SIMULATION OF CORE LIFTING PROCESS FOR LOST GAS CALCULATION IN SHALE RESERVOIRS

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ABSTRACT

Canister gas measurements are a popular technique to assess gas in place in coalbed methane systems and are being increasingly applied to shale reservoirs. The accuracy of these techniques for shale reservoirs, however, is dependent on correctly estimating the amount of gas lost from the core sample during collection. In this study, numerical simulations were used to investigate the lost gas from the core lifting process in a hydrocarbon-bearing shale formation. This data was analyzed using a compositional reservoir simulator that included desorption, multiphase flow, and phase behavior which are considered relevant physical effects for modeling shale reservoirs.

Once a suitable match of the measured data was obtained from a calibration procedure, the simulation results provided an estimate for gas lost during the coring process. In addition to quantifying lost gas volume, this procedure yielded an independent estimate of permeability that was compared to laboratory measurements.

This simulated lost gas volume was then compared to that calculated from the traditional linear extrapolation method (US Bureau of Mines) for lost gas estimation. In two separate wells studied from the Duvernay Shale in Alberta, Canada the USBM method significantly underpredicted the lost gas calculated by the simulation. The simulation results indicated that over 90% of the initial gas in both core samples escaped before canister measurements.

This work suggests that the USBM method may not be appropriate for estimating lost gas in shale samples with high initial reservoir pressures and significant quantities of both interstitial and adsorbed gas. Additionally, given the large quantity of lost gas and the inaccuracy of the USBM method, the value of canister measurements in shale reservoirs needs to be further assessed. We have shown, however, that the canister measurements are extremely useful in obtaining an independent estimate of permeability using the core lifting simulation workflow described in this work.

INTRODUCTION

Accurate measurement of gas in place is critical for assessing and developing shale gas reservoirs. Gas in shale reservoirs can exist as free gas in the pore space and as adsorbed gas adhered to the rock surface [1]. One challenge involved with determining gas content

in shales is the often significant presence of adsorbed gas, which is not amenable to volumetric calculations. In seeking to overcome this challenge, the industry has applied techniques developed for measuring gas in place (GIP) in coalbeds to gas-bearing shale formations.

Canister gas measurements from core samples have been regularly used to determine the gas content in coalbeds. These tests directly measure the gas emission from a core sample after being placed in a sealed canister at the wellsite. The total gas in place is calculated through the following equation,

$$\text{GIP} = \text{Lost Gas} + \text{Canister Gas} + \text{Residual Gas} \quad (1)$$

where lost gas refers to gas that escaped the sample during the core lifting process, canister gas is that measured in the laboratory test, and residual gas is the additional gas that can be measured by crushing the core sample at the conclusion of the canister test.

The lost gas is not directly measured, thus a critical component of this gas content calculation is estimating the amount of gas that escapes from the core while tripping up the wellbore. The most prominent method for lost gas calculation is the US Bureau of Mines (USBM) Direct Method as outlined by Kissell et al. [2]. This method applies the observation that methane emission from fine-grain coal particles can be described by a constant diffusivity desorption process that is proportional to the square root of time [3].

Gas transport in shale reservoirs is a result of many processes including but not limited to Darcy flow, Knudsen diffusion, and multiphase effects in addition to desorption. Javadpour et al. noted that these canister measurements are more correctly termed “gas evolution” tests as opposed to “gas desorption” tests when applied to shales to account for these additional flow mechanisms [4].

In this work, we modeled the core lifting process using a numerical reservoir simulator with the relevant physics for shale reservoirs including desorption and multiphase flow. We replicated the core lifting history and the associated pressure drop experienced by the core sample. This pressure history is then integrated into a reservoir simulation to model the gas flow within the core before it is placed in a sealed canister for laboratory study. We next calibrated the simulated core’s bulk permeability in order to replicate the gas volume found in canister measurements. This estimate of permeability is compared to that determined from direct laboratory measurement. Finally, from the calibrated simulation model, we compared this method’s prediction of lost gas to that from the USBM direct method to assess the validity of the USBM lost gas estimation to shale reservoirs.

SAMPLE MEASUREMENTS

Core samples from the Duvernay Shale in Alberta were studied in this work. The cores were cut from two different wells while drilling with oil based mud. Each core was then lifted up the wellbore over a matter of hours. Once at the surface, the cores were divided

into samples and placed in sealed canisters for gas evolution measurements. The dimensions of each sample were 3.5 inches in diameter and one foot in length.

