Final *Rapid Gas*^{SM} Report

Burch 10-17-29-12

J.M. Huber Corp.
Marmaton and Cherokee Groups
Elk County, Kansas
Cherokee Basin

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EXECUTIVE SUMMARY

Rapid Gas^{SM} analysis was performed on conventional 3.0-inch diameter core samples recovered during 10 and 15 September 2003 from the Cherokee Group seams in the Cherokee Basin, Elk County, Kansas. The analyses were performed according to **ASTM** and other best practice methods.

The following information was determined from the ***Rapid Gas***^{SM} analysis for each of the selected core samples:

1) Total Gas Content
2) Gas Sorption Time and Diffusivity
3) Sample Bulk Composition
4) Sorbed gas composition

The average gas content estimates on an air-dry and dry ash free basis for the Marmaton and Cherokee group seams have been summarized in **Table ES 1-1**.

The sorption time estimates for the Cherokee group seams have been summarized in **Table ES 1-1**. The sorption times indicate that these coals desorb gas at a slower rate to other commercial reservoirs (e.g. Powder River and San Juan Basin).

Sorbed phase gas composition for the Mulky seam at the Burch 10-17-29-12 well is comprised of 95.34% methane, 0.19% ethane, 1.05% carbon dioxide, and 3.31% nitrogen.

Table ES. 1-1 summarizes reservoir properties and gas-in place estimates elucidated from core data collected from the Cherokee group seams at the Burch 10-17-29-12well.

Table ES.1-1 *Rapid Gas*^{SM} Reservoir Property Estimates

Reservoir Property Analysis Temperatures					
Seam Nomenclature	Units	Un-named	Mulky	V Shale	Mineral
Sample Nos.		290-1	290-4	290-6	290-8
Reservoir Temperature	°F	90	90	90	90
Top of Seam*	feet	1,476.7	1,563.1	1,637.3	1,703.9
Bottom of Seam*	feet	1,478.6	1,566.5	1,638.3	1,704.9
Reservoir Properties					
Pressure Gradient**	psi/ft	0.433			
Average Lost Gas Content Estimate	scf/ton	1.68	5.68	0.40	0.89
Average DAF Gas Content at Reservoir Temperature	scf/ton	120.85	400.82	195.63	118.57
Average Air-Dry Gas Content at Reservoir Temperature	scf/ton	73.21	97.11	42.03	20.26
Average Gas Sorption Time Estimate	hours	390.94	232.07	1,610.42	81.93
Average Diffusivity Estimate	sec^{-1}	4.74E-08	7.98E-08	1.15E-08	2.26E-07
Bulk Properties					
Average Helium Density (Air-Dry Basis)	g/cm^3	1.657	1.750	2.274	2.489
Average Ash Content (Air-Dry Basis)	wt. %	37.91	50.55	77.52	81.70
Average Sulfur Content (Air-Dry Basis)	wt. %	2.11	2.21	2.86	1.82
Average Residual Moisture Content	wt.%	1.51	0.88	1.00	1.21
Sorbed Gas Composition					
Methane (C1)	volume %	N/D	95.34	N/D	N/D
Ethane (C2)	volume %	N/D	0.19	N/D	N/D
Higher Hydrocarbons (C3-C10)	volume %	N/D	0.00	N/D	N/D
Carbon Dioxide (CO_2)	volume %	N/D	1.05	N/D	N/D
Nitrogen (N_2)	volume %	N/D	3.31	N/D	N/D
Sorbed Gas-In-Place Volume Estimate					
Based on MAS results and 2.45 g/cm³ cut	MMscf/320acres	**0.842**			
Based on TOC results and 2.45 g/cm³ cut-off	MMscf/320acres	**0.680**			

1.0 INTRODUCTION

This report summarizes the procedures and results of gas content, reservoir property, and coal and shale property analyses determined from well log data and core samples from the Cherokee Groups at the Burch 10-17-29-12 well (Burch) in Elk County, Kansas (Section 17 Township 29S Range 12E) (**Figure 1.1**). Four of nine desorption canisters experiments at the Burch well from the Cherokee Groups gas reservoir system were selected for ***Rapid Gas***^{SM} analysis.

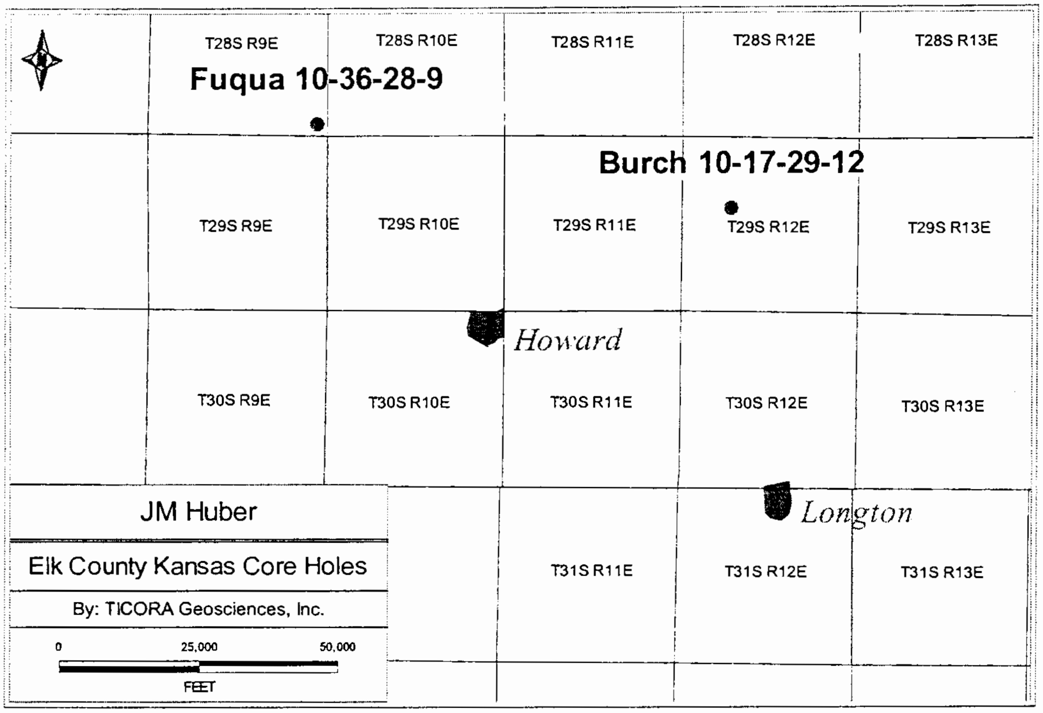

Figure 1-1 Corehole Location

At the request of Mr. David May, Senior Staff Geoscientist for J.M. Huber Corporation (Huber), TICORA Geosciences, Inc. (TICORA) conducted ***Rapid Gas*** ^{SM} analyses on four core samples from the Un-named, Mulky, V Shale, and Mineral seams at the Burch well.

The major goal of this project was to evaluate the sorbed phase gas content, gas composition, gas storage characteristics, and gas-in-place resources of the Cherokee Group seams at the Burch well. This report provides the following:

1) Background information;
2) A discussion of the field and laboratory activities;
3) Evaluation of the data set;
4) Sorbed gas-in-place volume section;
5) A Data Summary Section;
6) A description of core lithology; and
7) Digital core photographs.

TICORA's ***Rapid Gas***^{SM} analysis procedure provides a proven means to rapidly gather and report reservoir property estimated including: sorbed gas content, sorbed phase gas composition, sorbed gas-in-place volume estimates, and bulk sample composition for selected core samples recovered from coal and shale gas reservoirs. The results of the ***Rapid Gas***^{SM} program are finetuned in TICORA's final report subsequent to the completion of conventional long-term desorption testing.

Table 1-1 summarizes the ***Rapid Gas***^{SM} analysis program designed by TICORA and lists the locations associated with detailed data sets.

Table 1-1 Step-by-Step Summary of Analysis Program and Location of Associated Data

Step	Analysis Program	Location of Associated Data
1	Perform desorbed gas content measurements on 4 core samples from the Cherokee Group seams at reservoir temperature (90°F).	Data Summary (page 10) Appendix II Gas Content, Desorption Data Summary
2	Perform crushed gas content measurements on 4 core samples from the Cherokee Group seams at reservoir temperature (90°F).	Data Summary (page 9)
3	Estimate lost gas and total gas content for each desorption sample and estimate average total gas content for the 4 core samples from the Cherokee Group seams.	Data Summary (pages 10) Appendix II Gas Content, Desorption Data Summary
4	Determine residual moisture, ash, and sulfur contents (MAS) for all core samples. Determine helium density for all core samples. Determine total organic carbon for all core samples.	Data Summary (page 4) (MAS) Data Summary (page 5) (Density) Data Summary (page 6) (TOC)
5	Perform sorbed gas composition analysis on sample 290-4.	Data Summary (pages 7-8)
6	Estimate gas-in-place resource estimates for the Cherokee Group seams.	Report Section 4.3

2.0 FIELD ACTIVITIES

At the request of Mr. Mr. David May, Senior Staff Geoscientist for Huber, TICORA collected core samples for the gas content and resource evaluation of Marmaton and Cherokee Group seams in the Cherokee Basin, Elk County, Kansas. TICORA personnel were on location from 10-15

September 2003. Samples arrived at TICORA's laboratory in Denver on 16 September 2003. ***Rapid Gas***^{SM} analysis was performed on three of six desorption samples.

