AN INVESTIGATION INTO REFRACTURING OPERATIONS IN THE BARNETT SHALE PLAY

A Thesis

by

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Submitted to the Office of Graduate and Professional Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

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August 2016

Major Subject: Petroleum Engineering

ABSTRACT

In an attempt to maintain production levels during times of depressed pricing, some are exploring the practice of refracturing already hydraulically fractured wells currently within their operating portfolio. This study investigates the last two years of data of the refracturing program that was initiated by Devon Energy Corporation in the Barnett Shale play.

The purpose of this study was to identify the wells refractured in the Barnett Shale from publicly available data and completion filings. Data was collected from Drillinginfo.com, IHS.com, and FracFocus.com for these wells. Estimated ultimate recovery for these wells were generated with the aid of a reservoir engineering software program. Cost estimates were performed for each well based on comparable industry expenditures and completion methodology assumptions. All data collected and subsequent calculations were compiled into a database compatible for upload into a statistical analysis software program. Ordinary least squares regressions were performed within a statistical software program with the following objectives:

- Validate some published conclusions that suggest reservoir quality indicates refracture potential;
- Identify candidate characteristics with the best internal rate of return potential; and
- Investigate whether a correlational relationship exists when dummy variables are assigned to the use of chemical diverters.

The findings suggest a positive correlation between reservoir quality and refracture initial production potential. When combining the production history with this study's

completion and cost assumptions, the vertical and directional wells are ranked as more attractive refracture candidates in terms of internal rate of return. Chemical diverters showed no correlational relationship with refracture initial production values.

DEDICATION

To my family and friends who have always encouraged me to keep fighting the good fight.

ACKNOWLEDGMENTS

I would like to thank my undergraduate research assistant Kirk Sheng for his help. His dedication to duty, attention to detail, and positive attitude has helped make the data collection and research possible. I would also like to thank my research group members Omar Enriquez Tenorio, Dante Guerra, Jesse Guerra, Cody Kainer, and Ashley Gehring for their help and vetting of this research. Their pushback and engineering insight have improved my ability to think critically and develop ideas on how to analyze this topic. Additionally, their kindness and support have made each day working together more enjoyable.

Next, I would also like to thank the numerous industry professionals who took the time to explain concepts and provide suggestions on how to proceed with this topic.

And finally, I would like to thank my advisors Dr. Ding Zhu and Dr. Daniel Hill for their guidance, support, and encouragement during this research. I appreciate their unique ability to allow us freedom during research while also continually pointing us in the right direction. I would also like to thank Dr. Michael Pope for supporting me and serving as a member of my graduate committee.

NOMENCLATURE

a_i	Loss Ratio, Rate of Decline
API	American Petroleum Institute
b	Numerical Reservoir Factor
Bcf	Billion Cubic Feet
BHTP	Bottomhole Treating Pressure
C	Dummy Variable Representing Chemical Diverters
D_i	Dummy Variable Representing Directional Wells
E	Young's Modulus (psi, Mpa)
EUR	Estimated Ultimate Recovery
EUR_{bc}	Estimated Ultimate Recovery Without Fefracturing
EUR_a	Estimated Ultimate Recovery Net Change
EUR_{rf}	Estimated Ultimate Recovery With Refracturing
ϵ_{poro}	Poroelastic Stress Reorientation Number
ϵ_{mech}	Mechanical Stress Reorientation Number
h	Formation Thickness, ft
H_i	Dummy Variable Representing Horizontal Wells
IP	Initial Production
IRR	Internal Rate of Return
$IRR_{(\$2.50/Mcf)}$	Internal Rate of Return When Gas Sells For $2.50/Mcf
L_f	Initial Fracture Half Length, ft
m_s	Proppant Mass, lbm

MMcf	Million Cubic Feet
Mcf	Thousand Cubic Feet
OLS	Ordinary Least Squares Regression
P	Pressure
p_{ri}	Initial Reservoir Pressure, psi
p_{wf}	Wellbore Pressure, psi
q	Production
q_i	Initial Production
$Q_{i,bc}$	Initial Production Peak of Original Well
$Q_{(i,refrac)}$	Initial Production Peak of Refractured Well
Q	Cumulative Production
STB	Stock Tank Barrels
T	Time
$T_{bc\text{-}rf}$	Time Between Completions
Tcf	Trillion Cubic Feet
TVD	True Vertical Depth
V_i	Dummy Variable, Representing Vertical Wells
VIF	Variance Inflation Factor
w_f	Fracture Width, ft
υ	Poisson's Ratio
σ	Stress (psi, Mpa)
$\Delta\sigma_{h^r}$	In-situ Horizontal Stress Component

α	Biot's Constant
$\emptyset_f$	Fracture Porosity
ρ_s	Proppant Density lbm/ft^3

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1 INTRODUCTION

1.1 Background

Shale's low permeability (on the order of hundreds of nanoDarcies) requires hydraulic fracturing to create flow paths to allow for the economic production of oil and gas. When a well is hydraulically fractured, millions of gallons of fluid are pumped into the formation at a pressure above the formation's fracture gradient, inducing a fracture into the rock. Additionally, shale reservoirs normally have steep decline curves because these reservoirs do not have favorable flow characteristics.

Hydraulic fracturing's effect on flow improvement in low permeability shale reservoirs is analogous to a snowplow's effect on traffic flow improvement: both provide pathways to improve transport. Shale's low permeability restricts its hydrocarbons to their pore spaces, or "hydrocarbon garages." The completion fluid used in hydraulic fracturing, a water-based mixture of chemicals and proppants, pressures through the minimum horizontal stress plane to create fractures for hydrocarbon transport.

Proppants are carried by the completion fluid and dispersed within the created fractures. These proppants mitigate loss in conductivity by "propping open" the fractures and allowing the flow paths to remain open even after the pumping is stopped. Conductivity, a measure of flow ability, is the product of fracture width and fracture permeability. Over time the proppants embed, crush, or flow back and no longer successfully prop open the induced fractures. The fractures close in three parts: the confining stresses first cause the rock to deform elastically, then the rock deforms plastically, and finally, when static equilibrium is reached, the molecules reorient themselves to allow for stress relaxation (i.e., fracture creep). This decrease in fracture width restricts the fluid pathway, making the hydrocarbon drainage more difficult and resulting in decreased conductivity. Decreased conductivity results in lower flow ability, or in terms of well performance, a lower production rate.

During times of lower oil and gas prices, operating companies explore cost effective ways to increase production. One such method that has the ability to enhance production in a cost effective manner is refracturing wells that are currently producing, but with low performance. Refracturing is not a new concept. In 1996, the Gas Research Institute (GRI) was commissioned to analyze the potential for refracturing existing non-shale, low-permeability formations (Reeves 1996). The report concluded that the United States had over one Tcf of reserves with restimulation potential. These areas ranged from South Texas chalk formations to tight gas sands in Colorado. The study further suggested that among these restimulation candidates, 15% of the wells would supply 85% of the production gains. For this reason, many efforts are now being made to successfully identify the top 15% percent of refracture candidates due to their potential economic value.

Shale reservoirs, like tight sands and chalk formations, serve as potential refracturing targets. Firstly, refracturing may propagate new fractures that stimulate reservoir space previously untouched by the original hydraulic fracturing treatment. Secondly, refracturing aims to restore conductivity lost as original fracture connectivity and width deteriorate.

1.2 Overview of the Barnett Shale

The Barnett Shale is a gas producing reservoir stretching across northern Texas, including underneath the city and surrounding areas of Fort Worth, Texas. In 1981, George Mitchell drilled the discovery well, the C.W. Slay No.1, in the Newark East Barnett Shale (Steward 2013). At the beginning of the 21st century, the Barnett Shale play had become a hotbed of activity. By May 2010, over 14,382 wells were drilled including 9,757 horizontal wells, 4,075 vertical wells, and 550 directional wells (Hale et al. 2010). The primary areas for production are in the Denton, Wise, and Tarrant counties (DOE 2011).

The Barnett Shale formed during the Mississippian approximately 350 million years ago. The vitrinite reflectance across the Barnett Shale is approximately 1.2% (DOE 2011). Vitrinite reflectance serves as a thermal maturity indicator and is measured by the light reflected by the vitrinite particles in the rock. Depending on the type of kerogen classification, this value can be used to estimate tendency to contain oil or gas. Of the three kerogen basin classifications, a type I basin is more oil prone as it is primarily composed of algae- and animal-based decompositions. A type III basin is more gas prone as it is composed primarily of plant-based remains. The Barnett Shale is a mixture of both types and for this reason is considered to be a type II kerogen basin. Combining a 1.2% vitrinite reflectance value with a type II kerogen classification indicates that the Barnett primarily is a gas reservoir.

The petrophysical characteristics are as follows: porosity is approximately 6%, permeability is in the nanoDarcy range, formation pressure is between 3,000 and 4,000 psi, total organic content (TOC) is typically between 2% and 6%, and drilling depth is between 6,000 feet and 8,500 feet. The Barnett Shale thickness ranges from 50 to 1,000 feet (DOE 2011).

The location of the primary drilling activity occurred within the Barnett Shale is shown in Figure 1. The characteristics of a typical Barnett well are shown in Figure 2. The upper end of estimated ultimate recovery (EUR) varies from 1 billion cubic feet (Bcf) for vertical wells to 3.5 Bcf for horizontal wells. These wells have steep decline rates (Bruner 2011). The stratigraphy of the Barnett formation is shown in Figure 3.

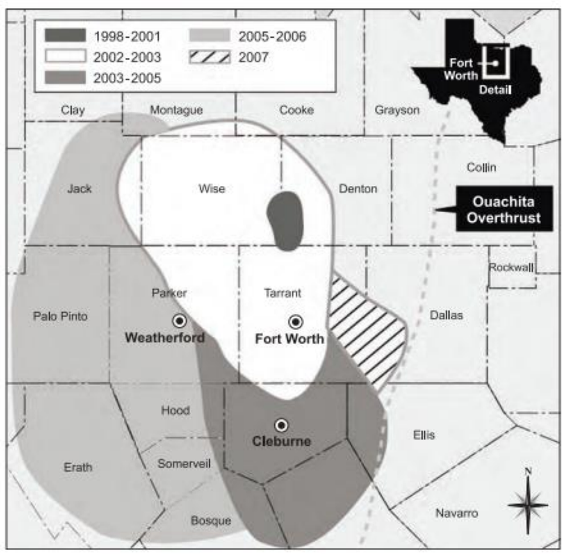

Figure 1: Stages of Exploration in the Barnett Shale, 1998–2007 (from Bruner 2011).

Barnett Field	Vertical Well	Horizontal Well
Technically Recovable Gas, Tcf	39	
Well Spacing, acres	27-55	
Initial potential, Mcf/day	700-1000	1,600-2,500
Estimated Ultimate Recovery, Bcf	0.7-1.0	2.4-3.5
Recovery Efficiency	7-12%; 12-20% with closer well spacing and shorter laterals; up to 20% with refrac	
Production Decline, first year	60-65%	50-55%
Well Cost	1,000,000	2,000,000
Finding and Development cost per Mcf	$1.71	$1.06

Figure 2: Gas volumes and well costs for Barnett wells (Bruner 2011).

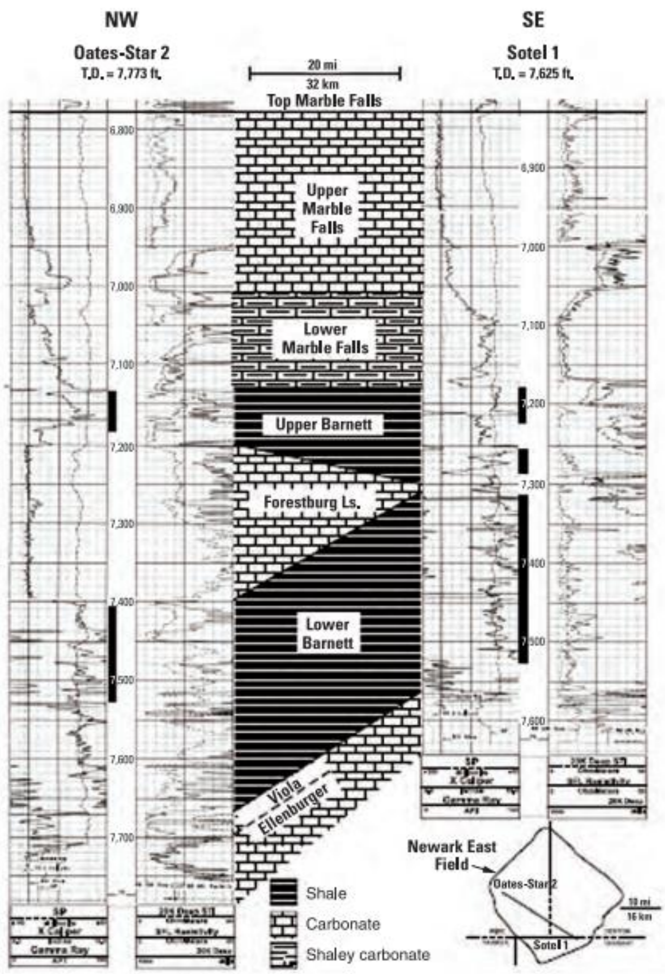

Figure 3: Well logs showing Cambrian-Pennsylvanian units of the Fort Worth Basin, the Upper and Lower Barnett Shale. The Barnett Shale is interbedded with limestone (from Bruner 2011).

The Barnett Shale is dominated by clay and silt-sized sediments deposited within a narrow seaway that formed the Fort Worth (Jarvie et al. 2001). The thermal history of the Barnett can be broken into three stages (Jarvie et al. 2001). These sediments were rapidly buried during the Pennsylvanian and Permian periods and the primary oil and gas generation occurred during this stage. The second stage of gas generation occurred towards the end of the Permian and the beginning of the Cretaceous. The heightened temperatures of this period resulted in cracking of the oil, bitumen, and kerogen, which created the Barnett's gas reserves. The third stage consisted primary of erosion and uplift.

1.3 Literature Review

1.3.1 Refracture Definition

When a previously hydraulically fractured well is recompleted and hydraulically fractured a second time, it is considered a refractured well. The first refractured wells occurred in Texas in the early 1950's (Sallee and Rugg 1953). By the 1970s, industry estimates suggest that 175,000 of the 500,000 hydraulic fracturing treatments were for refracturing wells (Howard and Fast 1970; Coulter and Menzie 1973).

Normally, wells that are refractured are actively producing hydrocarbons, albeit at a much lower rate than initial production levels. The purpose of the refracture is similar to the purpose of the initial hydraulic fracture—a refracture recreates the better pathways necessary for hydrocarbon transport. In theory, the refracture methodology seems like an excellent way to improve production of existing wells, but the results of this process is not straightforward. Ideally, refracturing is expected to bring an additional recovery without altering the decline rate (Figure 4).

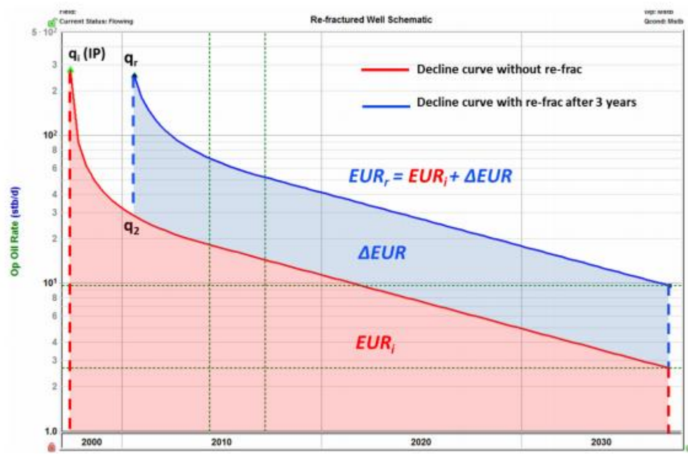

Figure 4: Schematic of a desired decline curve for a refractured well (from Oruganti et al. 2015).

As mentioned before, Reeves (1996) suggested that 15% of the refractured wells would supply 85% of the production gains. Successfully identifying these top 15% percent of refracture candidates would then hold tremendous economic value. Part of the aim of this study is to identify the preferred refracture candidates within the Barnett region.

1.3.2 Refracturing Case Studies

Case studies involving refractures are too numerous to be compiled into a single literature review. A brief table summarizing 143 refracture treatments in various fields was presented by Vincent (2010). The case studies presented in this study will involve the shale prone Barnett, Bakken, Eagle Ford, and Haynesville formations.

A study involving 17 Bakken refractures was conducted by Lantz et al. (2007). In their study, an operator ran tracer logs in horizontal wells, and candidates for refracturing were the wells with the original cemented liner showing an area of unpropped lateral. Additional perforations were added though a hydro-jetting procedure involving three nozzles. Diversion was attempted by pumping a slug at the end of each fracturing stage, which was intended to divert the hydraulic treatment to new sections. Ball sealers were also used. Post refracture, 30-day peak production approached an average of 75% of initial peak production. On average, the estimated ultimate recovery (EUR) increased 32%, or around 90,000 stock tank barrels (STB) per well.

Devon Energy conducted refracturing operations in the Barnett (Craig et al. 2012). From their case study involving 13 wells, low offset depletion and low cumulative recoveries were strongly correlated with wells that showed the most incremental gains in estimated ultimate recovery. On average, they found these wells to increase their estimated ultimate recovery by 0.8 Bcf while incurring an average cost of $0.9 MM (million dollars).

Significant data scatter occurred when matching computer simulation history with actual production data obtained from refractured wells; oftentimes the refractured wells, while still economically viable, frequently produced less than predicted (Craig et al. 2012). This was interpreted as an indication that the refracture treatments were not initiating new fractures into unfractured areas of the reservoir, which would theoretically release virgin reservoir pressure potential. Similarly, pore pressure increase from a refracture treatment was short-lived in another study by Diakhate et al. (2015), further supporting the notion that the refracture treatments were not initiating new fractures, only improving conductivity in existing fractures.

This lack of pressure increase within the wellbore indicates the possibility that refracture treatments travel within the originally hydraulically fractured pathways and not into the higher-pressurized virgin regions made accessible through added perforations during the refracture as some refractured wells were reperforated (Craig et al. 2012). When initial perforations were spaced at approximately 400 to 450 ft intervals, reperforations were added.

The refracture of seven Haynesville formation wells in 2015 was described by Melcher et al. (2015). In some wells where the operator deemed perforation spacing as inadequate, perforations were added. The completion jobs were broken into stages separated by chemical diverters. During the process, cross-linked fluid was used to carry the sand past the heel of the lateral. Overall, these wells averaged 1.5 Bcf incremental estimated ultimate recovery improvement.

Refracture treatments in the Bakken and Eagle Ford plays were analyzed by Oruganti et al. (2015). The study identified wells within the Eagle Ford and Bakken formations that showed a production uplift in their decline curves analogous to a refracture production uplift (Figure 4). The limitation of this approach, however, is that refractures with low initial production values and steep declines were less likely to be flagged. These flagged wells were verified as refractures, decline curves using Arps decline curve equations were created and incremental estimated ultimate recoveries were calculated by Oruganti et al. (2015).

16 Eagle Ford oil wells and five Eagle Ford gas condensate wells were also analyzed by Oruganti et al. (2015). Time to refracture ranged from nine to 45 months.

Estimated ultimate recoveries averaged an increase of 100,000 stock tank barrels (STB) and 60 MMcf. The study also investigated 22 Bakken formation wells and their time to refracture ranged from 21 to 75 months. Estimated ultimate recoveries averaged an increase of 127,000 STB.

In the Eagle Ford, the refracture initial production averaged 74% of initial production. In the Bakken, the refracture initial production averaged 92% of initial production. According to their respective economic evaluations, seven of the 16 Eagle Ford oil wells and two of the five Eagle Ford gas condensate wells were deemed to have positive net present value, an indicator that future cash flows are greater than the investment costs. Of the 22 Bakken oil wells, 19 were deemed to have positive net present value.

1.3.3 Refracturing Candidate Selection Studies

Numerical simulation was used to analyze Barnett Shale wells in order to determine ideal candidates for recovery by Tavassoli et al. (2013). They built a simulation model based on a dual permeability model and utilized a reservoir modeling software program.

In their simulations, they used two cases of refractured wells (Tavassoli et al. 2013). Case (1) was a horizontal well refractured after 4.5 years of production with 1.5 years of refractured production. Case (2) was also a horizontal well with 5.5 years of production and 2.5 years of refractured production. The primary difference between these cases was that in Case (1), new perforations were placed between the original perforations whereas in Case (2), the existing perforations were reused in the fracture process. No details concerning the completion methodology were given for either well.

Their results estimated that in cases of both high and low permeability, porosity, and conductivity, refracturing could improve production between 30% and 70% (Tavassoli et al. 2013). They suggested that the ideal refracturing position was between the original perforations. Since permeability, porosity, and conductivity all showed refracturing production gains regardless of input magnitude, these characteristics could not individually serve as an indicator of refracturing potential, and the authors created a production indicator variable called "refracturing efficiency," a ratio of 30 years of refracturing production to 30 years of non-refracturing production (Tavassoli et al. 2013). Comparing refracturing efficiency to porosity, permeability, and conductivity yielded correlational results. In low permeability, poor conductivity, and high porosity reservoirs a greater potential for refracturing efficiency occurred. Upon demonstrating the relationship between these values and refracture efficiency, ideal candidates for refracture were defined as follows: wells with high porosity, low permeability, and low conductivity (Tavassoli et al. 2013).

A previous simulation study identified four cases that had both low and high permeability with low and high depletion (Reese et al. 1994). These four cases had varied conductivities and fracture lengths. It was found in low permeability reservoirs that fracture length mattered more than conductivity, whereas in high permeability reservoirs, conductivity is of greater importance than fracture length. Additionally, their simulation results showed refracturing to be uneconomic in pressure-depleted, low permeability reservoirs (Reese et al. 1994).

Refracturing candidate selection was analyzed the completion methods used in the Barnett Shale (Sinha and Ramakrishnan 2011). This study exclusively used publicly available Barnett production data from IHS (2011) and Drillinginfo (2011). The first step was to examine which completion parameters affected the production index. They determined the number of stages per unit length of the lateral and the total volume per unit length of the lateral to be positively correlated with quality completions. This study then defined the product of these two inputs as a “Completion Index.” The study omitted proppant type as an input because these values were considered to be reflected in the proppant volume parameter.

The completion index was plotted against the production index of the well and subdivided into four quadrants (Sinha and Ramakrishnan 2011). Those wells with a low completion index and high production index (quadrant one) warranted further examination because of their potential for further stimulation (Figure 5).

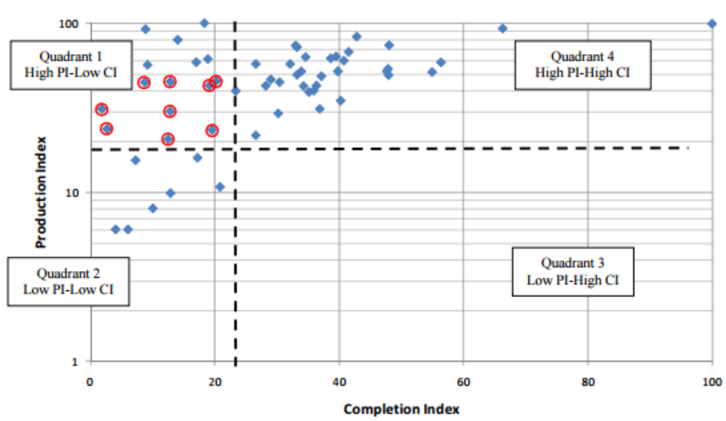

Figure 5: Completion Index vs. Production Index (Sinha and Ramakrishnan 2011)

The next step was to plot these quadrant one wells against a "Reservoir Quality Index," which was a function of logged effective gas porosity-foot. The original quadrant one wells were then subdivided into four sub-quadrants. The ideal refracture candidates were the wells located within the new quadrant one of the original quadrant one (surrounded by the green box in Figure 6). These wells would serve as ideal refracture candidates because they were poorly completed in a high quality reservoir.

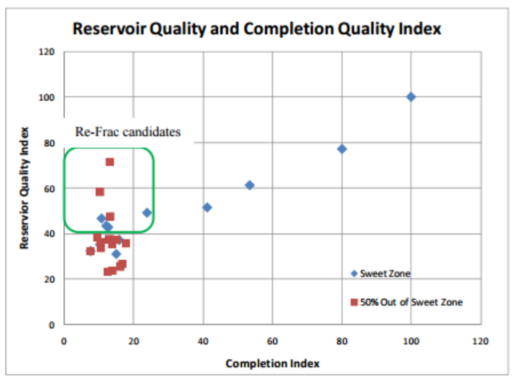

Figure 6: Reservoir Quality vs. Completion Quality Index (Sinha and Ramakrishnan 2011)

Production data available to field engineers was analyzed in order to select refracture candidates (Roussel and Sharma 2011). They proposed investigating four criteria: (1) the extent of stress reorientation; (2) the ratio of initial production value to theorized production values; (3) adjacent well production; and (4) the decline rate. Criteria two through four are specific to the individual well whereas criterion one is specific to the general field of operations. The data is from 300 vertical Codell formation tight gas wells in Wattenberg field, which is a tight sandstone, non-shale formation.

Effects determining a well's stress re-orientation potential are categorized into mechanical and poroelastic effects. Mechanical effects are a function of Young's Modulus, Poisson's ratio, proppant density, formation thickness, initial fracture half-length, and the horizontal minimum and maximum stress contrast. Poroelastic effects are a function of the minimum and maximum stress contrast, Poisson's ratio, and the pressure differential between the reservoir and wellbore.

$$\epsilon_{poro} = \frac{\Delta\sigma_h}{\frac{\alpha(1-2v)}{1-v}(p_{ri} - p_{wf})} \tag{1.1}$$

$$\epsilon_{mech} = \frac{4\Delta\sigma_h(1-v^2)(1-\emptyset_f)\rho_s L_f h^2}{E m_s} \tag{1.2}$$

These equations assign a numerical value to stress re-orientation potential. The lower the number, the more potential for stress reorientation. Values of less than 0.1 for either mechanical or poroelastic effects indicate potential for stress reorientation, with the lowest value between the two effects driving the stress reorientation.

The second criterion is the ratio of initial 30-day production values to the theorized 30-day production values. Theoretical production values from linear approximations using the Guppy et al. (1981) model. This ratio becomes the "Fracture Completion Number" and is a ratio of actual to ideal conductivities.

The third criterion is the "Reservoir Depletion Number," which is the sum of the ratio of production from each nearby well to its respective distance away (Roussel and Sharma 2011). It factors in reservoir characteristics and drainage patterns to achieve a value between zero and one.

The fourth criterion is the "Production Decline Number." This number is the product of the initial decline rate and the length of time producing (Roussel and Sharma 2011).

The power of big data analytics to optimize refracture candidate selection decisions was harnessed by Oberwinkler and Economides (2003). Their theory began with data mining for cross-plots of various completion and reservoir inputs versus production and populating the data into self-organizing maps (SOMs) that automatically group data by like patterns. Ultimately, a neural network can then be trained to rerun simulations for optimization.

Parameters used as inputs for the optimization study were proppant characteristics, net pay of formation, fracking and pad fluid amount, injection rate, fracture pressure, and formation variability (Oberwinkler and Economides 2003). They used cross-plots to establish a relationship between type of proppant and expected recovery increase. Then, this data was uploaded into SOMs in order to extrapolate macro trends and indicate the best proppant type. They also showed that large fluid pad volume, large total volume, and high average rate led to the best outcomes.

The optimum results were shared with a neural network that could be trained to run "what if" scenarios in order to continue to determine optimal results. The network is trained to search for nonlinear relationships, and the data is adjusted in order to allow for better scenario generation and assistance with ranking the given refracture candidates.

The numerical simulation, production data analysis, and case study method all suggested that better quality reservoirs have higher potential for more effective refractures (Tavassoli et al. 2013, Sinha and Ramakrishnan 2011, Craig et al. 2012). Additionally, wells with the best reservoirs make for the best refracture candidates was the suggestion of another study (Vincent 2011). This common finding of positively correlating reservoir quality with successful refractures follows logically. Wells that are strong producers or near strong producers have demonstrated that they are in a good hydrocarbon reservoir. This production data indicates the reservoir has quality characteristics that logs or seismic data alone cannot establish.

1.4 Problem Description

As well production declines, operators need to continue drilling and completing new wells in order to maintain production levels, especially in shale wells due to the steep decline rates. In order to drill new wells, leases have to be acquired, the wells that are drilled must be completed, and production facilities must be installed to handle the well production. All of these actions require capital expenditures. One alternative to drilling new wells to raise production is refracturing already producing wells. Theoretically, if the well is already being operated, then the primary cost of a refracture would be limited to the refracture costs, which could make a refracture a more economically attractive option than drilling a new well.

Refracturing is a complex problem and the outcome depends on many factors. For example, a “plug and perf” completion where multiple-stage fracturing is mechanically isolated by composite plugs is not possible during a refracture unless the original perforations are mechanically sealed and new perforations are added again during each refracture stage. Additionally, refracturing a producing well only adds value if the difference of estimated ultimate recovery of the refracture and the estimated ultimate recovery of the original fractured well is greater than the costs of the refracture. Risk is involved because existing production is now being taken offline in hopes that it will be greater in the long run. If completion methodology cannot be optimized in the same way during refracturing as the original completion, the risk of increasing the well's decline rate exists.

Regardless of these complexities, refracturing still could be a solution to economically developing unconventional resources. This study focuses on analyzing field data for refracture and production history to illustrate the effect of known parameters, like initial production, initial decline rates, type of well, and amount of sand in refracturing design.

1.5 Research Objectives and Methodology

The study utilizes publically available production data and completion filings from Devon Energy Corporation's recent refracture attempts involving Barnett Shale wells. The abilities to screen Barnett Shale refracture candidates and predict Barnett Shale refracture peak production values were of interest. These two values, once estimated, can then be used as drivers to determine the estimated ultimate recovery of a Barnett Shale refractured well, and economic viability can then be better predicted. Additionally, the effectiveness of chemical diverters, which are used to delineate hydraulic treatment stages and divert flow to under-stimulated regions, was statistically examined. Any correlation could be valuable for ranking refracture opportunities and running project economics on the refracture treatment. The study utilizes the following approach:

1. Identify a company currently conducting a refracture program in a shale field. By solely working with one company's wells, the data will be typical of a company's

well portfolio. Additionally, completion procedures vary from company to company so utilizing one company's data will best control for completion methodology assumption variance and cost estimate variance.

2. Identify the wells refractured by that company within the last two years. Limiting the data to the last two years will best control for technology improvements.
3. Compile the publicly available production data, completion filings, and completion data (such as amount of water, length of completion, amount/type of sand proppant, type of diverter, and addition of perforations).
4. Using the publicly available production data, develop decline curves to calculate the change in estimated ultimate recovery that results from the refracturing efforts.
5. Develop a cost estimate procedure to estimate the cost of each refractured well and calculate an internal rate of return (IRR) valuation.
6. Conduct ordinary least squares regression analysis on compiled and calculated data.
7. Examine correctional trends in order to better predict the added initial production that would result from a refracture. Additionally, examine the data for indicators to group/rank the candidate selection. Finally, test for statistical indicators of chemical diverter significance.