After the samples were collected, the canister pressure and temperature was monitored closely over a period of weeks. From these measurements, the volume of gas released from the core was calculated at standard conditions over time for the two Duvernay core samples. The USBM direct method was then used to estimate the gas lost before the sample was placed in the canister. By extrapolating back to when the core was first pulled, the USBM method estimates the amount of gas lost before the sample was sealed. The gas evolution curve and USBM lost gas calculation for the second well sample is shown in Figure 1.

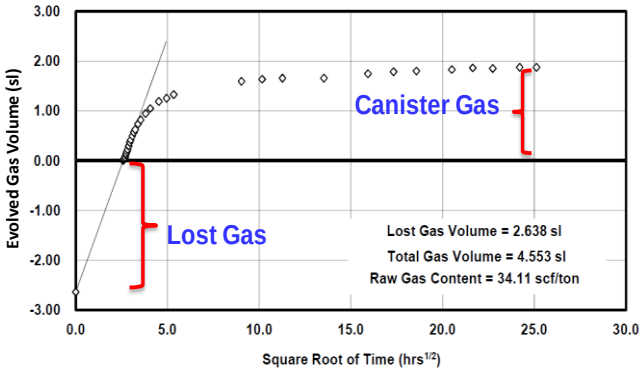

Figure 1: Canister gas measurement and USBM lost gas calculation for the Well #2 sample.

NUMERICAL MODELING

Grid Properties

The core volume must be discretized into a grid for the purposes of numerical simulation. In this work, a Cartesian grid was introduced that preserved the volume and surface area of the cylindrical core. As shown in Figure 2, additional grid cells were placed adjacent to the outer surface area of the core and used to control the mud weight pressure in the well during the lifting process. By controlling the pressure in the well, the pressure history of the core lifting process can be replicated in the simulator. The grid cells representing the well were given a permeability value much higher than the shale core and quickly equilibrated to the well pressure constraint provided to the simulator.

In this grid representation, flow occurs only through the sidewall of the cylindrical core, not the top or bottom of the sample. This simplification is justified because the core was lifted as a continuous piece of rock and samples are cut at the surface. This will cause a slight underprediction of gas emission volume in the canister measurements. For these core samples, less than 15% of the surface area corresponds to the top and bottom surfaces.

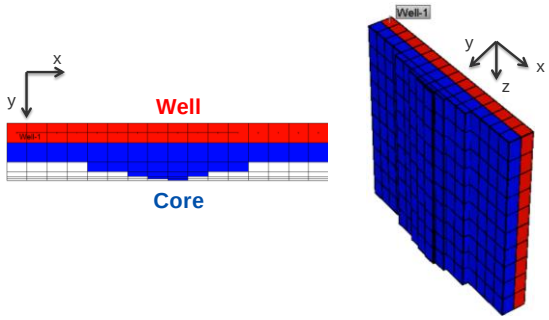

Figure 2: Cartesian representation of cylindrical core sample.

Fluid Properties

The Duvernay Shale's reservoir fluids vary with depth and temperature, and the wells studied here contained both a gas condensate and a volatile oil system. Fluid properties were modeled using a four-component Peng-Robinson equation of state. The components include methane and three created by lumping heavier hydrocarbons. In the first well, the properties were calibrated from fluid composition and recombination ratio data gathered at the separator of an offset well. For the second well studied, separator oil and gas composition data was directly available.

In the first well, the reservoir fluid is initially a supercritical gas condensate system ($T_{res} > T_c$). A liquid phase is expected to condense in the reservoir once the pressure falls below the dew point of approximately 3600 psia. The condensate gas ratio (CGR) is initially calculated to be 70 bbl/MMscf at stock tank conditions. .

The second reservoir fluid contains more C7+ hydrocarbons and is a volatile oil system at subsurface conditions ($T_{res} < T_c$). Importantly, the second fluid is a supercritical liquid in situ and will only evolve gas below the bubble point pressure of 4000 psia. Phase envelopes for both hydrocarbon fluids are shown in Figure 3.