2.1 Formation Temperature and Pressure

Temperature data was provided to TICORA on 10 September by Mr. Mike Allred (Huber well site geologist). This data was in the form of a bottom hole temperature recorded by Schlumberger Well Logging Services on the immediately adjacent Burch WDW 10-17-29-12. TICORA used the data to calculate reservoir temperatures at the subject well. All desorption experiments were carried out at a temperature of 90°F. During coring operations, monitoring of circulating fluid temperatures indicated temperatures throughout most of the well were consistent, with no abnormal increases (or decreases) in the assumed geothermal gradient. This information allowed TICORA to desorb all samples collected at reservoir temperature.

Mr. David May instructed TICORA via verbal confirmation to use the normal pressure gradient of 0.433 psi/ft. This pressure information is summarized in **Table ES-1**. This gradient will also be used to calculate the lost gas content for desorption samples collected at the subject well.

2.2 Drilling and Coring Operations

Layne Christensen Drilling (Calgary, Alberta) spudded the Burch 10-17-29-12 well at 20:00 hrs on 9 September 2003. A 12 ¼ inch surface hole was drilled to 138 ft., reaching TD at 01:00 hrs on 10 September. Surface casing (8 5/8 inch) was run to 138 ft. Cement was penetrated and drilling of a 7 7/8 inch new hole commenced at 12:30 hrs this same day. Core point was reached at a depth of 1,470 ft. at 13:45 hrs on 11 September. Core point was picked by Huber's well site geologist (M. Allred).

A total of 44 wire-line retrievable core runs were made from 1,470.0 feet to 1,887.0 feet. Of the 417 feet of 3.0 inch core cut, approximately 416.5 feet were recovered (+99%). The bottom hole coring assembly included a 10.5-foot core barrel, wire-line retrievable inner-tube, and a PDC core bit. The average length of a core run was a little over 10.0 feet. Typically the driller would cut 10.2 to 10.5 feet of core per run, as Layne felt a full core barrel had better chances of complete recovery. Coring fluid was composed of fresh water mud with a density ranging from 8.4 to 8.5 lbs/gallon. Wireline retrieval times ranged from 6 minutes 20 seconds up to 10 minutes and 40 seconds with an average of approximately seven minutes. Core runs containing sampled intervals are summarized in **Table 2.1**.

Table 2.1 Summary of Core Runs

Core Run	Coal Seam	Cored Interval	Feet Cored	Feet Recovered	Number of Desorption Samples	Core Recovery Time	Circulating Fluid Temp	Fluid Density	Depth Correction
No.	[illegible]	Feet	[illegible]	[illegible]	[illegible]	hh:mm:ss	[illegible]	[illegible]	Feet

1	Unnamed	1,470-1,480	10.0	10.3	1	0:17:45	76.5	8.4	0
9	Lil'Osage	1,551-1,561	9.3	10.5	1	0:16:01	73.4	8.5	+1
10	Excello	1,561-1,571	10.5	10.7	2	0:15:49	73.4	8.5	+1
16	Mulky	1,617-1,627	10.5	5.4	1	0:19:07	72.1	8.5	+1
18	Bevier	1,632-1,642	10.0	10.1	2	0:14:34	72.5	8.5	+1
25	Mineral	1,703-1,713	10.3	10.3	1	0:09:50	73.3	8.5	+1
27	Tebo	1,723-1,734	10.2	10.2	1	0:14:40	76.7	8.5	0

TICORA reports all depths as drill depths, which will require adjustment to correlate to geophysical log depths.

2.3 Field Desorption Measurements

A total of 9 core samples approximately one-foot in length were collected at Burch well. Produced water pre-heated to reservoir temperature was used as the headspace filler. Headspace filler was added to all canisters for two reasons:

1) to reduce headspace volume thereby increasing the accuracy of desorption measurements and to optimize the quality of gas samples collected for compositional analysis, and;
2) to prevent oxidation and desiccation in the coals.

Canisters were then placed in water baths of appropriate temperature for desorbed gas measurements. Desorption reading were taken at a high frequency for the first few hours to better estimate lost gas content. Field desorption measurements were collected for one to 2-days before the desorbed canisters were transported to TICORA's laboratory for ***Rapid Gas***^{SM} and long-term desorption tests.

2.4 Geophysical logs

Log Tech recorded geophysical logs (resolution = 0.5 feet) including caliper, gamma ray, and bulk density tracks at the Burch on September 18, 2003. Unless otherwise stated reference to core depths throughout this report are based on drill depth and require a depth correction. **Figure 2-1** illustrates the geophysical well log. Heartland supplied the geophysical log to TICORA in LAS format.

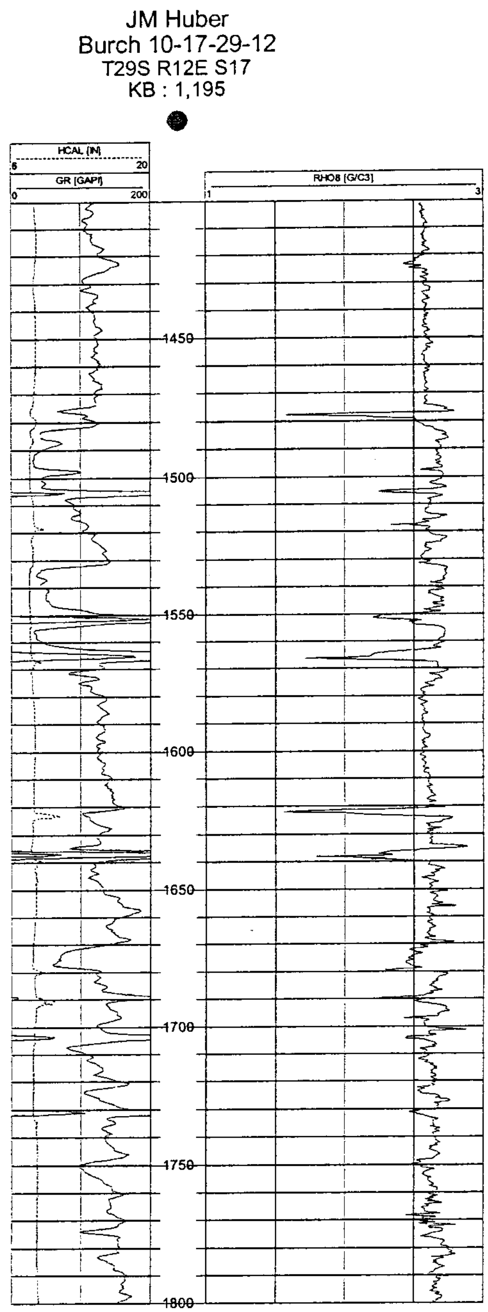

Figure 2-1 Geophysical Log

3.0 LABORATORY ACTIVITIES

Sample analyses conducted by TICORA rigorously followed best practice analysis protocols developed by the American Society for Testing and Materials (ASTM) and the Gas Technology Institute (GTI).

3.1 Sorbed (*Rapid Gas*^{SM}) Phase Gas Content Measurements and Protocols

Short-term desorption tests were conducted on three core samples selected for ***Rapid Gas***^{SM} analysis at constant reservoir temperature conditions (Page 2 of the Data Summary Section provides the reservoir temperatures used for each ***Rapid Gas***^{SM} sample). Desorbed gas volumes were measured to the nearest 1.0-milliliter by fluid displacement. The frequency of the measurements was greatest during the early phase of desorption tests to ensure sufficient data were available for more precise lost gas volume determination. Desorption tests for the ***Rapid Gas***^{SM} samples were terminated within three to five days of the coring operations. The gas desorption data was used to calculate the lost gas volume using TICORA's variation of the graphical US Bureau of Mines method (Page 10, Data Summary Section).

At the conclusion of the short-term desorption tests the core samples were removed from the canisters, digitally photographed, and detailed lithological description of the core sample were performed. The lithological descriptions and digital photographs of the ***Rapid Gas***^{SM} core samples are provided in Appendix I.

Subsequent to lithological description and digital core photography, the sample particle size was quickly reduced to a 1-inch diameter top size. Three approximately equal weight splits were then quickly removed from the sample. The volume of the each split was calculated using sample weight and density. The remaining sorbed phase gas volume was determined by measuring the amount of gas released after pulverizing the triplicate splits (Page 9, Data Summary Section).

The triplicate splits were pulverized in a specialized sealed crushing vessel, under an inert gas (argon) atmosphere. Desorbed gas (crushed gas) volume measurements were measured at the respective reservoir temperatures. The desorbed gas (crushed gas) volumes were measured periodically until no measurable gas was observed from the crushing vessel. A sample of the gas released following pulverization was collected from ***Rapid Gas***^{SM} sample 290-4 for gas composition analysis by gas chromatography.

The ***Rapid Gas***^{SM} gas content estimate was obtained by dividing the sum of the calculated lost gas, desorbed gas, and average crushed gas volumes by the air-dried core sample weight (Page 10, Data Summary Section).

ASTM methods were used to determine residual moisture and ash content (**ASTM D 5142**), and total sulfur content (**ASTM 4239C**) of air-dried splits of the bulk core samples (Page 8, Data Summary Section). The particle density was measured (in triplicate) by helium multi-pycnometry on the pulverized air-dried sample splits. The results of the triplicate density analysis are reported on Page 5, Data Summary Section. Due to the heterogeneity of the ***Rapid Gas***^{SM} samples, helium multi-pycnometry testing was performed on the same air-dried split used of the bulk core samples for moisture, ash and total sulfur content testing (Page 4, Data Summary Section).

