Overview of Coal and Shale Gas Measurement: Field and Laboratory Procedures

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ABSTRACT

Methods for measurement of gas in coals were initially developed to improve coal-mine safety. The Direct Method introduced by the U.S. Bureau of Mines for estimation of lost gas in the early 1970s has been updated to better estimate subsurface gas content of coals and shales. Proper sampling procedures and sample handling are critical factors in determining the in situ sorbed gas in coals and shales, especially with regard to the estimation of lost gas. Determining total gas content requires measurement of three components— lost gas, measured gas, and residual gas. Lost gas is estimated by projecting the first few hours of desorption measurements back to the time at which desorption begins. The desorption process may require two or more months to reach a point where the desorption rate becomes negligible. Because lost-gas volumes cannot be measured directly, careful measurement of sorbed gas and selection of an appropriate mathematical projection are essential in deriving an accurate estimate of lost-gas. Residual gas is not produced from the reservoir, but it is part of the total gas measured in adsorption isotherms. Analyses of coals usually include proximate analysis and bulk density measurements of all samples, adsorption isotherms of several representative samples, and sequential gas-compositional analyses. Other analytical work might include detailed coal descriptions and photography, maceral composition, cleat mineralogy, vitrinite reflectance, pyrolysis, gas isotope analysis, and measurement of residual gas. Shales are commonly analyzed for total organic carbon (TOC) in lieu of proximate analyses. The method used for collecting down-hole samples for desorption has a huge impact on the reliability of gas content data. Getting a large, unbroken sample of coal or shale to the surface in a short amount of time gives the best results. Continuous wireline-core-retrieval systems usually fulfill both of these needs, yielding better core recovery and shorter retrieval times than conventional coring. At shallow depths, conventional coring can provide good gas-content data and can be less costly if only one or two seams are to be cored. Rotary sidewall coring is a good option with deeper wells, particularly for coal sequences where multiple seams make conventional coring impractical. Desorption of conventional drill cuttings can provide a quick look at gas contents for exploratory wells, but the results are less reliable.

INTRODUCTION

Data on the gas content of coals are used both in the mining industry, to predict and control the level of gas emissions in underground coal mines, and in the gas industry, to calculate in-place gas resources in subsurface coal beds. Direct measurement of the "sorbed" gas content of a coal sample enclosed in an airtight canister is a relatively simple procedure, but the total gas content of the coal includes two other important components— lost gas and residual gas. Lost gas is the volume of gas that escapes to the atmosphere and the wellbore between the time a coal sample is retrieved (cut) and the time at which it is placed inside the canister. Residual gas was defined by Bertard et al. [1] as "that (amount of gas) which is in equilibrium with a pressure of 1 bar of pure gas."

The purpose of this paper is to review the methodology involved in estimating the gas content of coal and shale for the gas exploration industry, especially for the benefit of those new to the industry. A brief historical perspective is important because it helps explain why certain procedures are now considered necessary for obtaining accurate estimations of in situ gas contents.

The Direct Method is the most commonly used technique for determining gas content of coals. The basic methodology was developed in France by Bertard et al. in 1970 [1] while evaluating gas emission hazards in underground coal mines. Bertard used a combination of gas measurements and diffusion rates to estimate lost gas, which in this case was the volume of gas lost between the time when the coal samples were retrieved from horizontally drilled boreholes inside the mine and the time in which the samples were placed inside airtight canisters. Bertard also observed that the rate of gas release was proportional to the square root of time for the first 20% of the total desorbed gas volume for what were assumed to be spherically shaped coal particles, and less than 20% for irregularly shaped particles.

In 1973 Kissell et al. [2] with the US Bureau of Mines applied the Direct Method to coal cores collected from deeper, vertically drilled wellbores in an effort to quantify the amount of gas contained in "virgin" (unmined) coal beds in order to better predict total gas emissions from a mine in advance of actual mining operations. Kissell et al. refined Bertard's approach by making a straight-line extrapolation of the early-desorbed gas measurements to the time when the "methane pressure" was first released. They noted that with air-drilled holes, gas was released as soon as the core was cut. In the case of water-drilled holes, they chose the halfway mark uphole as the point were gas release was presumed to have commenced. This method has been referred to as the "US Bureau of Mines Direct Method," or the "Bureau of Mines Method."

McCulloch et al. [3] in 1975 introduced a graphical method for estimating residual gas, which they termed the "Decline Curve Method". These authors also recommended doing all reading at standard temperature (70° F/21° C). In 1981 Diamond and Levine [4] suggested an improved method of measuring residual gas in which the desorbed coal

sample is crushed inside a sealed ball mill. In contrast to the original definition [1], residual gas had by now come to mean the volume of gas left in the coal after desorbed volumes have decreased to (arbitrarily defined) insignificant levels. As noted by Ulery and Hyman [5], proposed termination levels range from 0.05 cc/g/day over a one-week period up to 10 cc/day per sample.

Inaccuracies of the Bureau of Mines Direct Method were addressed in Ulery and Hyman's [5] "Modified Direct Method" in 1991. They suggested recording gas temperature and ambient pressure to correct each gas-volume measurement to standard temperature and pressure (STP). Furthermore, they recommended taking occasional samples of desorbed gas for compositional analysis.