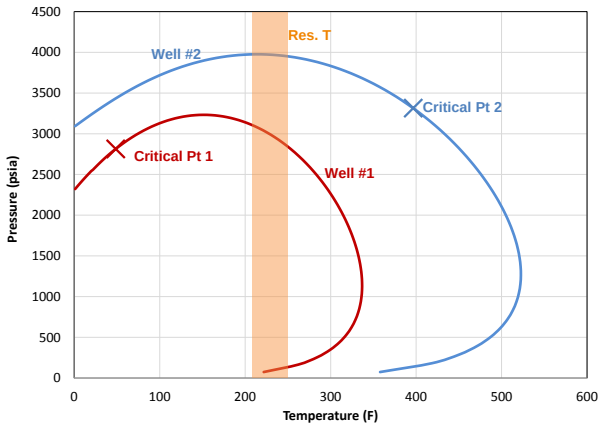

Figure 3: Phase envelopes for initial Duvernay fluid compositions used in core simulations. Reservoir temperature is indicated by the shaded orange band.

Reservoir Properties

Additional reservoir properties for the simulation models are displayed in Table 1. The first well (gas condensate) was completed to a total depth of 11,000 ft. The initial reservoir pressure is nearly 9,000 psi and the temperature is 250 °F. The second well studied was completed to a shallower depth and consequently has a lower reservoir temperature and pressure. Both cylindrical core samples have a 3.5 inch diameter and are one foot in length. Relative permeability curves were modeled using Corey exponents and parameters from analog fields. Separate relative permeability curves were developed for each core depending on the fluid system present.

Adsorption isotherm parameters were determined through laboratory tests. Samples were crushed to a 12 mesh particle size and measurements were taken at reservoir temperature. The adsorption data was fit to a single component (CH4) Langmuir model,

$$V = \frac{V_L p}{p + p_L} \qquad (2)$$

where V is the amount of adsorbed methane in standard cubic feet per ton of rock, p is pore pressure, and V_L and p_L are the Langmuir volume and Langmuir pressure respectively. The desorption process is assumed to be in constant equilibrium with the pore pressure and transient effects are not considered in the simulation.

Table 1: Reservoir properties used in the Duvernay core simulation

Formulation	Three-phase Compositional Model
Depth	9,500 – 11,000 ft
Total Porosity	4 – 6%
Total Water Saturation	5 – 15%
Permeability	20 – 200 nd
Cylindrical Core Dimensions	Diameter: 3.5 in; Height: 12 in
Initial Reservoir Pressure	7500 psi – 9,000 psi
Reservoir Temperature	210 – 250 ˚F
Rock Compressibility	5e-6/psi
Langmuir Volume	50 – 80 scf/ton
Langmuir Pressure	1000 – 3000 psi

Both adsorption isotherms for the two wells are displayed in Figure 4. The adsorption curves have a much steeper slope at pressures below the Langmuir pressure. This indicates gas desorption will preferentially occur during the later portion of the core lifting phase, where the external pressure on the sample dropped to atmospheric pressure. No hysteresis effects were assumed and the adsorption and desorption isotherms are equivalent.

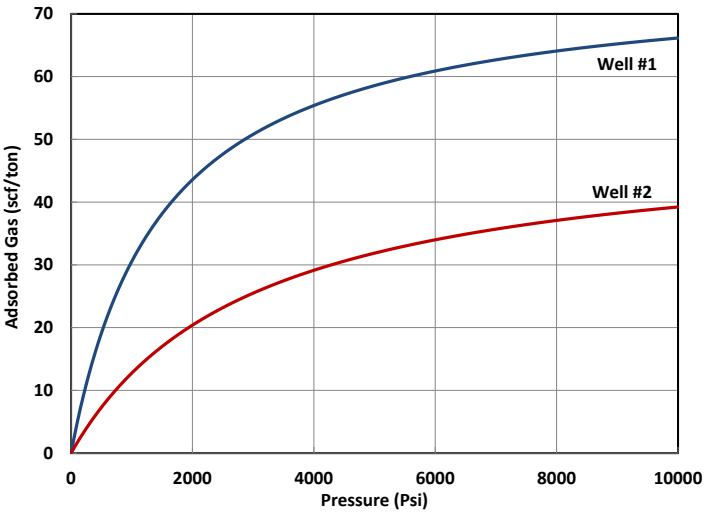

Figure 4: Langmuir isotherms for the two Duvernay core samples studied.