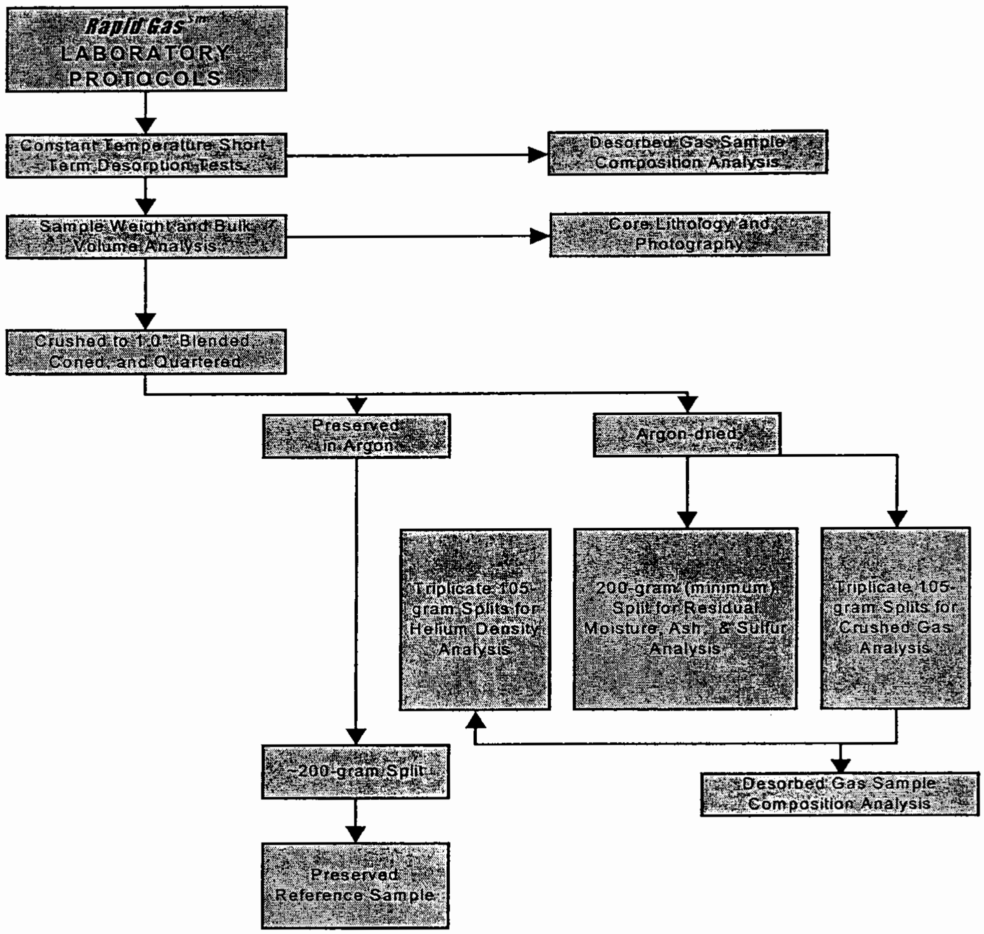

Figure 3-1 Flowchart of Sample Processing and Analysis

3.2 Desorbed Gas Composition

TICORA performed the desorbed gas composition data collection for analysis and interpretation. Desorbed gas was collected from 1 core sample (TICORA Nos. 290-4) during the desorption tests and analyzed by gas chromatography to determine the average desorbed gas composition. Desorbed gas sample composition was determined following standard method ASTM D 1945 (Modified) [5]. The average desorbed gas composition yields an estimation of the sorbed phase gas composition.

3.3 Sample Bulk Composition and Property Analysis

Sample bulk composition and property analyses were performed according to **ASTM** or other standardized methodologies[5] (**Table 3-1**).

Table 3-1 Sample Bulk Composition and Property Analyses and Associated Standard Methodology	
Analysis	Methodology
Residual moisture content	**ASTM D 5142**
Ash content	**ASTM D 5142**
Total sulfur in coal content	**ASTM D 4239C**
Sample bulk volume	Standard water displacement technique
Helium Density	Helium Multipycnometry (see section 3.3)

A third-party commercial laboratory: Commercial Testing and Engineering Co. conducted Sulfur analysis.

3.4 Helium Density Analysis

Density analysis requires the measurement of sample volume and mass. Sample volume was measured at room temperature conditions on triplicate air-dried samples of approximately 100-grams using a helium multi-pycnometer. Sample volume was calculated from helium expansion pressure measured by the multi-pycnometer. Helium can penetrate the coal micro pore structure without adsorption and does not add moisture to the sample. Sample mass was determined to the nearest 0.001-gram using an electronic balance. Sample density is calculated by dividing the measured sample mass by calculated sample volume.

4.0 FINDINGS

This section provides summaries and discussions of the ***Rapid Gas***^{SM} analysis results. A detailed summary of the analysis data is provided in the Data Summary Section and Appendix I.

4.1 Sorbed Phase *Rapid Gas*^{SM} Content Estimates

Sorbed Phase ***Rapid Gas***^{SM} content is the summation of lost gas content, desorbed gas content, and crushed gas content. The total gas content (air-dry basis) estimates were obtained by dividing the total gas volume by the air-dried core sample weight. The residual moisture and ash and sulfur content were then used to convert the air-dry basis gas content data to dry ash free basis. **Table 4-1** summarizes gas content estimates for the Marmaton and Cherokee Group seams.

In some reservoirs a statistically significant relationship exists between the gas content of each sample and the inorganic content. The inorganic content assumed to be the sum of the moisture, ash, and sulfur contents. **Figure 4-1** illustrates excellent correlations between gas content and inorganic content for the Marmaton and Cherokee Group seams samples collected at the Burch and Fuqua wells. The extrapolated gas content at 0% inorganic content, regression coefficient (R^2), slope of the relationship, and inorganic content at the zero gas content intercept is illustrated in **Figure 4-1**. A similar relationship can also exists between the gas content of each sample and the total organic carbon content. **Figure 4-2** illustrates this relationship. Sample 290-4 from in the Mulky Seam at the Burch well appears to be outliers with a larger gas content value than expected; this may be due to maceral variation in respect to other samples. Based on TICORA's experience, this is comparable to research wells conducted in the Marmaton and Cherokee Group seams in the Cherokee City Basin; however, accuracy of these results would be greatly enhanced with the collection of coal samples with less than 20% inorganic content.

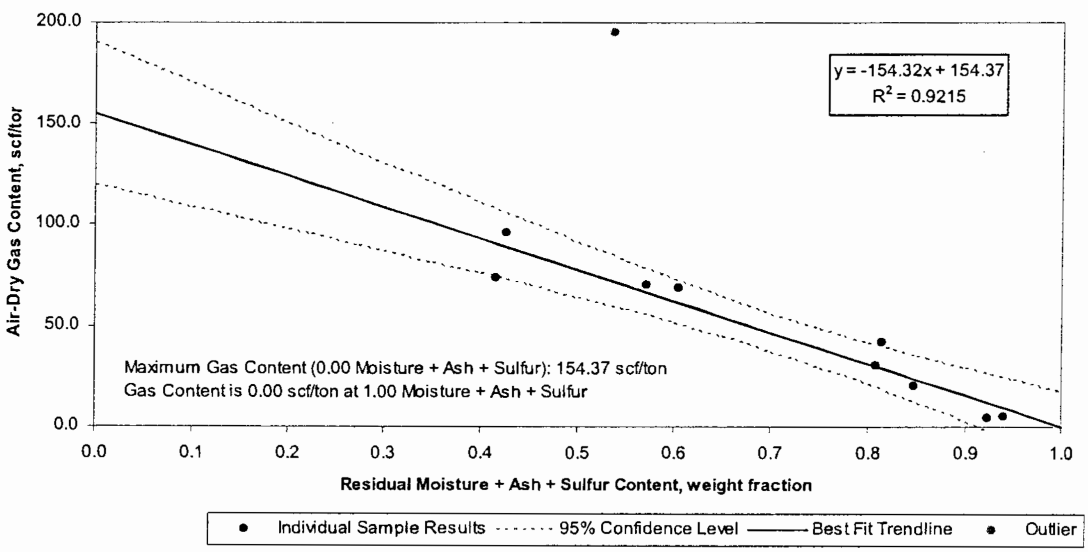

Figure 4-1 Sorbed Gas Content (Air-dry basis) versus Residual Moisture, Ash, and Total Sulfur at the Burch and Fuqua wells

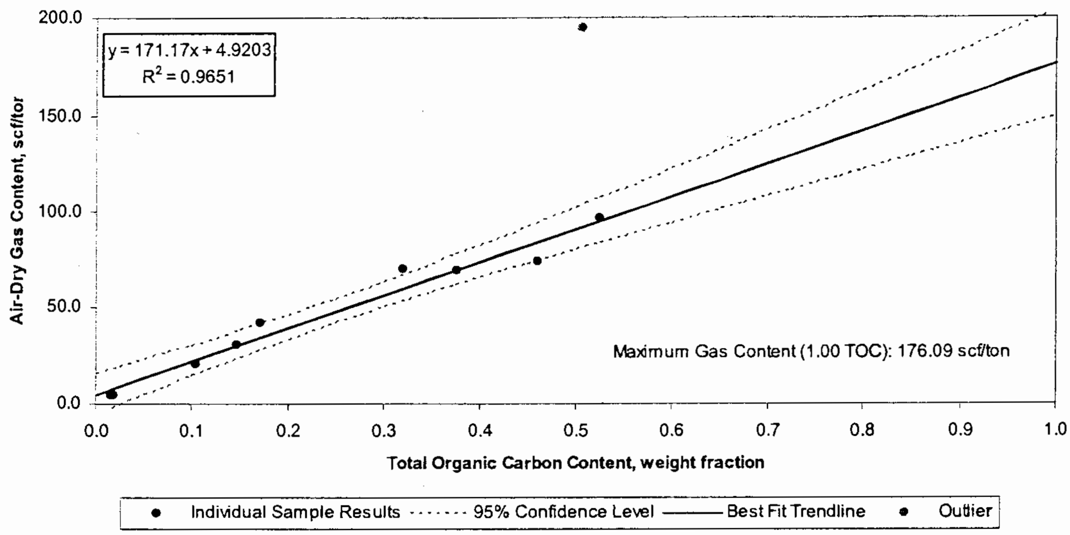

Figure 4-2 Sorbed Gas Content (Air-dry basis) versus Total Organic Carbon at the Burch and Fuqua wells

