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Gas Composition Analysis Using Limited Production Data Eagle Ford Case Study

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by

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Determining the composition of produced hydrocarbons is valuable information that is not commonly obtained die to high cost associated with a full fluid analysis. If this information is obtained, the analysis is likely only done for one well, one time during the life of the field. It is important to know how these properties change over time in order to help identify properties like saturation pressure, when artificial lift should be installed, or other problems that might happen to the well. A method was proposed in SPE Paper #166414 that uses commonly available field data to estimate reservoir fluid composition. The basis of their paper was to use correlations to get the composition, and then perform a linear regression to hone in on the correct "estimate". Though the workflow is straightforward, it would be interesting to see if this process can be done more easily and with less available data. The goal was to use only production data and some publicly available field averages to see how closely a calculated gas oil ratio could get to the actual one.

History

"The Eagle Ford Shale is quite possibly the largest single economic development in the history of the state of Texas and ranks as the largest oil & gas development in the world based on capital invested. The play has brought over 116,000 jobs to South Texas, spanning over 20 counties." (Eagle Ford Shale, 2013)

The play is named after the town of Eagle Ford, Texas, located a few miles west of Dallas, because an outcropping of the formation is visible in the area. There is discrepancy when determining who discovered the Eagle Ford (Eagle Ford Information, 2013). Some companies were drilling in the area, but targeting a different formation, see the geology section. Ultimately, most sources agree that Petrohawk, with the help of Gregg Robertson, drilled the first well in the Eagle Ford in 2008. The initial rate of this well flowed at 7.6 MMscf/Day (1,000,000 standard cubic feet per day). There are many operators currently in the Eagle Ford such as Anadarko Petroleum Corporation, Apache, Chesapeake, and EOG (Eagle Ford Shale, 2013).

Geology

The Eagle Ford was deposited in South Texas during the middle to late Cretaceous period. During the same depositional time of the Eagle Ford, the Wattenberg Play in Colorado was also being deposited. Since the climate during that time was warm and dry, which is ideal for biogenic generation. The organic material that eventually created the hydrocarbons was cyanobacteria and coccolithophores. Though the Eagle Ford formed in a relatively low energy environment, there are large variations in stratigraphy over short distances. In areas of high productivity, the Eagle Ford is a laminated, black, calcareous, organic-rich shale with a very low permeability. Where the carbonate content is high the shale can be brittle, allowing a positive reaction to hydraulic fracturing. (Scoggins, 2012 & King, 2013)

Originally, the belief was that the hydrocarbons found in the Eagle Ford were acting as a source rock for the Austin Chalk (just below the Eagle Ford as seen in the stratigraphic column, Figure 1). The Austin Chalk is a formation that stretches from South Texas to Louisiana and has been producing since the late 1990's (George, 2013). Below the Eagle Ford lies the Pearsall formation. This is another formation that was targeted by the oil and gas industry before the Eagle Ford boomed.

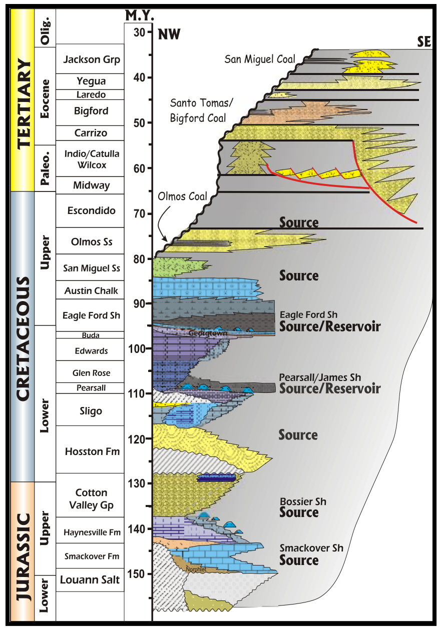

Figure 1: Eagle Ford Shale Stratigraphic Column (Westacott, 2012)

Statistics

As seen in Figure 2, the Eagle Ford formation is located throughout Texas, spanning 14 counties, and is about 400 miles long and 50 miles wide. The formation stretches from the Mexican border northeast into east Texas. The depth at which the Eagle Ford can be found is from 4,000 to 14,000 feet, increasing as it goes south. This variation in depth causes three distinct zones for hydrocarbon production. In the shallow regions, the formation fluids have high liquid content and are considered “oily”. As the formation goes deeper, the formation increased in temperature that transformed the oil into gas. In between these two zones is the condensate window, where the formation fluids are gas but contain higher amounts of heavier components. These zones can be seen shaded in different colors on Figure 2.

The Eagle Ford has experienced a drilling boom in the past five years. In 2008, 26 drilling permits were issued targeting the formation. In 2012, this number rose to 4,143. This rise in permits correlates with an increase in production from 685 BOE/Day to over 814,000 BOE/Day (Barrels of Oil Equivalent). Due to this drastic growth, the United States, especially South Texas, has experienced a huge economic growth. In 2012, the total impact of the Eagle Ford Shale play was $61 billion and there were more than 116,000 full-time jobs associated with the play. (King, 2013 & Eagle Ford Shale, 2013)

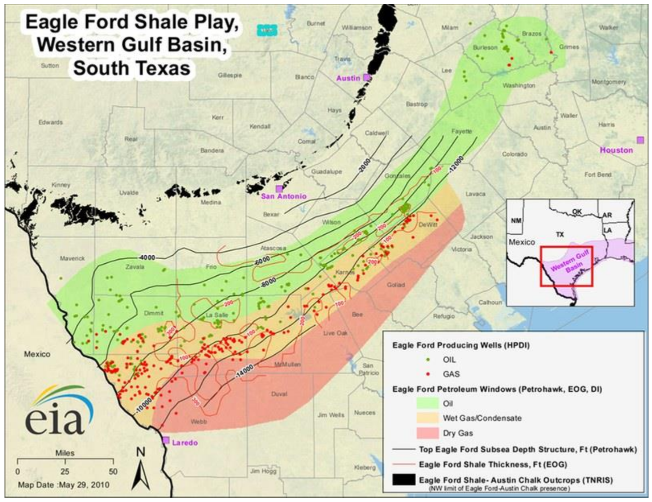

Figure 2: The Extent of the Eagle Ford Shale in Texas. Some of the types of wells are listed as green or red dots. Also the three distinct zones of the Eagle Ford can be shaded in different colors. (Eagle Ford Shale Map, 2013)

Typical Well

In the Eagle Ford most of the wells drilled are horizontals. This allows the operator to come in contact with as much of the reservoir as possible. The horizontal wells are usually drilled on pads of roughly five wells all following the same direction. The average well is approximately 7800 feet and cost roughly six million dollars to drill and complete (Aleklett, 2013). Once the well is drilled, it is then hydraulically fractured in order to stimulate the reservoir. Depending on the area and the company, different types of hydraulic fracture jobs are used. Following the completion of the well they follow a natural decline, eventually being put onto rod pump towards the end of the life. The field varies significantly, with some wells coming online at over 4,000 bbls/day, but usually declining rapidly (EOG Resources, 2013). Just this year, the field has produced over 630,000 barrels per day (Eagle Ford Information, 2013).

Overview

Data is one of the most valuable tools in the industry. With more data, better decisions can usually be made. Due to the boom of activity, lack of data is a problem faced in the Eagle Ford. With the amount of wells rising, it is hard for an operator to run an expensive gas composition analysis on their produced fluids. Since tests are rarely done once, an operator is not able to track composition changes over time. This can be important to determine why changes in production are occurring. By tracking how gas composition changes over time, it can

be determined if these changes are a result of PVT properties varying or if it is a flow issue. The following workflow was performed to provide a simplified approach to approximate and track how gas composition changes over time using commonly available field data.