Core Pressure History

With the simulation grid and reservoir properties defined, the next step was to recreate the pressure history of the core as it traveled up the wellbore and was collected for measurement. For the first sample, a staged trip schedule was followed to maintain the core's physical integrity for geomechanical testing. The depth history from this schedule was combined with the drilling mud weight to provide bottomhole pressure (BHP) constraints over time for the well grid cells surrounding the core in the numerical simulation. For the second well, geomechanical testing was not a priority and the core was lifted at a constant speed. As a result, significantly more time was spent lifting the first core sample out of the well compared to the second. A summary of the time spent on various phases of the coring process is found in Table 2.

Table 2. Elapsed time of stages in the core lifting and collection process.

Time (hrs)	Well #1	Well #2
Lifting	20.25	8
Laying at Surface	2	2.5
Cut & Collect	1.5	1
Total	23.75	11.5

After the lifting phase, additional time was spent laying the core and cutting samples. In total, the first core sample spent nearly 24 hours losing gas before it was placed in a sealed canister for gas evolution measurements. The second sample was pulled using a faster lifting schedule and only experienced 11.5 hours subject to gas loss.

Once the core was cut and placed in canisters, the samples remained at atmospheric conditions for over 1000 hours while detailed gas volume measurements were collected.

A reconstructed pressure history for the entire coring process is displayed in Figure 5. The samples experienced large pressure changes during the lifting phase but then remained at atmospheric conditions for the remainder of the test.

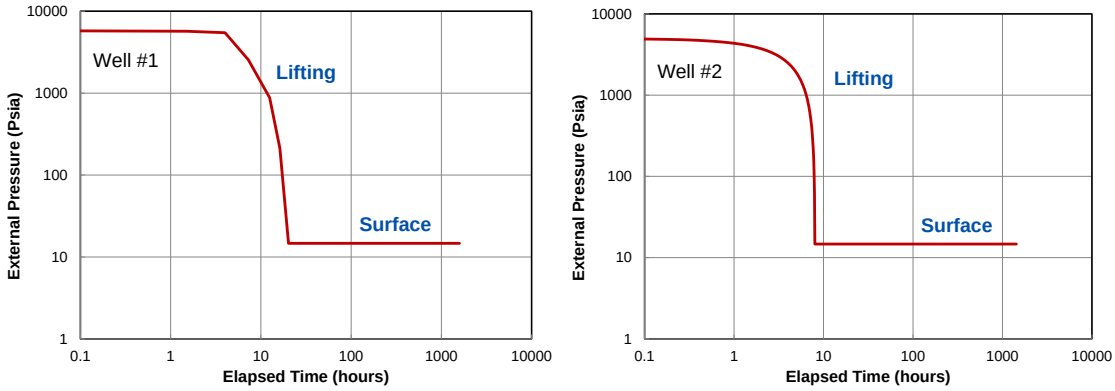

Figure 5: Pressure history of the coring process for the Duvernay core samples.

RESULTS

Numerical simulations were conducted to estimate the lost gas volume from core samples as they were collected from the Duvernay Shale in Alberta, Canada. The simulation spanned from the beginning of core lifting process until the end of the canister measurements. By studying the simulation results, the canister gas evolution curve and the lost gas can be estimated. The simulated gas evolution curve was calculated by considering the gas volume that escapes the core after the moment it was sealed in a canister for measurement. In addition to quantifying lost gas volume, the calibration procedure described in the next section yielded an independent estimate of permeability that was compared to laboratory measurements.

Calibration Procedure

The first step in the simulation workflow was to adjust the bulk permeability of the core in order to calibrate the simulated gas production to that observed in the canister measurements. Because the adsorption isotherm and porosity were quantified in lab tests, the bulk and relative permeabilities are the most uncertain parameters governing the gas flow from the sample inside the canister. The gas-phase permeability governs the amount of gas remaining inside the core sample once it is placed inside the canister. In a higher permeability sample, more gas evolves from the core during the lifting phase and less gas remains for canister measurements. In this way, the volume of canister gas and the bulk permeability of the core sample are inversely related.

In the first sample, the calibration procedure indicated a permeability of 70 nanodarcies (nd) was sufficient to match the measured canister gas volume. For the second core sample, more canister gas was observed and a tighter permeability of 27.5 nanodarcies

was required for a suitable match to the measured data. The canister data and simulated gas evolution curves at different bulk permeability values are shown in Figure 6.