Table 4-1 *Rapid Gas*[SM] Content Summary

TICORA No.	Drill Depth	TOC	Ash	Residual Moisture	Sulfur	Calculated Lost Gas Volume		Measured Desorbed Volume		Measured Crushed Volume		Total Air-Dry Gas Content	Total DAF Gas Content
	feet	Air-Dry Basis, Weight %				%	scf/ton	%	scf/ton	%	scf/ton	scf/ton	scf/ton
Un-Named Seam													
290-1	1,478.2-1,479.2	45.98	37.91	1.51	2.11	2.29	1.68	33.57	24.58	64.14	46.96	73.21	120.85
Mulky Seam													
290-4	1,566.2-1,567.2	50.55	50.55	0.88	2.21	2.92	5.68	47.20	91.89	49.88	97.11	194.69	400.82
V Shale Seam													
290-6	1,637.3-1,638.3	17.20	77.52	1.00	2.86	0.95	0.40	18.28	7.68	80.77	33.95	42.03	195.63
Mineral Seam													
290-8	1,703.9-1,704.9	10.42	81.70	1.21	1.82	4.40	0.89	61.56	12.47	34.03	6.90	20.26	118.57

TOC -- Total Organic Carbon
DAF -- Dry, Ash-Free Basis

Actual gas content

4.1.1 Lost Gas Content

Lost gas volume was calculated using the USBM technique[6]. Extrapolations are restricted to desorption data collected after the sample temperature stabilized at the reservoir temperature. Lost gas content estimates for the Cherokee Group seams at the Burch well are summarized in **Table 4-1**. These lost gas estimates represents less than 5% of the total gas content. Lost gas extrapolations from the Cherokee Group seams at the Burch well are illustrated in **Appendix II.**

4.1.2 Measured Gas Content

All ***Rapid Gas***^{SM} desorption curves include lost gas content (red), measured gas content (green), and crushed gas content (blue) for the Cherokee Group seams at the Burch well are included in **Appendix II.**

4.1.3 Crushed Gas Content

Crushed gas content was measured on six of eighteen core samples collected from the Cherokee Group seams at the Burch well. Average crushed gas content estimates for the Cherokee Group seams at the Burch well are summarized in **Table 4-1**.

The crushed gas content analysis data is presented in page 9, Data Summary Section. The crushed gas contents were added to the lost gas and measured gas contents for the respective desorption samples to determine total gas content estimates.

4.1.4 Gas Diffusivity and Sorption Time

Gas storage and flow through coal and shale seams are generally modeled with dual porosity reservoir models. Gas is stored by sorption within the primary porosity system within the organic material within the coal and shale matrix. The primary porosity consists of micro- (< 2 nanometers) and meso-porosity (2 to 50 nanometers). Gas flows to the well bore through the secondary porosity system, which consists of macro-pores (> 50 nanometers) and natural fractures. Gas flow through the primary porosity is dominated by diffusion and quantified with Fick's Law while that through the secondary porosity is quantified with Darcy's Law.[1] Diffusivity is the diffusion coefficient (D) divided by the square of an average diffusion distance (r^2). Diffusivity can be estimated from the method used for determining lost gas volume using the relationship listed in **Equation 4.1**.

$$\frac{D}{r^2} = \left(\frac{m}{203.1G_{cad}}\right)^2 \quad [4.1]$$

where:

D/r^2 *diffusivity, sec*$^{-1}$
m *slope of desorbed gas content versus square-root time graph, scf/ton-hour*$^{0.5}$
G_{cad} *air-dry total gas content, scf/ton*

Although diffusivity values are used in reservoir models, an easier concept to understand is the sorption time. Sorption time is defined as the time required to desorb 63% of total gas content if a sample is maintained at constant approximate reservoir temperature. The relationship used to relate sorption time to diffusivity is listed in **Equation 4.2**.

$$\tau = \frac{1}{3600\alpha \frac{D}{r^2}} \qquad [4.2]$$

Where:

τ sorption time, hours
D/r^2 *diffusivity, sec*$^{-1}$
α *geometrical shape factor, cm*^{2}

The geometrical shape factor for a sphere, the most common assumed geometry is 15. **Table 4-2** summarizes diffusivity and sorption time estimates for the ***Rapid Gas***^{SM} desorption samples. The gas sorption time is inversely related to the gas desorption rate. The rate of gas desorption from the organic matrix is a critical parameter that can significantly affect the early time gas production rate from coal and shale bed reservoirs. In general, the faster the gas desorption rate (i.e. the shorter the gas sorption time value) the greater the early time gas production rate. Based on the results summarized below, the Cherokee Group seams at the Burch well indicates that they desorb gas at a slower rate to some other commercial coal gas basins, such as some Powder River Basin and San Juan coal reservoirs where gas sorption times are on the order of 15 to 50 hours. Gas mobility characteristics have been summarized in page 11, Data Summary Section.

Table 4-2 Diffusivity and Sorption Time Estimates

Sample ID	Sample Depth feet	Sorption Time hours	Diffusivity sec^{-1}
Un-named Seam			
290-1	1,478.2-1,479.2	390.94	4.74E-08
Mulky Seam			
290-4	1,566.2-1,567.2	232.07	7.98E-08
V Shale Seam			
290-6	1,637.3-1,638.3	1,610.42	1.15E-08
Mineral Seam			
290-8	1,703.9-1,704.9	81.93	2.26E-07

4.2 Desorbed Gas Composition

Knowledge of the desorbed gas composition is required to properly evaluate the gas storage capacity and to anticipate variations in wellhead gas composition over production history.

Figure 4-5 graphically illustrates the apparent sorbed phase gas composition of ***Rapid Gas***^{SM} core sample collected for the Mulky seam at the Burch well. The raw data used to make these computations is presented in the Data Summary Section (pages 7-8). In addition to methane, natural gas produced from coal and shale gas reservoirs may contain significant volumes of higher hydrocarbons, carbon dioxide and nitrogen. This does not appear to be the case for the Mulky seam at the Burch 10-17-29-12 well is comprised of 95.34% methane, 0.19% ethane, 1.05% carbon dioxide, and 3.31% nitrogen.

Sorbed phase gas composition estimates reported in **Table ES 1-1** are believed to be representative of the actual sorbed phase gas for the Mulky seam at the Burch well. This is because desorbed gas compositions were calculated by integrating 4 to 6 gas composition data points over the gas desorption history of the selected samples (Data Summary Section, Pages 7-8). Desorbed gas samples were collected during canister desorption measurements and upon crushing the sample. The only uncertainty associated with this technique is the inability to determine the composition of gas lost during sample recovery. Since the volume of the lost gas was relatively small for all samples (≤5% of the total gas volume), a high level of confidence can be associated with the desorbed gas composition results. This observation is important for two reasons:

1) It demonstrates that a representative gas storage capacity estimate can be determined from methane adsorption isotherm data alone;

2) It suggests that the produced gas stream can be anticipated to remain the same over the life of the well.