Yee et al. [6] in 1993 discussed a curve-fit method in which *all* the desorption data are fitted to a solution of the diffusion equation. This contrasts with the Bureau of Mines and other methods that use only selected early-time measurements to estimate lost gas. This curve-fit method has been referred to as the "Amoco Method" [7, 11]. They reviewed the literature to date and compared the various methods used in determining lost gas.

In 1995 the Gas Research Institute [7] published a step-by-step procedural manual that encompasses and defines most of the current procedures for measuring and estimating gas content of coals. The authors' consensus was that the US Bureau of Mines Direct Method was best for estimating lost gas as long as certain procedures were followed—namely, desorption at reservoir temperature, correction of gas volumes to STP and corrections for volume expansion and contraction of gas inside the canister (headspace changes) due to temperature and barometric changes during gas measurement.

Subsequent contributions by other researchers have helped to refine gas-content assessment of coals and shales. For example, Testa and Pratt [8] wrote a comprehensive overview of sample preparation, Pratt and Baez [9] discussed relationships of gas composition and rock properties. Nelson [10] outlined special procedures for low gas-content subbituminous coals.

THE DIRECT METHOD

As mentioned earlier, total gas content of a coal or shale consists of three components—measured gas, lost gas and residual gas. A typical desorption curve shows the relative proportions of lost, measured and residual gas for a wireline-retrieved core plotted as cumulative desorbed gas vs. square root of time in minutes (Figure 1). These same three components of total gas can be viewed as the percentage of gas desorbed vs. time in days (Figure 2). The volume of sorbed gas can be quantified by first recovering a core sample, placing it as quickly as possible inside a hermetically sealed canister (Figure 3) at the wellsite, and then periodically measuring the volumes of gas released inside the
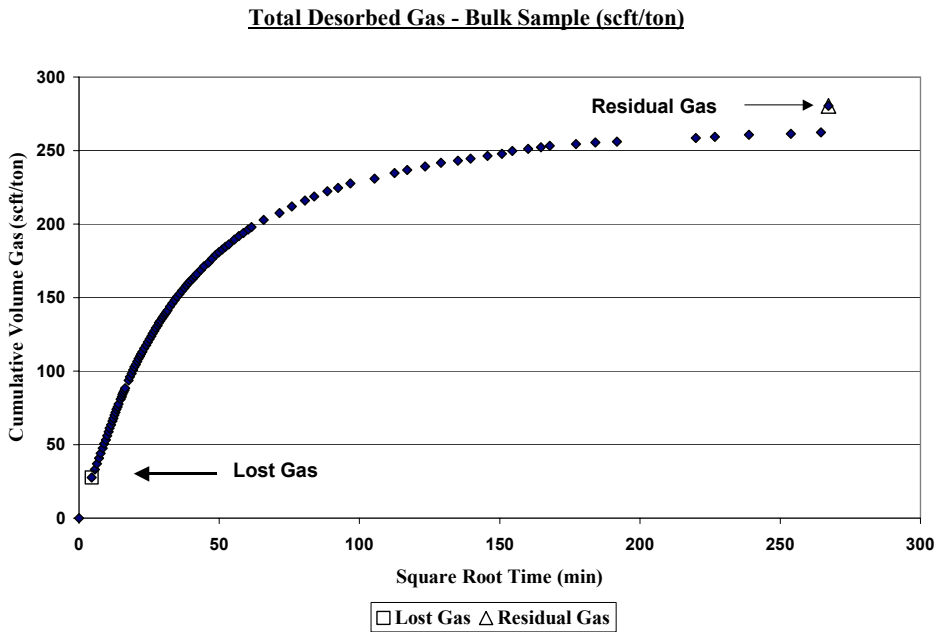
Total Desorbed Gas - Bulk Sample (scft/ton)

Figure 1. Desorbed gas vs. square root of time (scft/ton).
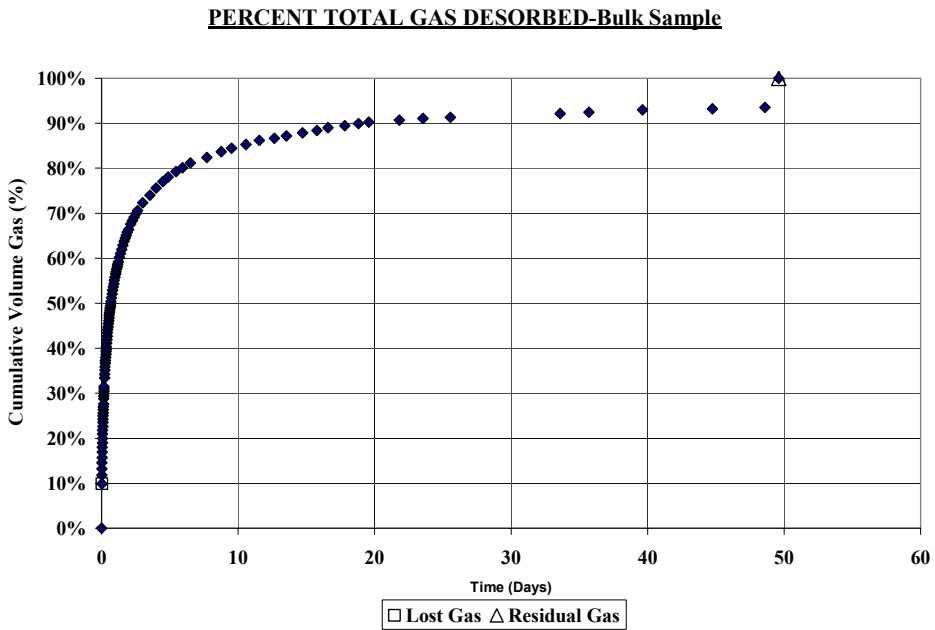
PERCENT TOTAL GAS DESORBED-Bulk Sample

