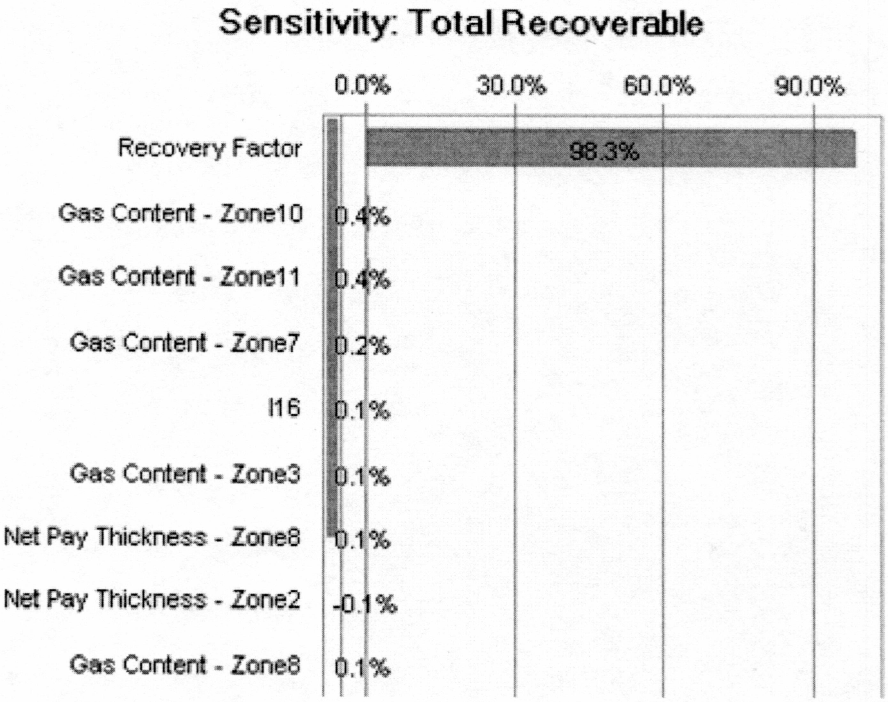

Figure 18 Sensitivity Chart (5000-Trials)

4.3.5 Economic Issues in the Recovery and Conversion of CBM Reserves

Any viable economic development of CBM reserves relies greatly on the interrelationship between a number of geological factors and economic considerations. Some of the more important geological factors used to identify potentially economically viable CBM plays are listed and briefly described on Table 10 (*McCurdy, 2001*). The geologic factors control the possibility of obtaining sufficient quantities of gas in a given location needed to justify the building of gathering and transportation facilities.

Successful CBM producing districts can show widely differing geological characteristics. The differences in geological characteristics between the Powder River Basin coals of Wyoming and the San Juan Basin coals of New Mexico and Colorado, both successful CBM producers, demonstrates this, as illustrated on Table 11.

The low rank Powder River Basin coals have a very low gas content (less than 80scf/ton) compared to the gas content characteristic of coals in the San Juan Basin of New Mexico and Colorado (greater than 800scf/ton). However, the Powder River Basin coals generally are thick (typically 30 to 100 ft), occur at shallow depths (less than 1000 ft), are highly permeable (approximately 1,000mD) and do not require hydraulic fracturing (as do many of the San Juan Basin wells). (*McCurdy, 2001*)

The economic considerations include cost of drilling, completing and operating multiple wells, gas prices and tax incentives, proximity to pipelines and other infrastructure, and ease of access. The initial drilling and completion equipment and well operating costs need to be relatively low, as surface collection, upgrading and transportation costs can be quite high. Thus, the major conditions necessary to make CBM recovery economic are low costs of drilling and completing multiple wells, and geologic factors favorable to obtaining sufficient quantities of gas.

The Cook Inlet Basin coals have to be evaluated against such geologic factors and economic considerations to determine the economic viability of developing the basin. The basin needs to be evaluated for the existence of thick and continuous coal seams beyond the 1245 ft investigated. If thick and laterally continuous coal seams are found, they need to be evaluated for the possibility of obtaining sufficient quantities of gas using the geologic factors listed on Table 10. Then, the economic considerations, discussed earlier, need to be applied to make the best judgment on developing the basin for CBM gas.