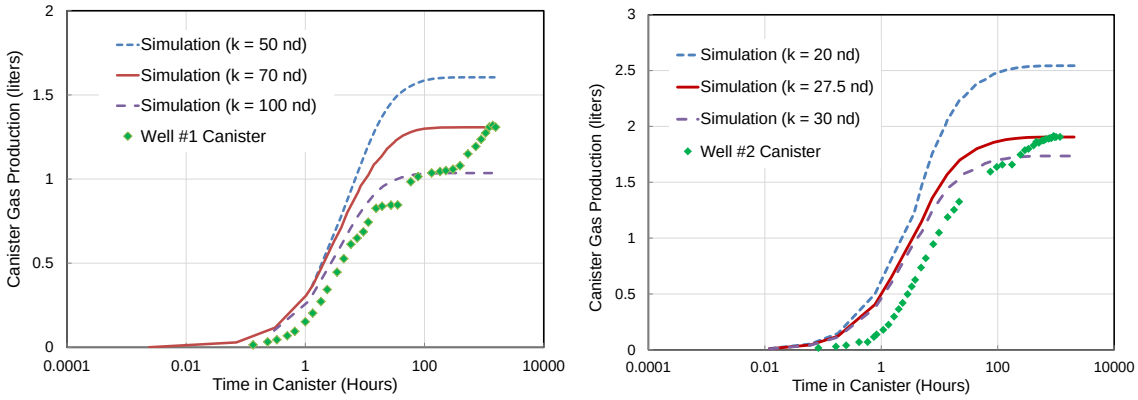

Figure 6: Experimental and simulated canister gas evolution for the Duvernay core samples.

A comparison of the permeability estimates obtained in this work was made to the range of values found using a pressure-decay method on crushed samples of the same core in Table 3. For the first well, the permeability found through the simulation-based workflow fell within the range of laboratory measurements. For the second well, the permeability estimate from the simulation workflow was lower than the range found with the pressure-decay method. A possible explanation for this disagreement is the impact of multiphase flow effects on the permeability estimate from the simulation workflow and this will be further investigated in the next section. The permeability obtained through the simulation workflow is also sensitive to the total porosity, water saturation, and adsorption parameters of the core sample so accuracy in their measurement is essential.

Table 3. Comparison of permeability estimates from simulation workflow and laboratory measurement.

	Calibrated from Simulation	Pressure-Decay Lab Measured	Significant Multiphase Flow?
Well #1	70 nd	120 - 230 nd	No
Well #2	27.5 nd	50 - 330 nd	Yes

Multiphase Flow Analysis

Multiphase flow is a complex physical phenomenon and it will impact the certainty of the bulk permeability estimate obtained from the core lifting simulation. To investigate the presence of multiphase flow, the fluid saturations in the simulated core were analyzed over time. For the gas condensate system (Well #1), oil saturation peaked around 5% before falling back to 0% and multiphase flow effects are expected to be minimal. In the

volatile oil system (Well #2), gas evolved below the bubble point and multiphase flow existed for the majority of the core lifting process. The final simulated oil saturation value of 26% agreed with laboratory core saturation analysis. Retort analysis as described by Handwerger et. al. [5] found an average mobile oil saturation of 29%. Simulated oil and gas saturations along with pore pressure versus time are shown in Figure 7.

Based on this analysis, relative permeability effects are negligible for the first well as the gas phase was dominant and gas relative permeability was near the endpoint (k_{rg} = 1) throughout the core lifting process. In the oil-saturated core, the presence of significant multiphase flow rendered the bulk permeability a second-order effect on gas production when compared to the relative permeability ratio of the mobile phases (k_{rg}/k_{ro}). This leads to greater uncertainty in the bulk permeability estimate and helps to explain the discrepancy between the calibrated permeability value and that obtained from lab measurement.