2 DATA INDENTIFICATION, COLLECTION, AND ANALYSIS PROCEDURES

This section describes data identification and collection used to create the database for decline curve generation and economic and statistical analyses.

2.1 Description of Data Identification and Collection

The models created in this study use data from DrillingInfo, Information Handling Services (IHS), and FracFocus Chemical Disclosure Registry.

DrillingInfo is a company that compiles and collects public domain data on well leases, permitting, operator history, production data, and completion information on oil drilling in the United States. This website was used to conduct a query on the completion designs in the Barnett Shale for Devon over the last two years. The wells identified in this query were then manually inspected for number of completion filings. If a well was previously hydraulically fractured prior to 2014 and again by Devon after 2014, then for the purposes of this study it qualified as a refractured well. In addition, completion information for the wells was pulled from the completion permits listed on DrillingInfo. The type of well, location, amount of fracture fluid, type and amount of sand proppant, and other completion details such as length of completion and location of added perforations were noted and compiled into a database for this study.

The American Petroleum Institute (API) assigns a unique well number or identifier for wells drilled in the United States. The API well numbers compiled by the DrillingInfo query were used to search the IHS database to locate production history. Information

Handling Services is a company that provides a dataset that tracks many of the public domain data elements for oil and gas wells, one of which is monthly production history. The monthly production history was compiled into another database that was compatible for upload into a reservoir engineering software program for further decline curve analysis.

Again, the API number identified with the DrillingInfo query was used to search the FracFocus Chemical Disclosure Registry. FracFocus is an industry-led consortium that serves as a national hydraulic fracturing chemical registry. On FracFocus, companies voluntarily submit their completion chemicals to better inform the public and alleviate concerns regarding groundwater contamination. The chemicals listed on the site were recorded into the database of this study and assigned dummy variables (0 or 1) depending on whether the chemical was included in the refracture. From the FracFocus data, whether or not chemical diverters were used can be ascertained.

The completion methodologies for these wells are unknown,. The wells with chemical diverters are assumed to have been completed in a “bullheaded” manner where fluids and proppant were pumped down the pipe and the fracturing was sub-divided into stages by pumping chemical diverters in between the fracturing fluids. Mechanical isolation would not be employed in this manner. For shorter wells, it is possible that the “cement squeeze, drill out, and reperforate” method was employed. Similar completion methods for Devon refractures were described by Craig et al. (2012). For the purposes of this study (such as cost estimation), it is assumed that Devon is continuing similar practices and expanding their use of diverters.

The final dataset for this study includes 20 wells refractured by Devon in the Barnett Shale. These 20 wells span three counties: Tarrant, Wise, and Denton County. The well types are as follows: 11 horizontal wells, one vertical well, and eight directional wells. Several Devon-operated refractures were excluded because the lack of production history post refracture rendered decline curve analysis uncertain. Additionally, one well utilized a larger sand proppant (20/40 mesh) during the refracture than every other well. This well's production behavior was inconsistently negative compared to the other wells, skewing the regression. For this reason, the data from this well was excluded.

The final data set used is as follows:

Table 1: Summary of Wells Used

#	API	Well_Name	Hole_Type	County	TVD (ft)	Date of the IP	Date of the Refrac
1	42-439-33015	J. Tom Shelton 13H	Horizontal	Tarrant	7149	Jun-08	Jul-15
2	42-439-30369	Laprelle 3	Directional	Tarrant	7463	Feb-03	Sep-14
3	42-439-31301	Jarvis Fossil Creek 1	Directional	Tarrant	7320	Nov-06	Jul-15
4	42-439-30698	Devon Styrochem 1H	Directional	Tarrant	7507	Apr-04	May-15
5	42-439-30408	Jarvis Fossil Creek 3	Directional	Tarrant	7415	Dec-03	Jul-15
6	42-439-30745	J. Tom Shelton 4H	Horizontal	Tarrant	7091	Jun-04	Jun-15
7	42-121-32567	Blakley GU E 11	Directional	Denton	7835	Oct-05	Mar-15
8	42-439-31768	Lottie Barton Johnson 30H	Horizontal	Tarrant	7248	May-07	Aug-15
9	42-497-36110	RM Alliston 5H	Horizontal	Wise	7355	Feb-07	Sep-15
10	42-121-31151	James L. Wood G.U. 5	Vertical	Denton	7900	Nov-01	Apr-15
11	42-439-31065	Margaret Tadlock 2H	Horizontal	Wise	7133	Jul-05	Jun-15
12	42-121-31883	TCU 17H	Horizontal	Denton	9000	Jul-03	Jul-15
13	42-121-31430	James L Wood GU 8	Directional	Denton	7870	Aug-02	Aug-15
14	42-439-31054	Margaret Tadlock 4H	Directional	Tarrant	7665	Jul-05	Jun-15
15	42-439-30814	Trinity Industries 2	Directional	Tarrant	7495	Aug-04	Jun-15
16	42-121-32236	Day-Adams 1H	Horizontal	Denton	7533	Jun-04	Jun-15
17	42-439-32095	J Tom Shelton 12H	Horizontal	Tarrant	7174	Oct-07	Dec-14
18	42-439-31940	Laprelle 14H	Horizontal	Tarrant	7198	Sep-07	Jul-15
19	42-439-31545	RM Alliston 5H	Horizontal	Tarrant	7092	Jan-07	Jun-15
20	42-439-31573	J. Tom Shelton 6H	Horizontal	Tarrant	7190	Oct-06	Jul-15

While this dataset does represent a reduction from the initial number of identified refractures, the resulting data points are sufficient to estimate the parameters using the ordinary least squares regression methods.

2.2 Data Analysis Methodology

2.2.1 Decline Curve Analysis

Prior to running an ordinary least squares regression on the data, certain inputs have to be generated through Arps (1945) decline curve analysis using the reservoir engineering software PHDWin 2.9. The Arps (1945) decline curve defines a relationship between production and time.

$$\frac{d}{dt}\left(\frac{q}{\frac{dq}{dt}}\right) = -b \tag{2.1}$$

Production rate is represented by q, and b represents a numerical reservoir factor. Integrating equation 2.1 gives equation 2.2.

$$\frac{q}{\frac{dq}{dt}} = -bt - \frac{1}{a_i} \tag{2.2}$$

A loss ratio or rate of decline is represented by a_i. Integrating 2.2 and using initial peak production for q_i at time t=0 gives equation 2.3.

$$q = \frac{q_i}{(1 + a_i bt)^{\frac{1}{b}}} \tag{2.3}$$

Cumulative production can be obtained by integrating q for the length of time the well is producing. Additionally, similar to the Arps (1945) decline curve analysis employed by Oruganti et al. (2015), a limiting secant decline rate of 8% is applied. The time period at which the well was deemed to be no longer economically producing was 2000 Mcf/month, because lease operating expenses may be greater than production revenues at this production rate.

In the PHDWin 2.9 dialogue box below, "De" represents the decline rate, a (Figure 7). "Qi" represents initial peak production. "Qf" represents the production at which the well is shut in. "Dm" represents the limiting secant decline rate that is applied. "b fact" represents the numerical reserve factor, b. When this value is not 0 or 1 then the decline is considered to be hyperbolic. The b value for most shale reservoirs is between 1.01 and 1.5 (Oruganti et al. 2015).

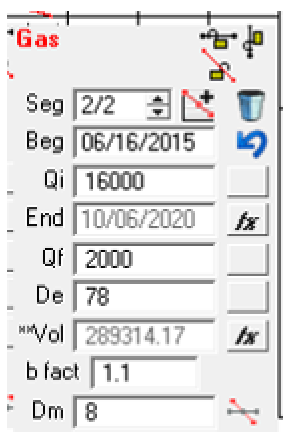

Figure 7: PHDWin Input Dialogue Box

The production history of information handling systems can be downloaded into PHDWin 2.9, and a decline curve estimate can be generated by selecting numerous production history values. The values for b and a can then be manipulated to generate a best fit decline curve for the production history. Once the b, a, and q_i values are ascertained in the Arps (1945) equation, the program can generate an estimated ultimate recovery for the well's production cycle.

For the purposes of this study, two decline curve scenarios were generated for each well. The first scenario was prepared as if the refracture never occurred and the well declined from its original peak production value. Figure 8 shows the base case estimated ultimate recovery calculation for a well without a refracture. This study refers to the estimated ultimate recovery without a refracture as EUR_{bc}.

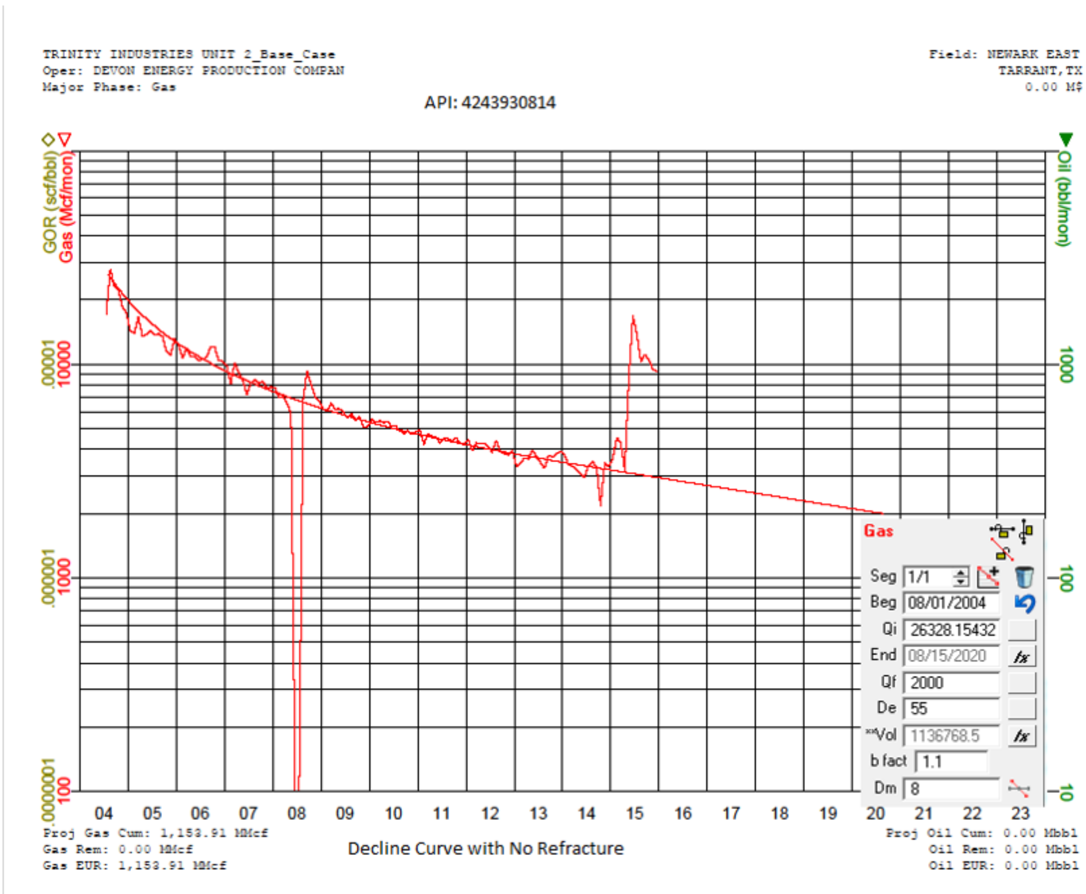

Figure 8: Scenario One: Decline Curve Generation Assuming No Refracture Occurs

A second scenario was then generated to account for the refracture. This case separates the decline curve into two segments. The first segment represents the time before the refracture, and the second segment represents the time after the refracture (Figure 9).

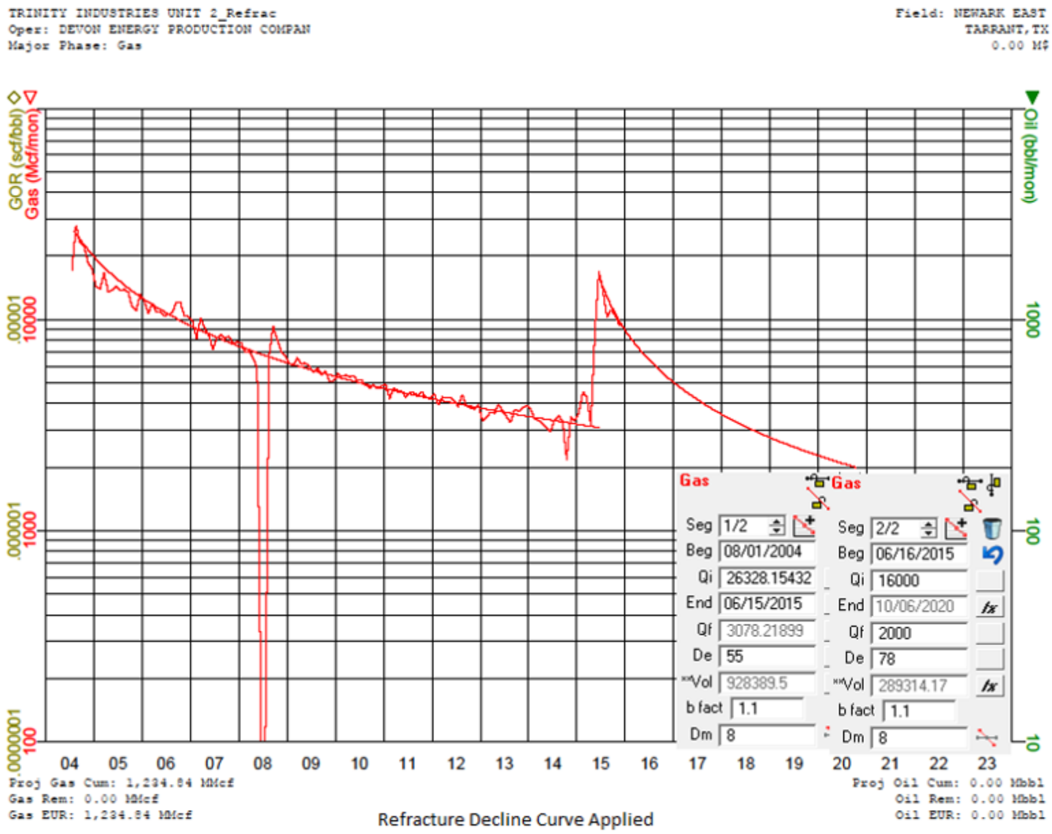

Figure 9: Scenario Two: Decline Curve Generation Including Refracture

This study refers to the estimated ultimate recovery generated from the refracturing scenario as EUR_{rf}. The difference between the estimated ultimate recoveries gives the estimated ultimate recovery increase resulting from a refracture treatment.

$$(\mathrm{EUR})_{\mathrm{rf}} - (\mathrm{EUR})_{\mathrm{bc}} = EUR_a \ or \ \Delta EUR \tag{2.4}$$

This study refers to EUR_a as the estimated ultimate recovery increase that occurs as a result of a refracture treatment. The goal in refracturing is to create a large EUR_a.

2.2.2 Internal Rate of Return Calculations

After the production profiles were built, internal rates of return

(IRRs) were calculated. The first step in developing an internal rate of return is to provide cost assumptions. All cost inputs were provided by Devon operators or similar industry completion engineers. Costs were assumed for each well in the following manner.

The cost for pumps, $Cost_{pumps}$, was calculated in the following manner.

$$RefracCost_{total=} 1.1(Cost_{pumps} + Cost_{water} + Cost_{chemicals} + Cost_{proppant}) \tag{2.5}$$

$$\frac{Costs}{Stage} * \left(\frac{Stage}{Hour}\right) * \ Pumping_{hours} = Cost_{pumps} \tag{2.6}$$

It is assumed that the average stage would take two hours and the average cost per stage, based on a 0.7 psi/ft fracture for the Barnett Shale, would be $7,500. Pumping hour is calculated on an assumed 70 bbl/min flow rate and the number of barrels of water used during the refracture.

$$Pumping_{hours} = \frac{Refrac\ bbl_{water}}{Flow\ rate} \tag{2.7}$$

The cost of water was assumed to be $0.60/bbl. This estimate was provided by a Devon engineer with experience in their Barnett refractures.

$$\frac{\$0.60}{bbl_{water}} * Refrac\ bbl_{water} = Cost_{water} \tag{2.8}$$

Based on the absence of guar in the FracFocus chemical listings and the lower sand-to-water ratios, Barnett Shale refractures were assumed to be slickwater completions. The chemical cost of a slickwater refracture treatment were estimated to be $1.10/bbl for a slickwater completion.

$$\$1.10 * Refrac\ bbl_{water} = Cost_{chemicals} \tag{2.9}$$

The cost estimate for sand was $105/ton of sand.

$$\frac{\$105}{2000} * Refrac\ lbs_{sand} = Cost_{sand} \tag{2.10}$$

Finally, a 10% cost overage estimate was applied in order to account for miscellaneous expenses. Once cost estimates were calculated, an internal rate of return could be generated for various price scenarios. An internal rate of return is calculated by solving for r using the following equation.

$$NPV = 0 = \frac{Revenue_{Refrac}}{(1+r)^{time\ producing}} - RefracCost_{total} \tag{2.11}$$

Additionally, a discount rate of 10% was assigned to future cash flows, $3,000 was assigned for lease operating expenses, a 75% royalty stake was assumed, and all ad valorem and severance state taxes were assumed. With these cost assumptions, an internal rate of return can be generated for various price scenarios. Internal rate of return is a tool used to compare capital expenditure projects within a company and can be employed when ranking refracture opportunities within a company's portfolio.

Two internal rate of return tables are listed. The first table for internal ignores the opportunity cost (OC) of foregoing existing production the operator would receive without the refracture. The second table includes the opportunity cost of this foregone production, and includes that revenue in the refracture total costs.

2.2.3 Ordinary Least Squares Regression Analysis

The data generated and compiled for this study was organized into a database for ordinary least squares regression analysis. In this study, ordinary least squares analysis can then generate a statistical model to predict internal rate of return, refracture initial production, and refracture decline rates. Additionally, this study aims to test the hypothesis that well location within better quality reservoirs is positively correlated with refracture success.

The first model specified for regression is listed below:

$$Ln\left(IRR_{\frac{\$2.50}{Mcf}}\right) = \beta_0 + \beta_1 \mathrm{Q}_{\mathrm{i,bc}} + \beta_2 \mathrm{a}_{\mathrm{i,bc}} + \beta_3 \mathrm{t}_{\mathrm{bc-rf}} + \lambda V_i + \lambda D_i + u_{\mathrm{i}} \tag{2.12}$$

The dependent variable, the internal rate of return ($IRR_{\frac{\$2.50}{Mcf}}$), is represented logarithmically, allowing internal rate of return changes, which are dependent on the size of the refracture treatment, and expressed as a percentage. When the dependent variable is expressed as a percentage, logging it allows for easier comparison across different types of wells. The independent variables were selected for analysis because they indicate reservoir quality, and any operator can ascertain them from completion permits and production history decline curve analysis.

$Q_{i,bc}$ represents the peak initial production of the original well. The second variable, $a_{i,bc}$, represents the decline rate of the original decline curve. $T_{bc\text{-}rf}$ represents the length of time between the original completion and the time of refracture. V_i and D_i are dummy variables assigned to account for different types of wells. V_i represents vertical wells and D_i represents directional wells. The β_0 term represents the intercept. The β_i term, one for each of the independent variables, represents a value signifying the strength of the relationship between the independent variable and the dependent variable. The error term is represented by u_i.

The second model specified for regression is listed below:

$$Q_{i,refrac} = \beta_0 + \beta_1 \mathrm{Q_{i,bc}} + \beta_2 \mathrm{t_{bc-rf}} + \beta_3 \mathrm{S_{refrac,lbs}} + \lambda H_i + u_{\mathrm{i}} \qquad (2.14)$$

The dependent variable is the initial peak production of the refracture, $Q_{i,refrac}$. Developing a correlational model for refracture initial production would allow for improved estimations of ultimate recovery changes as a result of refracturing the well. $Q_{i,bc}$ again represents the peak initial production of the original well. $T_{bc\text{-}rf}$ again represents the length of time between the original completion and the time of refracture. $S_{refrac,lbs}$ represents the amount of sand proppant used during the refracture treatment. H_i represents a dummy variable depicting a horizontal well. Again, the β_0 term represents the intercept and the β_i term represents the independent variables. The error term is represented by u_i.

The third model is a derivation of the second model and is specified below. The difference between the second and the third models is the addition of dummy variables representing the various types of diverters used during the refracture treatments. Not all the wells used diverters, but the diverters listed in the FracFocus filing were compiled and assigned dummy variables.

$$Q_{i,refrac} = \beta_0 + \beta_1 \mathrm{Q_{i,bc}} + \beta_2 \mathrm{t_{bc-rf}} + \beta_3 \mathrm{S_{refrac,lbs}} + \lambda_i H_i + \lambda_{1,i} D_{1,i} + \lambda_{2,i} D_{2,i} + \lambda_{3,i} D_{3,i} + \lambda_{4,i} D_{4,i} + u_{\mathrm{i}} \qquad (2.15)$$

The dependent variable is once again the initial peak production of the refracture, $Q_{i,refrac}$. The purpose of the addition of diverter dummy variables is to examine whether the use of diverters had a statistically significant effect on the refracture's initial production. $Q_{i,bc}$ again represents the peak initial production of the original well. $T_{bc\text{-}rf}$ again represents the length of time between the original completion and the time of refracture. $S_{refrac,lbs}$ again represents the amount of sand proppant used during the refracture treatment. H_i again represents a dummy variable depicting a horizontal well. $D_{1,i}$, $D_{2,i}, D_{3,i}$ and $D_{4,i}$ are dummy variables depicting the four types of diverters used. Again, the β_0 term represents the intercept and the β_i term represents the independent variables. The error term is represented by u_i.

The fourth model specified for regression is listed below:

$$\ln(a_{i,refrac}) = \beta_0 + \beta_1 \mathrm{Q_{i,bc}} + \beta_2 \mathrm{t_{bc-rf}} + \beta_3 \mathrm{S_{refrac,lbs}} + \beta_4 a_{i,bc} + \lambda H_i + u_\mathrm{i} \tag{2.14}$$

The dependent variable is decline rate, $a_{i,rf}$, expressed logarithmically due to the fractional change per unit time (percentage). Developing a correlational model for refracture decline rates also allows for improved estimated ultimate recovery change predictions. $Q_{i,bc}$ again represents the peak initial production of the original well. $T_{bc\text{-}rf}$ again represents the length of time between the original completion and the time of refracture. $S_{refrac,lbs}$ represents the amount of sand proppant used during the refracture treatment. The addition of $a_{i,bc}$ represents the initial decline rate. H_i represents a dummy variable depicting a horizontal well. Again, the β_0 term represents the intercept and the β_i term represents the independent variables. The error term is represented by u_i.

The fifth model is a derivation of the fourth model. The difference between the fourth model and the fifth model is the addition of dummy variables representing the various types of diverters used during the refracture treatments. Not all the wells used diverters, but the diverters listed in the FracFocus filing were compiled and assigned dummy variables.

$$\ln(a_{i,refrac}) = \beta_0 + \beta_1 \mathrm{Q}_{\mathrm{i,bc}} + \beta_2 \mathrm{t}_{\mathrm{bc-rf}} + \beta_3 \mathrm{S}_{\mathrm{refrac,lbs}} + \beta_4 a_{i,bc} + \lambda_i H_i + \lambda_{1,i} D_{1,i} + \lambda_{2,i} D_{2,i} + \lambda_{3,i} D_{3,i} + \lambda_{4,i} D_{4,i} + u_{\mathrm{i}} \quad (2.15)$$

The dependent variable is decline rate, $a_{i,rf}$, expressed logarithmically due to the fractional change per unit time (percentage). Understanding the correlational effects of including diverters would improve completion design considerations. $Q_{i,bc}$ again represents the peak initial production of the original well. $T_{bc\text{-}rf}$ again represents the length of time between the original completion and the time of refracture. $S_{refrac,lbs}$ again represents the amount of sand proppant used during the refracture treatment. The addition of $a_{i,bc}$ represents the initial decline rate. H_i represents a dummy variable depicting a horizontal well. $D_{1,i}$, $D_{2,i}, D_{3,i}, and\ D_{4,i}$ are dummy variables depicting the four types of diverters used. Again, the β_0 term represents the intercept and the β_i term represents the independent variables. The error term is represented by u_i.

STo validate an ordinary least squares regression model, three issues need to be examined. First, the R^2 adjusted term needs to be substantial. R^2 is a representation of how closely the observed data matches the modeled line.

$$R^2 = \frac{Predicted\ Variation}{Total\ Variation} \quad (2.12)$$

A higher R^2 indicates that the model better fits the data. In addition to R^2, a high R^2 adjusted is desirable. The R^2 adjusted value suggests that a few terms of statistical significance are driving the equation rather than a large amount of inconsequential independent variables being relied on to randomly generate a statistical correlation. The second issue is that the regression needs to be free of collinearity, meaning two independent variables cannot be highly correlated. When two independent variables are redundant, the model over accounts for their effects. Collinearity can be checked by doing a variance inflation factor calculation (VIF).

$$VIF_v = \frac{1}{1 - R_k^2} \tag{2.13}$$

R_k^2 is the value obtained by regressing that independent variable against the remaining independent variables in the model. VIFs below 5 are generally considered acceptable.

The third issue is to ensure that the residuals behave randomly and do not show a pattern. If a pattern emerges for the residuals, its existence would imply that the model was biased for a range of values. This pattern can be seen through a residual versus predicted plot. The plot's scatter should appear random.

3 RESULTS AND DISCUSSION

Overall the results from Devon's recent Barnett Shale refractures were mixed. Of the 20 wells examined, five horizontal wells (of the 11 total horizontal wells) experienced a net loss in estimated ultimate recovery. At $1.50/Mcf, eight wells were estimated to generate a negative internal rate of return. The refractured initial production of these wells averaged 63% of original initial production. Half of the wells improved their decline rates after refracture. All decline analysis curves for all wells studied are presented in the appendix.

3.1 Estimated Ultimate Recovery Calculations

Table 2 below displays the change in estimated ultimate recovery in the wells studied. The last three columns show the estimated ultimate recovery calculated—the estimated ultimate recovery before refracturing (EUR_{bf}), the estimated ultimate recovery after refracturing (EUR_{rf}), and the difference between before refracturing and after, EUR_a (the column on the far right). The table is ranked in descending order. The wells that experienced the largest increase in estimated ultimate recovery are listed first, and the five wells that declined in estimated ultimate recovery are listed at the bottom of Table 2. The wells averaged a 216.6 MMcf (million cubic feet) increase in estimated ultimate recovery.

Table 2: Estimated Ultimate Recovery (EUR) Change As a Result of Refracturing

#	API	Well_Name	Hole_Type	County	EUR_{bc} (MMCF)	EUR_{rf} (MMCF)	EUR_a (MMCF)
1	42-439-33015	J. Tom Shelton 13H	Horizontal	Tarrant	4,137	5,627	1,490
2	42-439-30369	Laprelle 3	Directional	Tarrant	1,334	1,881	547
3	42-439-31301	Jarvis Fossil Creek 1	Directional	Tarrant	1,215	1,562	347
4	42-439-30698	Devon Styrochem 1H	Directional	Tarrant	1,456	1,766	310
5	42-439-30408	Jarvis Fossil Creek 3	Directional	Tarrant	795	1,091	295
6	42-439-30745	J. Tom Shelton 4H	Horizontal	Tarrant	5,239	5,528	288
7	42-121-32567	Blakley GU E 11	Directional	Denton	706	963	256
8	42-439-31768	Lottie Barton Johnson 30H	Horizontal	Tarrant	2,219	2,462	243
9	42-497-36110	RM Alliston 5H	Horizontal	Wise	3,977	4,209	232
10	42-121-31151	James L. Wood G.U. 5	Vertical	Denton	594	820	227
11	42-439-31065	Margaret Tadlock 2H	Horizontal	Wise	5,190	5,369	178
12	42-121-31883	TCU 17H	Horizontal	Denton	2,155	2,332	177
13	42-121-31430	James L Wood GU 8	Directional	Denton	647	807	160
14	42-439-31054	Margaret Tadlock 4H	Directional	Tarrant	1,031	1,171	139
15	42-439-30814	Trinity Industries 2	Directional	Tarrant	1,154	1,235	81
16	42-121-32236	Day-Adams 1H	Horizontal	Denton	4,595	4,579	-17
17	42-439-32095	J Tom Shelton 12H	Horizontal	Tarrant	4,734	4,659	-75
18	42-439-31940	Laprelle 14H	Horizontal	Tarrant	3,387	3,249	-139
19	42-439-31545	RM Alliston 5H	Horizontal	Tarrant	2,706	2,525	-181
20	42-439-31573	J. Tom Shelton 6H	Horizontal	Tarrant	4,051	3,824	-227

In addition to estimated ultimate recovery values, the decline rates, a, the numerical reservoir factor, b, and the initial production values, Q_i, generated during the mapping of the decline curves were recorded for each well and entered into this study's database.

Table 3 shows the results of the reservoir quality indicators from decline curve analysis. The decline rate, a, and the initial production, Q_i, are presented both before refracturing and after refracturing. The numerical factor, b, is shown in the far right column.

Table 3: Reservoir Quality Indicators

#	API	Well_Name	Hole_Type	County	a_{bc} (%Annual Decline)	$Q_{i,bc}$ (Mcf)	a_{rf} (%Annual Decline)	$Q_{i,rf}$ (Mcf)	$Q_{i,rf}$ % of $Q_{i,bc}$	b
1	42-439-33015	J. Tom Shelton 13H	Horizontal	Tarrant	42	56,769	20	32,000	56.4%	1.35
2	42-439-30369	Laprelle 3	Directional	Tarrant	92	43,208	87	32,000	74.1%	1.38
3	42-439-31301	Jarvis Fossil Creek 1	Directional	Tarrant	90	49,687	95	40,000	80.5%	1.2
4	42-439-30698	Devon Styrochem	Directional	Tarrant	68	26,717	84	20,000	74.9%	1.7
5	42-439-30408	Jarvis Fossil Creek 3	Directional	Tarrant	94	41,057	85	22,000	53.6%	1.1
6	42-439-30745	J. Tom Shelton 4H	Horizontal	Tarrant	42	122,880	46	40,000	32.6%	0.56
7	42-121-32567	Blakley GU E 11	Directional	Denton	95	20,480	90	13,500	65.9%	2
8	42-439-31768	Lottie Barton	Horizontal	Tarrant	81	23,302	88	33,000	141.6%	1.5
9	42-497-36110	RM Alliston 5H	Horizontal	Wise	86	77,671	68	31,000	39.9%	1.98
10	42-121-31151	James L. Wood G.U. 5	Vertical	Denton	95	35,000	80	18,000	51.4%	1.05
11	42-439-31065	Margaret Tadlock 2H	Horizontal	Wise	68	110,285	78	54,000	49.0%	1.3
12	42-121-31883	TCU 17H	Horizontal	Denton	75	56,785	55	15,000	26.4%	1.2
13	42-121-31430	James L Wood GU 8	Directional	Denton	88	33,033	85	14,500	43.9%	1.1
14	42-439-31054	Margaret Tadlock 4H	Directional	Tarrant	20	11,455	88	27,000	235.7%	1.1
15	42-439-30814	Trinity Industries 2	Directional	Tarrant	55	26,328	78	16,000	60.8%	1.1
16	42-121-32236	Day-Adams 1H	Horizontal	Denton	35	127,126	75	38,000	29.9%	0.25
17	42-439-32095	J Tom Shelton 12H	Horizontal	Tarrant	57	73,586	64	40,000	54.4%	1.6
18	42-439-31940	Laprelle 14H	Horizontal	Tarrant	68	73,075	62	26,000	35.6%	1.3
19	42-439-31545	RM Alliston 5H	Horizontal	Tarrant	62	64,585	82	32,500	50.3%	1.1
20	42-439-31573	J. Tom Shelton 6H	Horizontal	Tarrant	66	100,055	63	30,000	30.0%	1.1

3.2 Internal Rate of Return (IRR) Evaluations

Comparing the internal rates of return by type of well, at \$2.00/Mcf the directional wells showed the largest estimated internal rate of return at 346%, though this calculation is subject to error in cost assumption. At $2.00/Mcf, the vertical well's internal rate of return was 121%, and the average internal rate of return for the horizontal wells was 55%. Table 4 shows the sensitivity study of the internal rate of return at different gas prices, ranging from $1.50/Mcf to $3.00/Mcf in $0.50/Mcf increments.