Work Flow

Data acquisition is the initial step in this analysis. This consists of researching public sites or contacting a company. Public data is the quickest way to get a variety of data. An example of this is SONRIS.com, the Louisiana Department of Natural Resources public oil and gas website (DNR, 2013). Data such as maps, well logs, and, most importantly, production data can be obtained through the site. Another way to gather data is to go through a company and use their production data. There are pros and cons with each method. When utilizing company data, it will be more specific (daily data vs. monthly), but there is a level of confidentiality with the data if it isn't made public yet.

For this case study, data was obtained through an active Eagle Ford operator. Daily production data was provided for a variety of wells in the Eagle Ford Shale. The area that the data encompasses is highlighted in Figure 3. In order to keep the data private, the wells have generic names and specific areas will not be listed. One limitation with the data provided is the relatively "new" nature of the Eagle Ford Shale play. Unlike older fields, only three years of production data is available. This lack of long-term production is a limiting factor in the analysis. The data that is needed when performing this analysis is gas and condensate production. As previously mentioned, it is better to have the daily production in order to avoid factoring in a well's down time in the analysis, but monthly data will suffice. When the data is obtained, it is important to quality check it, no matter where it is obtained from. Allocation errors primarily through reporting errors are common in the oil industry. As a result, there may be points of high, low, or even negative production. Obviously, these points should not be used in any analysis unless they can be corrected for the error.

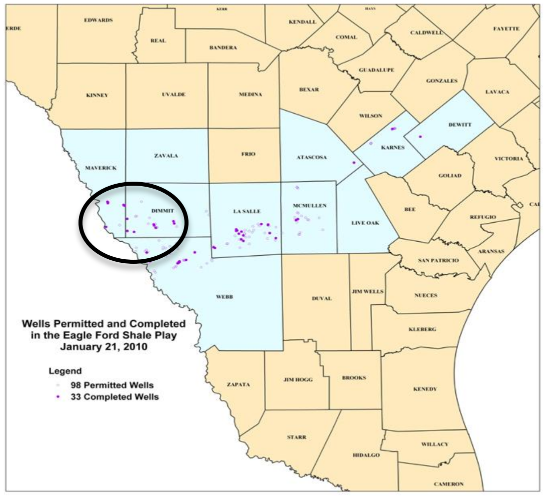

Figure 3: Study area (circled) in Eagle Ford. (Eagle Ford Shale Blog, 2013)

Once the data is obtained and screened, production needs to be converted to calculate the well's gas-oil ratio, or GOR. The units for this are Mscf of gas/bbl of oil (1,000 standard cubic feet per barrel of oil).

The GOR can then be correlated to obtain a heptanes plus (C_{7+}) percent. This was done using data from McCain (1994). Since a fit to the data was not given in that paper, a correlation was used from Stiernberg (2013) who digitized the data points from McCain (1994) and fit a curve to them. The R^2 value on the graph is over 96%, meaning a good match was found.

Once the heptanes plus percentage has been determined, it can be used to determine the remaining gas compositions. This was determined by using correlations provided in Spivey and McCain (2013). Though the paper discusses their workflow in preforming the analysis, the goal was to simplify it. In particular, there is an iterative step in the workflow where a full equation of state model (like the WINPROP model described later) is used to provide composition consistent with the producing gas-oil ratio, stocktank liquid and gas gravities, and any non-hydrocarbon gas impurities. This is a cumbersome process, especially when an equation of state model and the actual compositions are not available.

The first step in this analysis was to use the correlations provided to estimate the mole fraction amounts of C_6 to C_1 using the C_{7+} value. Initially all of the correlations were used and averaged, but after reevaluating, it was determined that the correlations with the best R^2 values

should be used. The correlations used are shown in the Appendix as Figures 8-13. In most cases, the difference between the average and the best R^2 cases was roughly two percent.

Given the amount of data provided, the number of wells to be analyzed was limited to five, wells #8, 17, 43, 59, and 60. These wells were chosen based on their clean decline trends. Since this is private data, the exact well locations were not made know, but they are in the same region of the field.

In order to see how composition changes over time, three dates representing early, middle, and late time for each well were selected. These dates vary for each of the wells since they do not have the same production. The dates were picked because they appear to be representative of trends in the data for each time period. Using the data at each of the times, the corresponding compositional fractions were determined.

Once the mole fractions of each of the components was obtained, the data is used as inputs to a program called WINPROP®, part of CMG's reservoir simulation suite of programs. This program allows users to model compositional analysis such as flash tests, differential liberation, and even create phase envelopes. As part of the analysis, this software was used to obtain a calculated simulated flash GOR for comparison to the actual well production data as well as use the phase envelopes generated to see how they change over time. This analysis can help identify various aspects of a well, such as possible liquid loading or when and where it may be crossing the dew point line.

To use WINPROP®, the components of the system must first be defined. The program gives the options to use set inputs or to create a user defined input. The predefined values for C_1 to C_6 were used, but since there are heptanes plus to account for all the heavy components, this needs to be defined by the user.

In order to create this component, the molecular weight, boiling point, and critical temperature and pressure must be provided. All of these properties can be found by knowing just one aspect of the fluid, the API gravity of the C_{7+} using a process described by Stewart et al (1959). If these numbers are known, say if a field test was done, values from the test should be used. If not, correlations can be used to estimate these numbers. The company did provided a fluid analysis for the area, but the data cannot be made public. This was used to check that the

API gravity of the heptanes plus that was picked was representative of the Eagle Ford. If an operator uses this technique, it is easy to determine the API gravity of the oil coming out of the well.

Once the components have been defined, the mole percent volumes for each of the time steps being investigated are entered. The program also gives the option to normalize the data, which was done to account for any errors in the correlations not yielding an exact 100% total.

The next step is to run the simulations on the data. The first analysis was a 2-phase envelope. The envelope will show at what temperatures and pressures the fluid changes from a single phase into a two phase fluid. When graphed over time, it can show phase envelope shifts which indicates the reservoir fluid is changing. Once WINPROP® has created the phase envelope, the data points can be transferred into Microsoft's Excel to graph the data changes over time.

With the envelope created, the Black Oil PVT properties can be simulated. Some of the properties simulated are oil viscosity and formation volume factors. Unlike the phase envelope, some of the inputs need to be changed. First, since we are dealing with a condensate system, a Gas-Water with Condensate model is selected rather than the default Black Oil. Next, the reservoir temperature and saturation pressure need to be estimated. Since this is an estimate, the guesses need to be reasonably close (± 75%), but does not need to be exact. For the study's data, 3200 psi and 250 degrees Fahrenheit was used. The pressure steps and separator conditions are next to be entered. For the study, 1500 psi was set for the pressure step and 250 psi and 100 degree Fahrenheit for our separator conditions. The final input is water properties. Since we did not receive a water analysis, an average value for salinity of 75,000 ppm was used. The program then calculated the various water properties using this value.

The final simulation that is run in order to piece everything together is a separator test. This allows users to obtain the GOR so it can be compared onto the original production data. All of the inputs for this simulation tab are estimates. Since the PVT properties were calculated in the previous step, it will automatically use these for the inputs.

The last step is to run the simulation and use the output file for the required information. In the case of this study, the saturation pressure and the calculated GOR were analyzed.