Figure 2. Percent gas desorbed vs. time (days).

canister at atmospheric pressure. Full desorption may require two months or longer to complete. For practical purposes, the effective end of the desorption cycle is the time

Figure 3. Desorption canister, barometer, and burette for taking gas readings. Size of burettes vary depending upon expected gas amounts.

at which the cumulative desorption-volume curve flattens to near-horizontal. Removing the sample from the canister early, splitting it, and measuring the remaining gas content on the crushed split can expedite this process.

Lost gas is estimated by extrapolating the first few hours of desorption measurements to "time zero," the time at which desorption is presumed to have begun. By convention, time zero is taken as the estimated time at which the sample is halfway out of the wellbore for water-filled drill holes. For air-drilled wells, time zero is the estimated time at which the coal was cut [1, 2].

Residual gas is measured at the end of the effective desorption cycle by pulverizing the sample in an airtight ball mill or other device to crush the sample.

FIELD PROCEDURES

Sampling procedures and sample handling are critical factors in determining the in situ sorbed gas in coals and shales, especially with regard to the estimation of lost gas. To improve the accuracy of desorbed-gas and lost-gas calculations, we recommend the following:

1. Using coring methods designed to maximize core recovery, minimize uphole travel time, and minimize surface core handling, preparation and placement inside the canisters under given field conditions.
2. Maintaining canisters at a constant reservoir temperature.
3. Recording gas volume, canister temperature, air temperature, barometric pressure and time for all desorption readings.
4. Normalizing gas volumes to standard temperature and pressure.
5. Correcting readings for changes in headspace volume. (Headspace is the air/gas space between the sample and the inside of the canister.)
6. Estimating lost-gas volume using the proper curve to fit the data.

To meet these criteria, certain logistical arrangements must be made at the wellsite. First, a temperature-controlled trailer with a reliable source of power is necessary at the wellsite to serve as an onsite field laboratory.

After a core has been retrieved, it is removed from the inner core sleeve and laid out on a catwalk or, preferably, in a core-handling trailer. Depths are marked on the core with lumber crayons. If gassy coals or shales are present in the core, brief field descriptions should be recorded quickly. With depth intervals noted, the core samples then are placed inside the desorption canisters. Low-rank coals should be protected from oxidation and desiccation by using water-filled canisters and inert gas where appropriate [10].

It has been demonstrated that desorbing gas from samples kept at reservoir temperature more realistically reflects the subsurface conditions under which the gas would actually desorb when it ultimately is produced [7]. After canisters are moved to the field laboratory trailer, they are heated to and maintained at reservoir temperature by means of thermostatically controlled water baths, air boxes or thermal blankets. Water baths afford the best heat conduction to the canisters (Figure 4), but a source of reasonably clean water must be provided at the wellsite. Being able to keep temperatures relatively constant inside the trailer helps the temperature-control devices maintain canister temperatures.

Figure 4. Water bath for maintaining canisters at a constant reservoir temperature.

If the coals appear very gassy, readings should commence as soon as possible. Each reading should include gas volume, time and date, canister temperature, air temperature (temperature of gas inside the burette) and barometric pressure. These data will be used to correct gas volumes to STP and to make volumetric corrections for expansion or contraction of the headspace. Time intervals between subsequent readings will vary depending upon gas content and diffusivity of the coals or shales. Readings should be taken at the wellsite for at least 24 hours if possible and practical [7]. Then the canisters are transported to a central offsite laboratory where they are reheated and readings resumed.

Detailed core descriptions can be completed later either at the wellsite, or offsite at a core-storage facility. Core descriptions done at the wellsite should not, however, interfere with the timely measurement of desorbed gas, which cannot be delayed. If detailed descriptions of the entire core are required at the wellsite, additional personnel may be

necessary, especially if the project involves hundreds or thousands of feet of continuous wireline core. Getting the job done right in the field is the most important step in estimating gas resources in the ground.

ESTIMATION OF LOST GAS

Lost gas is estimated by extrapolating the first few hours of desorption measurements to the time at which desorption begins (time zero). Sampling procedures and sample handling affect accurate determination of in situ sorbed gas in coals and shales, especially with regard to the estimation of lost gas. The accuracy of lost-gas determinations is improved by using a coring method designed to get the coal or shale sample from the formation to the canister as quickly as possible, maintaining canisters at constant reservoir temperature, and projecting lost gas using the proper curve to fit the data.