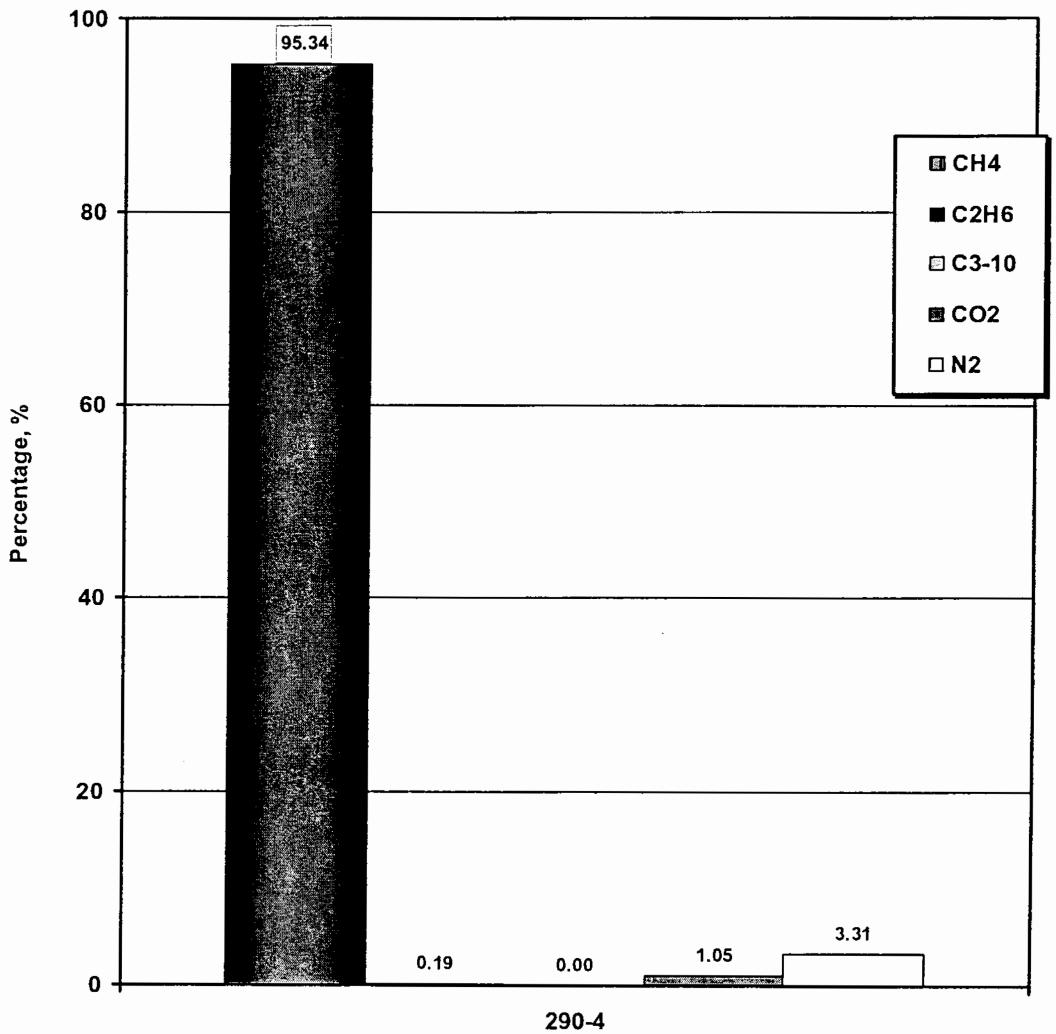

Figure 4-3 Apparent Sorbed Gas Composition

4.3 Residual Moisture, Ash, Total Sulfur, and Helium Density

The density of coal varies as a function of its bulk composition[1,4]. Since the mineral matter component of the coal has a significantly higher density than the organic matter component, the bulk density of coal varies directly as a function of its mineral matter content. The ash content of coal mainly represents the mineral matter component of the coal in a thermally decayed state. Although the mineral matter component is altered during the ashing process; the weight percentage of mineral matter and ash are essentially equivalent. Thus, a good relationship should exist between ash content and bulk density (or the reciprocal of bulk density) values. **Figure 4-4** illustrates how the dry basis reciprocal of helium density values of the core samples vary as a function of their dry basis ash content. A good correlation exists between ash content (dry basis) and the reciprocal of helium density (dry basis) for the Marmaton and Cherokee Group Seams at the Burch well (R^2 = 0.9685). Based on TICORA's experience, this is comparable to research wells conducted in the Marmaton and Cherokee Group seams in the Cherokee Basin; however, accuracy of these results would be greatly enhanced with the collection of coal samples with less than 20% inorganic content.

The organic density of coal typically varies between 1.18 to 1.35 g/cm³. The organic density value of 1.25 g/cm³ falls within this range. The inorganic density is typically believed to range between the densities of the minerals that typically occur in coal. Therefore, the inorganic density is typically believed to range between 2.42 g/cm³ (density of moist kaolinite) and 2.65 g/cm³ (density of quartz). The average inorganic density value of 2.97 g/cm³ is slightly higher than is normally anticipated. However, the presence of secondary pyrite (FeS_2), which has a density of 5.02 g/cm³, this may explain the relatively high inorganic density. Page 5 of the Data Summary Section presents the detailed helium density data.

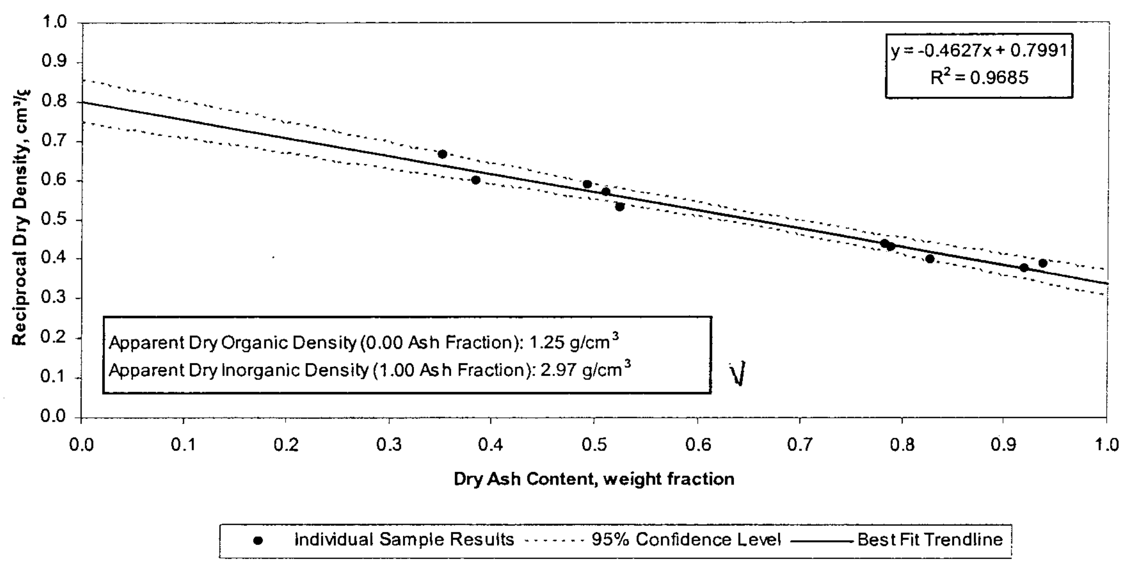

Figure 4-4 Variation of Reciprocal Helium Density versus Ash Content (Dry Basis) at the Burch and Fuqua wells

4.4 Total Organic Carbon

Humble Geochemical Services (Humble) performed total organic carbon (TOC) analysis of all samples using the LECO method. TOC is a measure of the richness of a rock with respect to weight percent organic carbon. The samples were initially dried and crushed. Subsequent treatment with hydrochloric acid effectively removed the carbonate portion of the material. The organic carbon component was measured through combustion in a furnace while measuring the amount of evolved carbon dioxide. True shale's can be extremely rich in organic carbon (~10%), but a minimum value for which rocks can be officially deemed source rocks is not always definable, as thermal history, specific variety of organic material, and efficiency of hydrocarbon migration all play a significant role in source rock potential. In general, shales containing less than 0.50 weight percent TOC and carbonates possessing less than 0.20 percent are not regarded as particularly good source rocks. Usually no further geochemical tests are performed with these organically lean samples. TOC analysis is a comparatively quick and inexpensive procedure that effectively screens potential source rock samples. Total organic carbon content was determined for all core samples.

The density of coal varies as a function of its bulk composition[1, 4]. Since the mineral matter component of the coal has a significantly higher density than the organic matter component, the bulk density of coal varies directly as a function of its mineral matter content. Therefore a good relationship can be established between reciprocal dry densities versus dry total organic carbon. **Figure 4-5** illustrates this well.

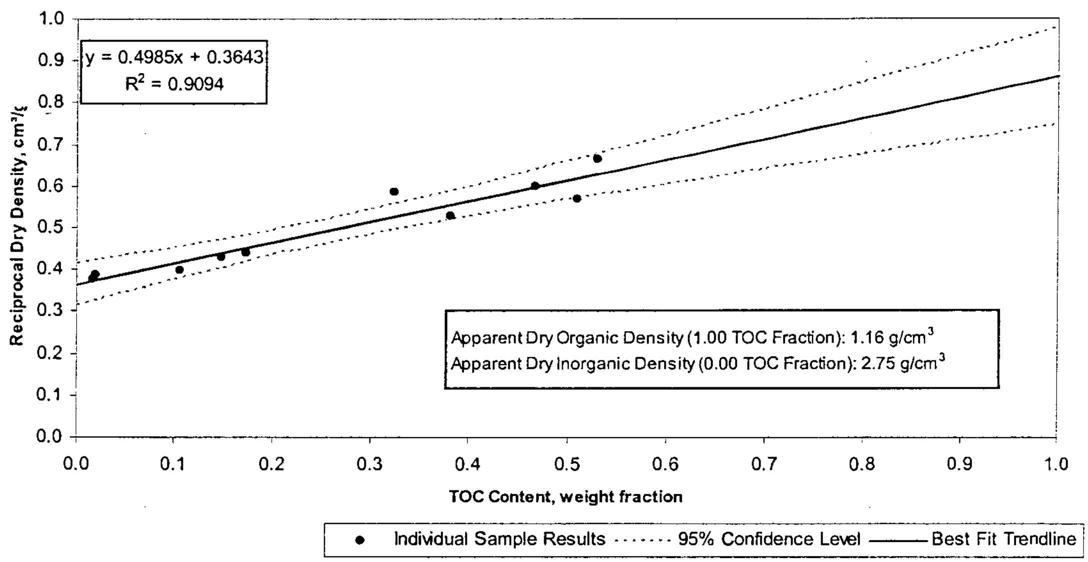

Figure 4-5 Variation of Reciprocal Helium Density versus Total Organic Carbon Content (Dry Basis) at the Burch and Fuqua wells

5.0 SORBED PHASE GAS-IN-PLACE ESTIMATES

Sorbed gas-in-place (GIP) analysis was performed on a gross reservoir interval including for the Marmaton and Cherokee Group seams at the Burch well by processing high-resolution open-hole density log data. Log Tech recorded high-resolution (resolution = 0.5 feet) open-hole geophysical logs (including: gamma-ray, bulk density, and caliper) of the Burch well. A graphical representation of these data is illustrated in **Figure 2-1**. Huber provided TICORA with the log data in a LAS format for processing.

The top and base of the gross reservoir interval was selected to be 1,400 to 1,800 feet to include the cored interval based on low gamma ray and density values from the log data. This corresponds to a total gross thickness of 400 feet.