Analysis

Using this workflow, five wells were analyzed over three time periods. This is a representative sample of the data provided. The following data steps through the analysis of Well 17. The remaining five wells' plots can be found in the appendix as Figures 14-29 and Tables 2-6.

The production of Well 17 was reviewed at first to ensure it was suitable to be used for the case study. As seen in Figure 4, the decline trend of this well is stable and what is expected. Data from dates chosen to analyze are shown as stars on the graph. In order to ensure that the times selected were not representative of a false trend, both the production and GOR plots were examined and a date that fell in the trend of both graphs was selected. When the GOR for the well is plotted, as shown in Figure 5, the ratio begins to decrease later in the life of the well. This correlates with the slight shift in slope of production. Since production data was all that was provided, we can only speculate on possible reasons for this.

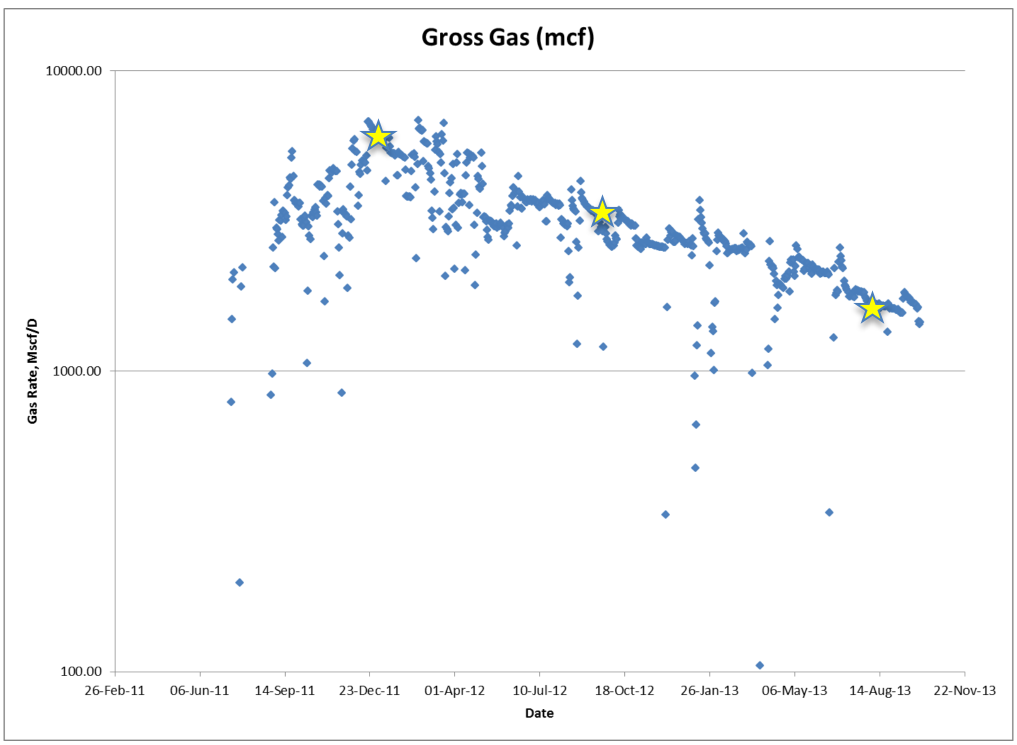

Figure 4: Well #17 Gas Production over time. The stars indicate where the time steps were picked for this well. Also, a change in the slope of production occurs in May 2013.

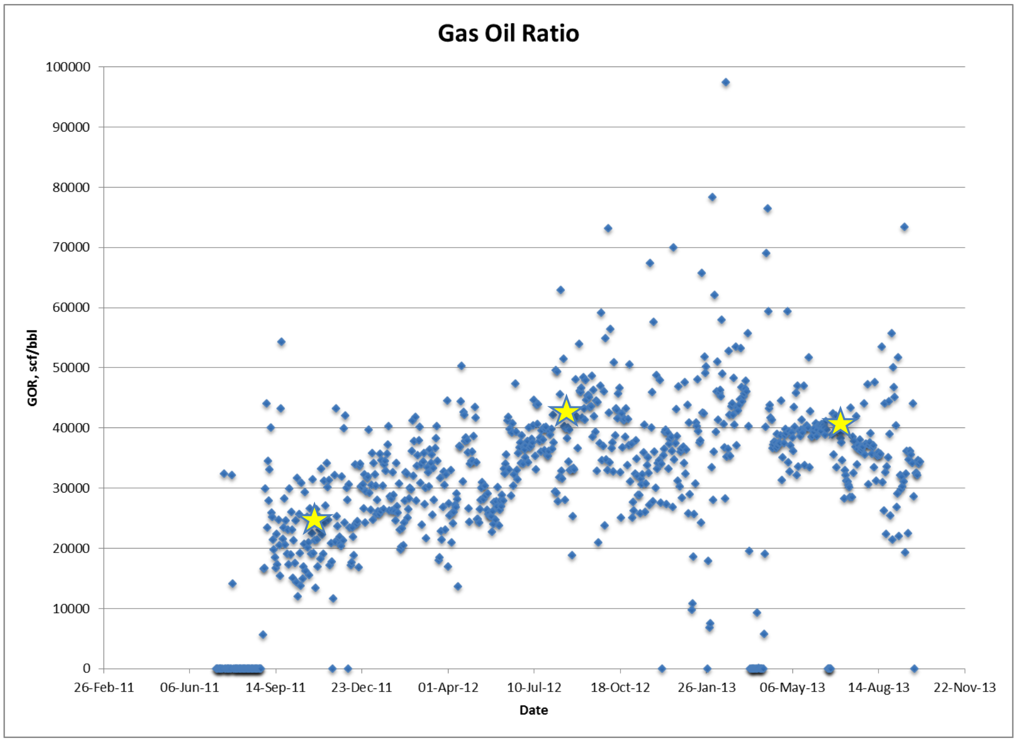

Figure 5: Well #17 Gas Oil Ratio over time. The stars indicate where the times steps were picked for this well. Also, the change in GOR slope occurs in May 2013.

Using the correlations provided in the paper, the composition of the gas was determined for each of the time steps seen in Table 1. The molecular weight and specific gravity were calculated, using the specific weight of each component.

Table 1: Well #17 Calculated Composition and Properties

Well	WELL #17	WELL #17	WELL #17
Daily Reading Date	12-Jan-12	24-Oct-12	29-Sep-13
GOR (scf/bbl)	25627.99	38461.94	34559.74
C_{7+} Mole Fraction	2.33%	1.71%	1.85%
C_6 (mole fraction) Fig 27	0.57%	0.48%	0.50%
C_5 (Mole Fraction) Fig 25	0.69%	0.57%	0.60%
C_4 (Mole Fraction) Fig. 22	1.32%	1.10%	1.15%
C_3 (Mole Fraction) Fig. 18	2.24%	1.89%	1.97%
C_2 (Mole Fraction) Fig. 13	4.97%	4.42%	4.56%
C_1 (Mole Fraction) Fig. 9	86.71%	88.82%	88.30%
Molecular Weight	21.52821	20.33325	20.61701
Specific Gravity	0.743313	0.702054	0.711852
Calculated GOR	31136.48	52631.22	48132
Error from Actual GOR	21%	37%	39%

With the composition determined, the simulations were run to obtain a 2-phase envelope as seen in Figure 6. The various markers correspond to the different time steps analyzed. As the well produces more, the envelope shifts to be smaller. This means that more gas will be produced since the dew point line is at a lower pressure for the same temperature. The same trend can be seen for last time step, which is in the region where the GOR is decreased, actually pushes out the phase envelope. Ideally, this work flow can be run for smaller time steps that would enable the shift to be captured in the data and what exactly is going on could be determined. The primary observation to note here is that the change from the initial phase envelope to the later ones is significant while the later one is more subtle.