As stated previously, time zero is the time the coal was cut by the bit when air or mist has been used as the drilling medium. In water-drilled holes, time zero is the time when the core is halfway out of the hole [1-5]. This convention is based on the premise that, although desorption starts as soon as the sample reaches the depth where the hydrostatic pressure is less than reservoir pressure, desorption will proceed at a slower rate than when the confining pressure on the sample is atmospheric (the pressure at which desorption readings are taken). In reality, desorption of gas occurs at variable rates during the trip uphole, and modeling the actual situation is difficult if not impossible. So, choosing the halfway mark is simply an approximation standard that most contractors use. When drilling with mud, one must consider the mud weight used and whether the hole was drilled balanced or overbalanced. If drilled overbalanced, time-out-of-the-hole starts when the sample reaches a depth where hydrostatic pressure in the hole equals the reservoir pressure.

Diffusion models suggest that the percentage of gas desorbed (or cumulative volume) varies linearly with the square root of time [1, 2]. Bertard [1] said that this relationship held true for the initial 20% of desorbable gas, assuming spherical coal particles. As the concept of the Direct Method was applied to deeper wells, the 20% limit became loosely translated to mean "early in the desorption." So, a typical graphical solution to determining lost gas has been to extrapolate the first few hours of desorption readings [3-5] to time zero using a linear fit to the plot of cumulative gas vs. square root of time.

Let us look at an example of some lost gas projections of an Upper Cretaceous coal from a Rocky Mountain basin. This coal contained 280 scft/ton of total gas. As shown in Figure 5, a linear fit to 2.8 hours of readings appears to give a good fit to the data and a lost gas value (*y*-intercept) of 1646 cc. However, by taking more readings (6.8 hours), the linear fit is not as close, and the lost gas value drops to 1469 cc (Figure 6). If a polynomial equation is fitted to the longer data set, the curve fits the data better and yields the highest lost-gas volume, 1886 cc (Figure 7).
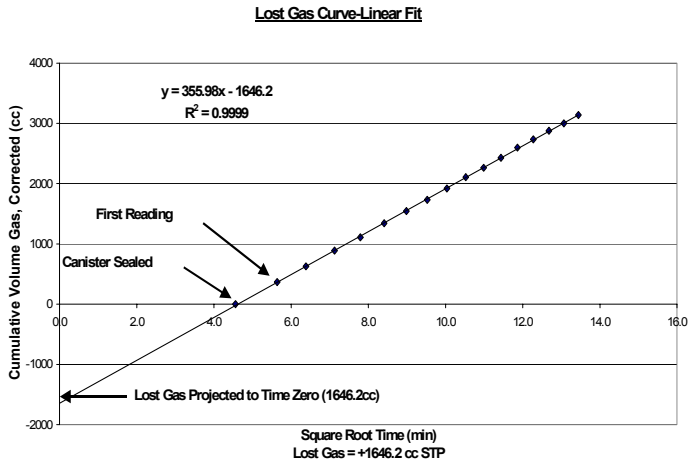
Lost Gas Curve-Linear Fit

y = 355.98x - 1646.2
$R^2 = 0.9999$

First Reading

Canister Sealed

Lost Gas Projected to Time Zero (1646.2cc)

Square Root Time (min)
Lost Gas = +1646.2 cc STP

(Cumulative Volume Gas, Corrected (cc))

Figure 5. Lost-gas projection: linear fit, 2.8 hours of readings.

Lost Gas Curve-Linear Fit, Using More Points

y = 337.56x - 1469.1
$R^2 = 0.9982$

Lost Gas Projected to Time Zero (1469.1 cc)

Square Root Time (min)
Lost Gas = +1469.1 cc STP

(Cumulative Volume Gas, Corrected (cc))
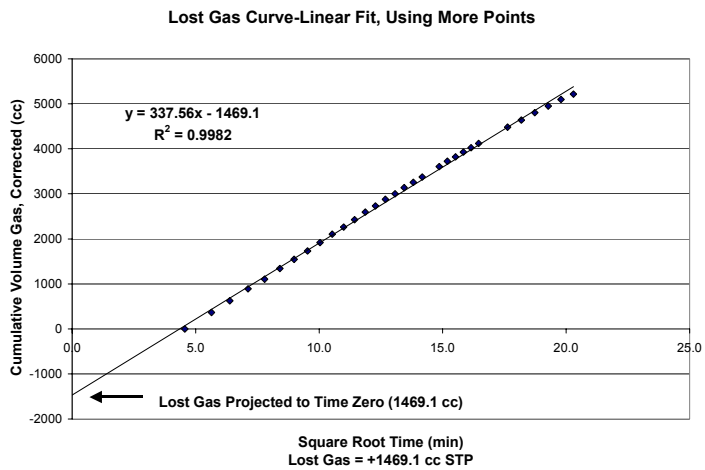
Figure 6. Lost-gas projection: linear fit, 6.8 hours of readings.