Six parameters are required to properly process the density log data:

1. Area of interest
2. Density cut-off value
3. Average organic density
4. Average inorganic density
5. Average in-situ moisture content
6. Maximum (100% organic) gas content

The area of interest over which the GIP estimates are made can be an assumed drainage area for a particular well or an arbitrary area surrounding the core well. The area of interest parameter chosen for the analysis was an arbitrary one-half square mile (320 acres). GIP resource estimates are reported in units of billions of square feet per 320 acres (Bscf/320 acres).

The potential producing coal and carbonaceous intervals are determined using density cut-off values. Producing coal intervals are determined from the open-hole density log data using a density cut-off value greater than or equal to the organic fraction density and less than or equal to the commonly used limit of 1.75 g/cm^3 (which typically approximates to an inorganic content of 50%). Producing carbonaceous shale intervals are generally selected based density limits above 1.75 g/cm^3 up to a maximum limit in the range of 2.45 g/cm^3. GIP resources estimates were computed using maximum density cut-off values of 1.75 and 2.45 g/cm^3.

Two methods were used when measuring the organic and inorganic density parameters used for GIP analysis at the Burch well:

1. Reciprocal density (dry-basis) and ash content (dry-basis) (Refer to Section 4.3) from the Burch and Fuqua wells. The average organic and inorganic densities were calculated as 1.25 and 2.97 g/cm^3, respectively, and;
2. Reciprocal density (dry-basis) and TOC content (dry-basis) (Refer to Section 4.4) from the Burch and Fuqua wells. The average organic and inorganic densities were calculated as 1.18 and 2.75 g/cm^3, respectively.

Average residual moisture content measured on multiple ***Rapid Gas***SM samples was substituted for in-situ moisture content in the GIP resource estimates. Time constraints for the "rapid" GIP resource estimates necessitate this substitution. TICORA protocol requires approximately 30-days to accurately determine in-situ moisture. A good relationship typically exists between residual moisture content and in-situ moisture content. Residual moisture content values are typically slightly less than in-situ moisture content. Therefore, this substitution theoretically overestimates GIP resource estimates. An average residual moisture content value of 1.15 weight percent was obtained from the ***Rapid Gas***SM samples.

Maximum gas (100% organic) content was estimated by using the following two relationships:

1. By substituting 0.00 moisture plus ash plus sulfur fraction into the equation of the linear regression line of gas content (air-dry basis) versus moisture plus ash content (air-dry basis) plot (**Figure 4-1**). A good correlation exists between air-dry gas content and air-dry moisture plus ash plus sulfur content for all the ***Rapid Gas***SM core samples at the Burch and Fuqua wells well (R^2 = 0.922). Based on this relationship, the calculated maximum gas content is 154.37 scf/ton (0.00 moisture plus ash plus sulfur fraction). The GIP resource estimates for the gross reservoir interval at the Burch well are summarized in **Tables 5-1, and 5-2**.
2. By substituting 1.00 TOC fraction into the equation of the linear regression line of gas content (air-dry basis) versus TOC content (air-dry basis) plot (**Figure 4-2**). A good correlation exists between air-dry gas content and air-dry TOC content for all the ***Rapid Gas***SM core samples at the Burch and Fuqua wells (R^2 = 0.965). Based on this relationship, the calculated maximum gas content is 179.06 scf/ton (1.00 TOC fraction). The GIP resource estimates for the gross reservoir interval at the Burch well are summarized in **Tables 5-3 and 5-4**.

The increase in the GIP resource estimates between the 1.75 and 2.45 g/cm^3 density cut-offs is directly related to the increase in reservoir thickness as a consequence of including carbonaceous shale intervals in the GIP calculation. The 2.45 g/cm^3 density value is probably the more representative cut-off for determining the true net thickness of organic bearing intervals that are capable of contributing to gas production due to likely production from the carbonaceous shale's.

Tables 5-1 and 5-2 represent GIP estimates based on relationship 1 using reciprocal dry density versus dry ash fraction and Residual moisture, ash, and sulfur contents versus gas content. **Tables 5-3 and 5-4** represent GIP estimates based on relationship 1 using reciprocal dry density versus dry TOC fraction and TOC contents versus gas content.

Table 5-1 Summary of Gas-In-Place Resource Estimates based on relationship 1, 1.75 g/cm^3 Density Cut-Off

Organic Density: 1.25 g/cm^3		In-organic Density: 2.97 g/cm^3			In-Situ Moisture: 1.15%	
Top Depth	Bottom Depth	Thickness	In-Situ Density	In-Situ Ash	In-Situ Gas Content	Gas-In-Place[1]
feet	feet	feet	g/cm^3	weight %	Scf/ton	Bscf/320 acres
1,477.0	1,477.5	0.5	1.631	40.739	89.706	0.032
1,621.0	1,621.7	0.7	1.615	39.444	91.704	0.045
Mean[2]			**1.622**	**39.984**	**90.872**	
Total		**1.2**				**0.077**

1. Maximum gas content parameter = 154.87 scf/ton
2. Mean values are weighted by thickness
3. Maximum Gas content parameter = 400.82 (DAF Gas Content) and Moisture of 0.88%.

Table 5-2 Summary of Gas-In-Place Resource Estimates based on relationship 1, 2.45 g/cm^3 Density Cut-Off

Organic Density: 1.25 g/cm^3		In-organic Density: 2.97 g/cm^3			In-Situ Moisture: 1.15%	
Top Depth	Bottom Depth	Thickness	In-Situ Density	In-Situ Ash[2]	In-Situ Gas Content	Gas-In-Place[1]
feet	feet	feet	g/cm^3	weight %	Scf/ton	Bscf/320 acres
1,422.6	1,423.0	0.4	2.436	84.580	22.029	0.009
1,476.7	1,478.6	1.9	1.977	61.848	57.120	0.093
1,504.4	1,505.4	1.0	2.312	79.736	29.506	0.030
1,516.8	1,517.1	0.3	2.388	82.747	24.859	0.008
1,549.6	1,551.5	1.9	2.286	78.642	31.195	0.059
1,563.1	**1,566.5**	**3.4**	**2.167**	**72.752**	**105.690**	**0.339**
1,620.4	1,622.9	2.5	1.985	62.083	56.757	0.123
1,635.7	1,638.8	3.1	2.213	75.035	36.763	0.110
1,675.8	1,676.4	0.6	2.444	84.864	21.590	0.014
1,678.5	1,679.3	0.8	2.356	81.506	26.774	0.022
1,688.8	1,689.5	0.7	2.346	81.110	27.385	0.020
1,696.5	1,696.7	0.2	2.435	84.540	22.090	0.005
1,703.6	1,703.8	0.2	2.446	84.917	21.509	0.005
1,767.5	1,767.7	0.2	2.447	84.963	21.437	0.005
Mean[2]			**2.195**	**73.505**	**52.054**	
Total		**17.2**				**0.842**

1. Maximum gas content parameter = 154.37 scf/ton
2. Mean values are weighted by thickness

Table 5-3 Summary of Gas-In-Place Resource Estimates based on relationship 2, 1.75 g/cm^3 Density Cut-Off

Organic Density: 1.18 g/cm^3		In-organic Density: 2.75 g/cm^3			In-Situ Moisture: 1.15%	
Top Depth	**Bottom Depth**	**Thickness**	**In-Situ Density**	**In-Situ Ash**	**In-Situ Gas Content**	**Gas-In-Place[1]**
feet	*feet*	*feet*	*g/cm^3*	*weight %*	*Scf/ton*	*Bscf/320 acres*
1,477.0	1,477.5	0.5	1.631	48.707	89.786	0.032
1,621.0	1,621.7	0.7	1.615	47.467	92.006	0.045
Mean[2]			**1.622**	**47.984**	**91.081**	
Total		**1.2**				**0.077**

Notes:
1. Maximum gas content parameter = 179.06 scf/ton
2. Mean values are weighted by thickness

Table 5-4 Summary of Gas-In-Place Resource Estimates based on relationship 2, 2.45 g/cm^3 Density Cut-Off

Organic Density: 1.18 g/cm^3		In-organic Density: 2.75 g/cm^3			In-Situ Moisture: 1.15%	
Top Depth	**Bottom Depth**	**Thickness**	**In-Situ Density**	**In-Situ Ash[2]**	**In-Situ Gas Content**	**Gas-In-Place[1]**
feet	*feet*	*feet*	*g/cm^3*	*weight %*	*Scf/ton*	*Bscf/320 acres*
1,422.6	1,423.0	0.4	2.436	90.689	14.614	0.006
1,476.7	1,478.6	1.9	1.977	68.921	53.591	0.088
1,504.4	1,505.4	1.0	2.312	86.050	22.920	0.023
1,516.8	1,517.1	0.3	2.388	88.933	17.757	0.006
1,549.6	1,551.5	1.9	2.286	85.003	24.795	0.047
1,563.1	1,566.5	3.4	2.167	79.388	79.088	0.254
1,620.4	1,622.9	2.5	1.985	69.146	53.188	0.115
1,635.7	1,638.8	3.1	2.213	81.549	30.980	0.092
1,675.8	1,676.4	0.6	2.444	90.961	14.127	0.009
1,678.5	1,679.3	0.8	2.356	87.745	19.884	0.016
1,688.8	1,689.5	0.7	2.346	87.366	20.563	0.015
1,696.5	1,696.7	0.2	2.435	90.650	14.682	0.003
1,703.6	1,703.8	0.2	2.446	91.011	14.036	0.003
1,767.5	1,767.7	0.2	2.447	91.055	13.957	0.003
Mean[2]			**2.195**	**80.088**	**42.340**	
Total		**17.2**				**0.680**

Notes:
1. Maximum gas content parameter = 179.06 scf/ton
2. Mean values are weighted by thickness
3. Maximum Gas content parameter = 400.82 (DAF Gas Content) and Moisture of 0.88%.