The final aspect of the analysis was to check the work in comparison to the actual production data. This consisted of looking at the GOR's at the time steps for each well. The actual verses calculated GOR's are plotted on Figure 7 with error bars of 50 percent to give a reference for where the data lies. The calculated data is within an acceptable error compared to the production data. The accuracy could be improved with the addition of field data, but for a quick and easy tool to determine field composition, it is sufficient. Note that the trends seen in the actual data (GOR increase followed by a GOR decrease) are also seen in the modeled results. After compiling the data for each time step for the wells, the average error between the calculated GOR and the actual was 52 percent high, whereas the average error over time for Well 17 was just 33 percent high. That is a trend that was prevalent with all the data; it always predicted a higher GOR than the actual.

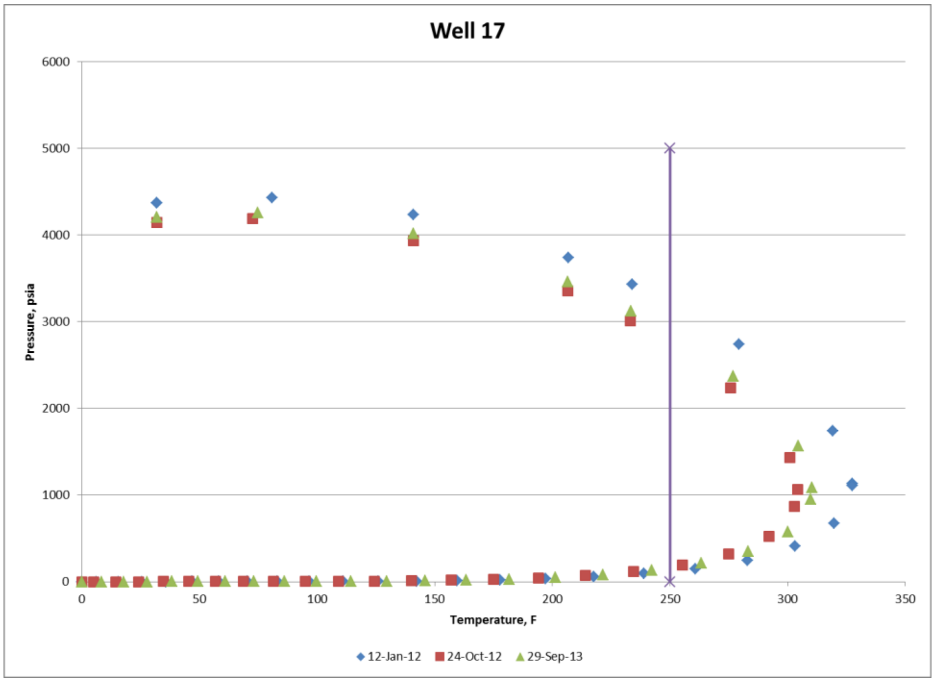

Figure 6: Well #17 Two-Phase Envelopes. Note the shift on the various time steps. The Purple line marks the cricondotherm at the given reservoir temperature.

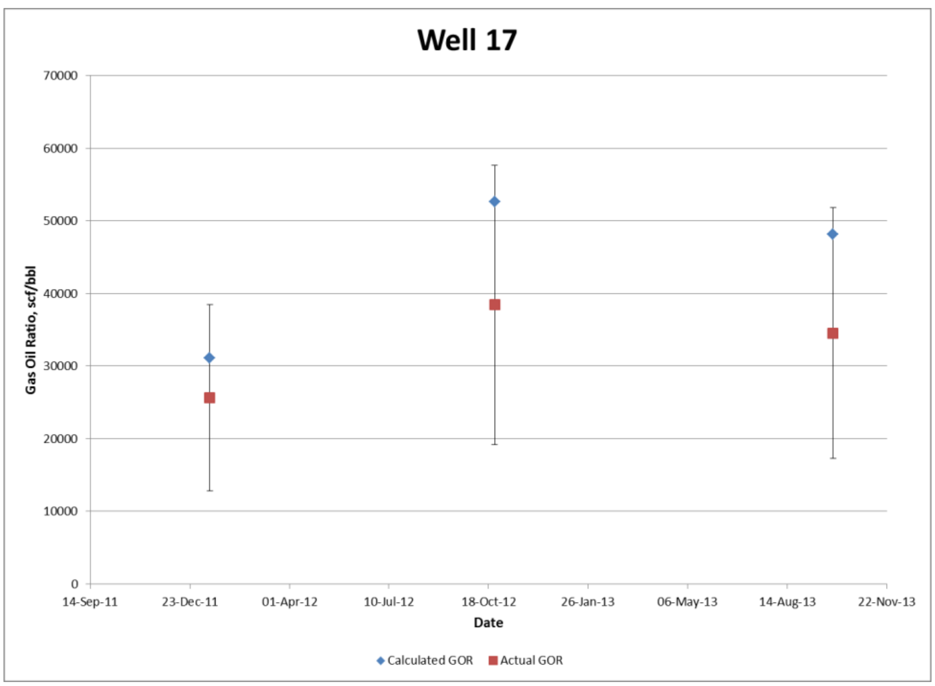

Figure 7: Well #17 Actual verses calculated GOR over time. The error bars represent ±50% of the actual data.

Assumptions

Due to the nature of this analysis, quite a few reasonable assumptions had to be made. The first was the oil API gravity. Since this varies for each well and is something that can easily be obtained, this could decrease errors in the process. For this study, a reasonable value that was assumed to be common to the Eagle Ford was utilized for all the wells. Another assumption that was made was that the gas had no impurities. Again, this is something that an operator would have for their field, so this can be added to the analysis to increase the accuracy. Additionally, various properties for the heptanes plus inputs had to be assumed. The program incorrectly calculated some of these properties so it was necessary to manually input them based on average data. The final assumption was a reservoir temperature of 250 degrees Fahrenheit, which was held constant for all of the wells. In reality this would vary with the depths of the different wells in the field.

Conclusions and Recommendations

This case study was to look into a simplified version of the analysis proposed in SPE Paper #166414. The workflow can be used to obtain gas composition. It bypasses the iterative process that is used to loop back on the equation of state to hone in on a more accurate estimate. Using that process requires more data that is likely unavailable, so the goal was to see if a reasonable estimate could be determined using as little data as possible. The results confirmed that the simplified process could be used, but only when expecting estimates or when evaluating trends. In this study, the total average error that occurred was a GOR of 52 percent higher than actual. The error in this process can be mainly attributed to three reasons, the R^2 value of the correlations, lack of impurities, and the estimated properties. Since each field varies in impurities, this is an easy fix by an operator to account for this. The error can also be cut down by using better estimates if the data is available. One recommendation for a next step is to rerun the calculations with estimates that are higher and lower than what is expected to see how this affects the resulting error, possibly yielding a range. One property in particular is API gravity of the fluid. Since this can vary in the same field, a range should be used in order to get a better estimate. The error that cannot be eliminated is the R^2 error attributed with the correlations. Since they are not a perfect fit, any data that is obtained through them will include some error.

Another check that was done to confirm the results were reasonable was to review the calculated saturation pressures compared to the provided gas analysis. Since the data is confidential, the exact numbers cannot be released, but it falls within the range of saturation pressures that were calculated for the various time steps at each well (2743-4083 psia). The saturation pressure can be used to help optimize well production. If the bottom hole pressure can be maintained higher than saturation pressure for as long as possible, the system will remain in the vapor phase. A vapor system has less resistance to flow than a two-phase system. This is beneficial for production, especially if it is still in vapor phase as it travels through the perforations to the wellbore.