Table 4: Internal Rate of Return (IRR) Calculations

#	API	Well_Name	Hole_Type	County	IRR at $1.50/Mcf	IRR at $2.00/Mcf	IRR at $2.50/Mcf	IRR at $3.00/Mcf
3	42-439-31301	Jarvis Fossil Creek 1	Directional	Tarrant	458%	1000%	1000%	1000%
14	42-439-31054	Margaret Tadlock 4H	Directional	Tarrant	260%	715%	1000%	1000%
2	42-439-30369	Laprelle 3	Directional	Tarrant	212%	447%	795%	1000%
4	42-439-30698	Devon Styrochem 1H	Directional	Tarrant	122%	314%	640%	1000%
1	42-439-33015	J. Tom Shelton 13H	Horizontal	Tarrant	109%	185%	282%	407%
17	42-439-32095	J Tom Shelton 12H	Horizontal	Tarrant	41%	77%	121%	175%
5	42-439-30408	Jarvis Fossil Creek 3	Directional	Tarrant	30%	70%	120%	181%
6	42-439-30745	J. Tom Shelton 4H	Horizontal	Tarrant	25%	134%	289%	521%
10	42-121-31151	James L. Wood G.U. 5	Vertical	Denton	22%	121%	258%	410%
15	42-439-30814	Trinity Industries 2	Directional	Tarrant	22%	153%	372%	780%
18	42-439-31940	Laprelle 14H	Horizontal	Tarrant	14%	43%	76%	115%
11	42-439-31065	Margaret Tadlock 2H	Horizontal	Wise	11%	32%	55%	83%
7	42-121-32567	Blakley GU E 11	Directional	Denton	0%	56%	124%	1000%
8	42-439-31768	Lottie Barton Johnson 30H	Horizontal	Tarrant	0%	19%	40%	65%
9	42-497-36110	RM Alliston 5H	Horizontal	Wise	0%	45%	73%	107%
12	42-121-31883	TCU 17H	Horizontal	Denton	0%	12%	37%	64%
13	42-121-31430	James L Wood GU 8	Directional	Denton	0%	13%	82%	168%
16	42-121-32236	Day-Adams 1H	Horizontal	Denton	0%	48%	129%	241%
19	42-439-31545	RM Alliston 5H	Horizontal	Tarrant	0%	0%	12%	28%
20	42-439-31573	J. Tom Shelton 6H	Horizontal	Tarrant	0%	17%	37%	60%

Additionally, for the purposes of these calculations, this study assumed all production revenue after the date of the refracture as refracture induced cash flows. In reality, true value add cash flows would be the difference between the refracture cash flows and the cash still being generated by an original production cycle. However, companies use internal rate of return to rank investment projects so it can still be applied to rank the candidates for refracture because this error is constant throughout.

Table 5 accounts for opportunity cost (OC) of the foregone production by including this revenue as a cost in the refracture total cost. As seen below the directional and vertical wells are still the preferred candidates.

Table 5: Internal Rate of Return (IRR) Calculations Including Foregone Revenue as a Cost

Well_Name	Hole_Type	County	IRR w/OC at $1.50/Mcf	IRR w/OC at $2.00/Mcf	IRR w/OC at $2.50/Mcf	IRR w/OC at $3.00/Mcf
Laprelle 3	Directional	Tarrant	454%	456%	947%	1000%
Jarvis Fossil Creek 3	Directional	Tarrant	30%	70%	120%	181%
James L. Wood G.U. 5	Vertical	Denton	22%	121%	258%	410%
Jarvis Fossil Creek 1	Directional	Tarrant	0%	0%	6%	5%
Margaret Tadlock 4H	Directional	Tarrant	0%	0%	0%	0%
Devon Styrochem 1H	Directional	Tarrant	0%	0%	0%	0%
J. Tom Shelton 13H	Horizontal	Tarrant	0%	0%	0%	0%
J Tom Shelton 12H	Horizontal	Tarrant	0%	0%	0%	0%
J. Tom Shelton 4H	Horizontal	Tarrant	0%	0%	0%	0%
Trinity Industries 2	Directional	Tarrant	0%	0%	0%	44%
Laprelle 14H	Horizontal	Tarrant	0%	0%	0%	0%
Margaret Tadlock 2H	Horizontal	Wise	0%	0%	0%	0%
Blakley GU E 11	Directional	Denton	0%	0%	0%	289%
Lottie Barton Johnson 30H	Horizontal	Tarrant	0%	0%	0%	0%
RM Alliston 5H	Horizontal	Wise	0%	0%	0%	0%
TCU 17H	Horizontal	Denton	0%	0%	0%	0%
James L Wood GU 8	Directional	Denton	0%	13%	82%	168%
Day-Adams 1H	Horizontal	Denton	0%	0%	0%	0%
RM Alliston 5H	Horizontal	Tarrant	0%	0%	0%	0%
J. Tom Shelton 6H	Horizontal	Tarrant	0%	0%	0%	0%

3.3 Ordinary Least Squares Regression Analysis

3.3.1 Ordinary Least Squares, Internal Rate of Return

In examining the results from the logged internal rate of return regression analysis, both the vertical and directional wells had a statistically significant positive relationship with internal rate of return. Table 5 below displays the regression results for equation 2.12 where internal rate of return is the dependent variable.

Table 6: OLS Regression for internal rate of return (IRR)

Response of Ln (internal rate of return (IRR) @ \$2.50 / Mcf) , Eq 2.12 *denotes statistical significance					
Summary of Fit					
RSquare	0.6557				
Rsquare_Adj	0.5327				
Root_Mean_Square_error	0.8940				
Mean_of_Response	4.9702				
Observation(or_Sum_Wgts)	20				
Parameter_Estimates					
Term	**Estimate**	**Std error**	**t Ratio**	**Prob>|t|**	**VIF**
Intercept	6.5256	1.3794	4.73	0.0003	.
Directional	2.8290	0.6852	4.13	0.0010*	3.1983
Vertical	3.4627	1.2418	2.79	0.0145*	2.0786
Decline rate, a, of Original Well	-0.0227	0.0097	-2.35	0.0340*	1.2252
Time between completions	-0.0166	0.0117	-1.41	0.1808	1.9217
IP of Q of Original Well	1.2241e-5	8.727e-6	1.40	0.1825	2.4714

These findings are likely a result of the shorter wells operating at lower costs due to needing less water, sand, chemicals, and pump time. A horizontal completion costs more due to its greater length. Additionally, the decline rate of the original well was strongly positively correlated with internal rate of return. This relationship lends support to the theory that positive reservoir quality makes for better refracture candidates, in agreement with some previous studies (Vincent 2011; Rousell and Sharma 2011; Sinha and Ramakrishnan 2011). Furthermore, the positive internal rate of return relationship supports the suggestion that Devon's refracturing program has found the most success with the shorter directional and vertical wells (Craig et al. 2012. According to the data collected in this study, the last four years have not improved the economics for horizontal refracture production.

A plot of actual versus predicted values for these wells is Figure 10. The red line sloping upwards represents the predicted values. The scatter of plots represents the actual plotted values. The dotted red curve lines surrounding the predicted line represent confidence curves at the 95% level. The dotted blue horizontal line represents the mean value. When these confidence curves cross the dotted blue horizontal line as opposed to being asymptotic or not intersecting it, the regression shows the effect of the independent variables to be significant.

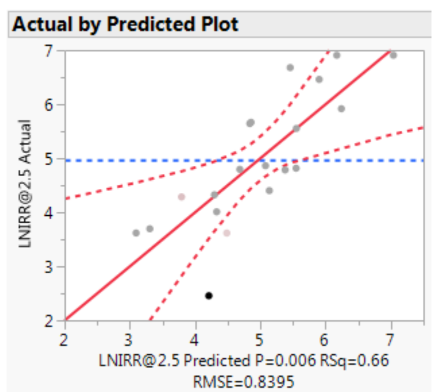

Figure 10: Actual Versus Predicted for internal rate of return (IRR)

This regression was deemed satisfactory as the R^2 was a robust 0.53, all variance inflation factor (VIF) values were below five, and the residual versus predicted plot showed a random scatter (Figure 11).

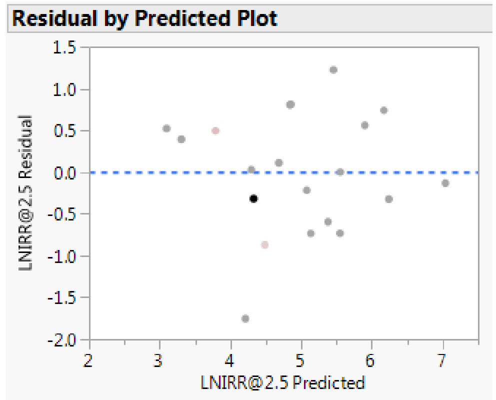

Figure 11: Residual Versus Predicted for internal rate of return (IRR)

3.3.2 Ordinary Least Squares, Initial Refracture Production

In this regression, all four independent variables exhibit statistical significance so the null hypothesis that they are unrelated to refracture initial production can be rejected. The results are below in Table 6. Additionally, Figure 12 shows the actual by predicted plot and the blue dotted line (the mean value) is crossed by confidence interval curves signifying the effects of the independent variables are significant.

Table 7: OLS Regression for Refrac Initial Production (IP)

Response of Refrac IP (Mcf), Eq 2.13 *denotes statistical significance					
Summary of Fit					
RSquare	0.6907				
Rsquare_Adj	0.6076				
Root_Mean_Square_error	6737.3				
Mean_of_Response	28725				
Observation(or_Sum_Wgts)	20				
Parameter_Estimates					
Term	**Estimate**	**Std error**	**t Ratio**	**Prob>|t|**	**VIF**
Intercept	40393.4	11568.8	3.49	0.0033	.
IP of Q of Original Well	0.20621	0.07155	2.88	0.0114*	2.5802
Time between completions	-198.189	88.3368	-2.24	0.0404*	1.6828
Refrac Sand, lbs	0.00488	0.00226	2.16	0.0474*	3.2728
Horizontal Well	-13228.2	6315.86	-2.09	0.0536*	4.3501

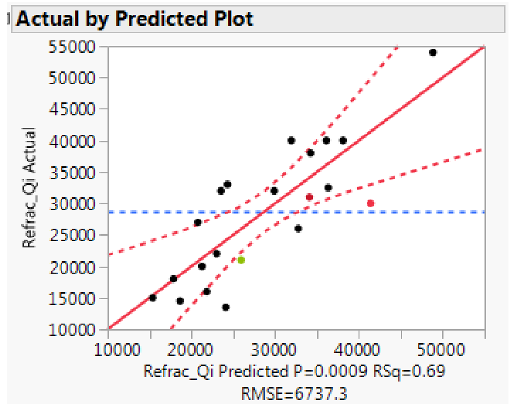

Figure 12: Actual Versus Predicted for Refrac Initial Production (IP)

As seen in Table 6, the independent variable, initial production of the original well, showed the strongest statistical correlation. Again, this finding supports some of the pre-existing data that better quality reservoirs make better refracture candidates. The time between completions is negatively correlated with refracture initial production. As the well is drained, if new fractures are not added and the refracture treatment only restores original conductivity, it would logically follow that the more drained reservoirs would produce a lower refracture initial production.

The amount of sand also is positively correlated with refracture initial production. This statistical relationship would suggest that the more proppant introduced into the formation, the more conductive pathways that are created. Finally, regarding the type of well, horizontal designation shares a negative correlational relationship with refracture initial production (Table 6). This negative relationship suggests that the "bullheaded" completion method of utilizing chemical diverters over long laterals is less effective.

The R^2 adjusted for this regression was a robust 0.61, all variance inflation factors were below five, and the residual versus predicted plot shown in Figure 13 depicts a random scatter between the residual and predicted values. Therefore, this regression is thought to be valid.

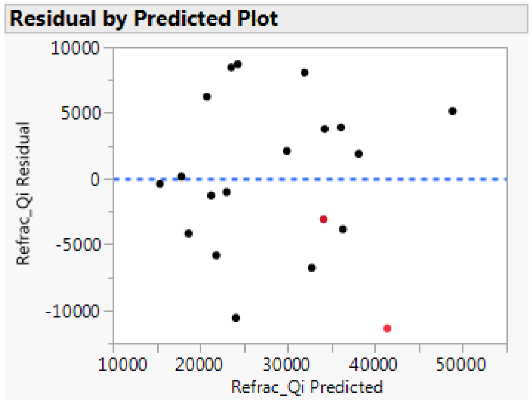

Figure 13: Residual Versus Predicted for Refrac Initial Production (IP)

3.3.3 Ordinary Least Squares, Initial Refracture Production with Diverters

In this regression, the initial production of the original well was again significantly positively correlated with refracture initial production, supporting some results indicating that reservoir quality is an indicator of high refracture potential. Time between completions also shared a significant negative correlation with refracture initial production, as depletion of the reservoir was lessens refracture initial production. The statistical relationship for the variable amount of sand was weaker with the addition of the diverters into the regression. Additionally, the effect of horizontal wells upon the regression were less significant but still strongly negatively correlated. None of the diverters showed a strong statistical relationship with refracture initial production. Any weak correlational relationship that existed also indicated that the use of diverters was negatively affecting the regression. The results are shown below in Table 7.

Table 8: OLS Regression for Refrac Initial Production (IP) with Diverters

Response of Refrac IP (Mcf), Eq 2.14 *denotes statistical significance					
Summary of Fit					
RSquare	0.7963				
Rsquare_Adj	0.6481				
Root_Mean_Square_error	6380.68				
Mean_of_Response	28725				
Observation(or_Sum_Wgts)	20				
Parameter_Estimates					
Term	**Estimate**	**Std error**	**t Ratio**	**Prob>|t|**	**VIF**
Intercept	44484.8	12581.8	3.54	0.0047	.
IP of Q of Original Well	0.24864	0.08116	2.96	0.0131*	3.9749
Time between completions	-228.374	96.6685	-2.36	0.0377*	2.2468
Refrac Sand, lbs	0.00455	0.00219	2.08	0.0617	3.4216
Horizontal Well	-13304.78	7345.87	-1.81	0.0975	6.5608
FDP_S1111_Bio_Ball_Diverters	-10905.44	6371.769	-1.71	0.1150	1.7949
BioBalls_MR_HR_Diverters	-1581.018	3789.179	-0.42	0.6860	2.3281
BioVert_NWB_Diverters	-3013.002	7256.595	-0.42	0.6845	1.74566
BioVert_CF_Diverters	-993.275	7108.44	-0.14	0.8914	2.23401

Figure 14 displays the actual by predicted plot for refracture initial production. Again, the independent variables within this regression are deemed significant because the confidence curves (the dotted red lines) pass through the mean value (dotted blue line).

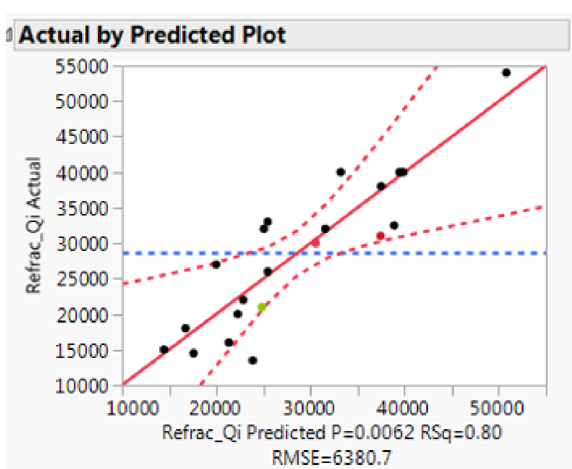

Figure 14: Actual by Predicted Plot for Refrac IP with Diverters

The R^2 adjusted is a robust 0.65. The variance inflation factor (VIF) indicates there is some collinearity with a 6.6 value; however, this can be allowed because the horizontal wells used the chemical diverters more frequently. The residual versus predicted plot, shows a random scatter (Figure 15), thus, this regression is thought to be valid.

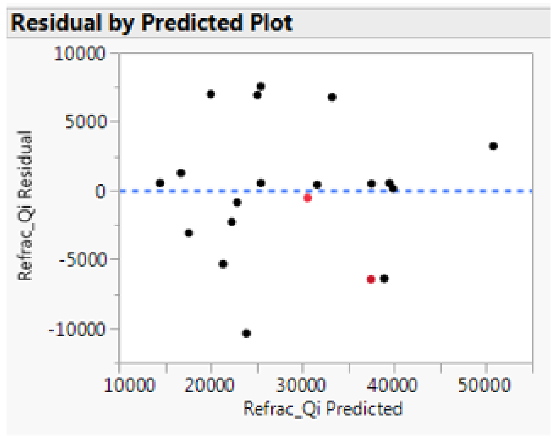

Figure 15: Residual Versus Predicted Plot for Refrac Initial Production (IP) with Diverters

3.3.4 Ordinary Least Squares, Refracture Decline Rate

In this regression, no independent variables exhibit statistical significance so the null hypothesis that they are unrelated to refracture initial production is accepted. The results are below in Table 8.

These findings suggest no relationship between any of these independent variables and the decline rate. The strongest relationship exists for horizontal wells and decline rate; however, ordinary least squares regression should be discarded when modeling this particular relationship

Table 9: OLS Regression for Refrac Decline Rate (IP)

Response of Ln Decline Rate, Eq 2.15 *denotes statistical significance					
Summary of Fit					
RSquare	0.2623				
Rsquare_Adj	-0.0011				
Root_Mean_Square_error	0.3850				
Mean_of_Response	4.2805				
Observation(or_Sum_Wgts)	20				
Parameter_Estimates					
Term	**Estimate**	**Std error**	**t Ratio**	**Prob>|t|**	**VIF**
Intercept	4.0288	0.70253	5.73	<.0001	.
Horizontal Well	-0.5913	0.36575	-1.62	0.1282	4.46
Refrac Sand, lbs	1.610e-7	1.323e-7	1.22	0.2438	3.43
Base Case Decline Rate	0.0015	0.00447	0.35	0.7284	1.24
Time Between Completions	0.0013	0.00513	0.26	0.7959	1.74
IP of Q of Original Well	9.151e-7	4.191e-6	0.22	0.8303	2.70

The R^2 adjusted of 0 renders the model invalid. Variance in completion methodologies, which is not public domain data, likely accounts for some of the variance that cannot be explained by this model. The confidence curves (dotted red lines) do not cross the mean line (dotted blue line) so the regression is considered insignificant (Figure 16).

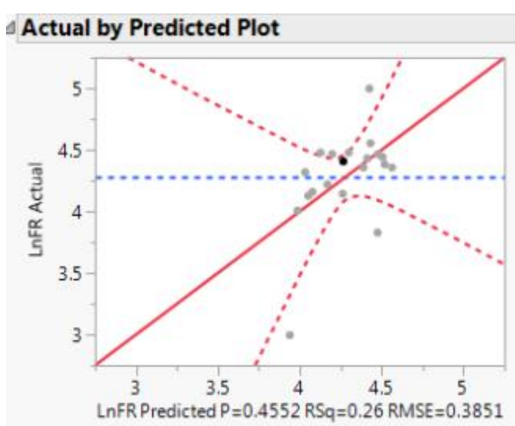

Figure 16: Actual Versus Predicted Plot for Decline Rate

3.3.5 Ordinary Least Squares, Refracture Decline Rate with Diverters

In this regression with chemical diverters included, again no independent variables suggested a significant statistical relationship with decline rate. The regression results are displayed below in Table 9. Again, because of the low R^2 adjusted the confidence curves shown in Figure 17 do not cross the dotted blue mean line, thus indicating the regression is insignificant.

Table 10: OLS Regression for Refrac Decline Rate with Diverters

Response of Ln Decline Rate with Diverters Eq 2.16 *denotes statistical significance					
Summary of Fit					
RSquare	0.3402				
Rsquare_Adj	-0.2534				
Root_Mean_Square_error	0.4308				
Mean_of_Response	4.28058				
Observation(or_Sum_Wgts)	20				
Parameter_Estimates					
Term	**Estimate**	**Std error**	**t Ratio**	**Prob>|t|**	**VIF**
Intercept	4.1974	0.91184	4.60	0.0010	.
Horizontal Well	-0.673002	0.525739	-1.28	0.2294	6.5608
BioBalls_MR_HR_Diverters	-0.25672	0.269087	-0.95	0.3625	1.9304
Refrac Sand, lbs	1.4612e-7	1.533e-7	0.95	0.3631	3.677
FDP_S1111_Bio_Ball_Diverters	-0.138839	0.431141	-0.32	0.7541	1.802
FDP_S1111_Bio_Ball_Diverters	-10905.44	6371.769	-1.71	0.1150	1.7949
Time between completions	0.002008	0.006609	-0.30	0.7675	2.3028
IP of Q of Original Well	1.5027e-6	5.681e-6	0.26	0.7968	3.9749
Original Decline Rate	0.000696	0.00549	0.13	0.9018	1.5044
BioVert_CF_Diverters	0.033985	0.49742	0.07	0.9469	2.3988
BioVert_NWB_Diverters	-0.01546	0.52255	-0.03	0.9770	2.6473

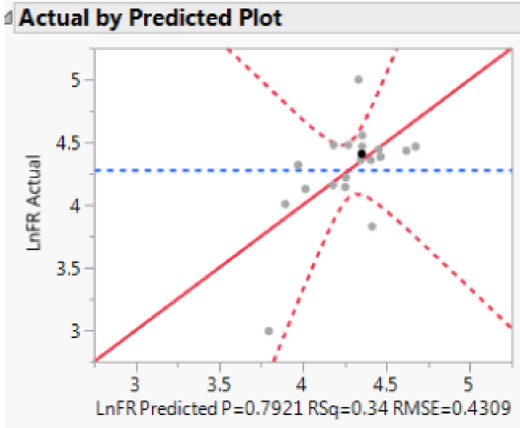

Figure 17: Actual Versus Predicted Plot for Decline Rate with Diverters

These findings would indicate that production data and basic completion information such as amount of sand are insufficient to predict the type of decline rate. Again, the extremely low value for R^2 adjusted renders this model invalid. Ordinary least regression cannot be used to predict decline rate in Barnett refractures.

4 CONCLUSIONS AND RECOMMENDATIONS

4.1 Conclusions

This study compiled and analyzed one company's refracturing program in the Barnett Shale. The conclusions are as follows:

1. The shorter directional wells and the vertical wells produce better internal rates of return than the longer horizontal wells.
2. Seventy-five percent the refractures improved estimated ultimate recovery when compared to the original decline curve's estimated ultimate recovery. Twenty-five percent showed no or equivocal improvement. Future research with a wider well sampling and access to additional parameters continue the focus on lessening failures and improving the success cases.
3. Based on internal rate of return calculations and estimated ultimate recovery changes, the directional and vertical wells within the portfolio are the preferred candidates.
4. The initial production of the original well and decline rate of the original well were significantly positively correlated with refracture initial production rates. This supports the existing literature, which suggests that the best refractures come from the best quality reservoirs.
5. Length of the production cycle and horizontal type well were significantly negatively correlated with refracture initial production. This indicates that reservoir drainage affects refracture initial production values. Additionally, it

indicates that pressures effective for fracture propagation in the shorter laterals may not be sufficient in longer laterals—even with the aid of chemical diverters.

6. Chemical diverters did not show a significant relationship in regard to affecting refracture initial production. This lack of a relationship could be an indication that chemical diverters are not successful in isolating perforations for various stages.
7. Ordinary Least Squares Regression utilizing publically available production data and basic completion information cannot be used to predict changes in the refracture decline rate.

4.2 Recommendations

The scope of this study can be further expanded in several directions. The following are recommendations:

1. The conclusions of this work are based on a limited data set. Further data collection involving refractured wells should be pursued within the Barnett and other reservoirs.
2. Much of the completion methodology was assumed. To more fully examine the problem, regressions should be run incorporating further completion data. Controlling for variances in completion methods and technology could more effectively isolate causation and illuminate correlational relationships with production.

3. Further details regarding the use of diverters needs to be pursued. The amount, frequency, and employment methods should be reviewed and studied before conclusions can be reached. This study was limited in that it could only assign a dummy variable to establish a correlational relationship for the effectiveness of diverters.

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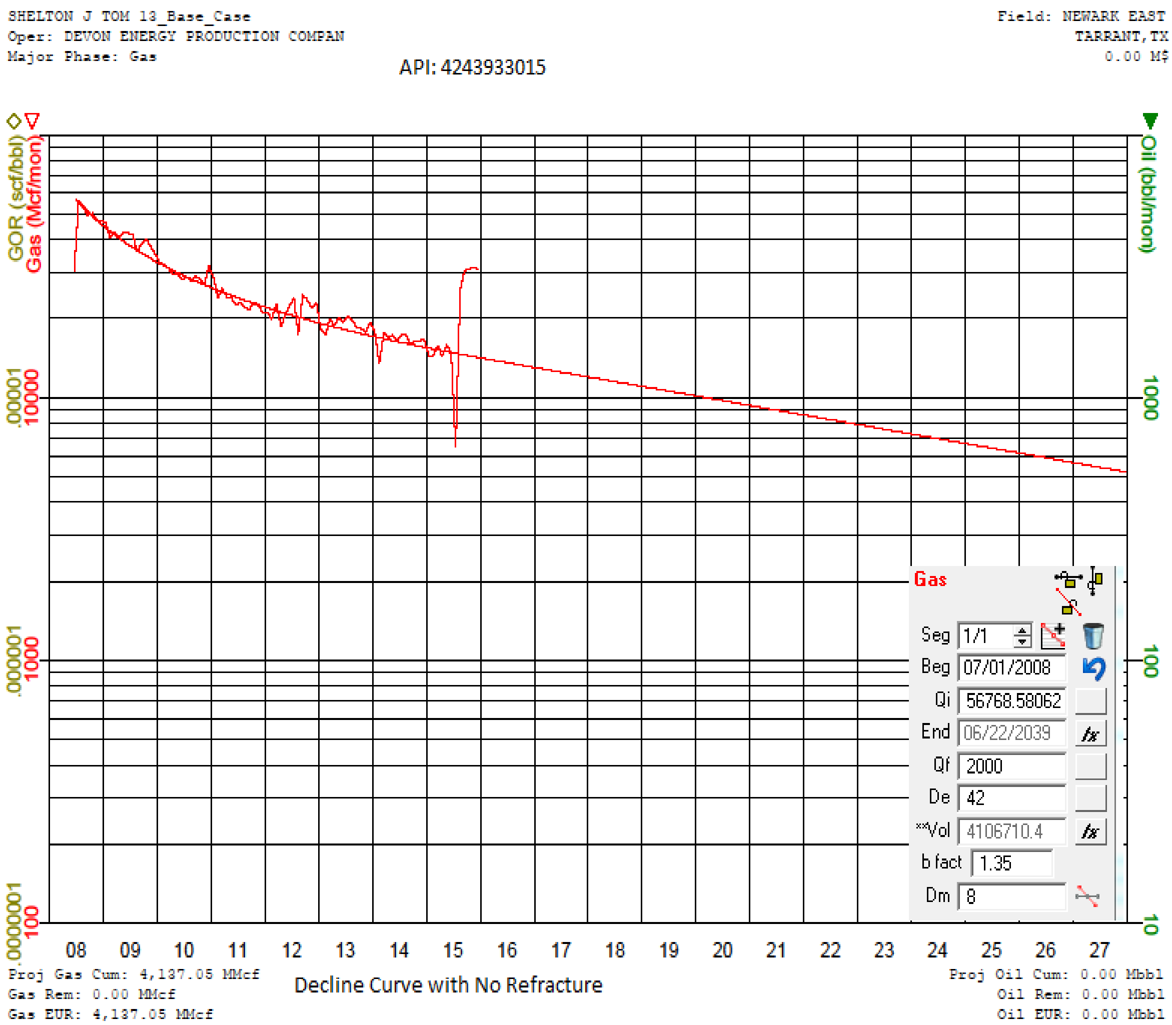
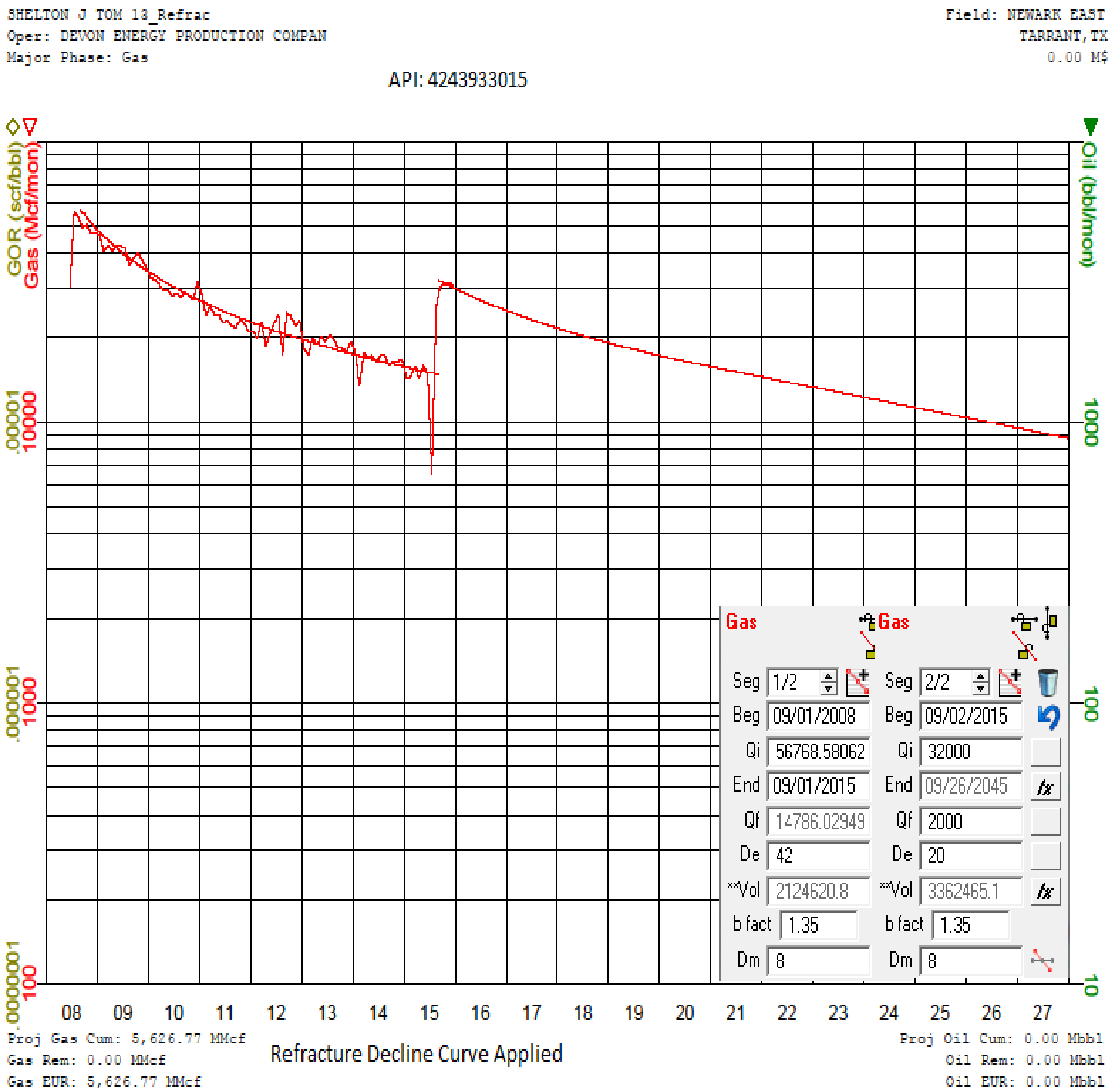
APPENDIX