6.0 ABOUT *RAPID GAS* SM ANALYSIS

Rapid Gas SM analysis provides a proven means to rapidly gather and report gas content, sorbed phase gas composition, and coal chemistry estimates for coal and shale gas reservoir systems. Analysis programs for reservoirs where the mechanism of gas storage is predominantly by sorption, such as coal and organic shale reservoirs typically require several weeks to several months to finalize. By comparison, the ***Rapid Gas*** SM analysis program can be completed and reported within three weeks of the arrival of samples at TICORA's laboratory.

Rapid Gas SM analysis is intended to address our client's needs quickly because the reservoir property estimates it provides, along with supporting geologic and engineering data, are utilized to assess the potential of a play, to make informed completion decisions, to evaluate initial production data, and to better understand future production trends and gas development economics. The explosive growth of the unconventional gas industry over the past several years coupled with the scarcity of qualified testing facilities and the protracted nature inherent to sorption analysis programs have resulted in increased turn-around-time for data sets or, even more damaging, incomplete or incorrect data sets. The ***Rapid Gas*** SM analysis program, on the other hand, allows the client an opportunity to confidently address critical issues shortly after the drilling operations are completed.

Rapid Gas SM analysis is not intended to substitute or replace longer-term conventional coal and shale gas analysis programs. Benefits of the conventional "long term" analysis program include:

- larger and thereby more precise gas storage data sets,
- quantification of gas movement characteristics,
- quantification of desorbed gas fractionation behavior,
- quantification of the true residual gas content,
- ability to perform adsorption isotherm tests at experimental parameters representative of the in-situ conditions,
- conversion of analyses results to an in-situ basis,
- larger and thereby more representative reservoir composition data sets, and
- the ability to collect minimum data requirements to properly and comprehensively evaluate critical properties of coal and shale gas reservoir systems.

Rapid Gas SM analysis alone does not address the minimum data requirements needed to comprehensively evaluate critical reservoir properties. But it does allow rapid estimates of the most critical data required namely the gas content, the sorbed phase gas composition, and the gas-in-place resource. Due to the nature of the testing protocol, ***Rapid Gas*** SM analysis may not provide gas content values that are as precise as those obtained from the long term desorption experiments. The error is not large. TICORA's experience indicates that the ***Rapid Gas*** SM gas content results are typically within ±5% of the conventional "long term" results.

7.0 REFERENCES

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2. Mavor, M.J., Pratt, T.J., and Nelson, C.R.: "Quantitative Evaluation of Coal Seam Gas Content Estimate Accuracy," Paper SPE 29577 presented at the 1995 Joint Rocky Mountain Regional / Low-Permeability Reservoirs Symposium, Denver, Colorado, March 20-22, 1995.

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6. Mavor, M.J.: "Coalbed Methane Reservoir Properties" in *A Guide to Coalbed Methane Reservoir Engineering*, Saulsberry, J.L., Schafer, P.S., and Schraufnagel, R.A. (Editors), Gas Research Institute Report GRI-94/0397, Chicago, Illinois (March 1996).

Desorption Sample Identification and Description

J.M. Huber Corporation: Burch 10-17-29-12

Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

		TICORA No.	Canister No.	Drill Depth feet	Description
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	Core 1. Headspace filled with Produced Water. 90°F Desorption Temperature.
	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	Core 10. Headspace filled with Produced Water. 90°F Desorption Temperature.
	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	Core 18. Headspace filled with Produced Water. 90°F Desorption Temperature.
	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	Core 27. Headspace filled with Produced Water. 90°F Desorption Temperature.

Desorption Sample Special Testing

J.M. Huber Corporation: Burch 10-17-29-12

Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

		TICORA No.	Canister No.	Drill Depth feet	Special Testing
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	Moisture, Ash and Sulfur. Helium Density. Crushed Gas. Total Organic Carbon.
	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	Moisture, Ash and Sulfur. Helium Density. Crushed Gas. Total Organic Carbon. Gas Composition.
	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	Moisture, Ash and Sulfur. Helium Density. Crushed Gas. Total Organic Carbon.
	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	Moisture, Ash and Sulfur. Helium Density. Crushed Gas. Total Organic Carbon.

Mass and Volume Data

J.M. Huber Corporation: Burch 10-17-29-12
Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

					Sample Mass				Volume			
		TICORA	Canister	Drill Depth	Raw	Air-Dry	Dry	"In-Situ"	Bulk Sample	Head Space	Desorption	Desorption to Headspace
		No.	No.	feet	g	g	g	g	cm^3	cm^3	cm^3	Ratio
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	1,543	1,518	1,495	N/D	950	258	1,164	4.51
Cherokee Formation	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	2,237	2,218	2,199	N/D	1,350	203	6,362	31.28
Cherokee Formation	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	2,878	2,855	2,827	N/D	1,300	163	685	4.19
Cherokee Formation	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	3,142	3,073	3,035	N/D	1,320	208	1,196	5.74

N/D - Not Determined

Desorption Sample Moisture, Ash, and Sulfur

J.M. Huber Corporation: Burch 10-17-29-12
Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

		TICORA	Canister	Drill Depth	Chemistry						
					Moisture			Ash		Sulfur	
		No.	No.	feet	Residual	Total	Holding Capacity	Air-Dry	In-Situ	Air-Dry	In-Situ
					fraction	fraction	fraction	fraction	fraction	fraction	fraction
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	0.0151	0.0312	N/D	0.3791	N/D	0.0211	N/D
	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	0.0088	0.0171	N/D	0.5055	N/D	0.0221	N/D
	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	0.0100	0.0178	N/D	0.7752	N/D	0.0286	N/D
	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	0.0121	0.0339	N/D	0.8170	N/D	0.0182	N/D

N/D - Not Determined

Desorption Sample Density

J.M. Huber Corporation: Burch 10-17-29-12

Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

		TICORA No.	Canister No.	Drill Depth feet	Density: Water Displacement Bulk g/cm^3	Density: Helium Displacement Air-Dry g/cm^3	Density: Helium Displacement Dry g/cm^3	Density: Helium Displacement In-Situ g/cm^3
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	1.66	1.657	1.667	N/D
Cherokee Formation	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	1.68	1.750	1.757	N/D
Cherokee Formation	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	2.24	2.274	2.287	N/D
Cherokee Formation	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	2.40	2.489	2.507	N/D

N/D - Not Determined

Desorption Sample Total Organic Carbon

J.M. Huber Corporation: Burch 10-17-29-12
Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

		TICORA	Canister	Drill Depth	Total Organic Carbon		
		No.	No.	feet	Air-Dry	Dry	In-Situ
					fraction	fraction	fraction
Cherokee Formation	Un-named Seam	290-1	GT-35	1,478.2-1,479.2	0.460	0.467	N/D
	Mulky Seam	290-4	GT-330	1,566.2-1,567.2	0.506	0.510	N/D
	V Shale Seam	290-6	GT-140	1,637.3-1,638.3	0.172	0.174	N/D
	Mineral Seam	290-8	GT-201	1,703.9-1,704.9	0.104	0.105	N/D

N/D - Not Determined

Desorbed Gas Analysis Composition[1]

J.M. Huber Corporation: Burch 10-17-29-12

Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

Sample Number	Collection Point	Air-Dry Gas Content	Incremental Volume[2]	N_2/O_2 Ratio Raw Sample[3]	Gas Analysis (Adjusted for Air)							
					C_1	C_2	C_{3-10}	CO_2	N_2	H_e	H_2	Total
	hours	scf/ton	cm^3		mole %	mole %	mole %	mole %	mole %	mole %	mole %	mole %
Depth (ft) 1,566.2-1,567.2				Lost Gas %: 2.92				Headspace Volume (cm^3): 203				
290-4-1	2.24	16.67	810	16.04	90.63	0.10	0.00	1.33	7.88	0.00	0.07	100.00
290-4-2	7.63	28.24	845	52.00	91.04	0.10	0.00	1.15	7.61	0.00	0.10	100.00
290-4-3	12.78	35.73	549	11.53	91.32	0.10	0.00	1.55	6.91	0.00	0.12	100.00
~~290-4-4~~	~~28.74~~	~~51.53~~	~~1,157~~	~~3.59~~	~~96.98~~	~~0.19~~	~~0.00~~	~~2.81~~	~~0.00~~	~~0.00~~	~~0.02~~	~~100.00~~
290-4-5	122.79	82.87	4,024	5.03	94.03	0.12	0.00	1.35	4.31	0.00	0.19	100.00
290-4-6	217.28	97.57	1,328	4.02	96.13	0.14	0.00	1.64	2.06	0.00	0.03	100.00
Final[5]	217.28	194.69	8,700	13.29	97.49	0.27	0.00	0.71	1.45	0.00	0.07	100.00
Apparent Sorbed Gas Composition[5]					**95.34**	**0.19**	**0.00**	**1.05**	**3.31**	**0.00**	**0.10**	**100.00**

Notes:

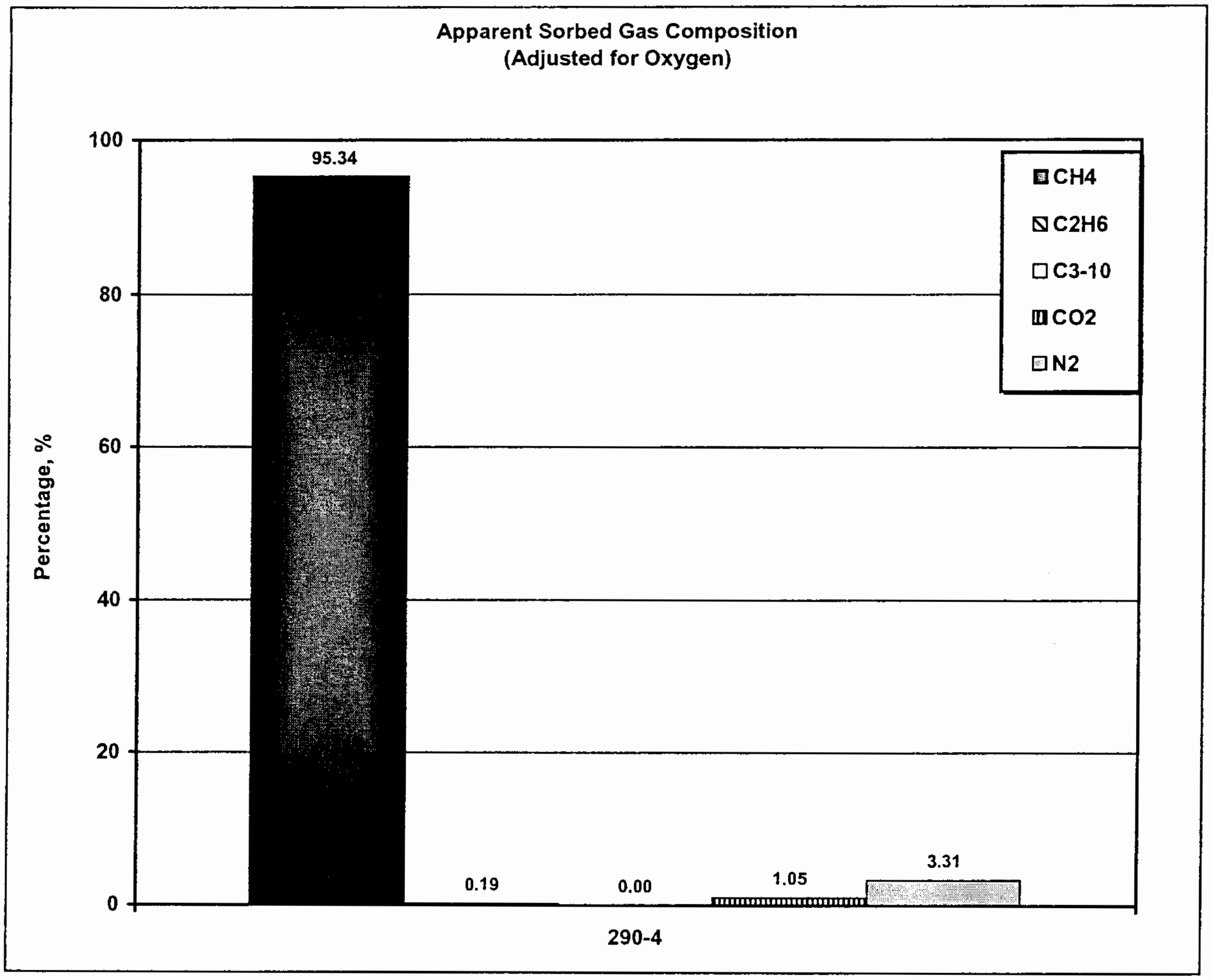
1. *To evaluate the gas composition, the nitrogen content of the gas sample is corrected for air contamination based upon the measured oxygen contents .*
2. *Incremental volume: Gas mixing in canister headspace must be considered when evaluating desorbed gas composition as a function of time. Attempts are made to collect a gas sample when the cumulative desorption volume (uncorrected), since the preceding gas sample was taken, exceeds the headspace volume. Headspace volumes are not determined until desorption experiments are terminated, therefore some assumptions must be made when sampling. Samples that do not adhere to the headspace guidelines are not generally in the analysis.*
3. *The nitrogen: oxygen ratio in air is ~3.73. Ratios larger than 3.73 indicate nitrogen generation or coal oxidation. For these samples, coal oxidation is not expected because produced water was used to consume canister headspace.*
4. *Sorbed gas composition estimates are calculated by integrating the gas composition and desorption data. The composition of the lost gas volume is assumed to be equivalent to the composition of the first gas sample. The composition of the volume of gas desorbed between two gas collection points is assumed to be equivalent to the gas composition of the latter point. The composition of the volume desorbed after the last gas sample is collected, is assumed to be equivalent to the composition of the last gas sample. Sorbed gas composition estimates do not account for the residual gas composition.*

~~Strikethrough~~: Data suspect (heavily contaminated) or did not meet sampling criteria. This data was not used to compute sorbed gas composition.
Hydrogen is believed to be an artifact and is not included in the average gas compostion results.

Desorbed Gas Analysis Composition Graphs

J.M. Huber Corporation: Burch 10-17-29-12

Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin



TICORA GEOSCIENCES, INC.

Crushed Gas Analysis Summary
Air-Dry Sample Weight Basis

J. M. Huber Corporation; Burch 10-17-24-12

Conventional Core (3.0-inch Diameter), Runs 1-4 (9 Canisters) Coal Zones

TICORA Number	Date Measured	Sample Weight (Air-Dry)	Sample Density	Sample Volume	Crushed Gas Content	Average Gas Content	Standard Deviation
		grams	*g/cm³*	*cm³*	*scf/ton*	*scf/ton*	*scf/ton*
Un-named Seam: 1,478.2' - 1,479.2' feet							
290-1-A	9/19/2003	91.753	1.748	52.490	41.446		
290-1-B	9/19/2003	91.576	1.655	55.333	46.972	46.960	5.508
290-1-C	9/19/2003	91.660	1.569	58.419	52.462		
Mulky Seam: 1,566.2' - 1,567.2' feet							
290-4-A	9/22/2003	95.631	1.739	54.992	97.116		
290-4-B	9/22/2003	95.215	1.553	61.310	97.108	97.112	0.006
~~290-4-C~~	~~9/22/2003~~	~~95.070~~	~~1.761~~	~~53.986~~	~~73.764~~		
V Shale Seam: 1,637.3' - 1,638.3' feet							
290-6-A	9/22/2003	95.401	2.256	42.288	40.656		
290-6-B	9/22/2003	95.803	2.282	41.982	30.517	33.948	5.809
290-6-C	9/22/2003	96.093	2.292	41.925	30.672		
Mineral Seam: 1,703.9' - 1,704.9' feet							
290-8-A	9/23/2003	94.827	2.509	37.795	6.697		
290-8-B	9/23/2003	94.839	2.535	37.412	6.526	6.895	0.497
290-8-C	9/23/2003	95.212	2.423	39.295	7.460		

~~*Strikethrough:*~~ *Measurement Suspect. Data not calculated in residual gas averages or standard deviation.*

Desorption & Gas Content Summary
Air-Dry, Dry-Ash-Free and In-Situ Weight Bases

J.M. Huber Corporation: Burch 10-17-29-12
Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

				Lost Gas		Measured Gas		Crushed Gas		Total Gas		
Sample No.	Canister No.	Drill Depth	Air-Dry Sample Weight	Calculated USBM Volume	Calculated USBM Content	Measured Desorbed Volume	Measured Desorbed Gas Content	Measured Crushed Volume	Measured Crushed Gas Content	Air-Dry Total Gas Content	DAF Total Gas Content	In-Situ Total Gas Content
		feet	*grams*	*%*	*scf/ton*	*%*	*scf/ton*	*%*	*scf/ton*	*scf/ton*	*scf/ton*	*scf/ton*
Un-named Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water												
290-1	GT-35	1,478.2-1,479.2	1,517.7	2.29	1.68	33.57	24.58	64.14	46.96	73.21	120.85	N/D
Mulky Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water												
290-4	GT-330	1,566.2-1,567.2	2,218.1	2.92	5.68	47.20	91.89	49.88	97.11	194.69	400.82	N/D
V Shale Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water												
290-6	GT-140	1,637.3-1,638.3	2,855.2	0.95	0.40	18.28	7.68	80.77	33.95	42.03	195.63	N/D
Mineral Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water												
290-8	GT-201	1,703.9-1,704.9	3,072.7	4.40	0.89	61.56	12.47	34.03	6.90	20.26	118.57	N/D

USBM = United States Bureau of Mines Lost Gas Method DAF= Dry, Ash-Free

Gas Sorption & Diffusion Characteristics

J.M. Huber Corporation: Burch 10-17-29-12
Continuous Core (3.0-inch Diameter),4 Canisters, Cherokee Basin

Sample No.	Canister No.	Drill Depth	Sample Competency Factor	Core Diameter	Shape Factor	Sorption Time (63.2%)	Diffusivity (63.2%)	Gradient of Lost Gas Slope	Sorption Time (Direct Method)	Diffusivity (Direct Method)
		feet		*inches*		*hours*	*sec* $^{-1}$		*hours*	*sec* $^{-1}$
Un-named Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water										
290-1	GT-35	1,478.2-1,479.2	Competent	3.00	15	*N/D*	*N/D*	3.24	390.94	4.74E-08
Mulky Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water										
290-4	GT-330	1,566.2-1,567.2	Competent	3.00	15	*N/D*	*N/D*	11.17	232.07	7.98E-08
V Shale Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water										
290-6	GT-140	1,637.3-1,638.3	Competent	3.00	15	*N/D*	*N/D*	0.92	1,610.42	1.15E-08
Mineral Seam. Core Sample. 90°F Desorption Temperature. Headspace filled with Produced Water										
290-8	GT-201	1,703.9-1,704.9	Competent	3.00	15	126.22	1.47E-07	1.96	81.93	2.26E-07

N/D - Did not meet sorption time criteria.