Due to confidentiality issues with the well data, one aspect that was not investigated was the reason for the change in GOR trend over time. Initially, as seen in the GOR plots, the GOR increases with production. This is indicative of liquids falling out of the system and possibly loading up the well. It can be speculated that the falling trend is the operator unloading the well in a certain way, but the trend should pick up where it left off and continue to rise again. Since this is not the case, more individual well data would be needed to possibly determine what is occurring with the well.

This workflow should be used when trying to get quick estimate of gas composition when a lab test is deemed too expensive, or even use this process to track how these properties change over time. This analysis technique could also find use in smaller companies that might be looking into investing in an area. If publically available production data is acquired, the company can look into whether the play is more liquid or gas rich. With the industry heavily focused on liquid, this can be used to make better decisions.

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APPENDIX

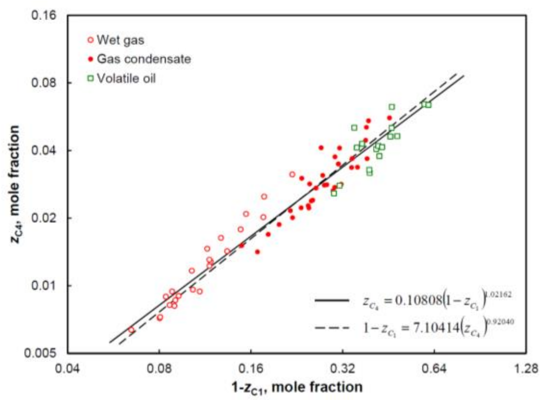

Figure 8: Correlation between mole-fraction butanes and mole-fraction methane.(From Spivey McCain 2013)

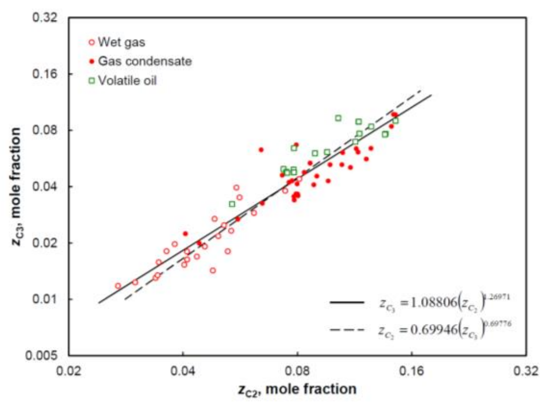

Figure 9: Correlation between mole-fraction propane and mole-fraction ethane. (From Spivey McCain 2013)

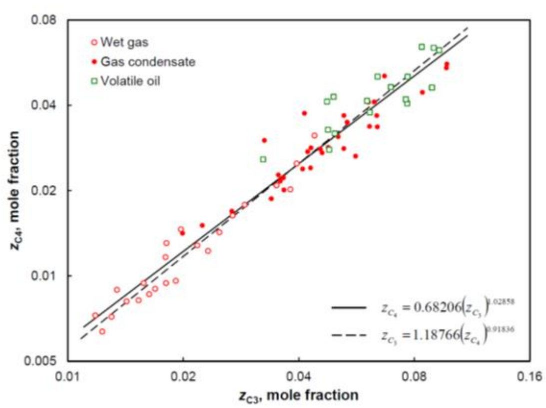

Figure 10: Correlation between mole-fraction butanes and mole-fraction propane. (From Spivey McCain 2013)

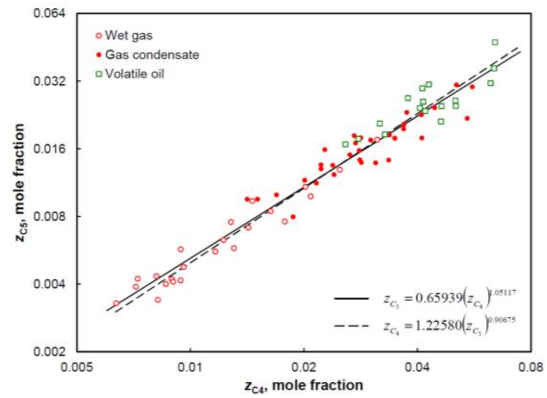

Figure 11: Correlation between mole-fraction pentanes and mole-fraction butanes. (From Spivey McCain 2013)

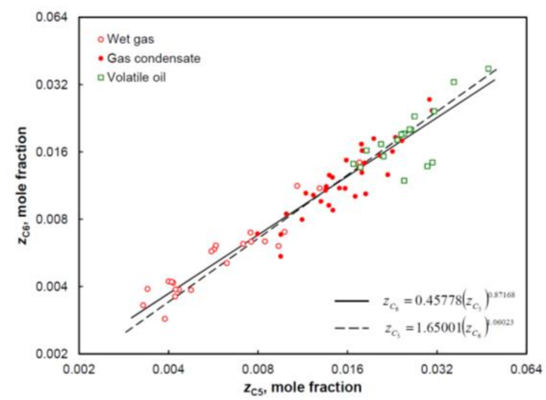

Figure 12: Correlation between mole-fraction hexanes and mole-fraction pentanes. (From Spivey McCain 2013)

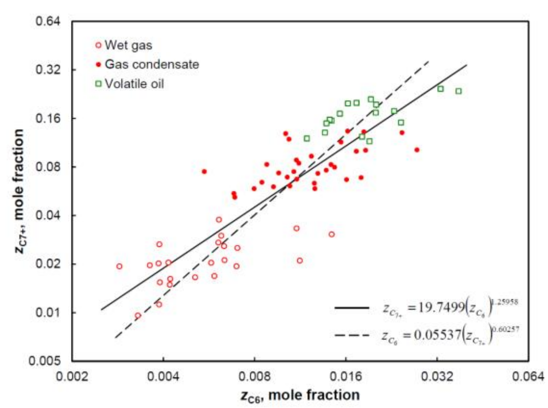

Figure 13: Correlation between mole-fraction heptanes plus and mole-fraction hexanes. (From Spivey McCain 2013)

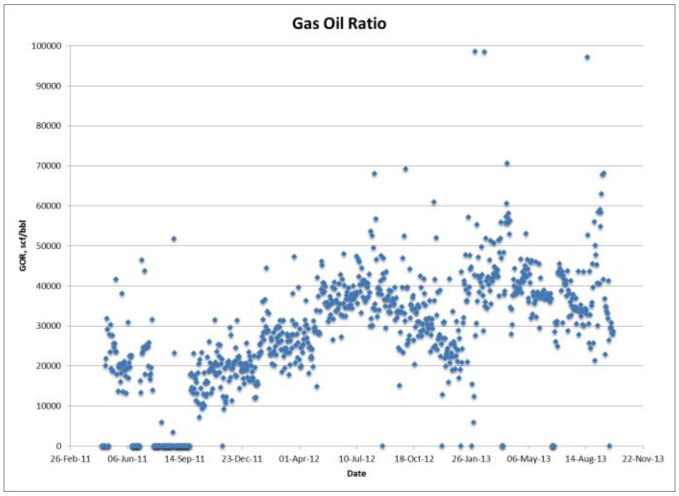

Figure 14: Gas-oil ratio for Well 8.