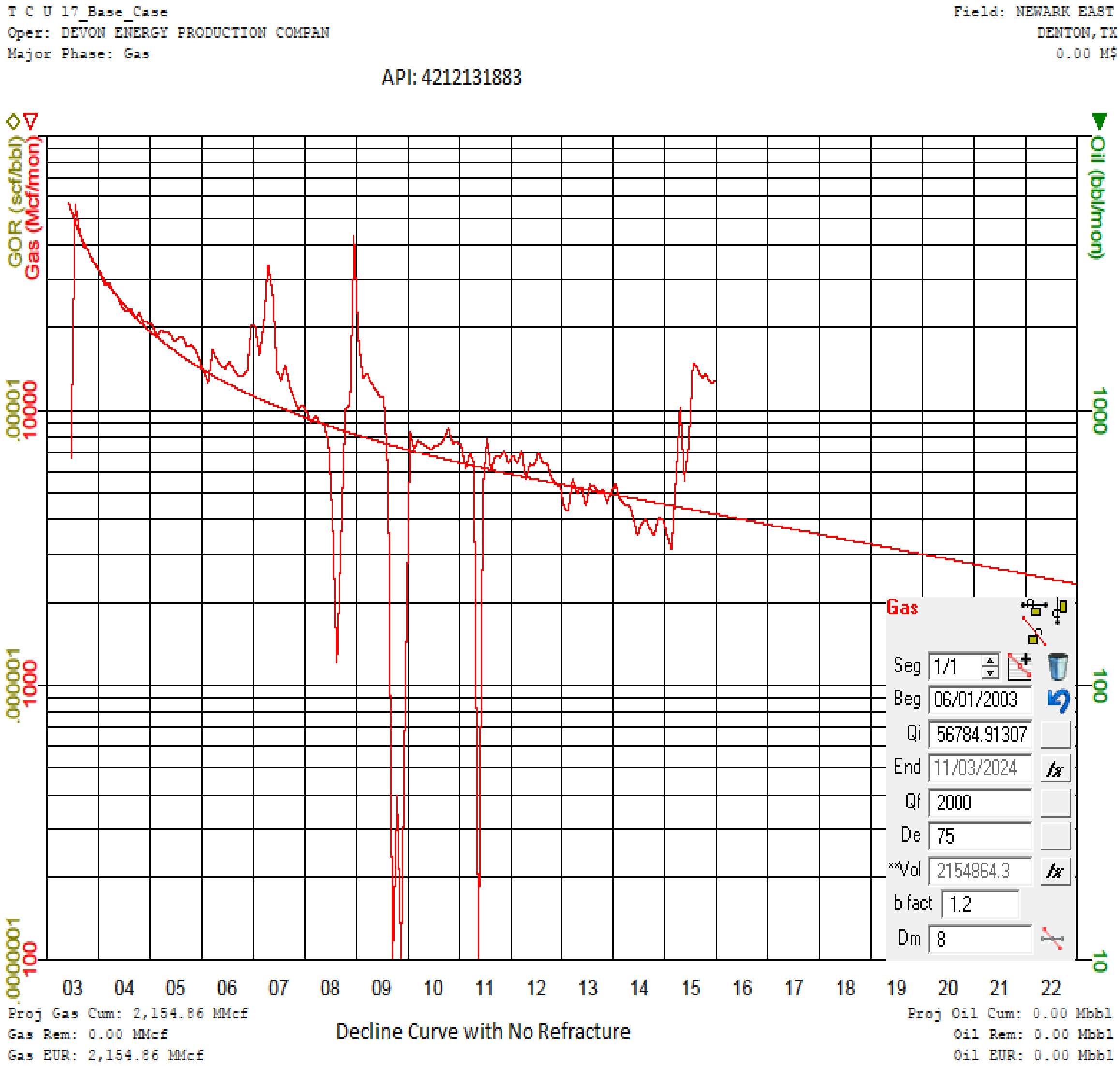
Constructed estimated ultimate recovery (EUR) Decline Curves



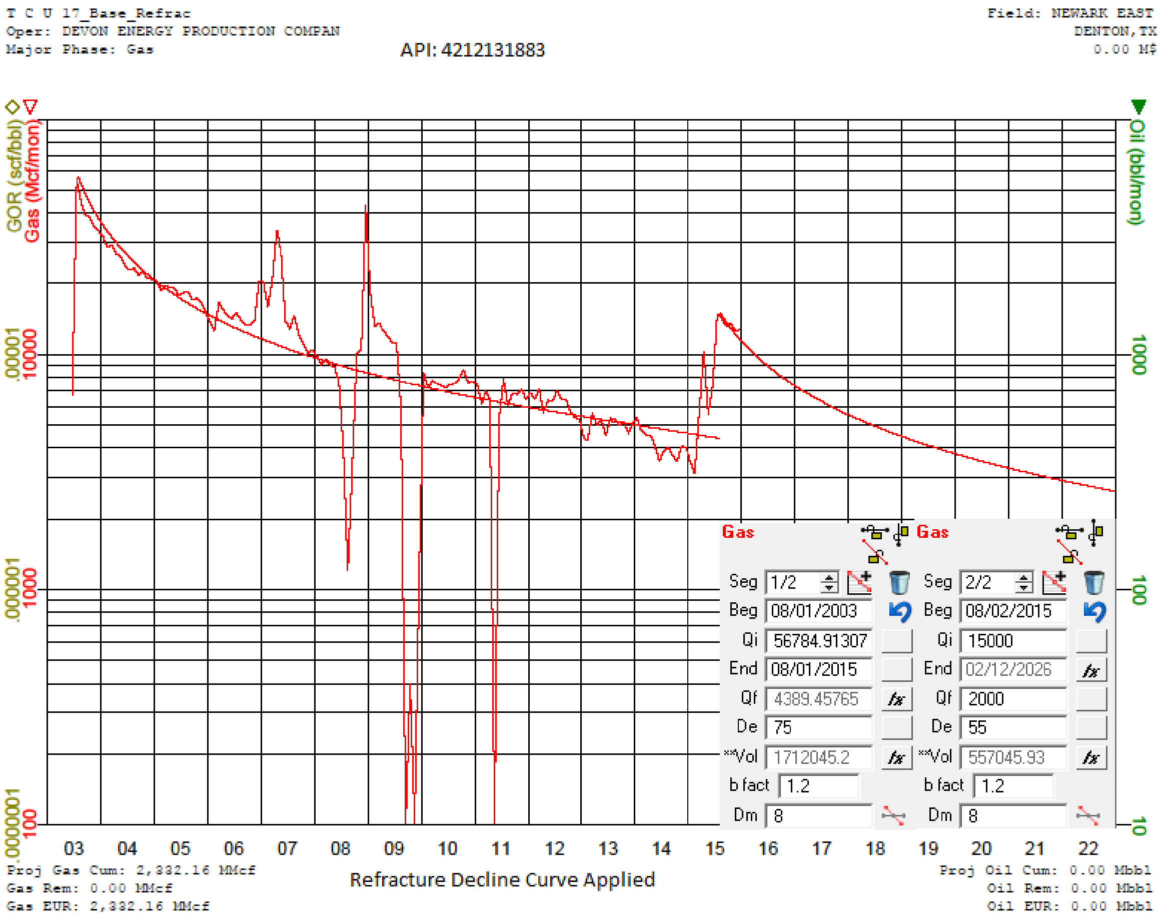


Refracture Decline Curve Applied

API: 4212131883



Decline Curve with No Refracture

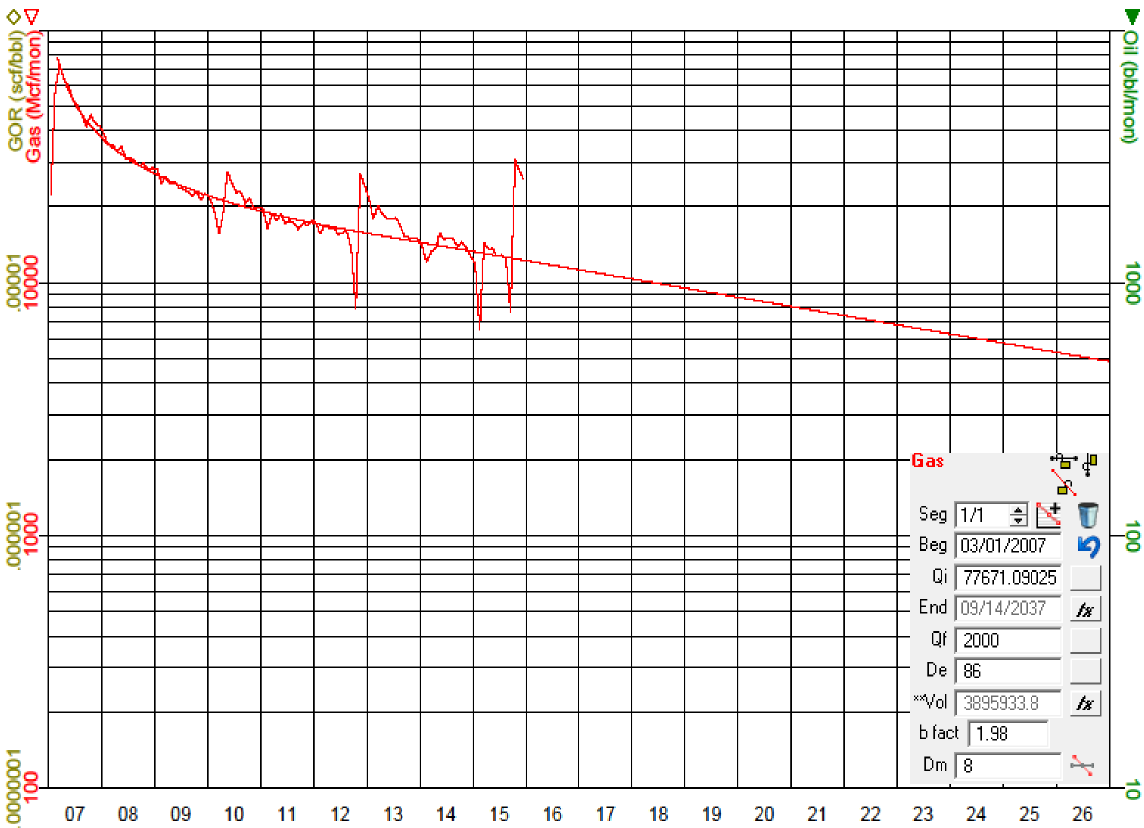


Refracture Decline Curve Applied

MCALISTER O H 20_Base_Case
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

API: 4249736110

Field: NEWARK EAST
WISE,TX
0.00 M$



Proj Gas Cum: 3,976.51 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 3,976.51 MMcf

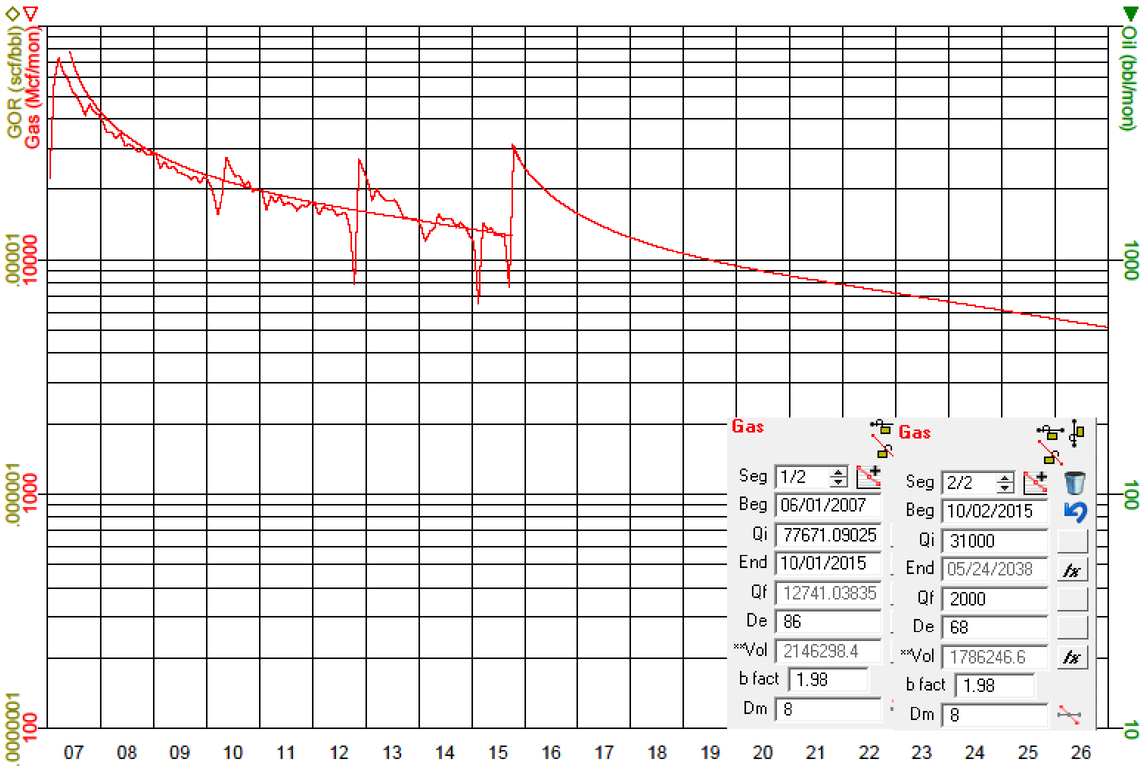
Decline Curve with No Refracture

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

MCALISTER O H 20_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

Field: NEWARK EAST
WISE,TX
0.00 M$

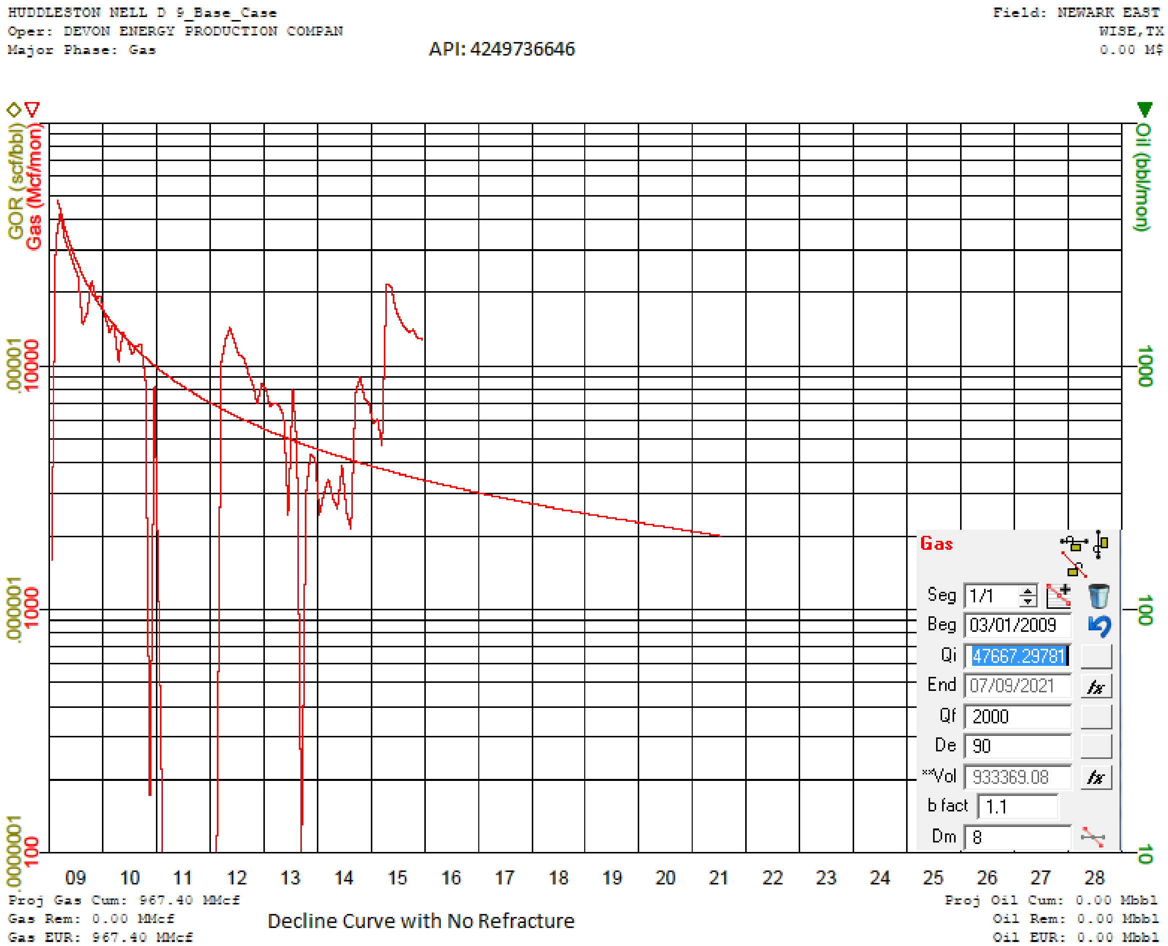
API: 4249736110



Proj Gas Cum: 4,208.85 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 4,208.85 MMcf

Refracture Decline Curve Applied

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

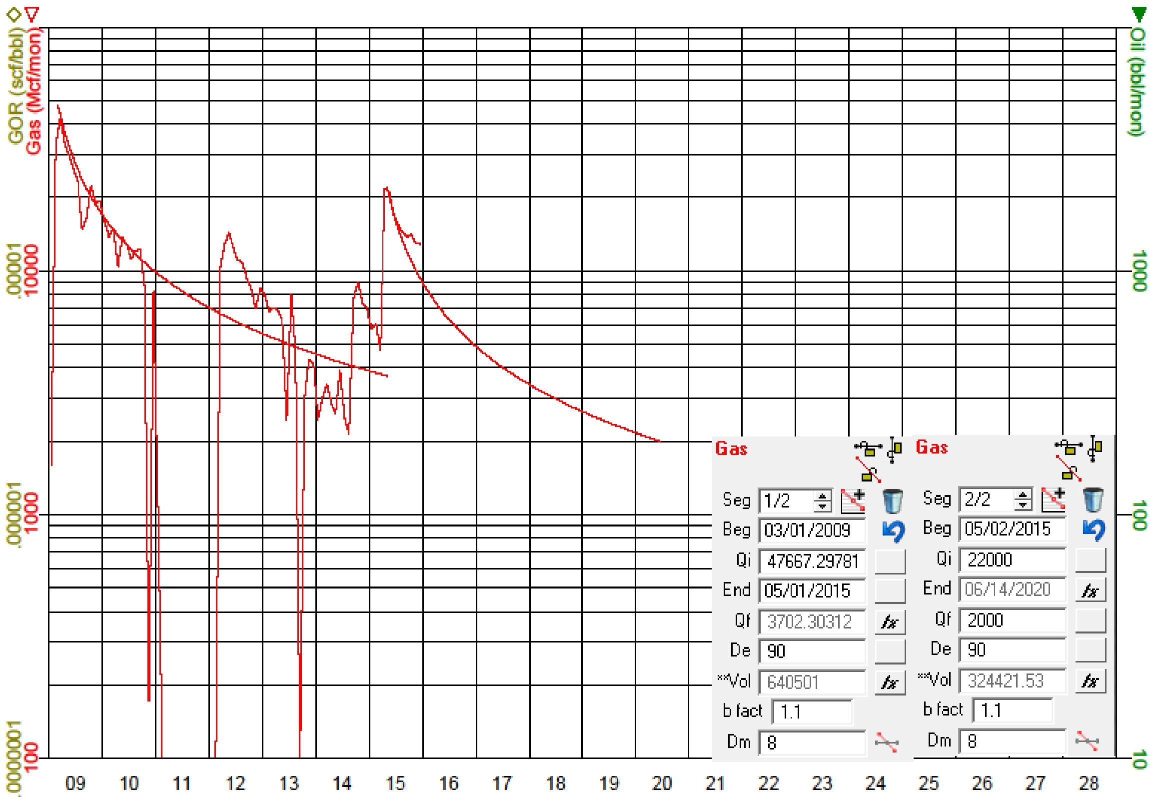


Decline Curve with No Refracture

HUDDLESTON NELL D 9_Refrac_ODC
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

API: 4249736646

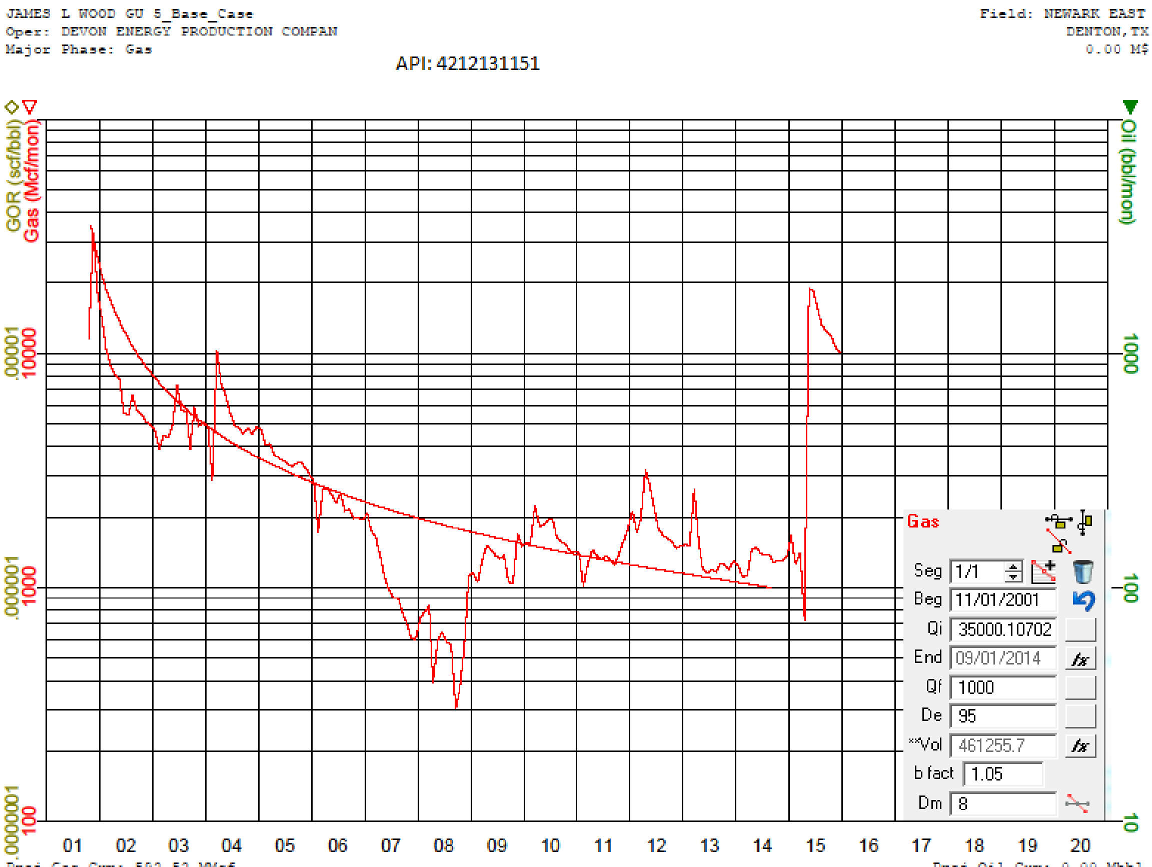
Field: NEWARK EAST
WISE,TX
0.00 M$



Proj Gas Cum: 998.95 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 998.95 MMcf