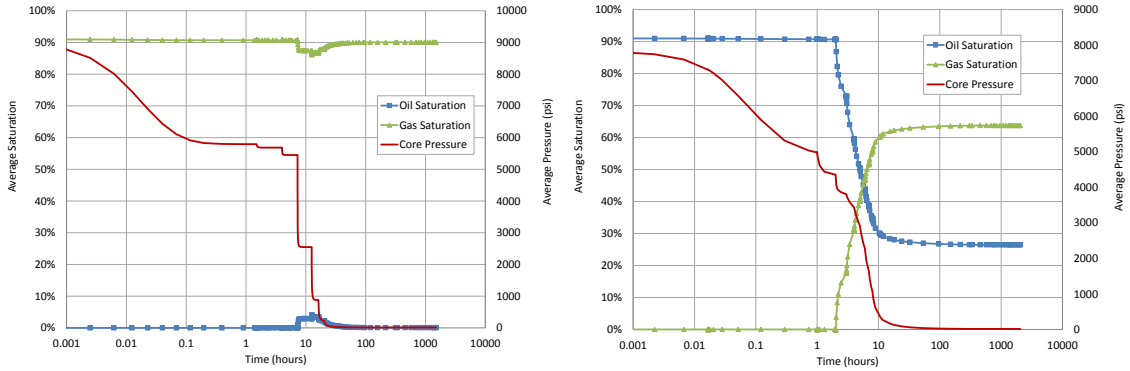

Figure 7: Phase saturations and pressure versus time for Well #1 (left) and Well #2 (right).

Lost Gas Analysis

Once the simulation was suitably calibrated to the canister gas measurements, the results can be analyzed to estimate the gas lost during the lifting period. The entire simulated gas production history for the core was considered for this analysis. This calculation was made by comparing the simulated gas production prior to canister measurements to the initial gas in place at reservoir conditions.

In Figure 8, the simulated gas production and the canister measurements with the USBM estimate are plotted against the square root of time. The dashed curve indicates the extrapolative nature of the USBM estimate and the solid diamonds represent measured canister data. Cumulative sample gas production was set to zero at the beginning of canister measurements and negative values indicate unmeasured or lost gas. The orange arrow indicates the point when the core sample was placed in the canister and measurement began. The difference in the two simulated production curves at early times was a result of different lifting schedules in the two wells.

The simulation results indicated that a significant amount of gas was lost during the first hour of the coring process. This was a result of drilling underbalanced, which exposed the

core to a significant initial pressure drop. Importantly, the simulated data does not indicate a linear relationship with the square root of time, as the USBM model suggests.

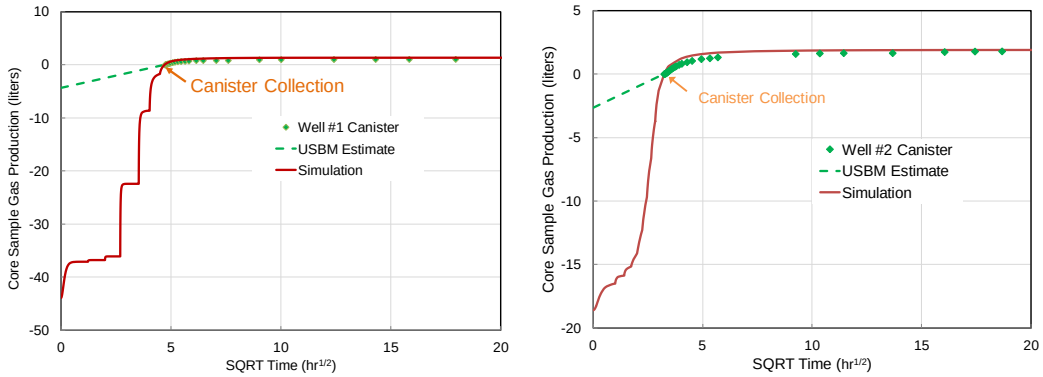

Figure 8: Comparison of core sample gas production estimates from simulation and USBM methods.

The USBM estimate and the simulated data differed greatly over the amount of gas lost from the core sample during the lifting phase. Figure 9 provides a summary of the lost gas comparison. For the first well, the USBM method predicted approximately 4.3 liters of gas lost, but the simulation calculated nearly 44 liters, an order of magnitude difference. The lost gas was estimated to be 77% of total GIP with the USBM method but 97% from the numerical simulation. The second well benefited from faster trip speeds and less gas was lost before the core was collected. Again, the USBM and simulation results diverged by nearly an order of magnitude over the amount of gas lost from the core sample.