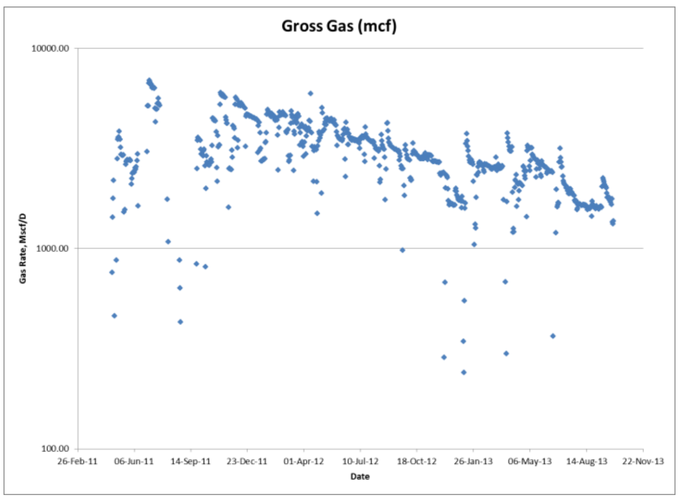

Figure 15: Gas production for Well 8.

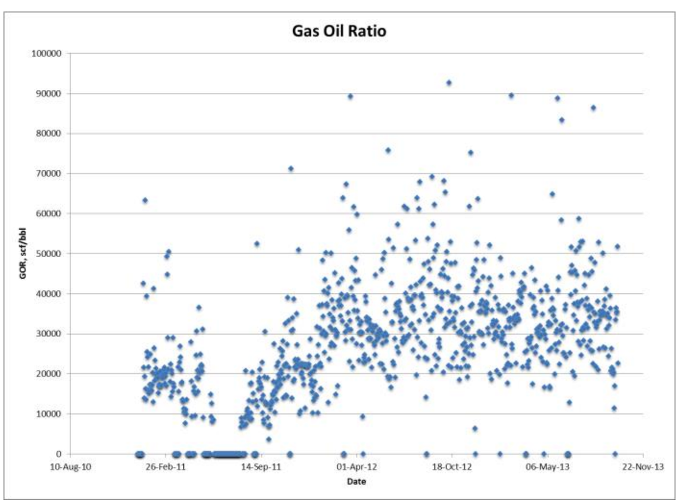

Figure 16: Gas-oil ratio for Well 43.

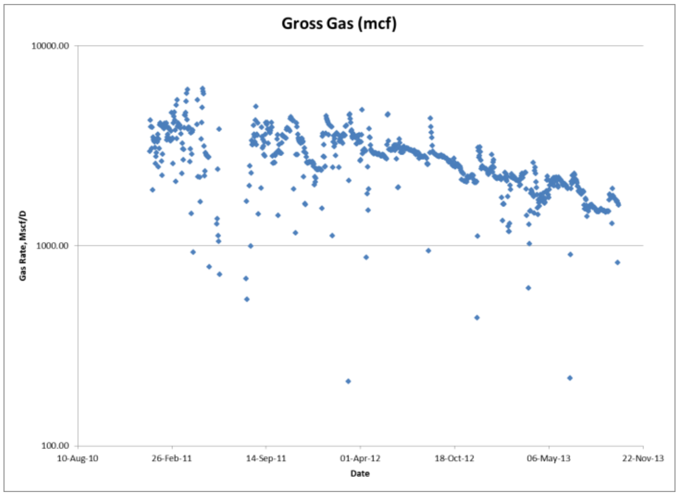

Figure 17: Gas production for Well 43.

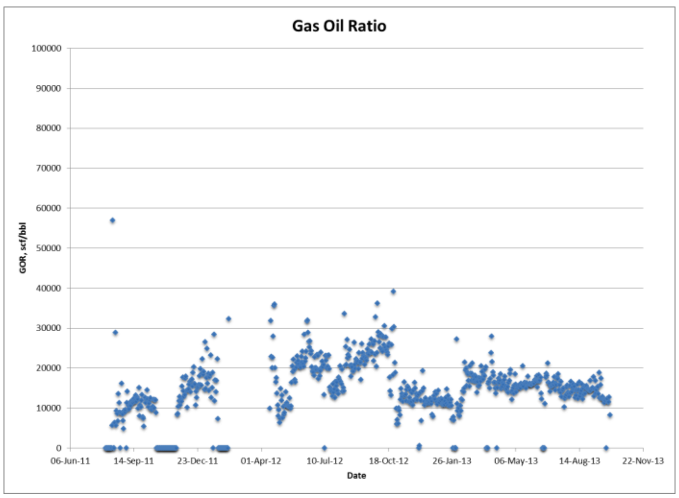

Figure 18: Gas-oil ratio for Well 59.

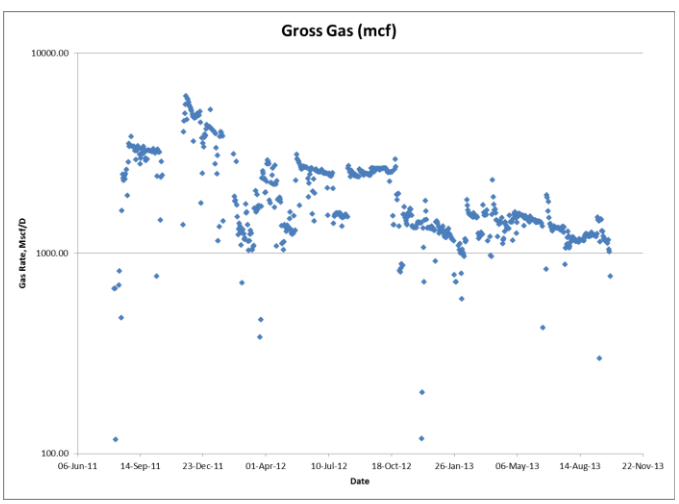

Figure 19: Gas Production for Well 59.

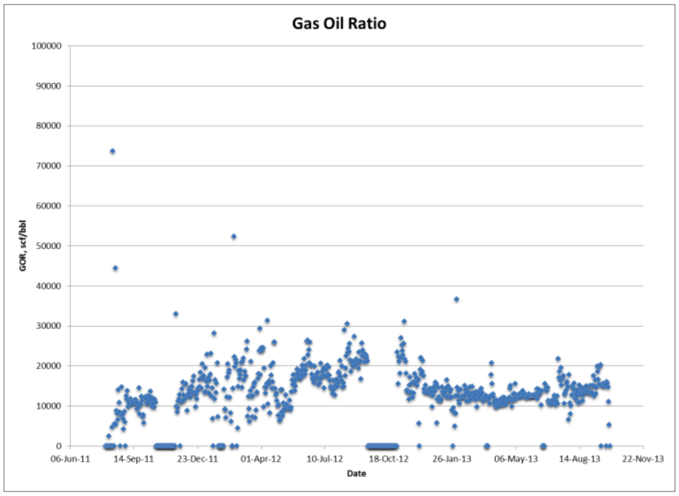

Figure 20: Gas-oil ratio for Well 60.

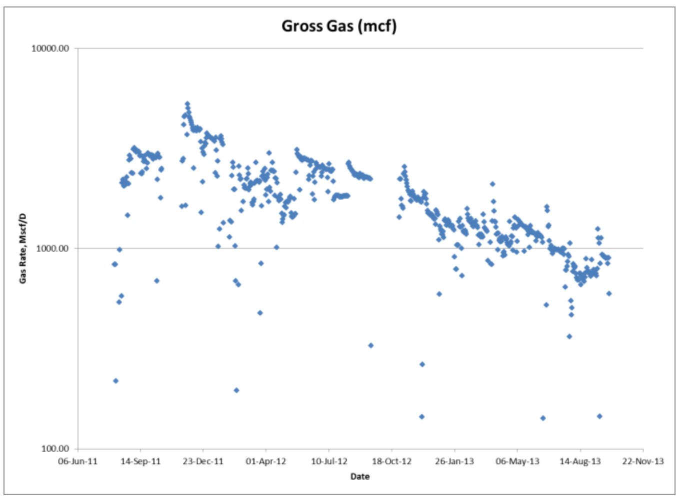

Figure 21: Gas production for Well 60.