Lost Gas Curve-Polynomial Fit

y = -2.9154x^2 + 411.61x - 1885.6
$R^2 = 0.9997$

Lost Gas Projected to Time Zero (1885.6 cc)

Square Root Time (min)
Lost Gas = +1885.6 cc STP
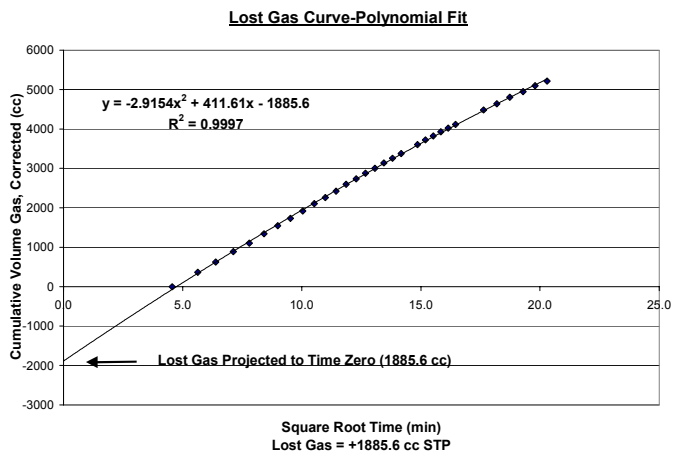
(Cumulative Volume Gas, Corrected (cc))

Figure 7. Lost-gas projection: polynomial fit, 6.8 hours of readings.

These differences become more pronounced in coals with high diffusion rates and high gas contents. Figure 8 compares the linear and polynomial fits for a different Upper Cretaceous coal that contained 630 scft/ton of total gas. The readings were taken over a period of 4.4 hours—at 1-minute intervals during the first hour, 2-mintute readings during the next two hours and 4-minute readings during the fourth hour. Even though the total reading time was shorter than in the previous example (Figures 6 and 7), the high gas content and high diffusivity of this coal yield a cumulative desorption curve that is obviously not linear. Using a polynomial fit for these data, lost gas was estimated at 23,824 cc, whereas the linear fit gave only 10,289 cc. When data from the lower gas-content coal shown in Figure 7 are plotted at the same scale as in Figure 8, the differences in the graphical properties of the two curves become even more striking (Figure 9).

Using a linear fit for lost gas has been the industry standard for years, but the "Amoco Method" employed polynomial fits for cumulative gas vs. square root of time data [6]. Knox and Hadro [11] mentioned polynomial fits for lost gas but gave no details of the procedure. Since 1999 HW&A has used both polynomial fits and linear fits for estimating lost gas and, with few exceptions, we have found that polynomial fits extrapolate to the target more consistently than do linear fits. As lost-gas time increases, the linear fit progressively underestimates lost-gas volume. In other words, because of the longer uphole trip time, more gas is lost initially, and a linear fit to the early part of the desorption curve will have a lower slope than would a linear fit to gas measured from the same core with a shorter lost-gas time. Also, it is within the first two hours of desorption readings that the data used to extrapolate lost gas are the least stable because the enclosed core often has not yet been fully reheated to reservoir temperature [7, 12]. As core temperature rises, the rate of gas diffusion increases, often resulting in a linear or even concave-up desorption curve during the "first few hours of desorption." This effect is most pronounced where reservoir temperatures are high and surface temperatures are very low (i.e., winter). For a polynomial fit, four to six hours of desorption readings can be used for extrapolating the lost-gas curve, if gas volumes are great enough. With a larger number of data points, the curve is more influenced by the data collected after the core temperature has stabilized.
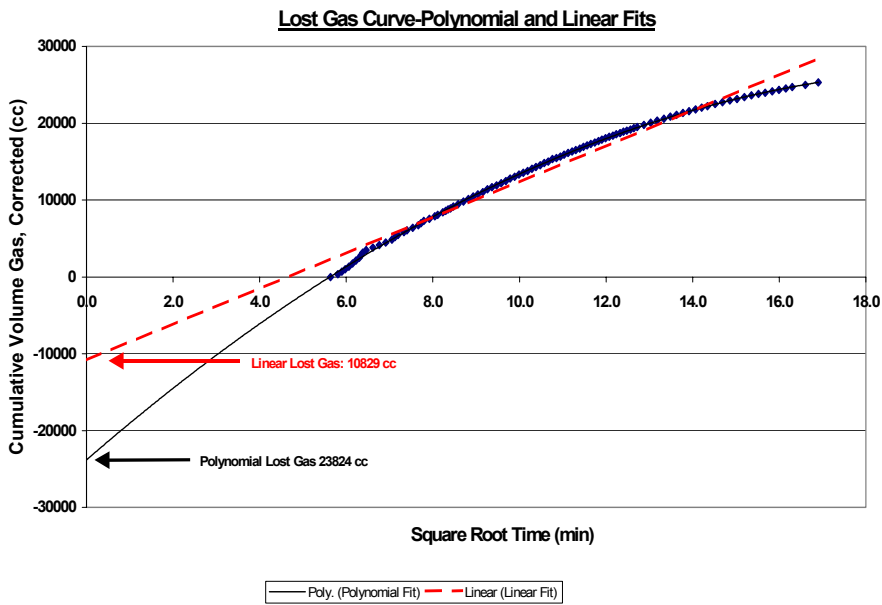
Lost Gas Curve-Polynomial and Linear Fits

Cumulative Volume Gas, Corrected (cc) vs Square Root Time (min)

Linear Lost Gas: 10829 cc

Polynomial Lost Gas 23824 cc

Poly. (Polynomial Fit)   Linear (Linear Fit)

Figure 8. Comparison of linear and polynomial fits in a coal with high gas content and high diffusion rate (4.4 hours of readings).