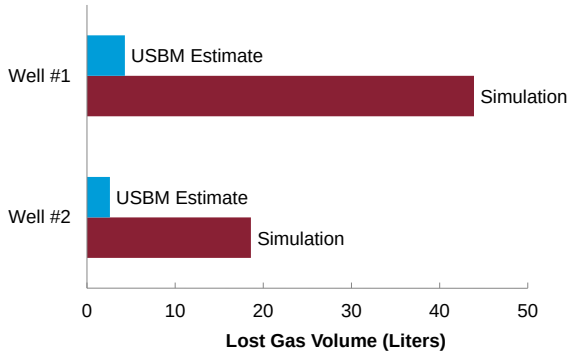

Figure 9. Comparison of lost gas estimates using the simulation workflow and the USBM method.

Shale gas systems can include significant amounts of both interstitial pore space gas and adsorbed gas on the rock surface [1]. This is in contrast to coalbed methane systems where the majority of gas in the system is adsorbed to the coal [6]. The fraction of total

gas that was adsorbed in the first shale core sample was analyzed over time as shown in Figure 10. Initially, adsorbed gas accounted for 25% of the total gas in the core sample, but this ratio increased as the sample depleted. At the time of canister collection, 65% of the total gas was adsorbed. This analysis indicated that these canister samples measured a mixture of desorbed gas and free gas and cannot be referred to only as "desorption" tests.

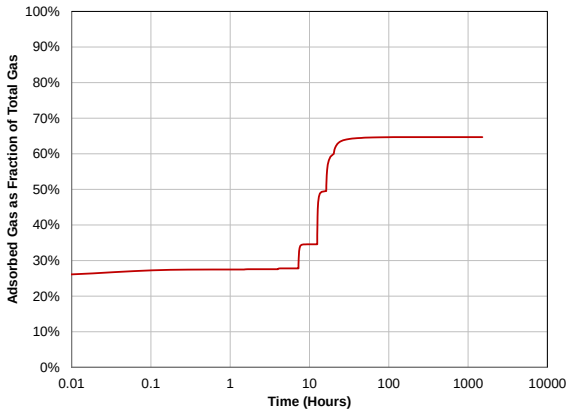

Figure 10. Adsorbed gas as a fraction of total gas over time from simulation results on first sample.

In addition to canister measurements, the first core sample underwent residual gas analysis to help quantify the total gas in place. Residual gas volumes were measured by crushing a portion of the core sample to determine the remaining gas after the canister tests have concluded. This test indicated that 0.55 liters of gas remained in the sample after the canister measurement. The residual gas was combined with the canister volume and the USBM lost gas to provide an estimate of the total gas in place at reservoir conditions. For the first core sample, the USBM methodology yielded a GIP estimate of 44 scf/ton. This is more than seven times smaller than the simulated value of 324 scf/ton as shown in Table 4. The simulation is expected to be more accurate because it considered PVT behavior and compressibility to calculate the initial pore space gas at reservoir conditions. Residual gas analysis was not performed on the second well sample and lab estimates of GIP are not available.

Table 4. Comparison of GIP using USBM method and simulation workflow for lost gas estimation.

Well #1	USBM Estimate	Simulation Estimate
Core Sample Lost Gas (l)	4.3	43.9
Core Sample Total Gas (l)	6.2	45.8
Reservoir GIP (scf/ton)	44	324

CONCLUSION

Canister measurements have been widely used to evaluate coalbed methane reservoirs. To assess this technique's effectiveness in gas shales, a reservoir flow simulator was used

to model and evaluate the gas lost during the coring process in the Duvernay formation of Alberta, Canada. These flow simulations were conducted on a Cartesian representation of the cylindrical core sample that preserved the surface area to volume ratio. A fully compositional reservoir simulation modeled gas flow from the core sample during both the lifting phase and the canister measurements. When compared to the USBM direct method for lost gas estimation, the simulation results indicated far more gas was lost during the lifting of the core sample. This result was confirmed on two separate wells in the Duvernay Shale including both a gas condensate and volatile oil fluid system.

The underestimation of lost gas from the USBM method led to a significant error in estimating the total gas in place in the reservoir when compared to the simulation results. It is recommended to use the simulation workflow to estimate lost gas in high-pressure shale systems because it captures the important physics of shale systems such as desorption, phase behavior, and multiphase flow. Faster trip speeds during the core lifting process could reduce the amount of lost gas as could pressure coring technology.

The canister measurements were also shown to generate a permeability estimate using the described core lifting simulation workflow that was compared to laboratory measurements using standard methods on crushed rock samples. This permeability estimate is more certain in dry gas fields where multiphase flow effects are not significant. Further work is needed to validate this workflow in dry gas shale formations.

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