Refracture with Original Decline Curve Applied to the Refracture

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

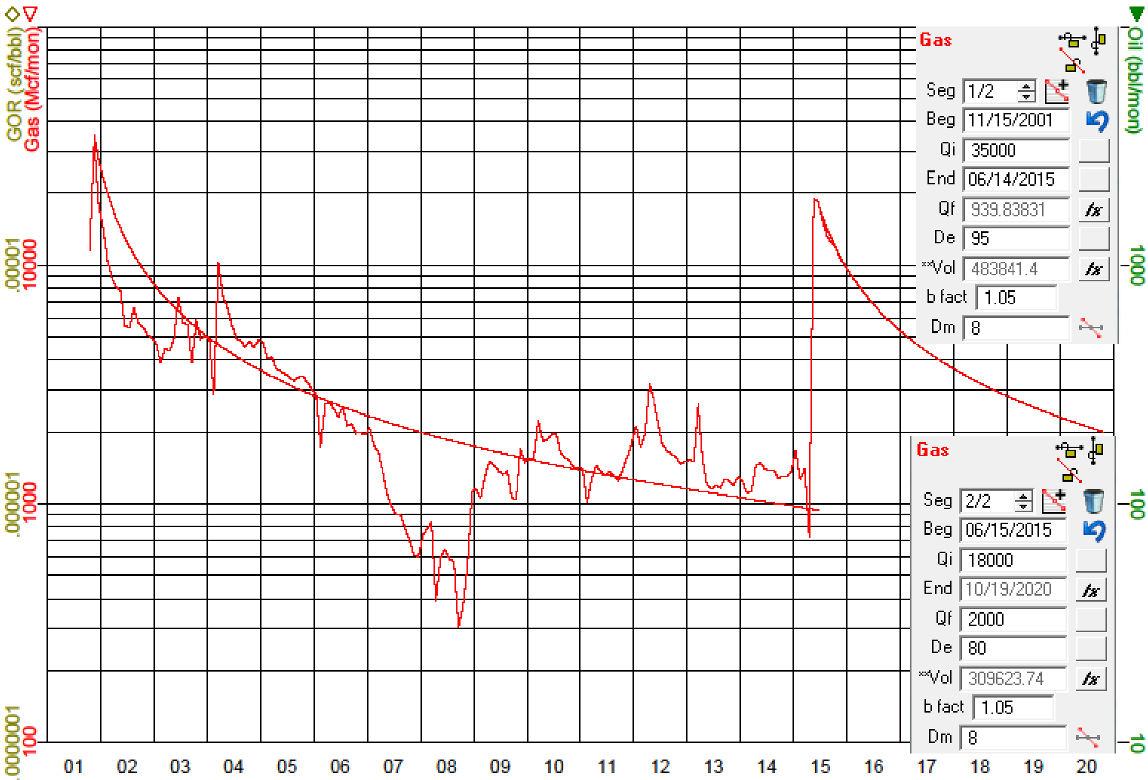


Decline Curve with No Refracture

Copy of JAMES L WOOD GU 5_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

API: 4212131151

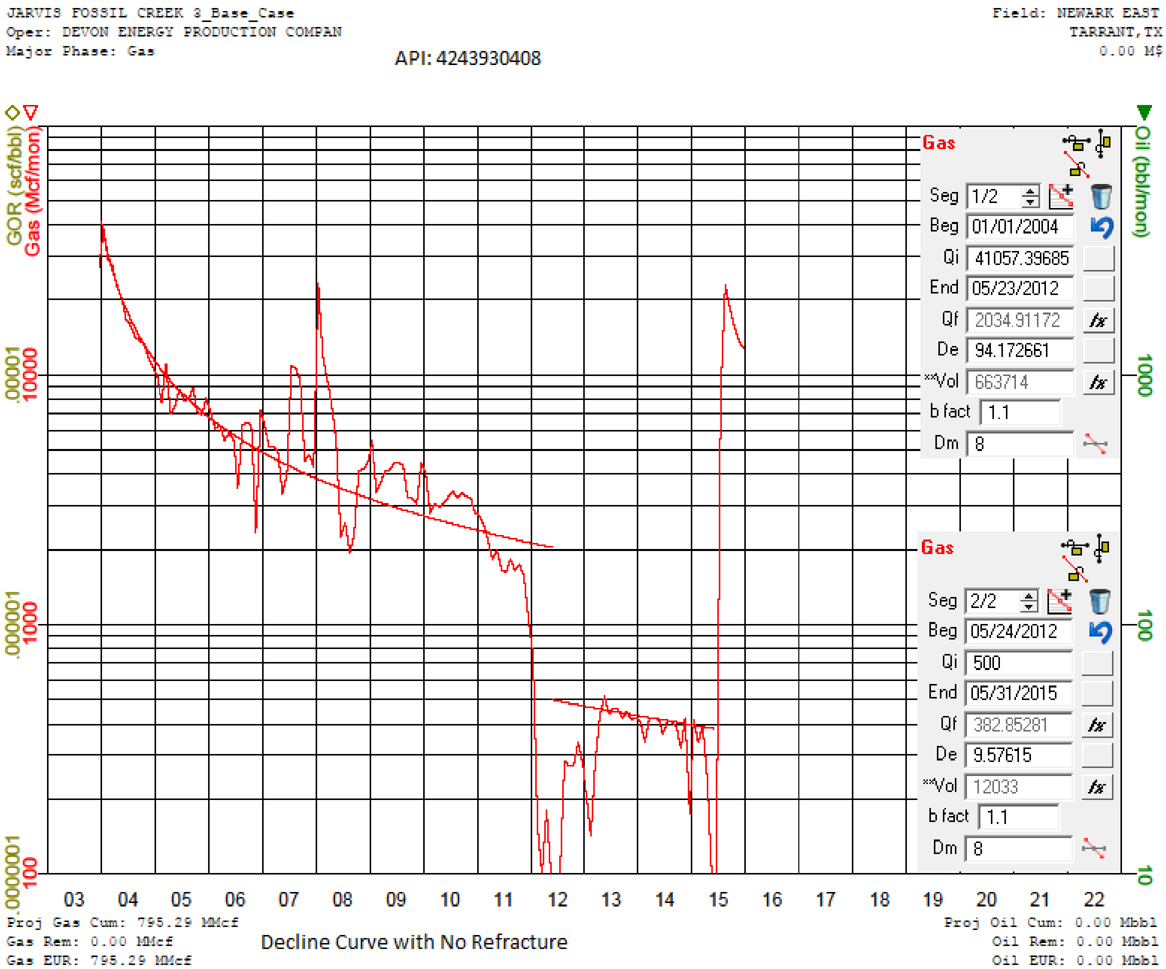
Field: NEWARK EAST
DENTON, TX
0.00 M$



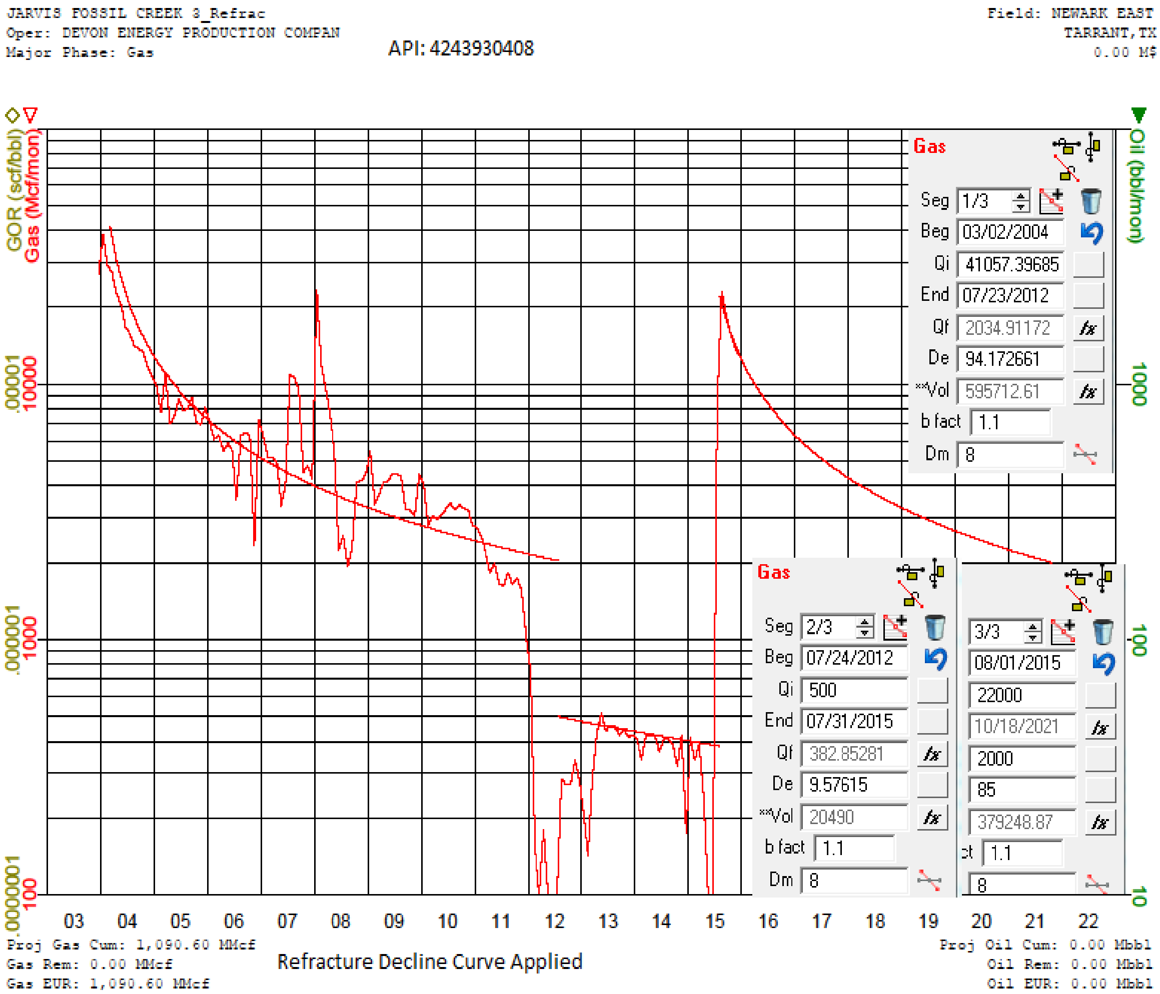
Proj Gas Cum: 820.17 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 820.17 MMcf

Refracture Decline Curve Applied

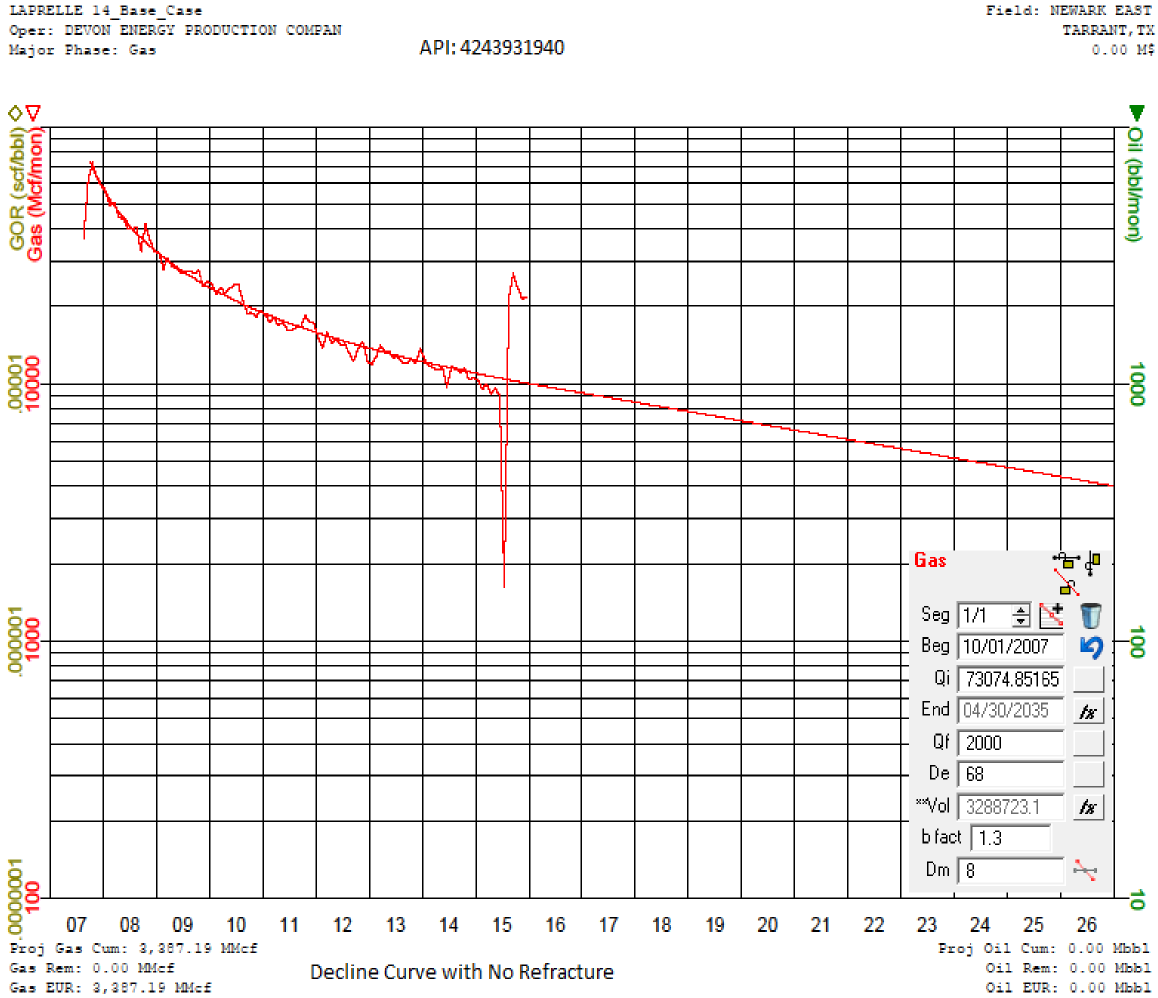
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl



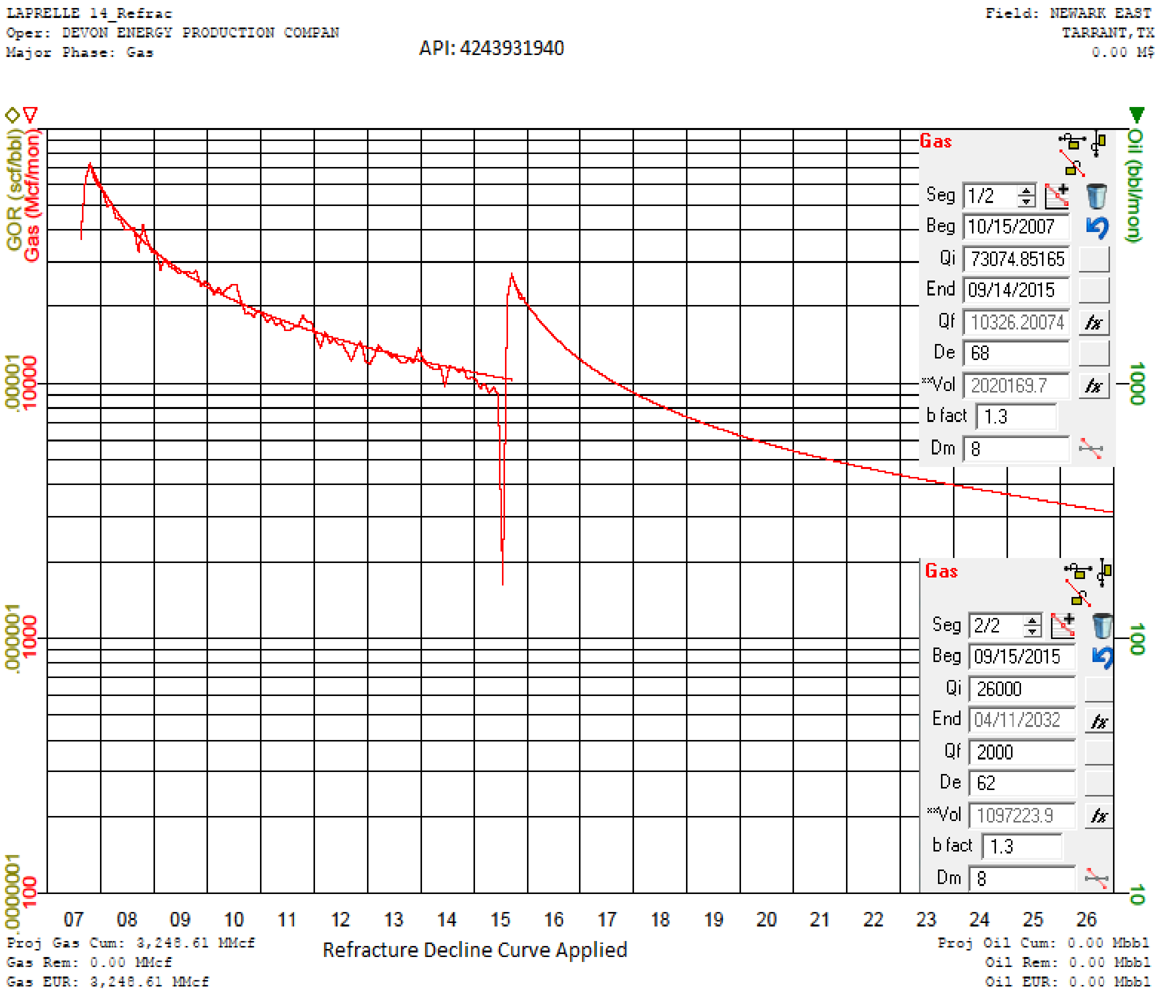
Decline Curve with No Refracture

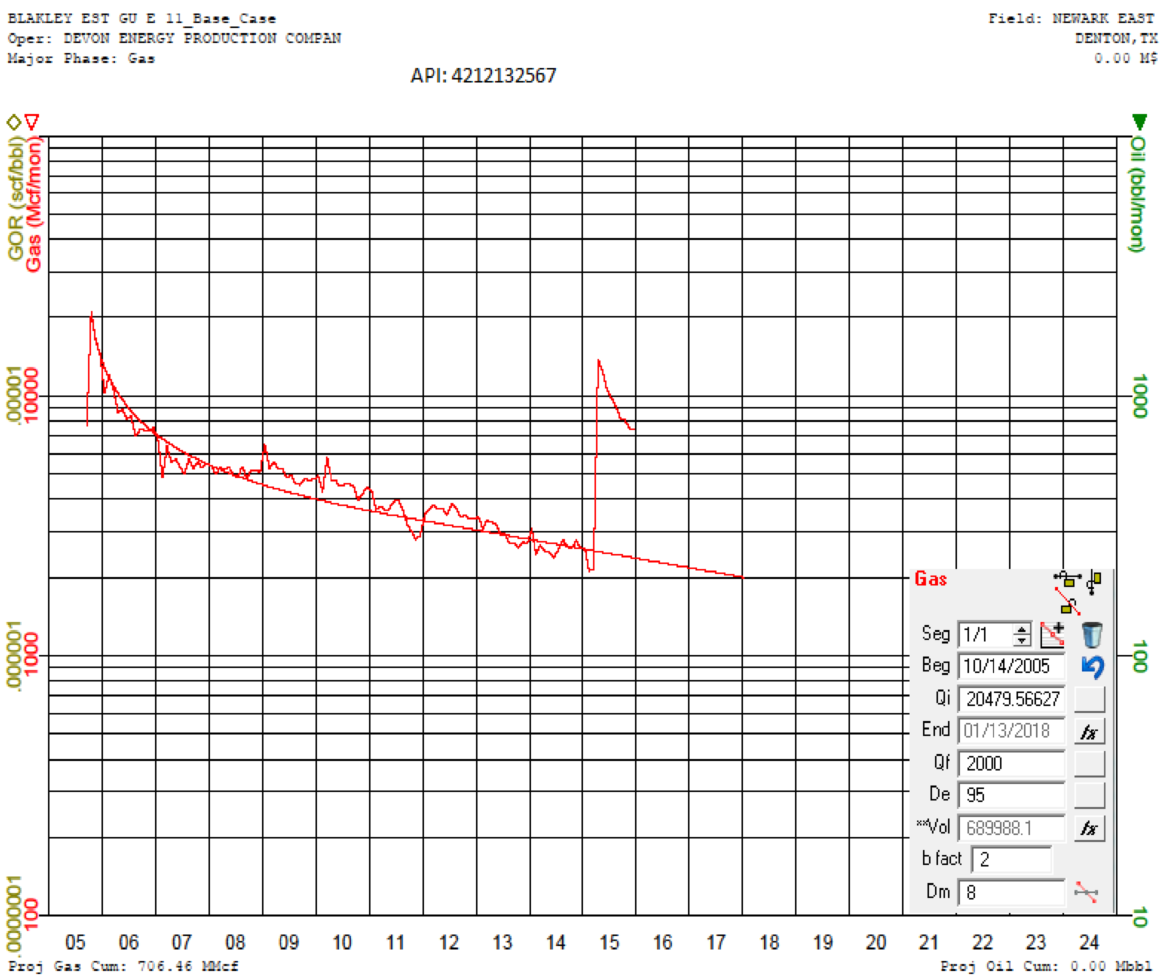


Refracture Decline Curve Applied



Decline Curve with No Refracture


LAPRELLE 14_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243931940
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 10/15/2007
Qi 73074.85165
End 09/14/2015
Qf 10326.20074
De 68
**Vol 2020169.7
b fact 1.3
Dm 8
Gas
Seg 2/2
Beg 09/15/2015
Qi 26000
End 04/11/2032
Qf 2000
De 62
**Vol 1097223.9
b fact 1.3
Dm 8
.00001 10000
.000001 1000
.0000001 100
1000
100
10
07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26
Proj Gas Cum: 3,248.61 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 3,248.61 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

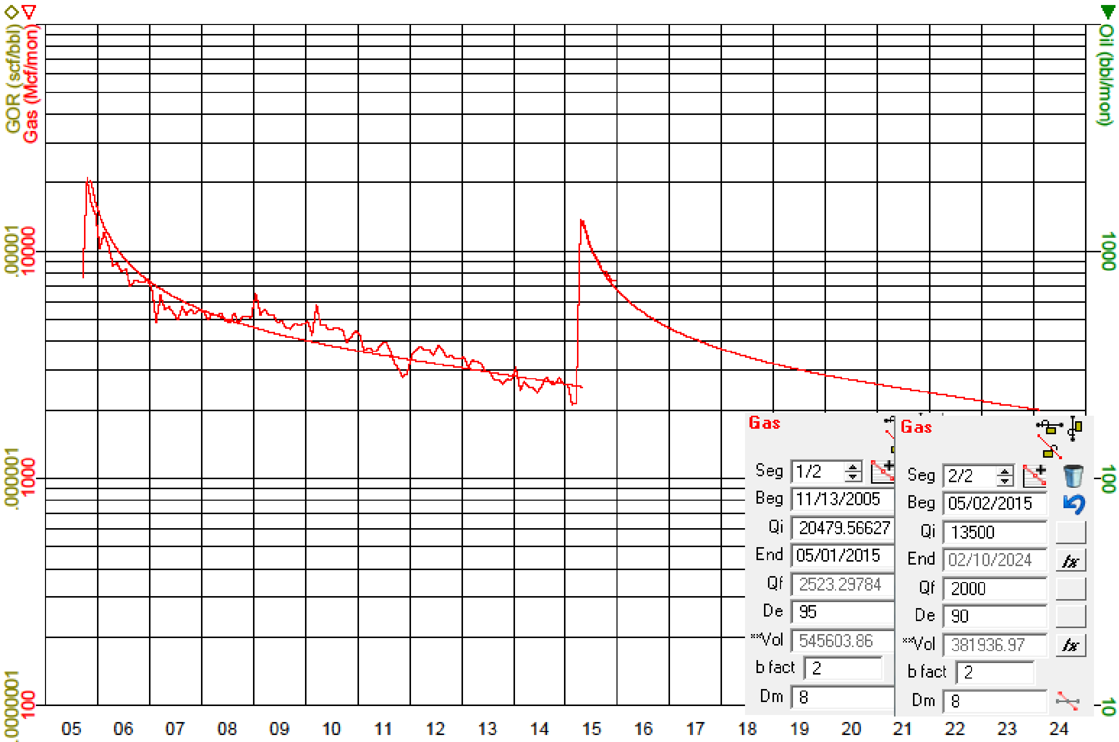


Decline Curve with No Refracture

BLAKLEY EST GU E 11_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

Field: NEWARK EAST
DENTON, TX
0.00 M$

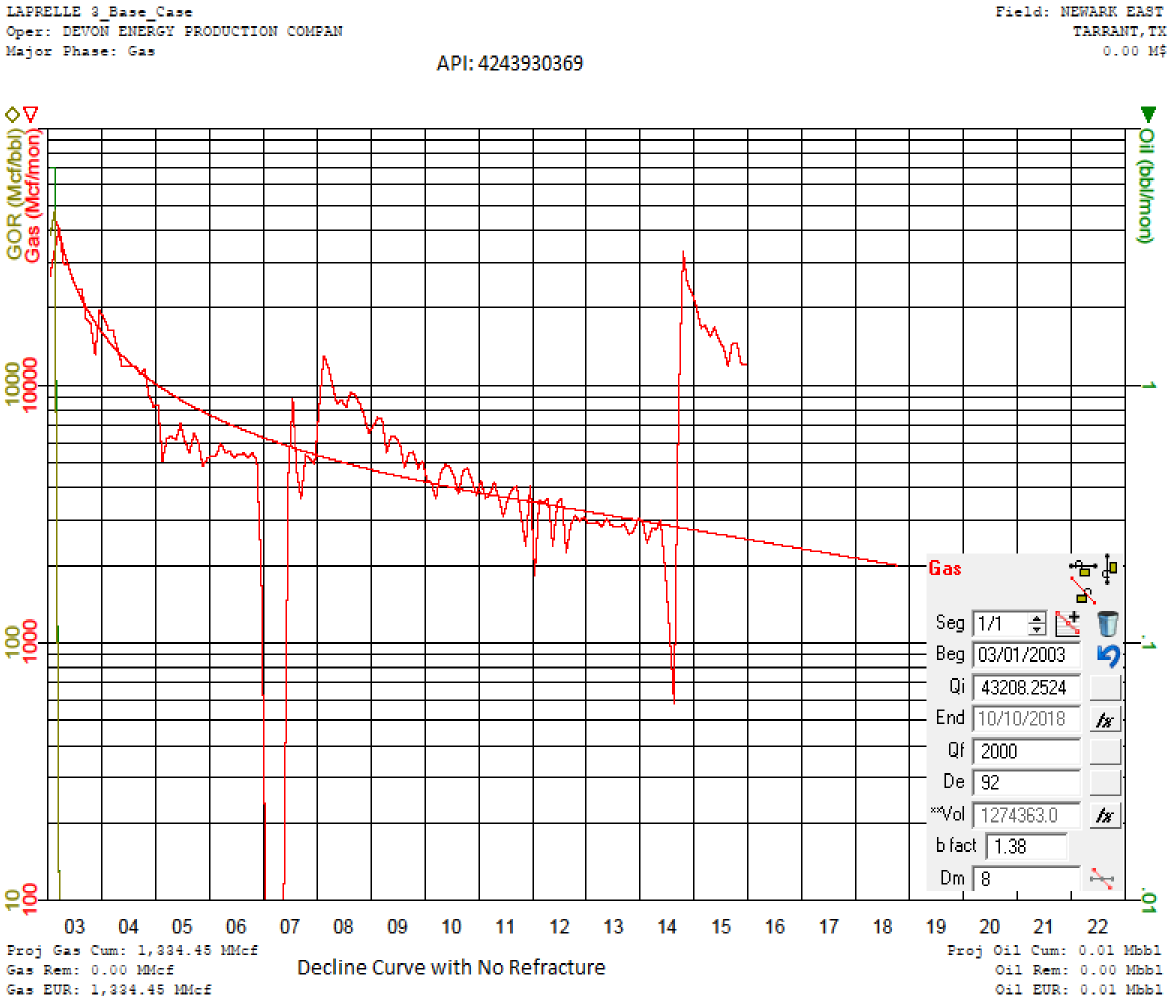
API: 4212132567



Proj Gas Cum: 962.72 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 962.72 MMcf

Refracture Decline Curve Applied

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

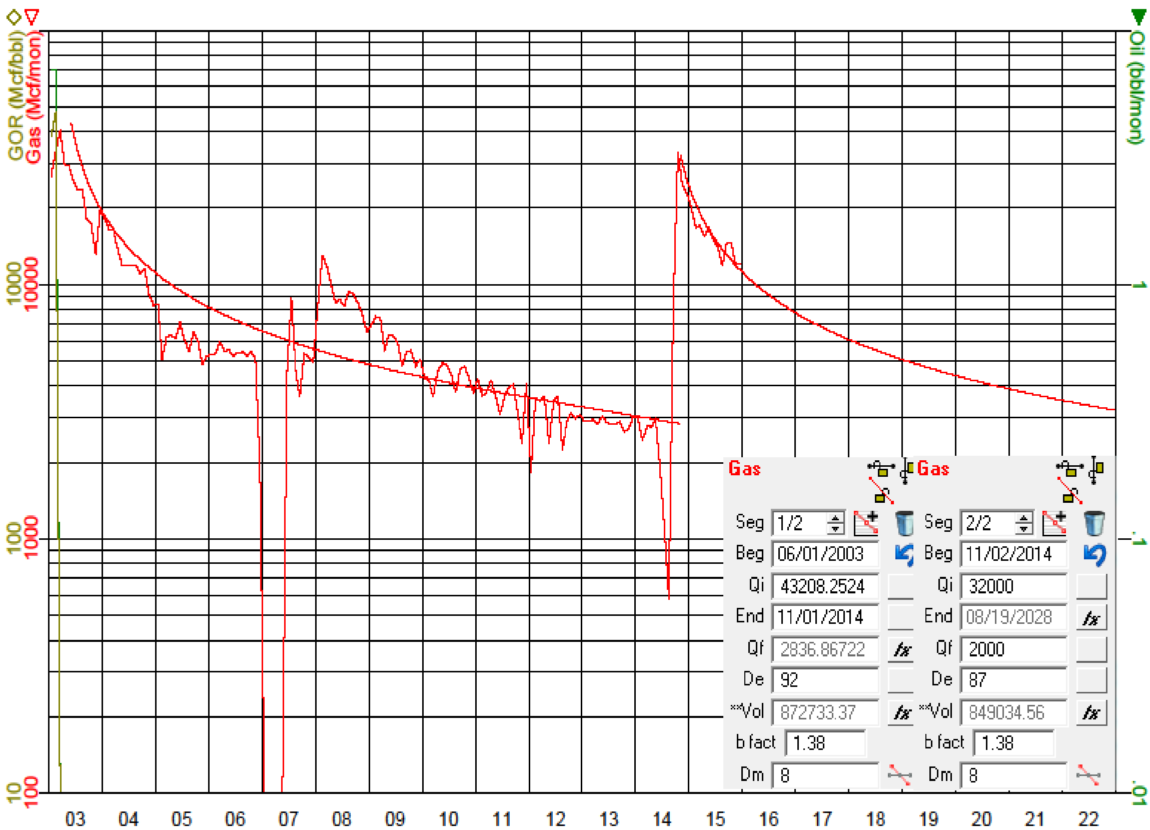


Decline Curve with No Refracture

LAPRELLE 3_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

Field: NEWARK EAST
TARRANT, TX
0.00 M$

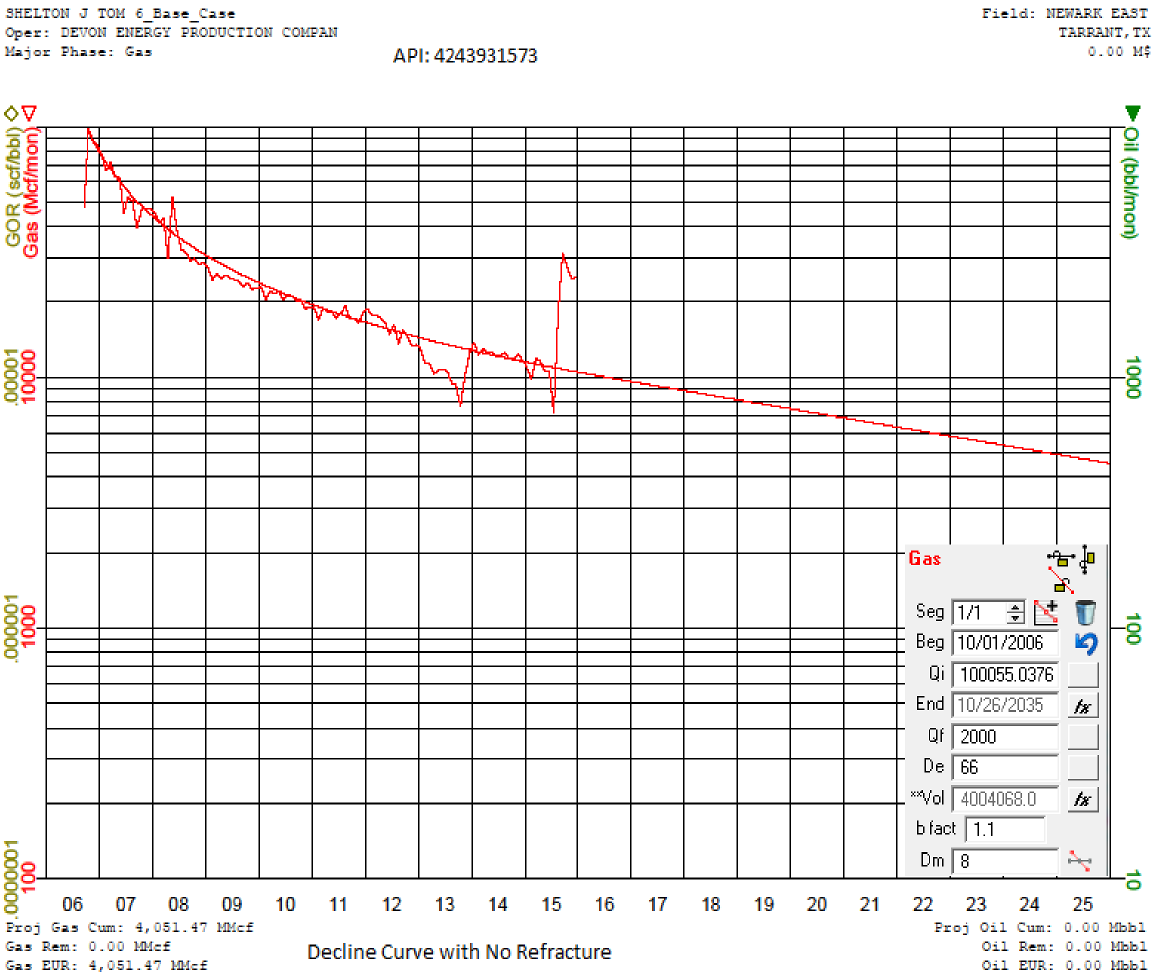
API: 4243930369



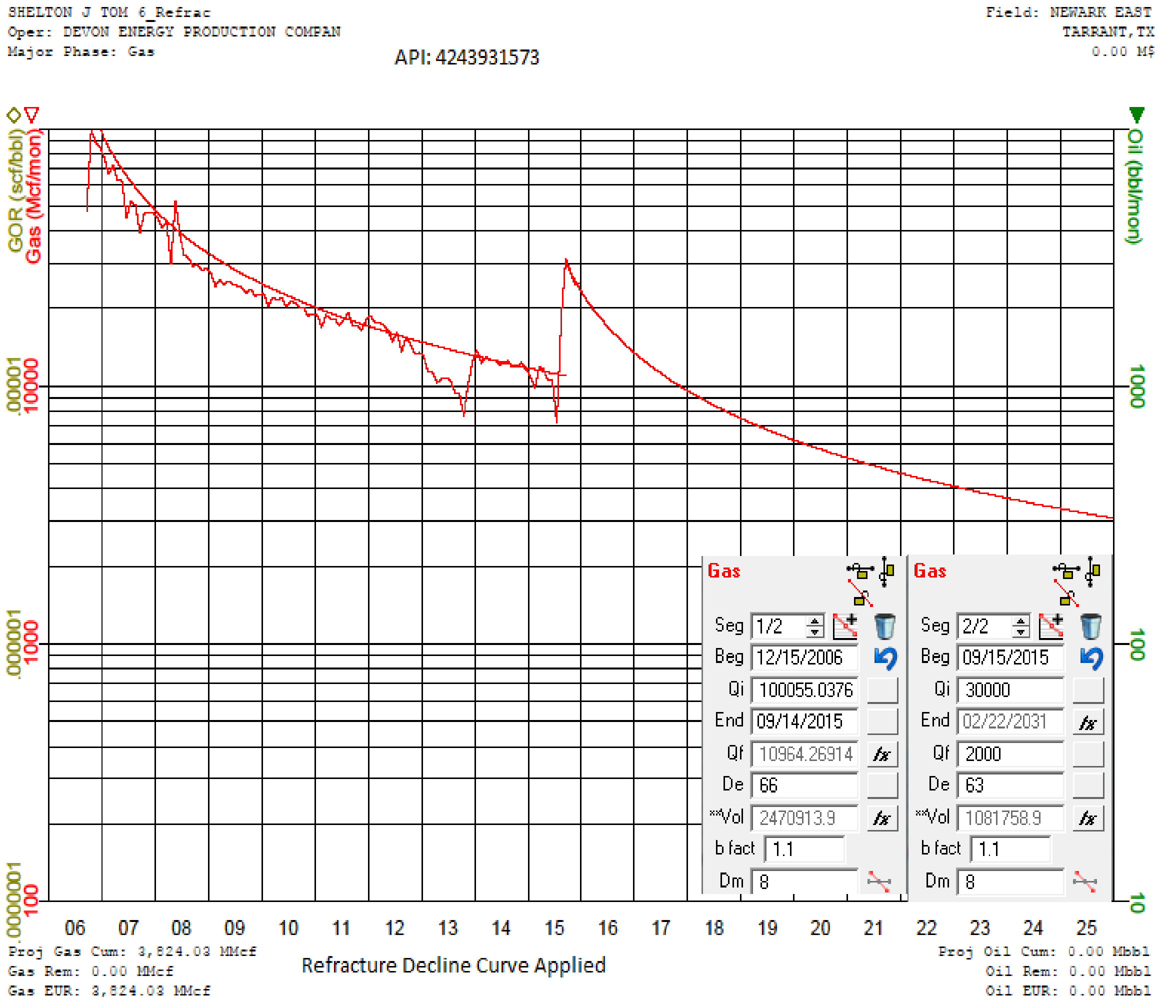
Proj Gas Cum: 1,881.26 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,881.26 MMcf