Table 2: Well #8 Composition and Properties

Well	WELL #8	WELL #8	WELL #8
Daily Reading Date	21-Dec-11	25-Jul-12	25-Aug-13
GOR (scf/bbl)	20607.59	36301.66	35862.03
C7+ Mole Fraction	2.75%	1.78%	1.80%
C6 (mole fraction) Fig 27	0.64%	0.49%	0.49%
C5 (Mole Fraction) Fig 25	0.77%	0.59%	0.59%
C4 (Mole Fraction) Fig. 22	1.46%	1.13%	1.13%
C3 (Mole Fraction) Fig. 18	2.46%	1.93%	1.94%
C2 (Mole Fraction) Fig. 13	5.30%	4.49%	4.51%
C1 (Mole Fraction) Fig. 9	85.42%	88.54%	88.48%
Molecular Weight	22.32019	20.48404	20.51657
Specific Gravity	0.770658	0.707261	0.708384
Saturation Pressure (Calculated)	3447.82	2813.45	2828.15
Calculated GOR (scf/bbl)	31265.49	50150.28	49642.61
Error from Actual GOR	52%	38%	38%

Table 3: Well #43 Composition and Properties

Well	WELL #43	WELL #43	WELL #43
Daily Reading Date	31-Jan-11	06-Apr-12	24-Sep-13
GOR (scf/bbl)	12920.14	23367.27	17034.65
C7+ Mole Fraction	3.94%	2.50%	3.19%
C6 (mole fraction) Fig 27	0.79%	0.60%	0.69%
C5 (Mole Fraction) Fig 25	0.97%	0.73%	0.85%
C4 (Mole Fraction) Fig. 22	1.82%	1.38%	1.60%
C3 (Mole Fraction) Fig. 18	3.00%	2.33%	2.66%
C2 (Mole Fraction) Fig. 13	6.07%	5.11%	5.60%
C1 (Mole Fraction) Fig. 9	82.23%	86.18%	84.20%
Molecular Weight	24.47619	21.84927	23.11612
Specific Gravity	0.8451	0.754399	0.79814
Saturation Pressure (Calculated)	3875.38	3316.29	3634.93
Calculated GOR (scf/bbl)	21148	34724.07	26665.07
Error from Actual GOR	64%	49%	57%

Table 4: Well #59 Composition and Properties

Well	WELL #59	WELL #59	WELL #59
Daily Reading Date	01-Sep-11	06-Jul-12	21-Sep-13
GOR (scf/bbl)	9581.711	21693.62	12000.2
C7+ Mole Fraction	4.96%	2.65%	4.17%
C6 (mole fraction) Fig 27	0.91%	0.62%	0.82%
C5 (Mole Fraction) Fig 25	1.13%	0.75%	1.01%
C4 (Mole Fraction) Fig. 22	2.09%	1.43%	1.88%
C3 (Mole Fraction) Fig. 18	3.40%	2.40%	3.09%
C2 (Mole Fraction) Fig. 13	6.62%	5.22%	6.20%
C1 (Mole Fraction) Fig. 9	79.83%	85.74%	81.66%
Molecular Weight	26.27549	22.12282	24.88628
Specific Gravity	0.907225	0.763843	0.859259
Saturation Pressure (Calculated)	4083.32	3394.79	3932.3
Calculated GOR (scf/bbl)	16439.17	32635.49	19875.36
Error from Actual GOR	72%	50%	66%

Table 5: Well #60 Composition and Properties

Well	WELL #60	WELL #60	WELL #60
Daily Reading Date	21-Sep-11	14-Dec-12	28-Aug-13
GOR (scf/bbl)	10557.9	13441.52	13667.33
C7+ Mole Fraction	4.61%	3.83%	3.78%
C6 (mole fraction) Fig 27	0.87%	0.77%	0.77%
C5 (Mole Fraction) Fig 25	1.07%	0.95%	0.95%
C4 (Mole Fraction) Fig. 22	1.99%	1.78%	1.77%
C3 (Mole Fraction) Fig. 18	3.26%	2.95%	2.92%
C2 (Mole Fraction) Fig. 13	6.43%	6.00%	5.97%
C1 (Mole Fraction) Fig. 9	80.64%	82.53%	82.65%
Molecular Weight	25.64957	24.26513	24.17798
Specific Gravity	0.885613	0.837812	0.834803
Saturation Pressure (Calculated)	4022.58	3843.54	3829.86
Calculated GOR (scf/bbl)	17842.87	21863.34	22171.26
Error from Actual GOR	69%	63%	62%

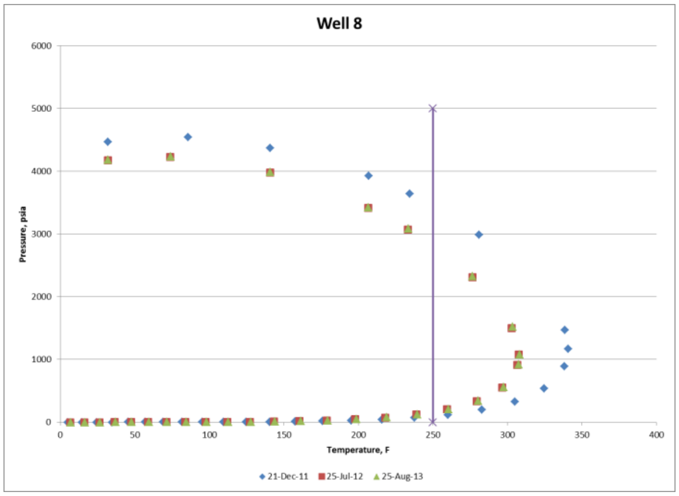

Figure 22: Well #8 Two-Phase Envelopes. Note the shift on the various time steps. The Purple line marks the cricondotherm at the given reservoir temperature.

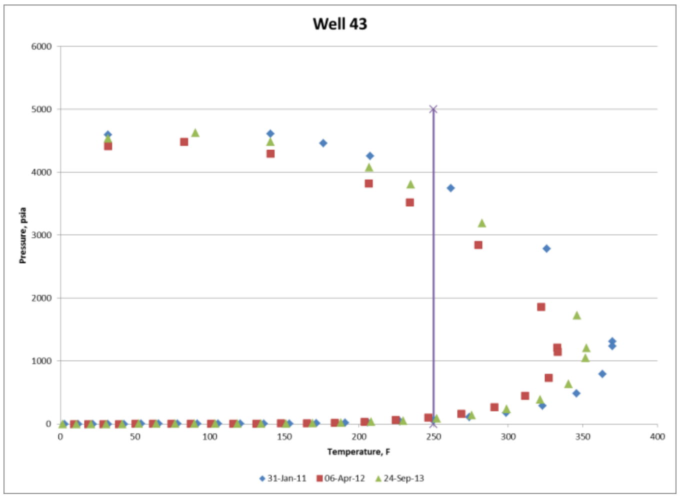

Figure 23: Well #43 Two-Phase Envelopes. Note the shift on the various time steps. The Purple line marks the cricondotherm at the given reservoir temperature.