Lost Gas Curve-Polynomial Fit, Using Larger Vertical Scale

Cumulative Volume Gas, Corrected (cc) vs Square Root Time (min)

$y = -2.9154x^2 + 411.61x - 1885.6$
$R^2 = 0.9997$

Lost Gas Projected to Time Zero (1885.6) cc
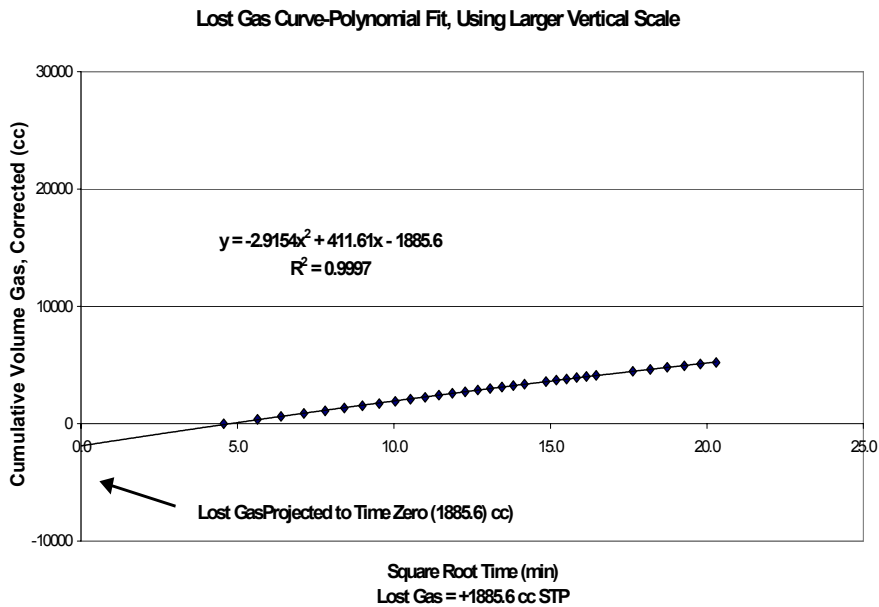
Lost Gas = +1885.6 cc STP

Figure 9. Data from Figure 7 plotted at the same vertical scale as Figure 8.

LABORATORY PROCEDURES

After desorption canisters are returned from the field, they are returned to reservoir temperature, and readings are continued in the laboratory. With coals of high gas content, readings may be necessary several times a day for the first few days, but then the frequency of readings can be decreased as the rate of gas desorption decreases. Gas sampling should be continued throughout the desorption cycle in order to monitor compositional changes with time. If desorption volumes are sufficient, at least three gas samples—early, middle and late—should be taken from canisters representing each individual bed or zone. Compositional analyses are used to determine heat content and quality of the gas for meeting pipeline requirements. They also are important to know before doing adsorption isotherms.

Desorption is continued until either the readings approach some insignificant amount or a decision is made to crush the sample early and measure the residual gas. Decisions on when to terminate desorption can be made on the basis of an arbitrary desorption-rate cutoff [2, 3, 5, 7] or when the cumulative desorption curve flattens (for example, Figures 1 and 2).

After gas desorption is complete, canister headspace is measured, and the samples are removed from the canisters and reweighed. At this time they may be described in more detail, photographed, and split into fractions for measurement of residual gas. Crushing the sample to a fine particle size for early total-gas measurement can be done to accelerate the desorption process. Measurements of residual gas should be done immediately after removing the sample from the canister. This is true even for samples that have desorbed to a point where they are releasing no more gas because removing a sample from a 100%-methane atmosphere accelerates the loss of any gas remaining in the sample [1]. Residual-gas measurements should be made at reservoir temperature using inert gas in the headspace to avoid adsorption of air and oxidation of the sample [8]. Although it is not produced from the reservoir, residual gas is part of the total gas measured in adsorption isotherms and must be accounted for in the calculations.

Coal and shale splits should be sealed in airtight bags to minimize drying and oxidation. Bagged coals should be kept moist without adding free moisture to the samples. Introduction of inert gas into the bags offers additional protection from oxidation. Coals may be slabbed and photographed before analyzing splits. To avoid delays in residual gas measurement, slabbing should be done on splits. Procedures for proper sample handling are detailed by Testa and Pratt [8].

Additional analyses of coals usually include proximate analysis (moisture, ash, volatile matter, fixed carbon, sulfur and heating value) and bulk density measurements of all samples, adsorption isotherms of representative samples, and sequential gas-compositional analyses from canisters representing each stratigraphic unit. Other analytical work might include detailed coal descriptions and photography, maceral composition, cleat mineralogy, vitrinite reflectance, pyrolysis, gas isotopic composition and measurement of residual gas. Shales should be analyzed for total organic carbon (TOC) in lieu of proximate analyses [9].