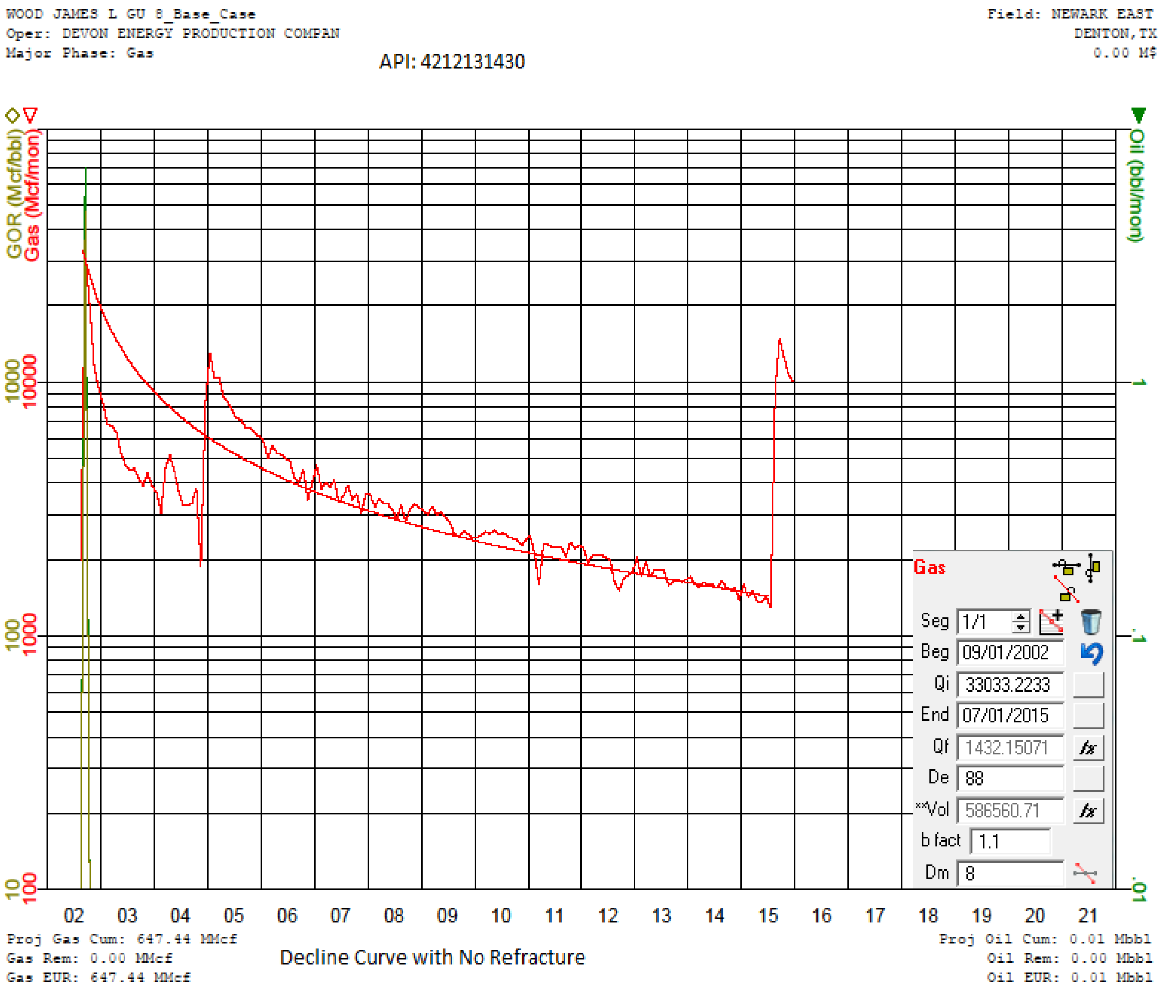
Refracture Decline Curve Applied

Proj Oil Cum: 0.01 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.01 Mbbl

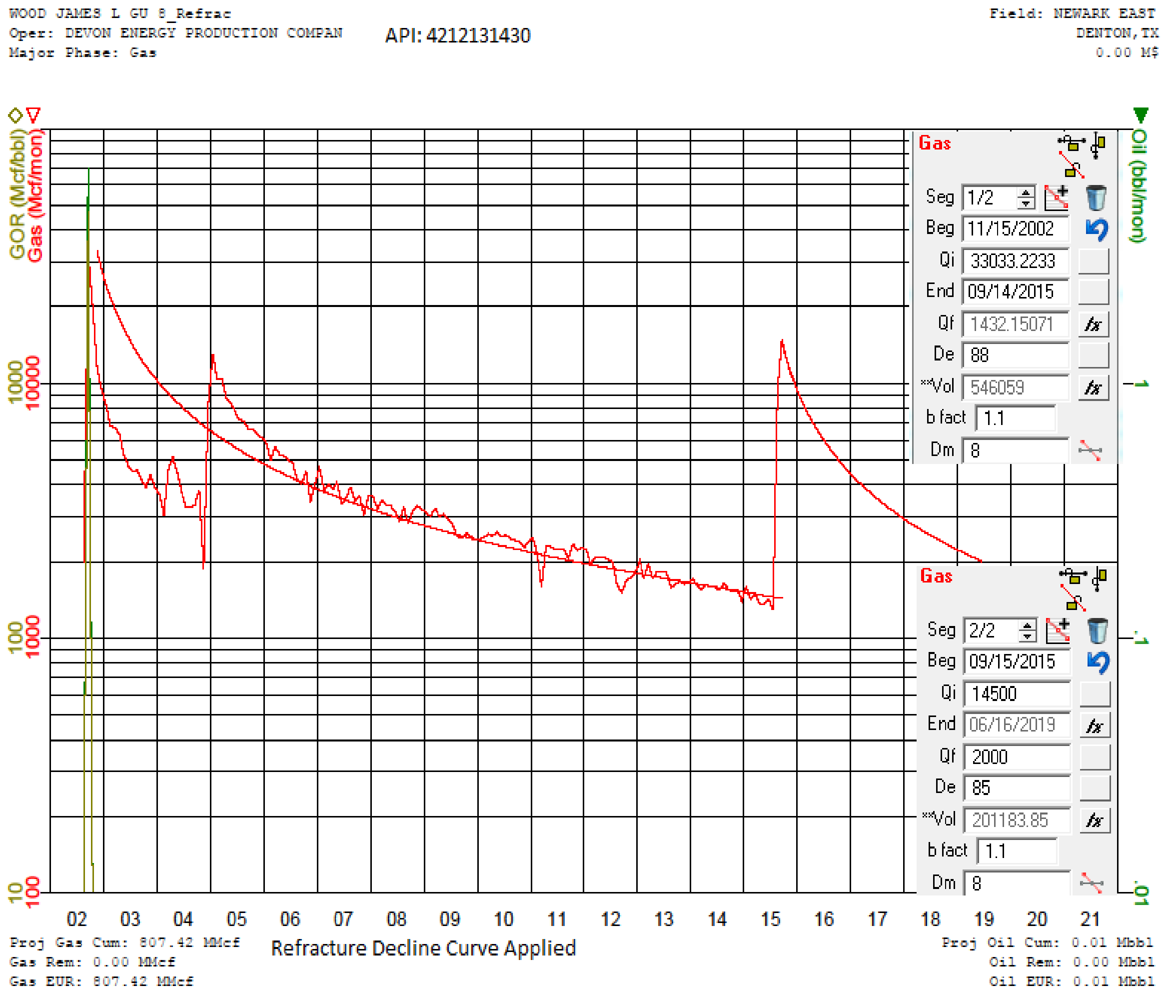


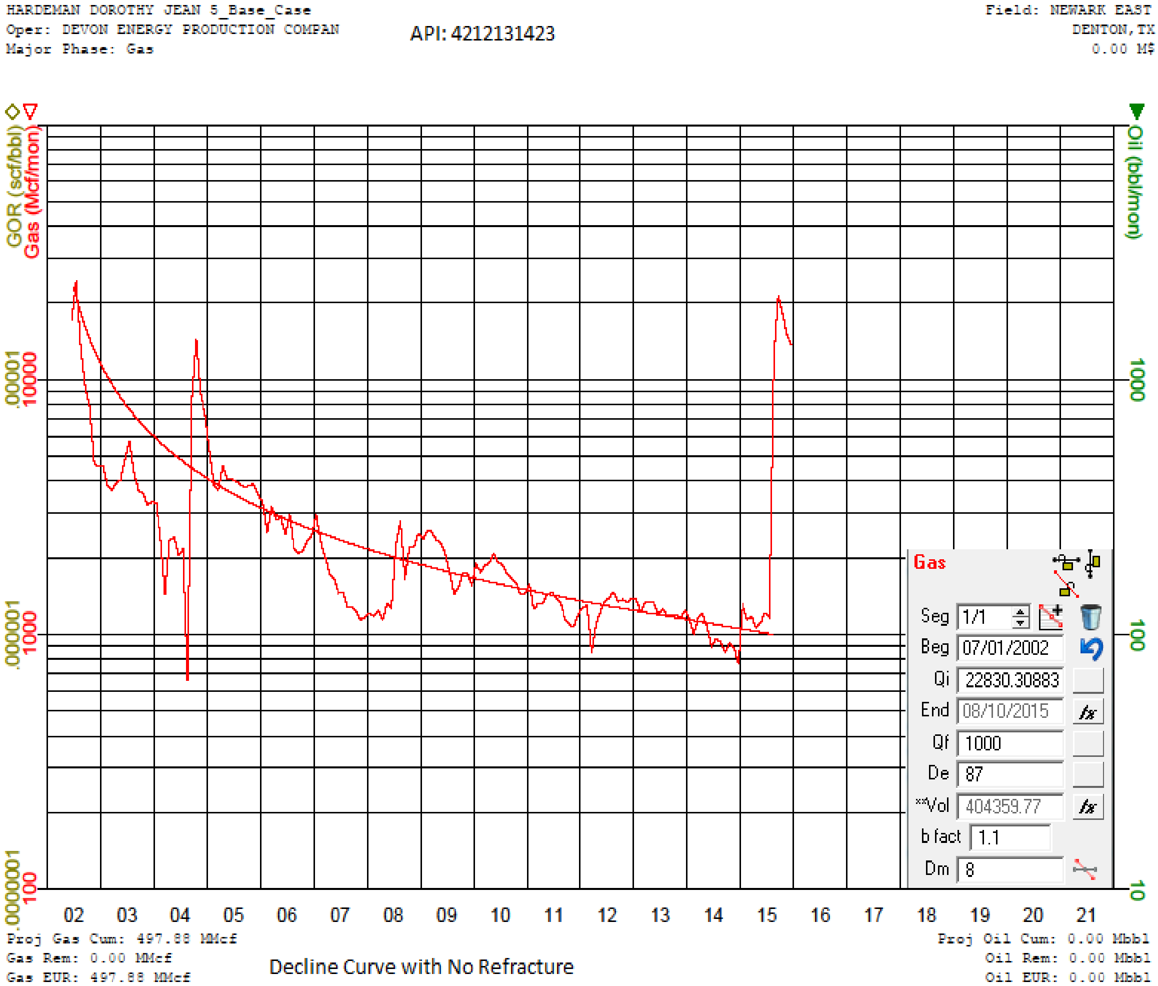
Decline Curve with No Refracture


SHELTON J TOM 6_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243931573
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 12/15/2006
Qi 100055.0376
End 09/14/2015
Qf 10964.26914
De 66
**Vol 2470913.9
b fact 1.1
Dm 8
Gas
Seg 2/2
Beg 09/15/2015
Qi 30000
End 02/22/2031
Qf 2000
De 63
**Vol 1081758.9
b fact 1.1
Dm 8
06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Proj Gas Cum: 3,824.03 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 3,824.03 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

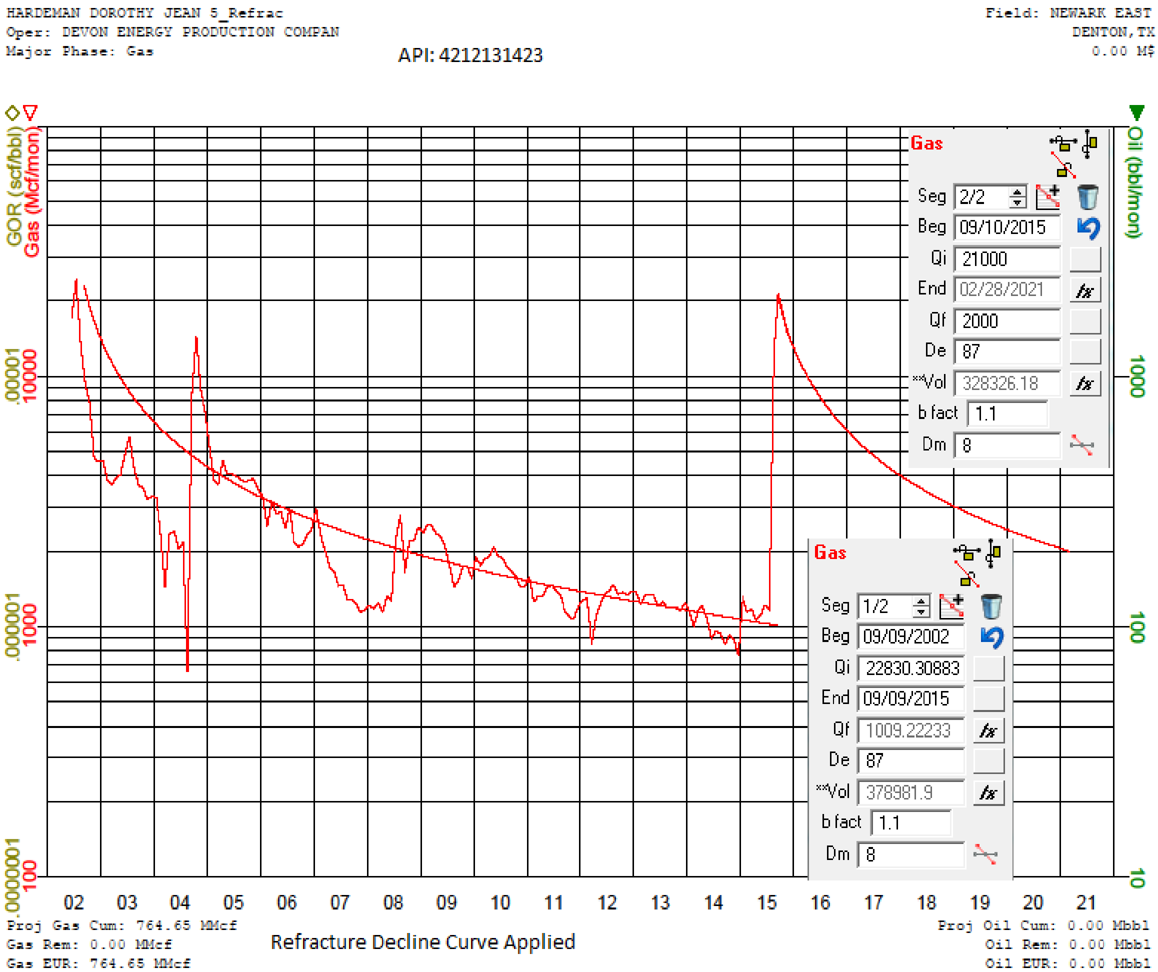


Decline Curve with No Refracture


WOOD JAMES L GU 8_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4212131430
Field: NEWARK EAST
DENTON, TX
0.00 M$
GOR (Mcf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 11/15/2002
Qi 33033.2233
End 09/14/2015
Qf 1432.15071
De 88
**Vol 546059
b fact 1.1
Dm 8
Gas
Seg 2/2
Beg 09/15/2015
Qi 14500
End 06/16/2019
Qf 2000
De 85
**Vol 201183.85
b fact 1.1
Dm 8
1000 10000
100 1000
10 100
02 03 04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21
Proj Gas Cum: 807.42 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 807.42 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.01 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.01 Mbbl



Decline Curve with No Refracture

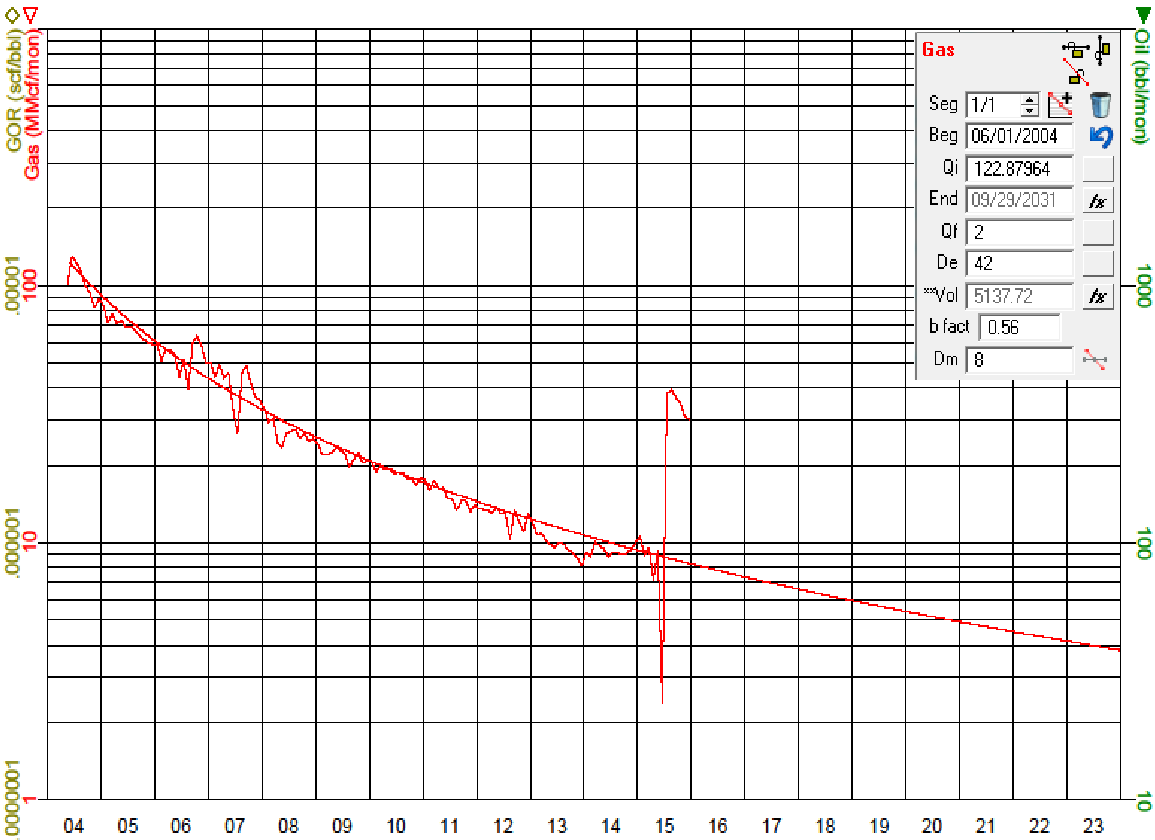


Refracture Decline Curve Applied

SHELTON J TOM 4_Base_Case
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

API: 4243930745

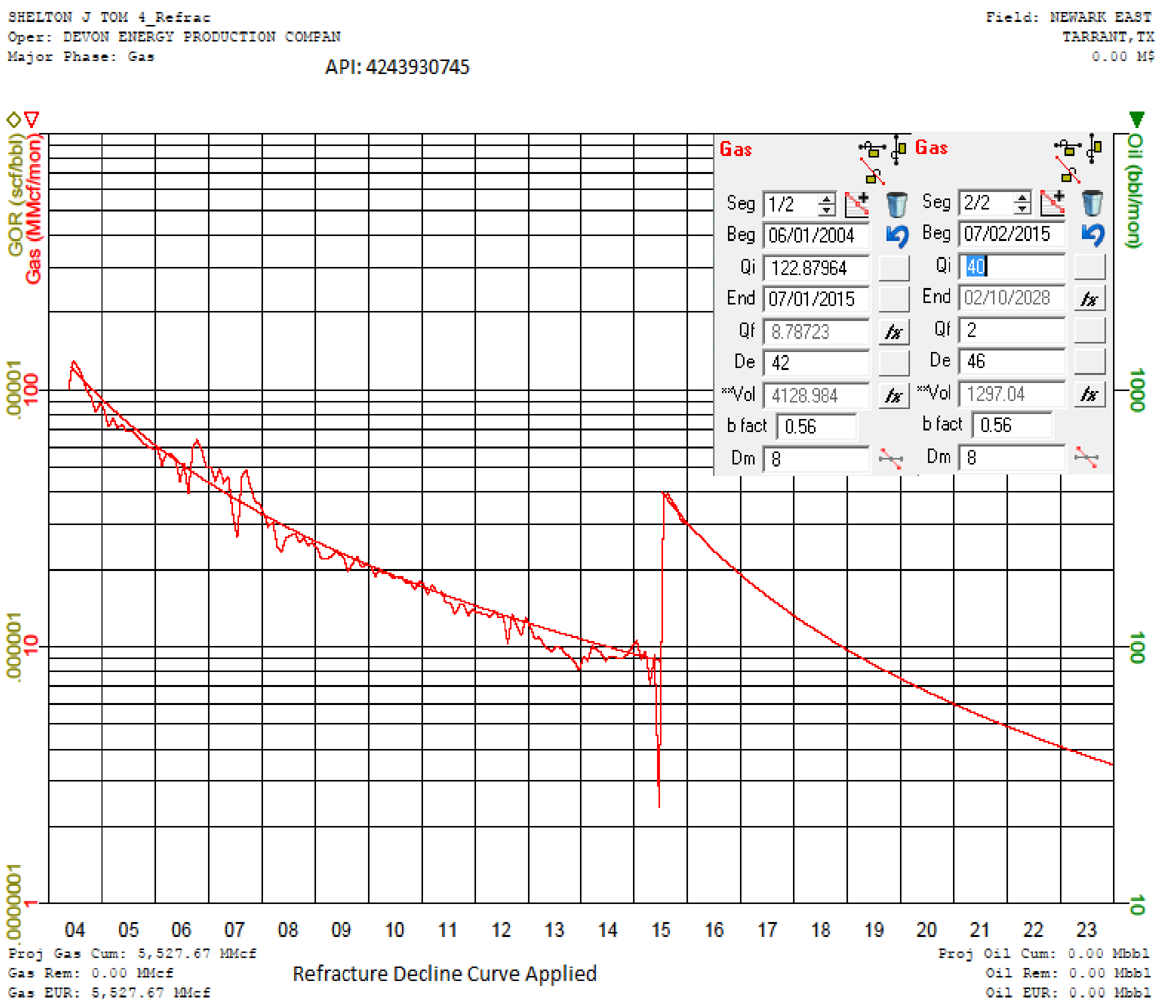
Field: NEWARK EAST
TARRANT, TX
0.00 M$

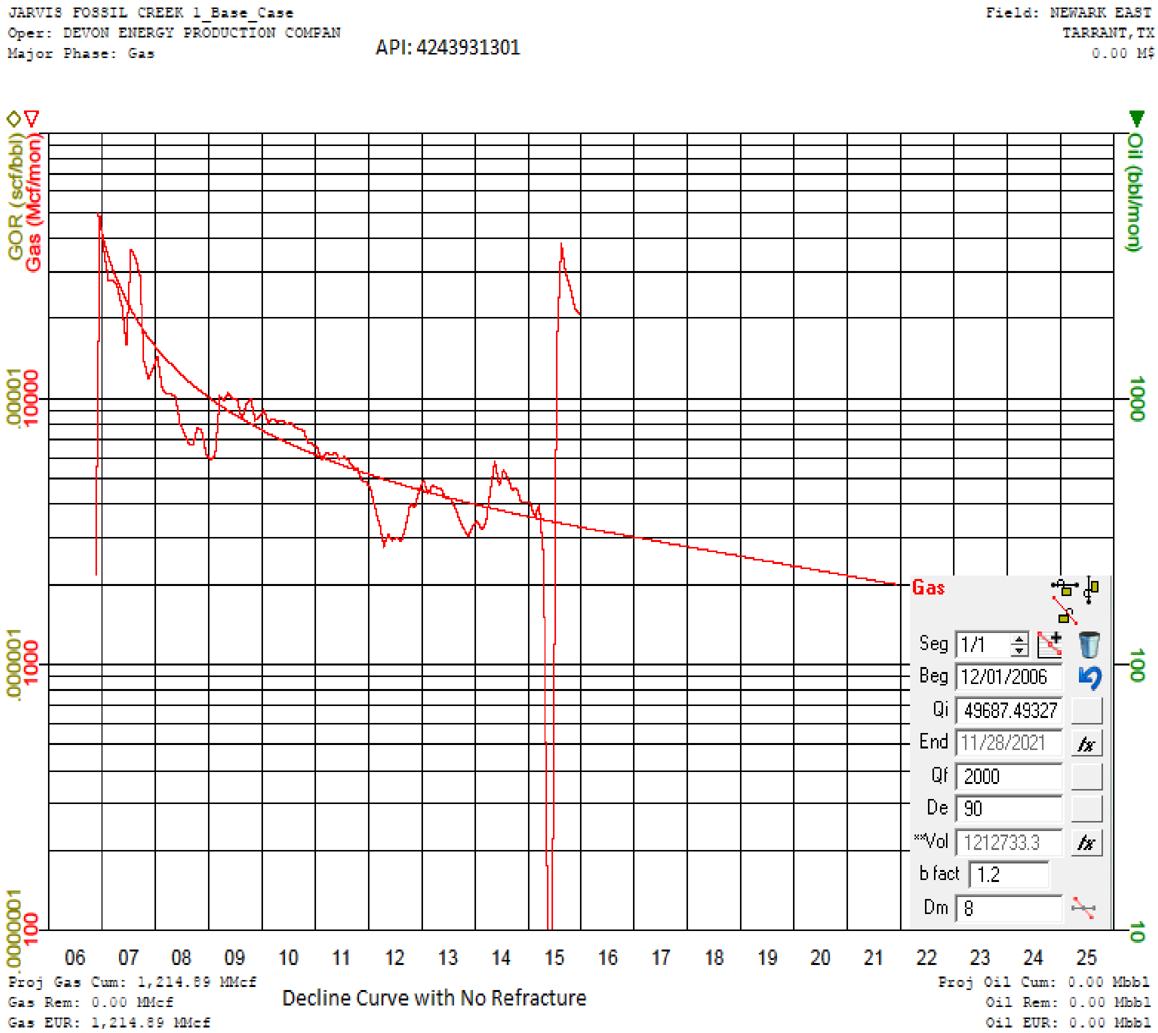


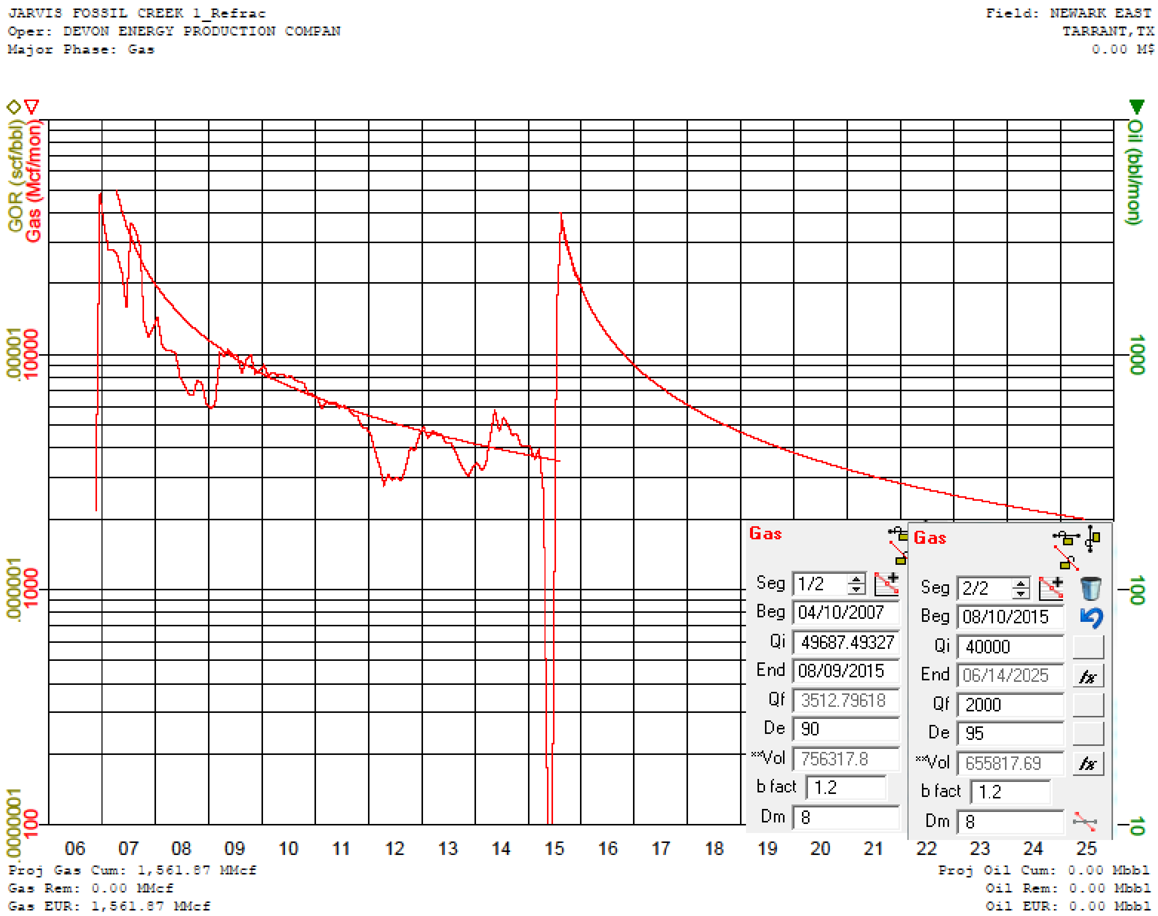
Proj Gas Cum: 5,239.37 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 5,239.37 MMcf