Table 10 Geologic Factors Controlling Viability of CBM Reserves (*McCurdy, 2001*)

Geologic Factor	Desired Characteristics
Coal Thickness	Thick coal
Depth to Coal	Shallow coal
Continuity of Coal	Continuous coal
Areal Extent of Coal	Large areal extent
Seals	Fine grained sediments in immediate roof & floor
Gas Content	High gas content
Gas Composition	High methane content
Permeability	High permeability
Structural Setting	Simple structural setting
Hydrology	Ease of dewatering

Table 11 Geologic Characteristics of Selected CBM Basins (*McCurdy, 2001*)

Typical Characteristics	San Juan Basin	Powder River Basin	Cook Inlet (AK94-CBM-1)
Individual Coal Bed Thickness	10 to 40 ft	20 to 90 ft	2.25 to 5.75 ft
Coal depth	1500 to 3000 ft	500 ft	379 to 1140 ft
Gas Content	100 to greater than 800scf/ton	Less than 80scf/ton	Less than 240scf/ton
Permeability	5 to 30mD	1,000mD	-

CHAPTER 5
CONCLUSIONS AND RECOMMENDATIONS

This study presents results of analysis of the AK94-CBM-1 well log data to determine the reservoir rock properties. The estimated CBM resource was calculated from the measured reservoir rock properties and the desorption data. Risk-weighted analysis of the CBM resource was carried out to estimate the recoverable reserves and account for the uncertainties in the log-derived input parameters. The sensitivity of the recoverable reserves with respect to the log-derived petrophysical properties was analyzed.

5.1 CONCLUSIONS

The following conclusions can be derived from the results of this study:

1. The Tyonek interval logged is comprised of various percentage mixes of mudstone, siltstone, sandstone and coal seams. The thickest coal seam is found in the lower part of the formation, measuring 5.75 ft.
2. The total rock volume is comprised of roughly 3.6% coal, 34.2% mudstone, 13.3% siltstone and 48.7% fine-grained and conglomeratic sandstones.
3. Gas contents obtained from the desorption data ranged from 38 scf/ton at 382 ft to 236 scf/ton at 1140 ft, on a dry, ash free basis.
4. The estimated CBM resource at the depth of investigation (approximately 1245 ft) from analysis of the logged data from the AK94-CBM-1 well stood at 12.05 MMcf of gas in place per acre-ft.
5. Actual recoverable reserves from risk weighted analysis range from 0.2 to 4.5 MMcf per acre-ft. The mean of recoverable reserves was 1.21 MMcf per acre-ft and the median was 1.18 MMcf per acre-ft.
6. Sensitivity analysis showed that the recovery factor has the greatest impact on the estimated recoverable reserves.

7. Results from this study show that there is need for additional data to evaluate the CBM potential of the basin before full scale development.

5.2 RECOMMENDATIONS

The following recommendations are presented for consideration, for future work in this area:

1. CBM gas content increases with coal rank and depth of burial and with reservoir pressure. The results of this study suggest the need to drill multiple exploratory wells beyond the depth of investigation (1245 ft) in order to confirm the CBM resource potential of the Cook Inlet Basin and the feasibility of production. Exploratory drilling to a shallow depth of 3000 ft is suggested before any realistic reserves estimate could be determined for the field explored and serve as basis for reservoir development.
2. Where actual desorption data are not available, the indirect method can be used to estimate gas content of coal. The relationship established by Kim may be used to determine gas content. However, detailed laboratory analysis should always be done where possible to determine the gas content from cores in any exploration venture, as the indirect method overestimates gas content.
3. The data obtained from Evergreen Resources pilot holes should be evaluated to validate and refine CBM potential assessment in the Basin.
4. A rigorous analysis of current and available technology should be an integral part of any CBM reservoir development plan and strategy. Such analysis should draw from the knowledge gained from existing and developed fields in the contiguous 48 states of the US.

NOMENCLATURE

ASCII	American Standard Codes for Information Interchange
Bcf	Billion Cubic Feet
$C_{a\text{-}f}$	Coal Volume
CALI	Caliper
CBM	Coalbed Methane
C_m	Coal Mass
Deep Res	Deep Resistivity
F	Degree Fahrenheit
ft	Feet
ft^3	Cubic Ft
g/cc	Grams per Cubic Centimeter
GAPI	Gamma Ray API Units
G_c	Gas Content
in	Inches
Lbs/ton	Pounds per Tonne
LLD	Deep Laterolog Curve
LLS	Laterolog Shallow Curve
Mcro Res	Shallow Resistivity
Med Res	Medium Resistivity
mi^2	Square Mile
mD	Milli-Darcy
MMcf	Million Cubic Feet
MSFLC	Borehole Corrected Micro Spherically Focused Laterolog Curve
mV	Milli-volts
OGIP	Original Gas In Place
Ohm-m	Ohms-Meter
PHI	Porosity
R^2	Trendline Reliability or Goodness of Fit

RHOB	Bulk Density Curve
Rm	Mud Resistivity
Rmf	Mud Filtrate Resistivity
Rv-r	Vitrinite Reflectance
Rw	Formation Water Resistivity
RWAPP	Apparent Formation Water Resistivity
SCF	Standard Cubic Feet
SG	Specific Gravity
SGR	Gamma Ray Curve
SP	Spontaneous Potential Curve
$T_{a\text{-}f}$	Tonnes per Acre–Feet
Temp	Temperature
TNPH	Neutron Porosity curve
Ton	Tonne
VCGLR	Clay Volume from Gamma Ray
VCLND	Clay Volume from Neutron/Density
VCLR	Clay Volume from Resistivity
VWCL	Volume Wet Clay

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