When dealing with a mixture of coals and shales, we recommend TOC for all samples as a basis for comparison of gas contents. Normalization of gas contents to a dry ash-free basis is commonly done for coals and shaly coals but is not appropriate when comparing coals to carbonaceous shales [9]. When reporting gas contents of mixed coal and shale sequences, an alternative is to report gas content on a volume-of-gas per unit-volume-of-rock basis (cc gas/cc of rock or cubic feet of gas/cubic foot of rock), in addition to the typical standard cubic feet (scft)/short ton and cc/g bases [12].

Of the analyses listed above, the most important are proximate analyses and adsorption isotherms. Moisture and ash from a proximate analysis enables calculation of gas contents on a dry ash-free basis. With high-sulfur coals, including sulfur in the proximate analysis allows calculation of gas contents on a dry mineral-matter-free basis.

Adsorption isotherms are used to determine the degree of gas saturation and to help predict how long a well may need to be on pump before the onset of gas production. With coals containing gas mixtures, separate isotherms of each gas species may be necessary to properly model the adsorptive capacity of a given coal [9, 13].

Knowing the correct reservoir temperature and pressure is essential for estimating in situ gas content of coal and shale, and for evaluating isotherm data. Too often companies try to save money in coalbed gas development projects by using inadequate logging suites that do not provide bottom-hole temperatures.

SAMPLE COLLECTION METHODS

The method used for collecting downhole samples for desorption has an enormous impact on the reliability of the gas-content data. All other things being equal, getting a large, relatively unbroken sample of coal or shale to the surface in the least amount of time yields the best results.

Continuous wireline core-retrieval systems usually fulfill both of these needs—core recovery and shorter retrieval times—better than conventional coring. After the initial trip into the hole with the coring bit, a wireline coring rig lowers a mechanism down the hole on a wireline that latches onto the inner core barrel and brings it to the surface in a matter of minutes, leaving the core bit and outer barrel in the ground. In a 2000-ft core hole, wireline retrieval times can be as little as six to eight minutes. More time is spent at the surface getting the core out of the inner sleeve than actually retrieving the core from the wellbore. Retrieval speeds are similar to those for routine wireline deviation surveys. Wireline rigs are referred to as "continuous coring rigs" because they recover core continuously in multiple runs, rather than tripping out of the hole with a single conventional core. Thus, the number of core runs is relatively inconsequential. In addition, because coring is quite fast, core starting-points can be chosen to allow for a greater margin of error. Wireline rigs typically core 100 to 300 feet within a 24-hour period, usually with better recovery than conventional coring. In one example, 2000 ft of continuous wireline core with 100% recovery was observed. Wireline coring is commonly done with controlled

bit weights and high rpm's. Cost can be a factor with wireline systems in that they normally require a special coring rig or at least modifications to an existing drill rig or pipe assembly. Wireline coring is especially useful for rocks containing multiple coal seams occurring over a wide stratigraphic interval.

Conventional coring can provide reliable gas content data and can be less costly if only one or two seams are to be cored and if drilling depths are not great. Knowing a drilling company's track record is important because we have seen conventional core trips from 1000 ft in the Powder River basin take as little as ½ hour (good) to as long as three hours (poor). Conventional coring requires less planning, and the decision to core is sometimes made even after drilling has commenced. Core recovery can be adequate, but wireline cores typically cut faster and achieve better recoveries, especially in coals that are highly fractured. The most important consideration for core retrieval with conventional rigs is the added lost-gas time for tripping out of the hole. For a depth of 2000 feet, lost-gas times may be on the order of two or three hours, depending on the drill rig and the efficiency of the crew.

Where conventional coring is impractical, for example, in deeper wells and multiple-seam coal sequences, rotary sidewall coring can be an acceptable alternative. Although sidewall samples are small (Figure 10) and represent only a small part of the stratigraphic section, core-retrieval times are relatively short, thereby improving the accuracy of the lost-gas estimate. Rotary sidewall cores are cut with a downhole logging tool after wireline geophysical logging has been completed. Bulk density, gamma ray and caliper logs are used to pick sidewall core points. Because washouts and filter-cake buildup can inhibit sidewall core recovery, close attention must be paid to the caliper log. Owing to the small sample size, specially designed desorption equipment is needed for sidewall cores, and a greater number of sidewall core is needed for adequate statistical accuracy. Also, if drilling or logging problems arise or if the wellbore is left open for extended periods, gas may be depleted from the formations adjacent to the wellbore prior to sampling. If borehole conditions and sample quality are optimal, however, gas contents derived from rotary sidewall cores can be as accurate as those derived from wireline cores (Figure 11). Percussion sidewall cores, which are used successfully in some types of rock, should not be used on coal because they damage the coal integrity and allow gas to escape too quickly.

Figure 10. Rotary sidewall coal core and sidewall canister.