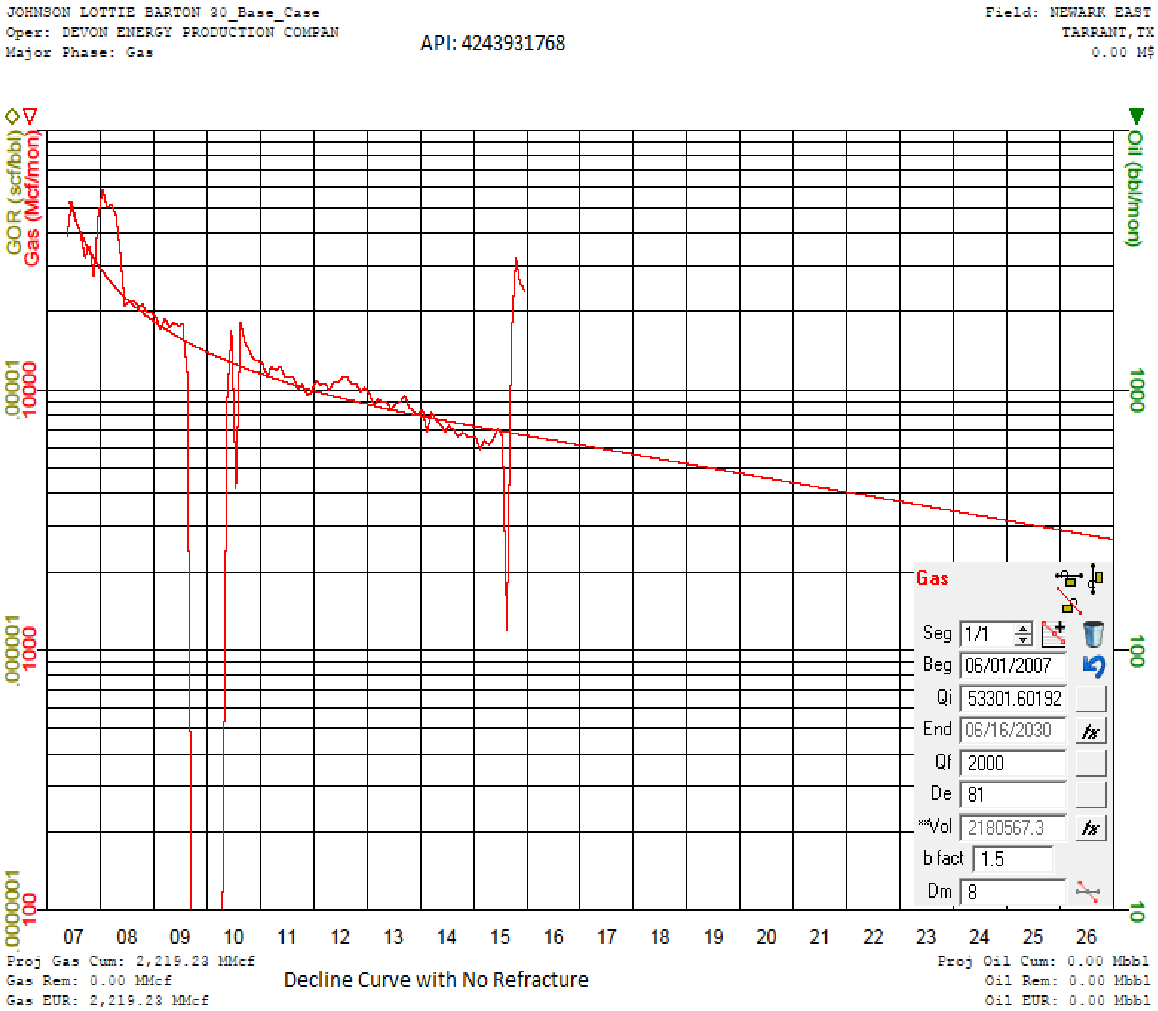
Decline Curve with No Refracture

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl


SHELTON J TOM 4_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243930745
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (MMcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 06/01/2004
Qi 122.87964
End 07/01/2015
Qf 8.78723
De 42
**Vol 4128.984
b fact 0.56
Dm 8
Gas
Seg 2/2
Beg 07/02/2015
Qi 40
End 02/10/2028
Qf 2
De 46
**Vol 1297.04
b fact 0.56
Dm 8
.00001 100
.000001 10
.0000001 1
1000
100
10
04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Proj Gas Cum: 5,527.67 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 5,527.67 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl


JARVIS FOSSIL CREEK 1_Base_Case
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243931301
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
.00001
10000
.000001
1000
.0000001
100
1000
100
10
Gas
Seg 1/1
Beg 12/01/2006
Qi 49687.49327
End 11/28/2021
Qf 2000
De 90
**Vol 1212733.3
b fact 1.2
Dm 8
06
07
08
09
10
11
12
13
14
15
16
17
18
19
20
21
22
23
24
25
Proj Gas Cum: 1,214.89 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,214.89 MMcf
Decline Curve with No Refracture
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl


JARVIS FOSSIL CREEK 1_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
Field: NEWARK EAST
TARRANT,TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
.00001 10000
.000001 1000
.0000001 100
1000
100
10
06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25
Gas
Seg 1/2
Beg 04/10/2007
Qi 49687.49327
End 08/09/2015
Qf 3512.79618
De 90
**Vol 756317.8
b fact 1.2
Dm 8
Gas
Seg 2/2
Beg 08/10/2015
Qi 40000
End 06/14/2025
Qf 2000
De 95
**Vol 655817.69
b fact 1.2
Dm 8
Proj Gas Cum: 1,561.87 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,561.87 MMcf
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

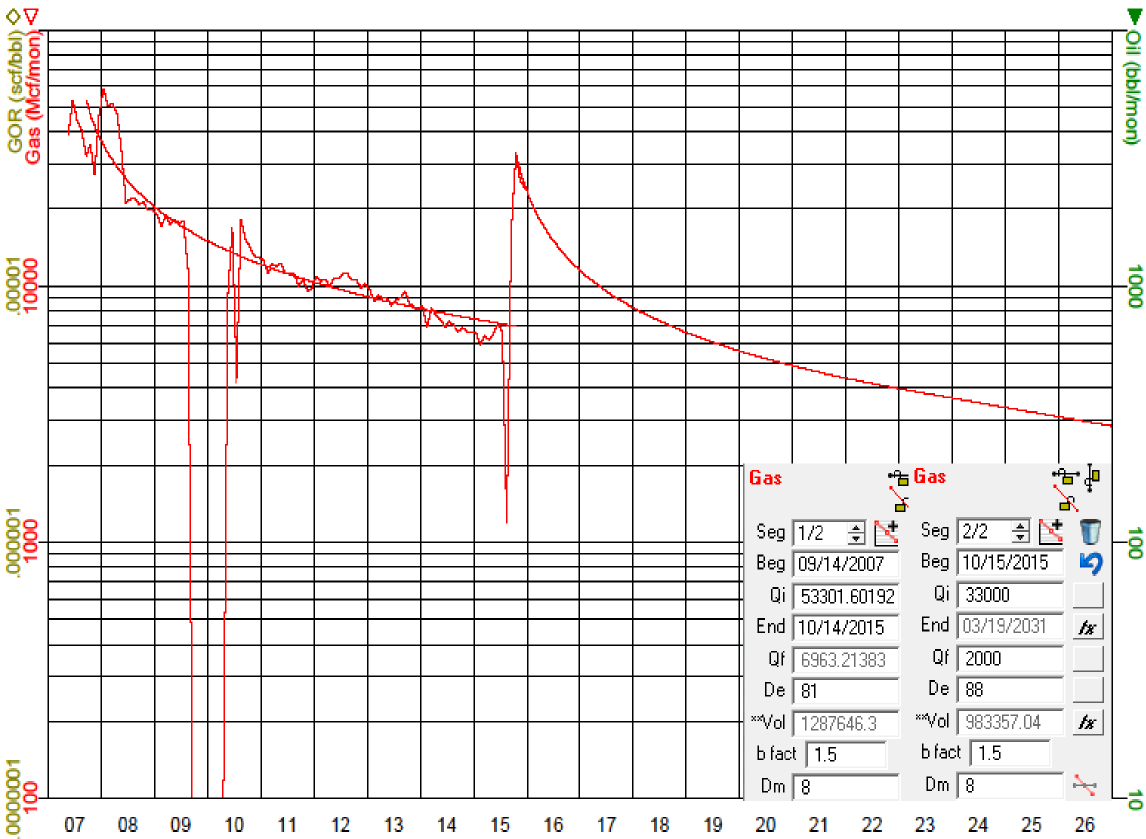


Decline Curve with No Refracture

JOHNSON LOTTIE BARTON 30_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

API: 4243931768

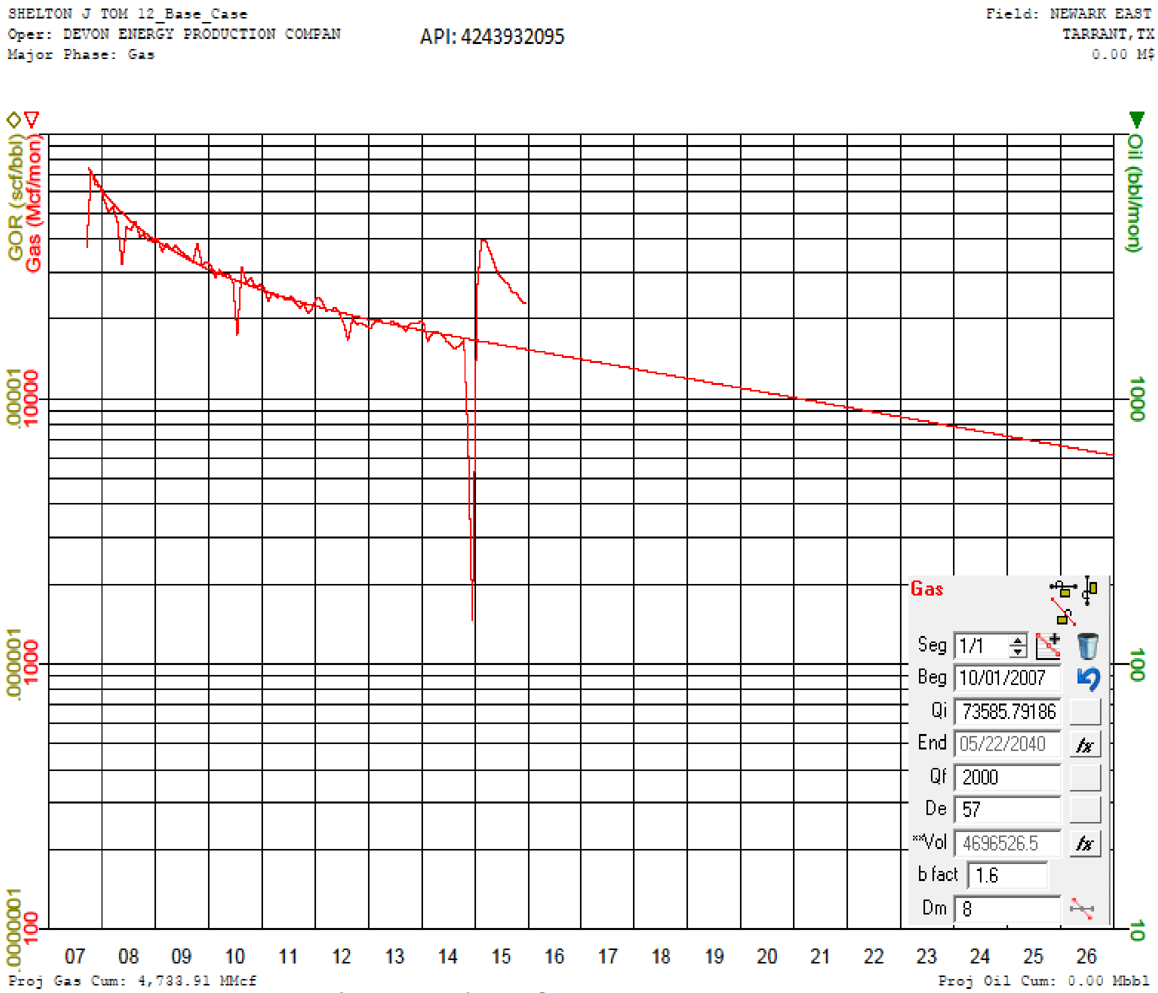
Field: NEWARK EAST
TARRANT, TX
0.00 M$



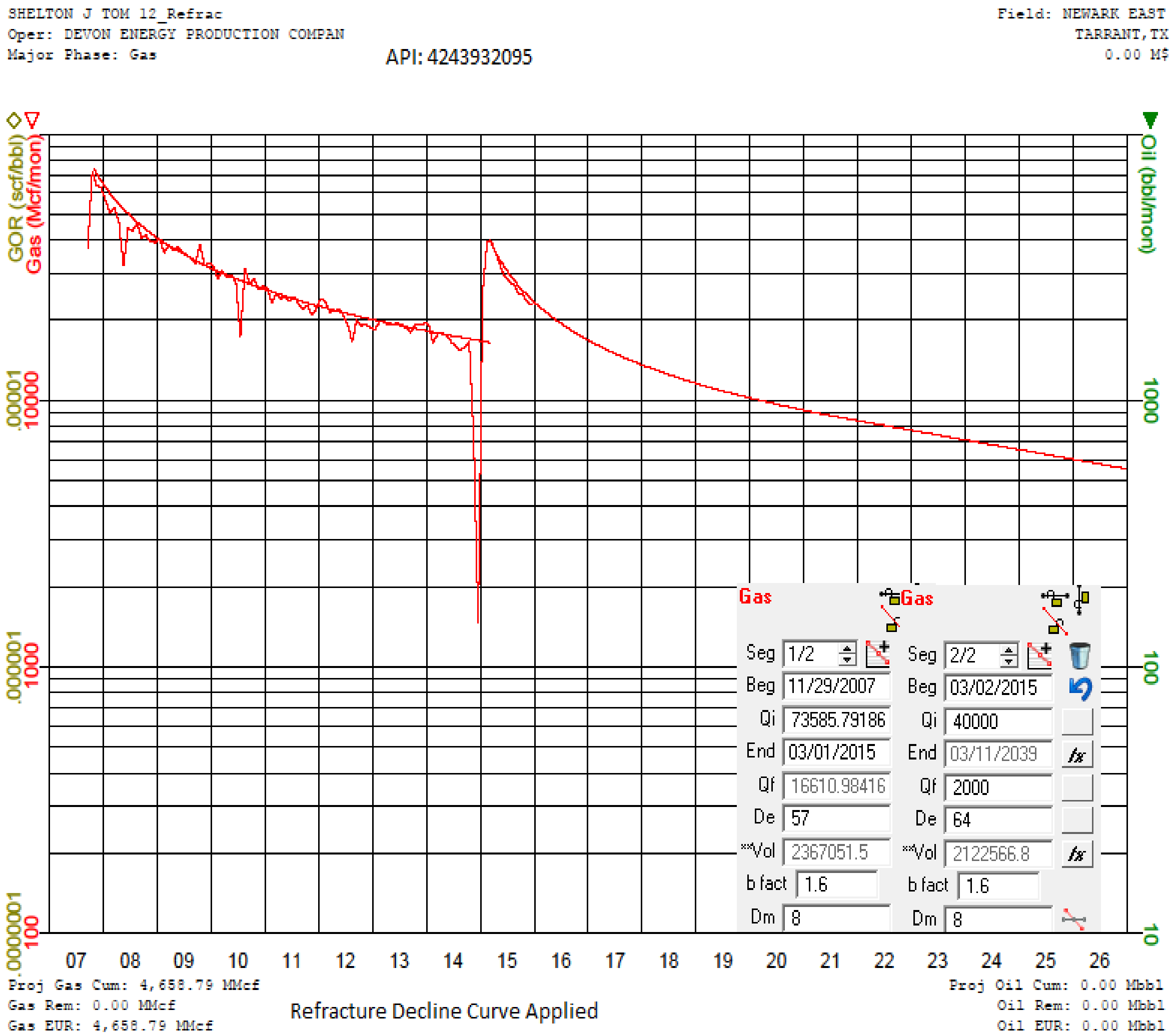
Proj Gas Cum: 2,461.78 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 2,461.78 MMcf

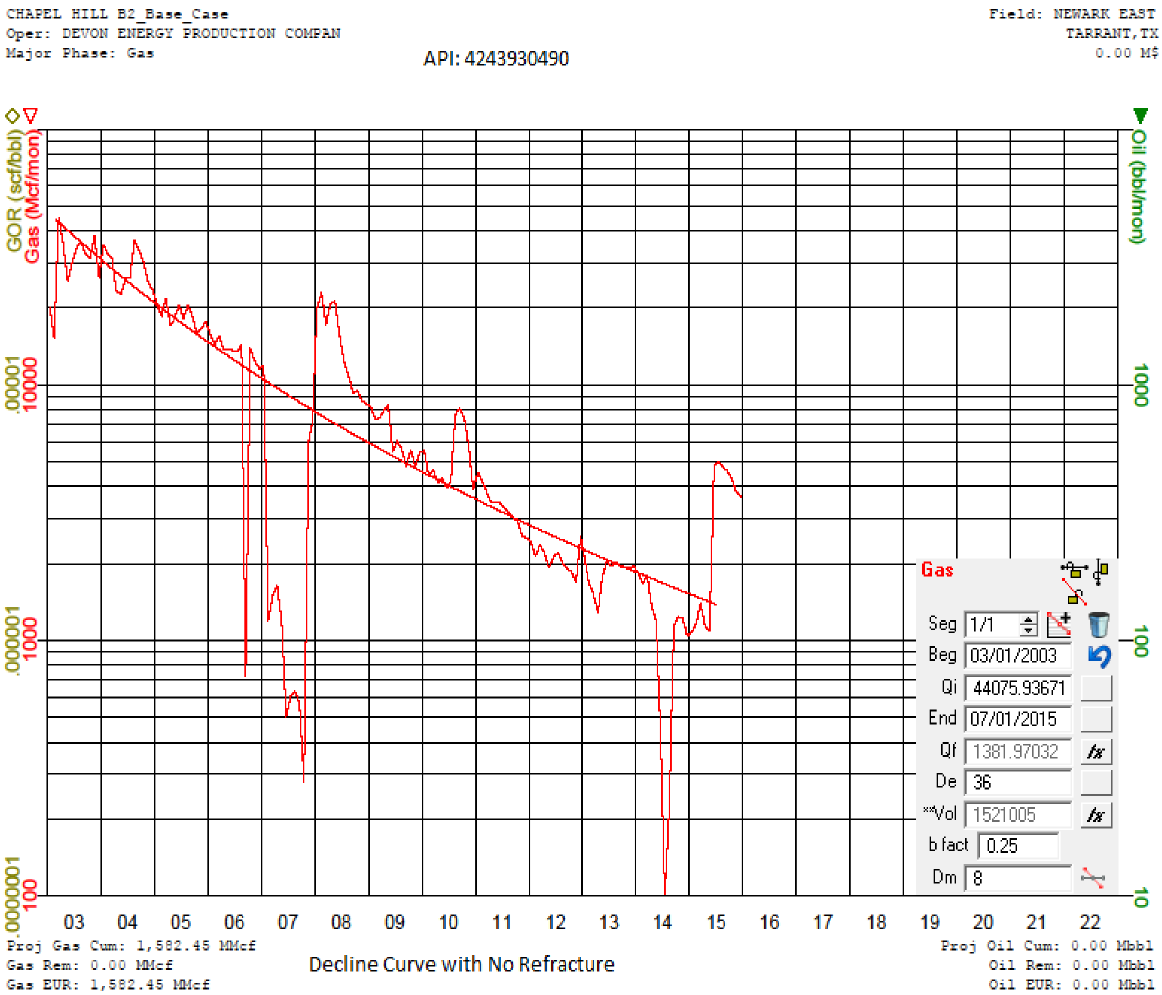
Refracture Decline Curve Applied

Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl

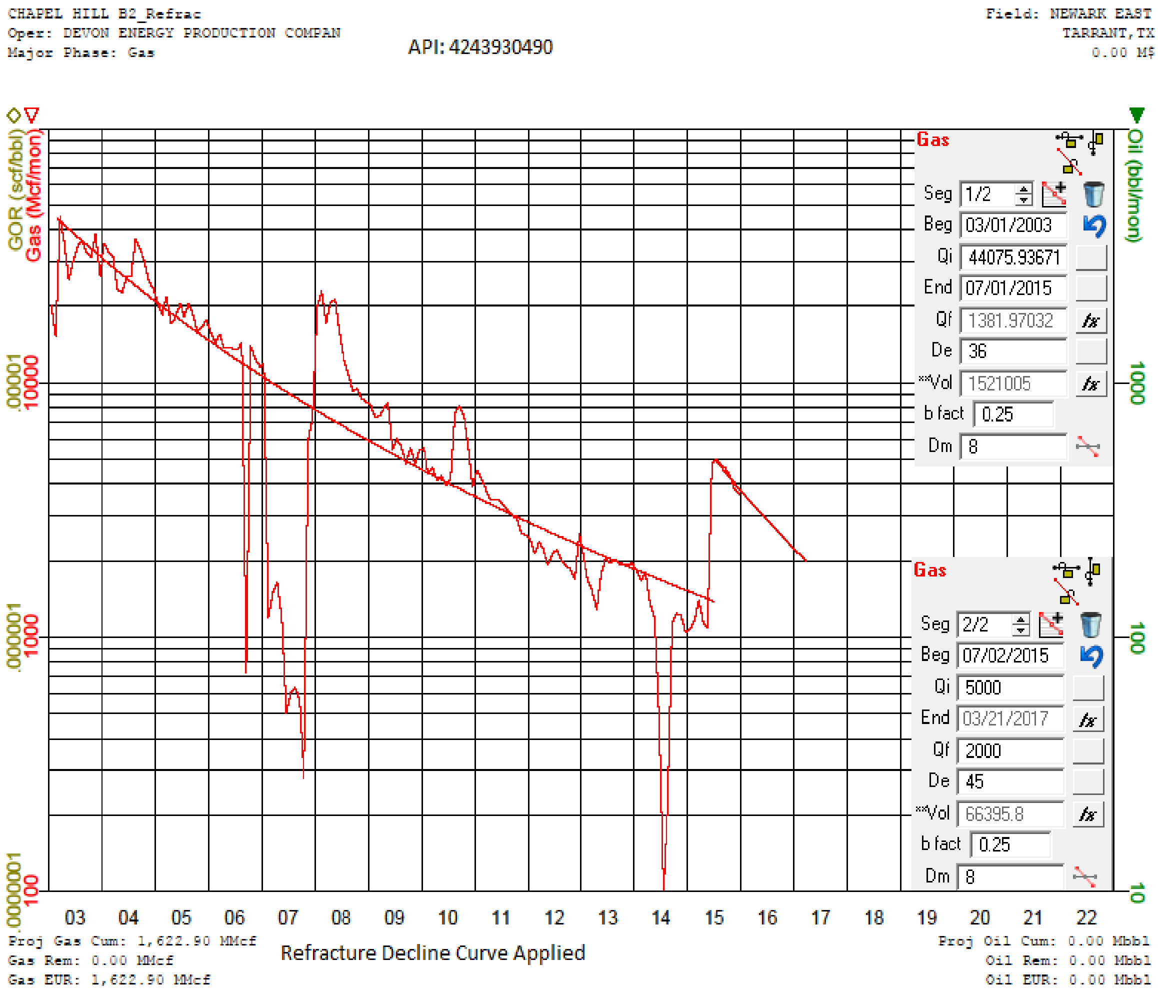


Decline Curve with No Refracture

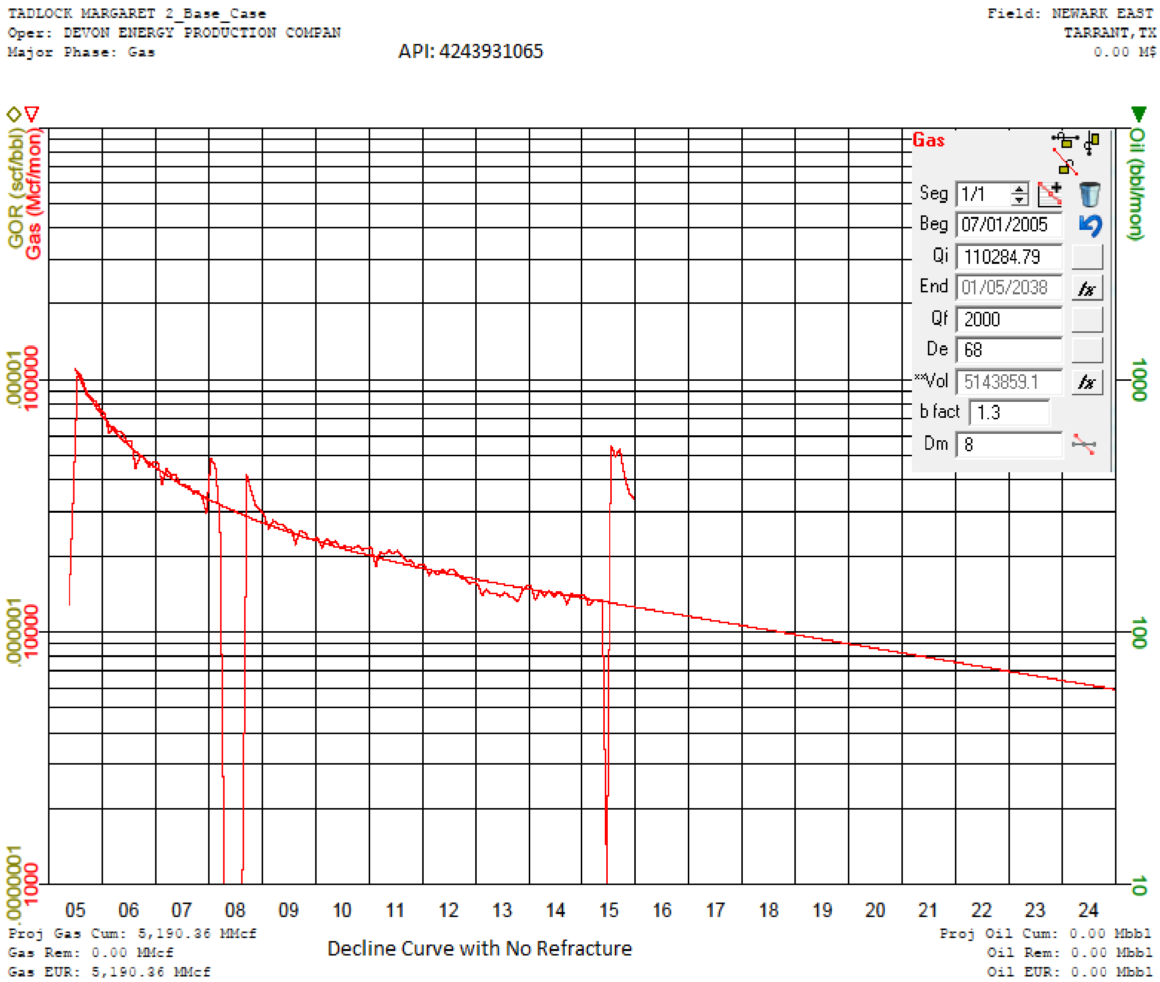

SHELTON J TOM 12_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243932095
Field: NEWARK EAST
TARRANT,TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 11/29/2007
Qi 73585.79186
End 03/01/2015
Qf 16610.98416
De 57
Vol 2367051.5
b fact 1.6
Dm 8
Gas
Seg 2/2
Beg 03/02/2015
Qi 40000
End 03/11/2039
Qf 2000
De 64
Vol 2122566.8
b fact 1.6
Dm 8
07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26
Proj Gas Cum: 4,658.79 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 4,658.79 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl