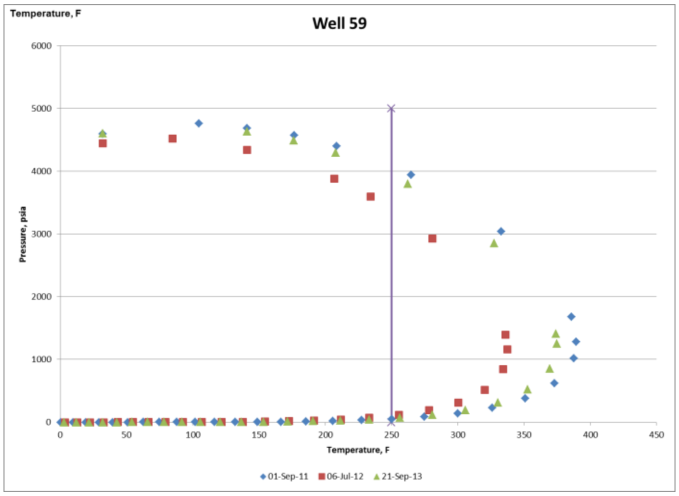

Figure 24: Well #59 Two-Phase Envelopes. Note the shift on the various time steps. The Purple line marks the cricondotherm at the given reservoir temperature.

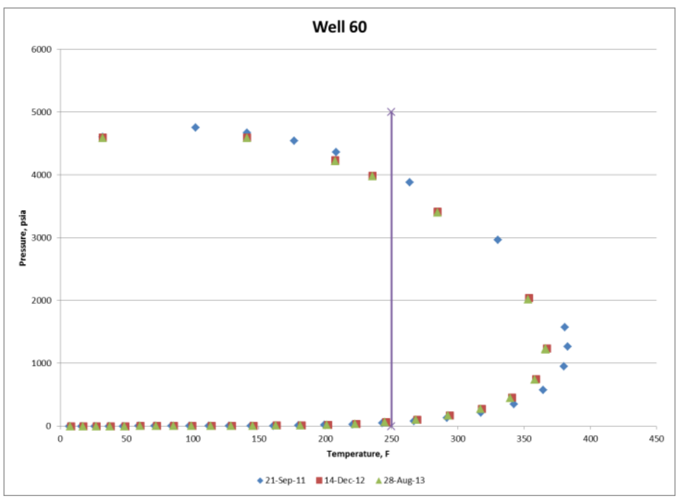

Figure 25: Well #60 Two-Phase Envelopes. Note the shift on the various time steps. The Purple line marks the cricondotherm at the given reservoir temperature.

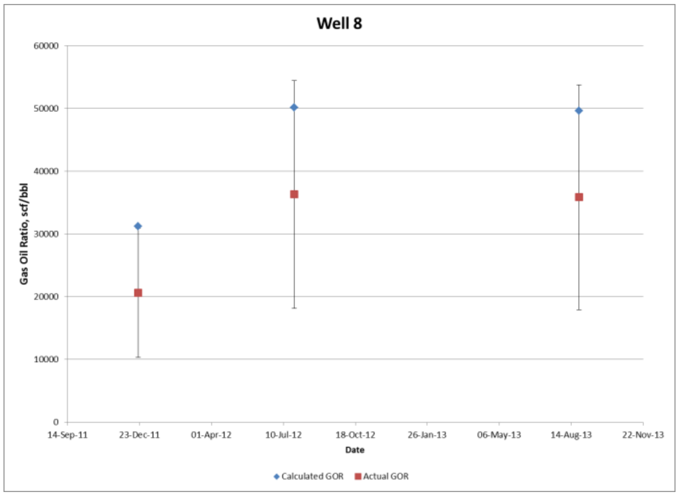

Figure 26: Well #8 Actual verses calculated GOR over time. The error bars represent ±50% of the actual data.

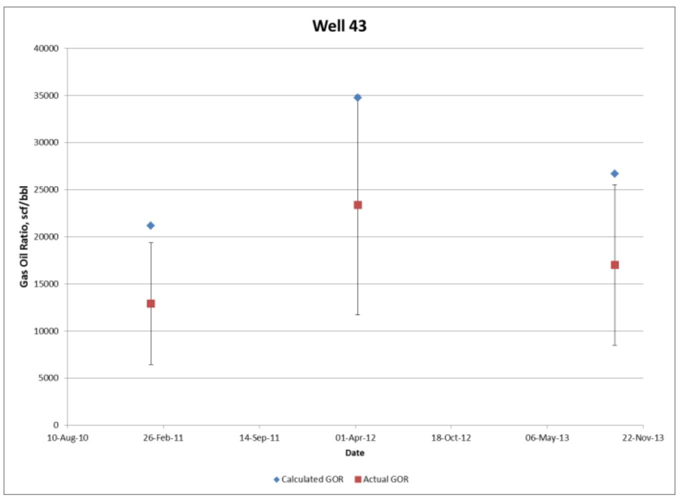

Figure 27: Well #43 Actual verses calculated GOR over time. The error bars represent ±50% of the actual data.

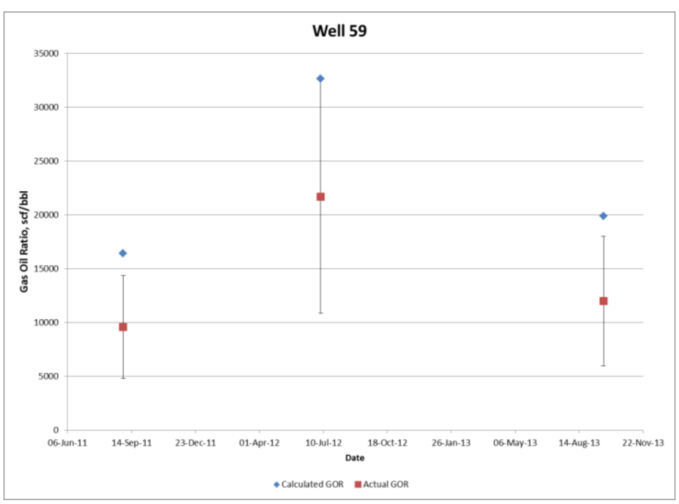

Figure 28: Well #59 Actual verses calculated GOR over time. The error bars represent ±50% of the actual data.

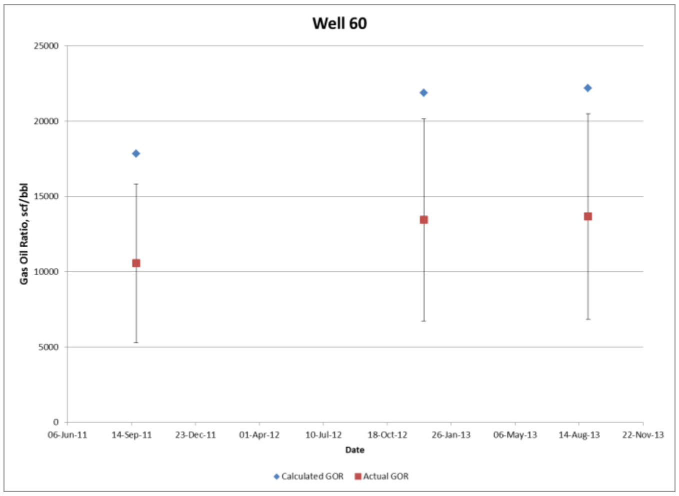

Figure 29: Well #60 Actual verses calculated GOR over time. The error bars represent ±50% of the actual data.