Desorption of conventional drill cuttings provides a quick look at gas contents for exploratory wells, but the results are less reliable. Particle size greatly influences the rate of gas loss. The shorter the diffusion path-length, from the center of a coal fragment to its

surface, the faster the sample will degas. Observations from various desorption projects
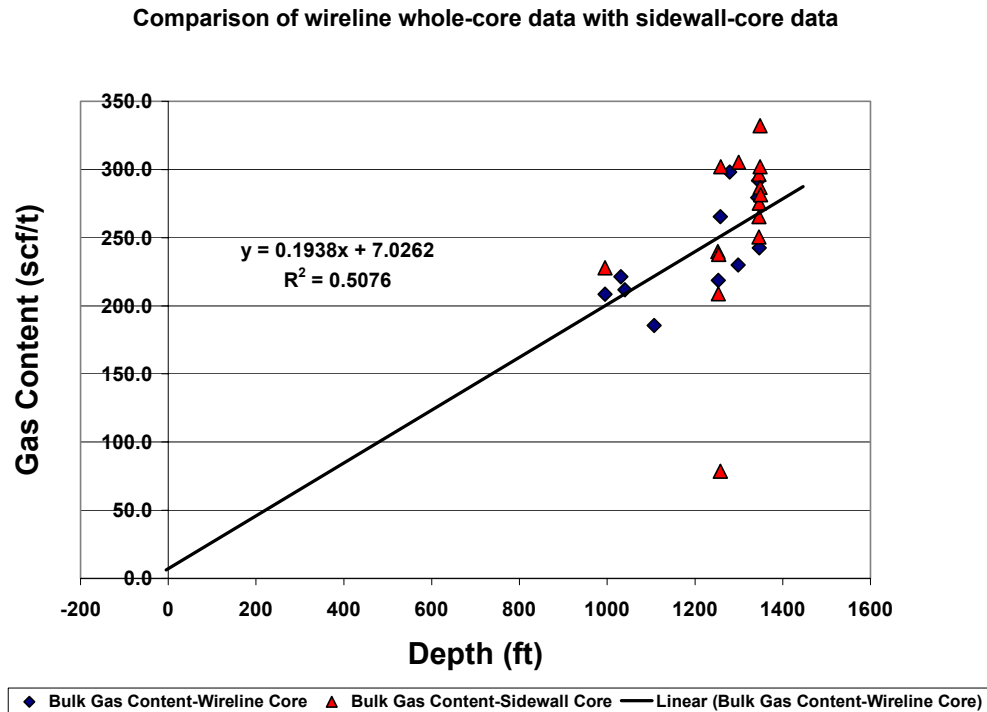have shown mixed results. In some cases the dry ash-free gas contents of cuttings from

Comparison of wireline whole-core data with sidewall-core data

Figure 11. Comparison of wireline whole core with rotary sidewall cores taken
from the same wellbore over the same intervals (example from the Green
River Basin of Wyoming, courtesy of Steve Hollis, Double Eagle
Petroleum).

reamed core intervals were nearly identical to those of the cores themselves. In other
instances where the particle size was very small, the gas content estimated from cuttings
was one-half that estimated from core of the same interval. Thin coal seams are difficult to
evaluate with cuttings because of dilution with cavings. Cuttings are useful in certain
exploration situations, where coring is not possible or practical, and for infill wells as a
supplement to core data. Some authors have agreed upon limitations of using drill cuttings
for gas content determination [6, 7, 9]. The Smith and Williams Method [14] was
developed specifically for improving the accuracy of lost-gas estimation from drill cuttings,
but the technique is cumbersome and does not conclusively improve results [6, 7, 15].

SUMMARY

Early applications for measurement of gas in coals were focused on coal-mine safety. Introduction of the Direct Method by the U.S. Bureau of Mines for estimation of lost gas in the early 1970s formed the basis for the techniques used today to estimate subsurface gas content of coals and shales. Subsequent improvements in the basic technique included reducing measured gas volumes to STP, conducting desorption at reservoir temperature, correcting for headspace changes, improving lost-gas calculation, inhibiting coal oxidation, and taking gas samples sequentially for analysis throughout the desorption.

Proper wellsite technique and data collection in the field are the most important steps in estimating in-place gas resources. Having a climate-controlled trailer, reliable electrical power and the proper number of field personnel necessary to do the work efficiently are essential to a successful project.

Determining total gas content requires measurement of three components— lost gas, measured gas, and residual gas. Because lost-gas volumes cannot be measured directly, careful measurement of sorbed gas and selection of an appropriate mathematical projection are essential in deriving an accurate estimate of lost-gas. Residual gas is not produced from the reservoir, but it is part of the total gas measured in adsorption isotherms. Knowing true reservoir temperature and pressure also is important for estimating in situ gas content of coal and shale and for evaluating isotherm data.

Accurate analytical data, including moisture and ash content measurements, are essential for deriving reliable dry ash-free gas contents. Adsorption isotherms help determine how soon a well will start producing. Proper sample handling therefore plays a critical role in data collection.

No one method is best for obtaining a sample from a wellbore for gas-content determination. The depth and distribution of coals, as well as depth restrictions of the equipment, dictate which method of coring to use. Continuous wireline retrievable cores usually give the best core recovery and the shortest retrieval times, but they cost more than conventional cores. Conventional cores can yield good data if trip times are short and if only one or two discrete zones are to be sampled. Multiple discontinuous coal beds are best sampled using wireline retrievable cores or, at greater depths, sidewall cores. Cuttings can serve as an acceptable reconnaissance tool to determine if a zone has promising sorbed gas contents, especially as an add-on to drilling programs with conventional objectives. However, gas contents determined from cuttings should be followed up with core sample testing if a coalbed gas or shale-gas play is to be pursued.

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