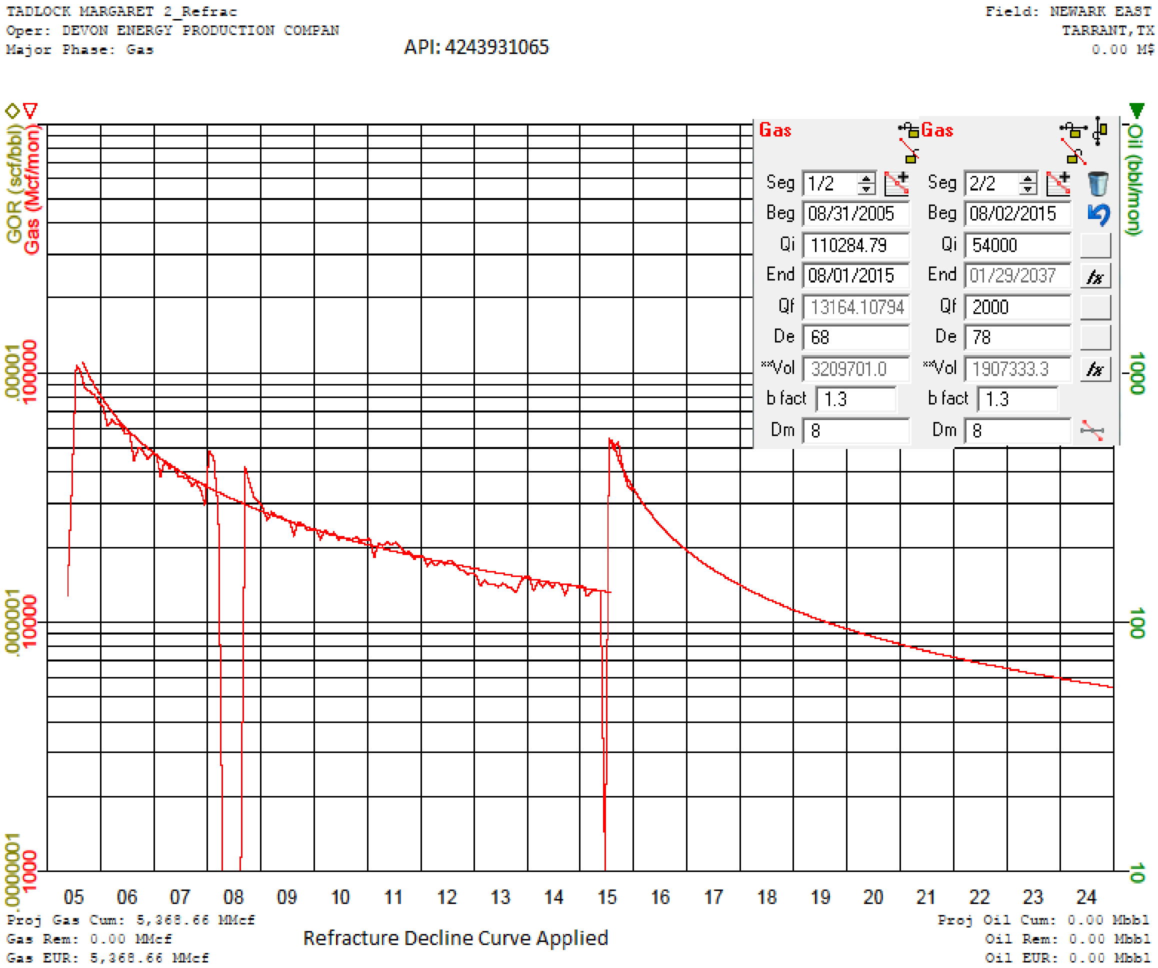
Decline Curve with No Refracture

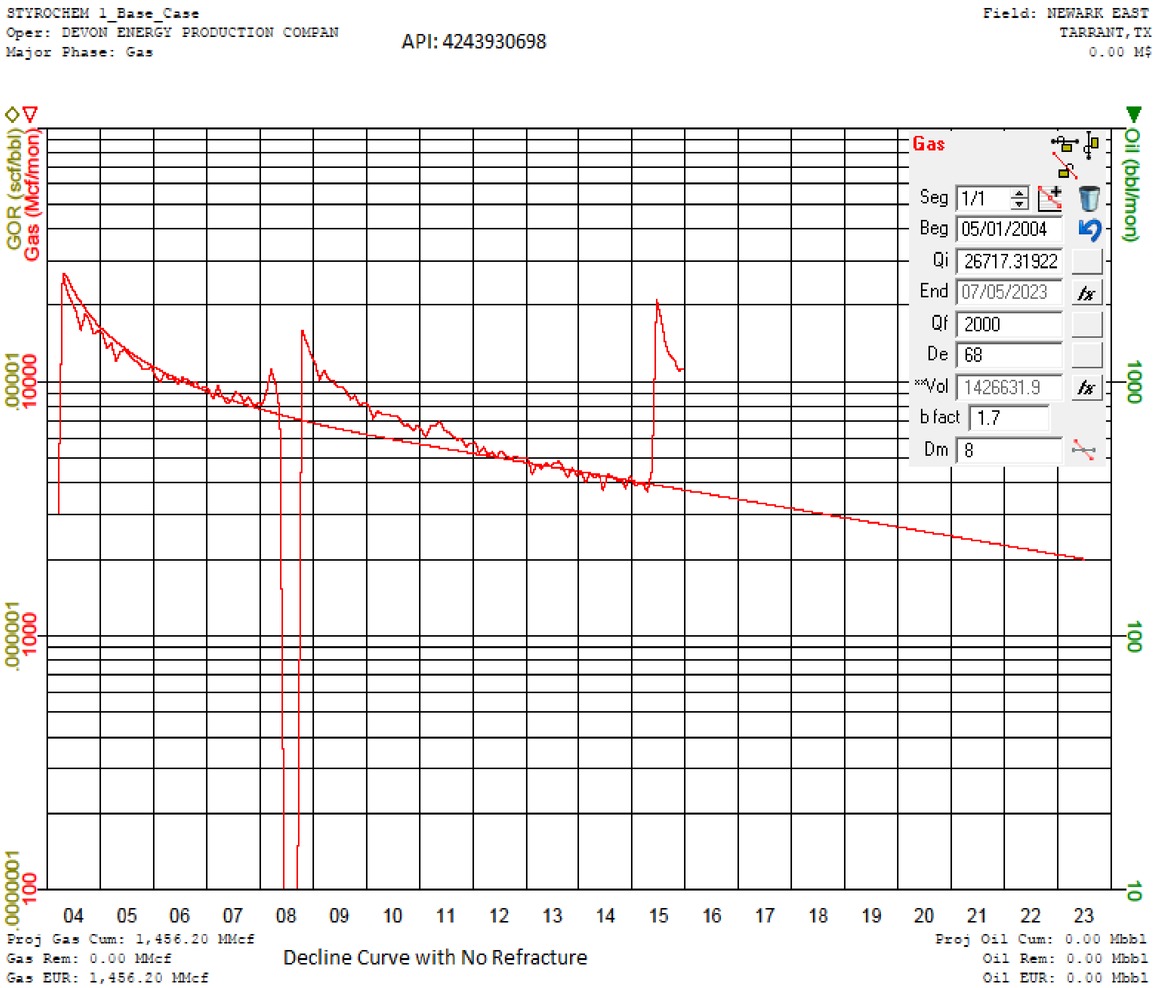


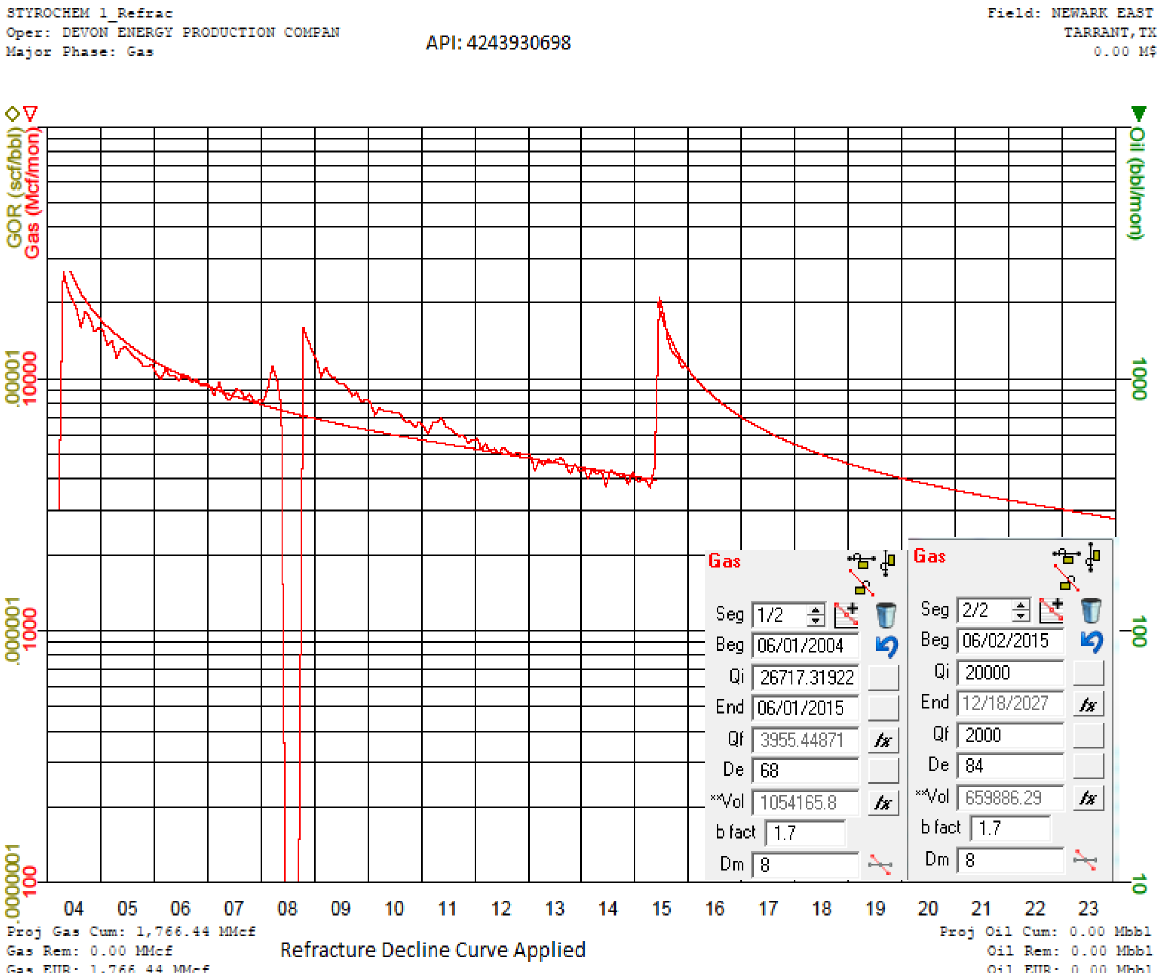
Refracture Decline Curve Applied

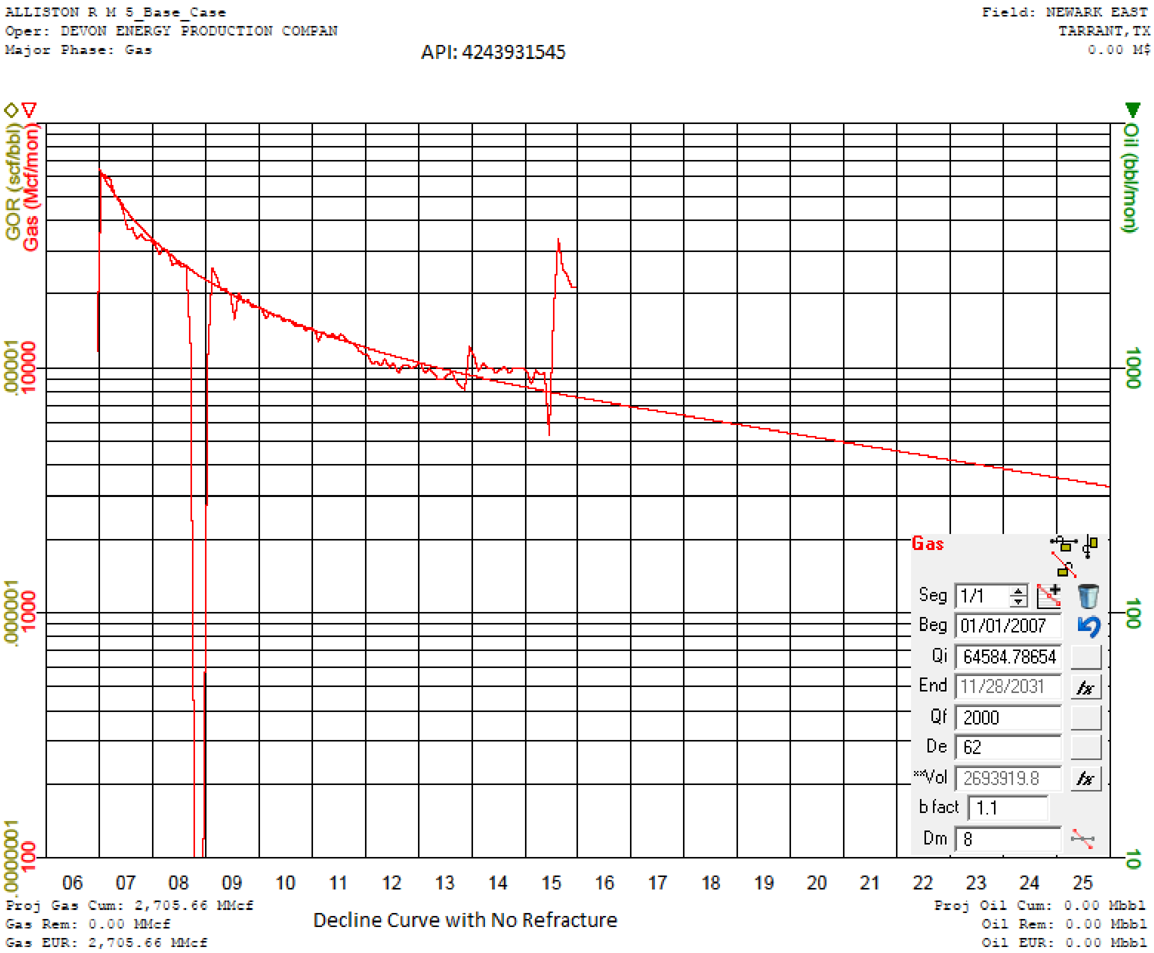


Decline Curve with No Refracture

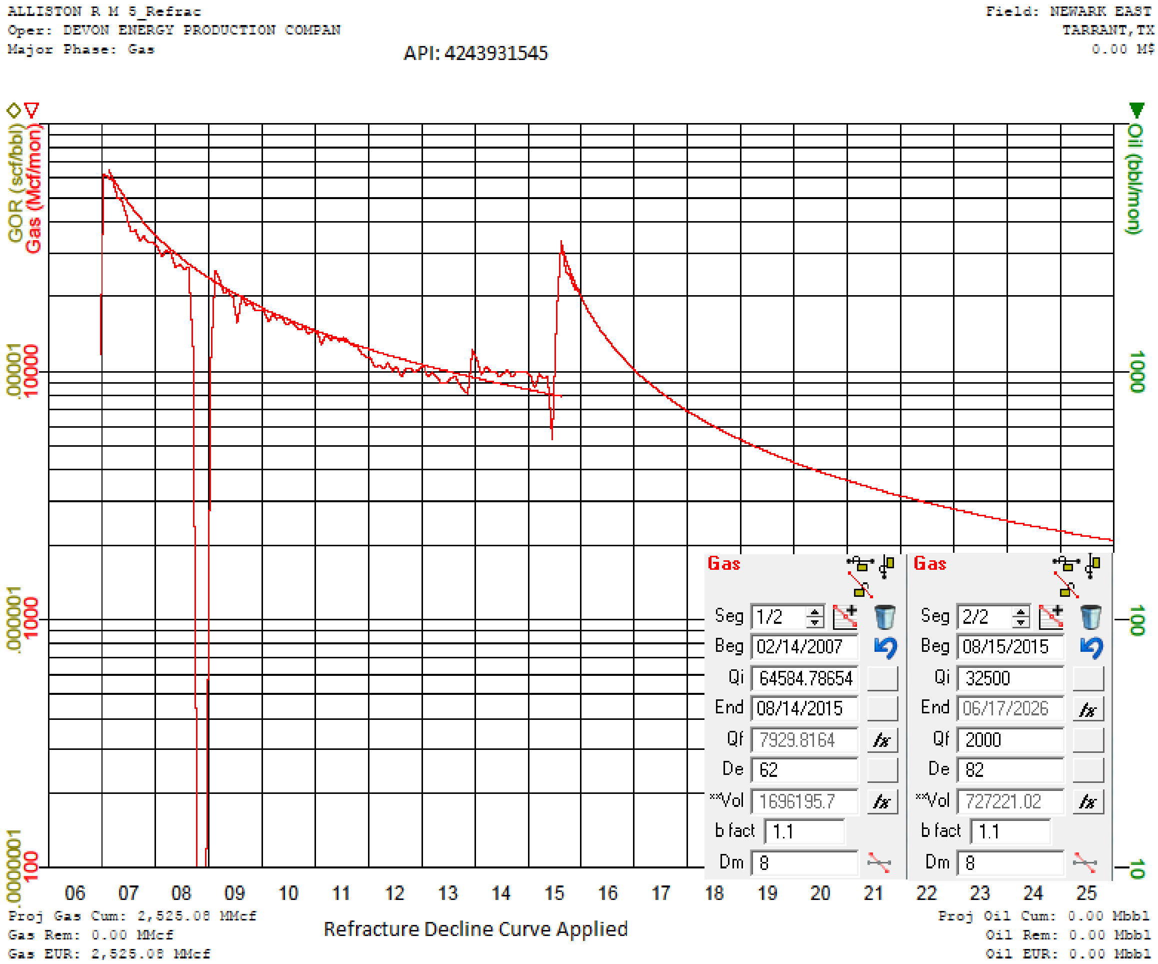

TADLOCK MARGARET 2_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243931065
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/2
Beg 08/31/2005
Qi 110284.79
End 08/01/2015
Qf 13164.10794
De 68
Vol 3209701.0
b fact 1.3
Dm 8
Gas
Seg 2/2
Beg 08/02/2015
Qi 54000
End 01/29/2037
Qf 2000
De 78
Vol 1907333.3
b fact 1.3
Dm 8
Proj Gas Cum: 5,368.66 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 5,368.66 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl


STYROCHEM 1_Base_Case
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243930698
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
Gas
Seg 1/1
Beg 05/01/2004
Qi 26717.31922
End 07/05/2023
Qf 2000
De 68
Vol 1426631.9
b fact 1.7
Dm 8
04
05
06
07
08
09
10
11
12
13
14
15
16
17
18
19
20
21
22
23
Proj Gas Cum: 1,456.20 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,456.20 MMcf
Decline Curve with No Refracture
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl


STYROCHEM 1_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243930698
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
.00001 10000
.000001 1000
.0000001 100
1000
100
10
04 05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23
Gas
Seg 1/2
Beg 06/01/2004
Qi 26717.31922
End 06/01/2015
Qf 3955.44871
De 68
**Vol 1054165.8
b fact 1.7
Dm 8
Gas
Seg 2/2
Beg 06/02/2015
Qi 20000
End 12/18/2027
Qf 2000
De 84
**Vol 659886.29
b fact 1.7
Dm 8
Proj Gas Cum: 1,766.44 MMcf
Gas Rem: 0.00 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl



Decline Curve with No Refracture

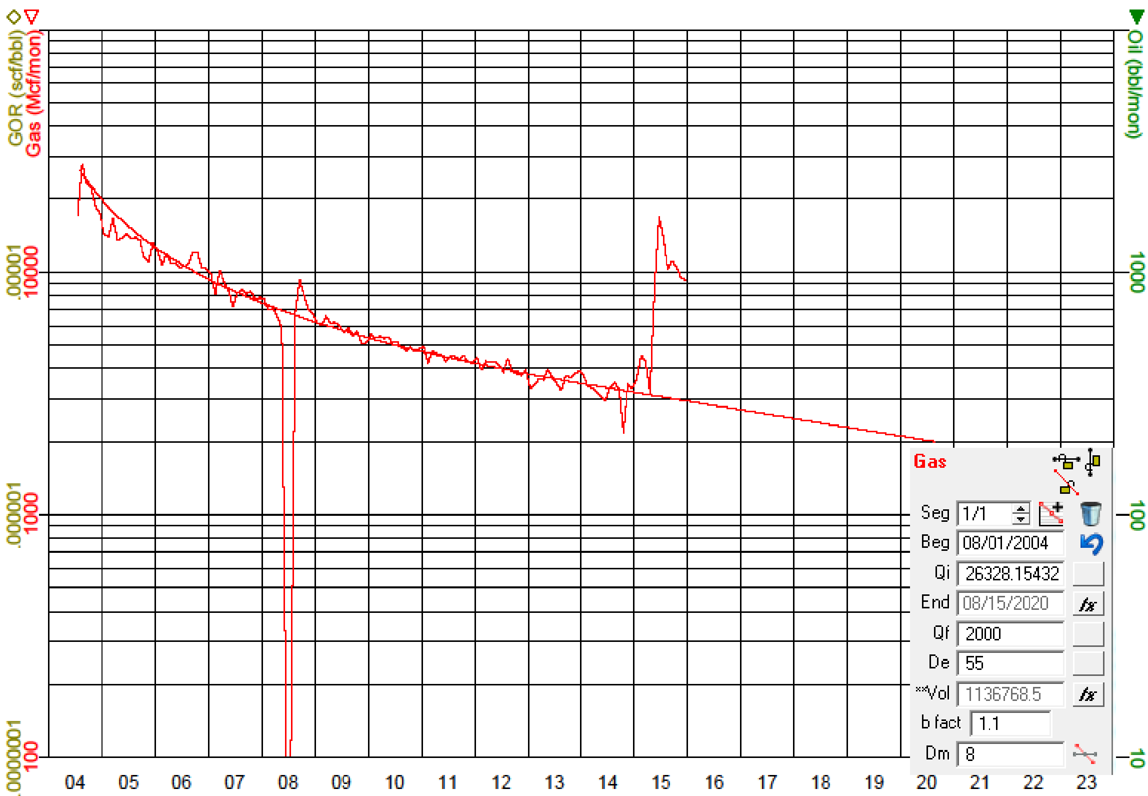


Refracture Decline Curve Applied

TRINITY INDUSTRIES UNIT 2_Base_Case
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas

Field: NEWARK EAST
TARRANT, TX
0.00 M$

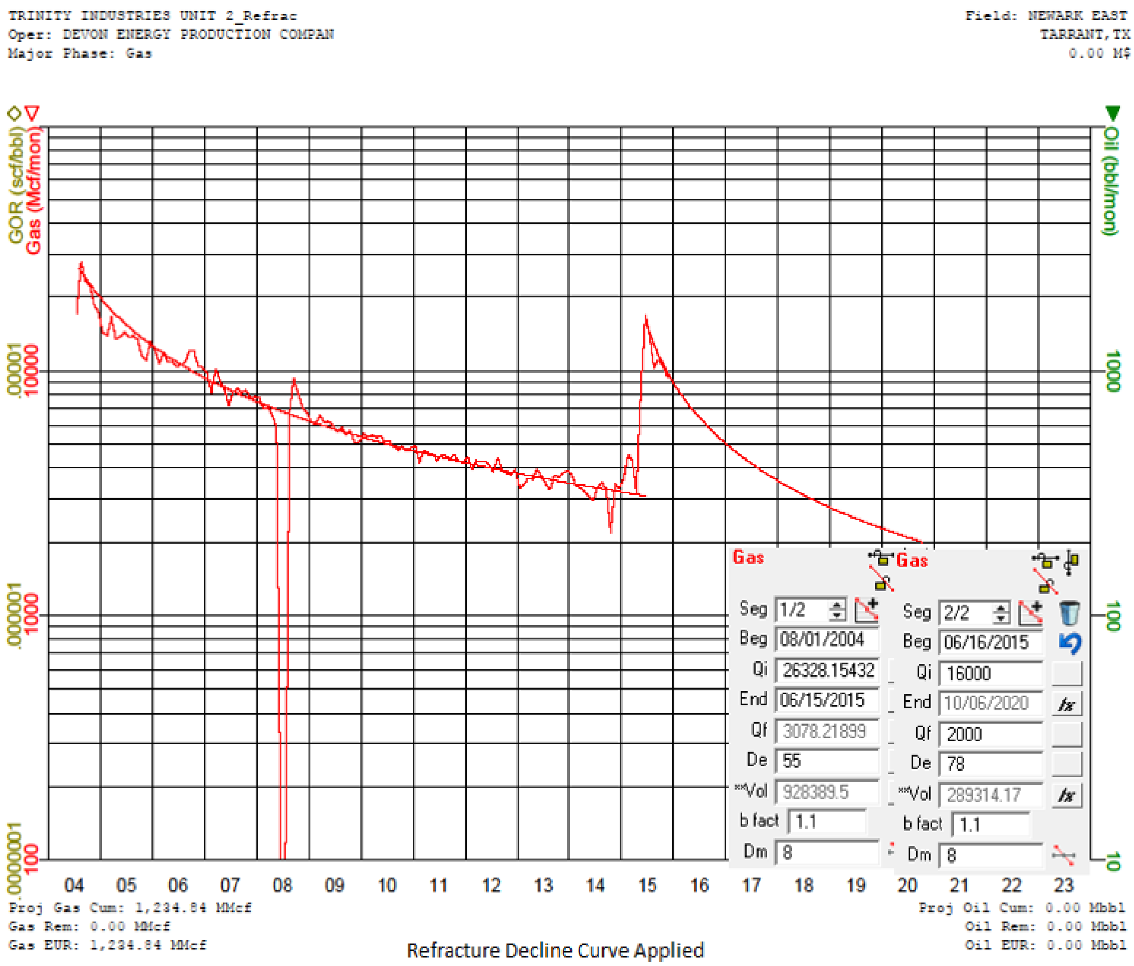
API: 4243930814



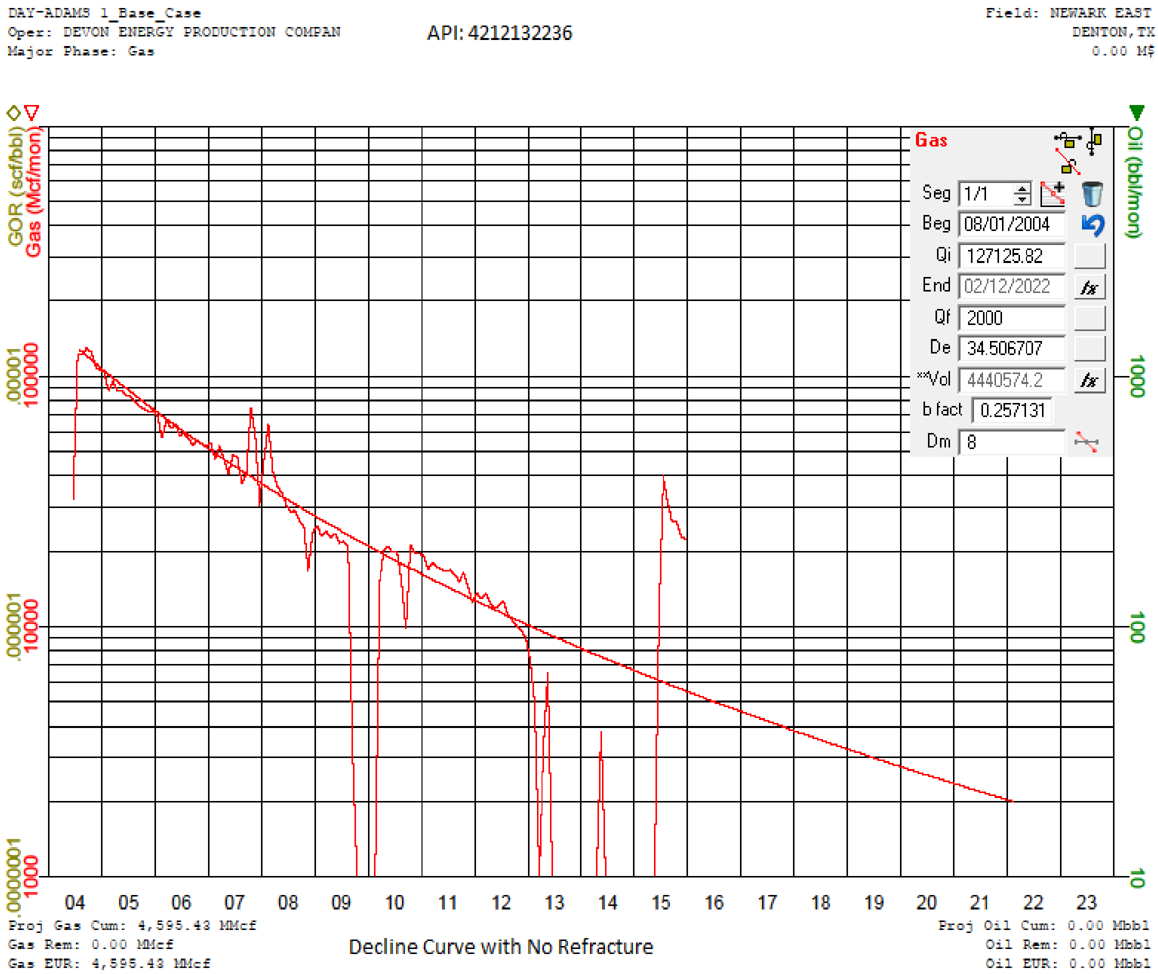
Proj Gas Cum: 1,153.91 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,153.91 MMcf

Decline Curve with No Refracture

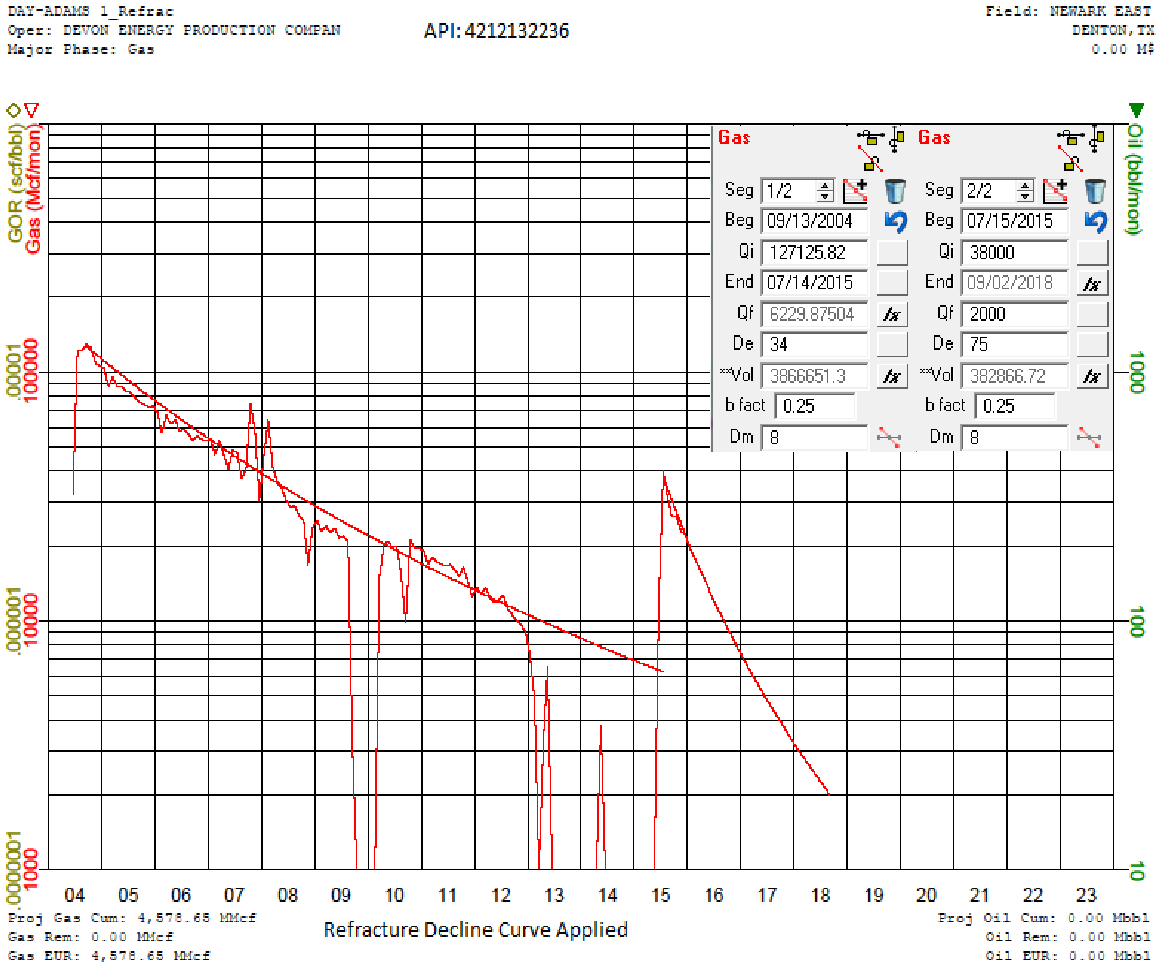
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl



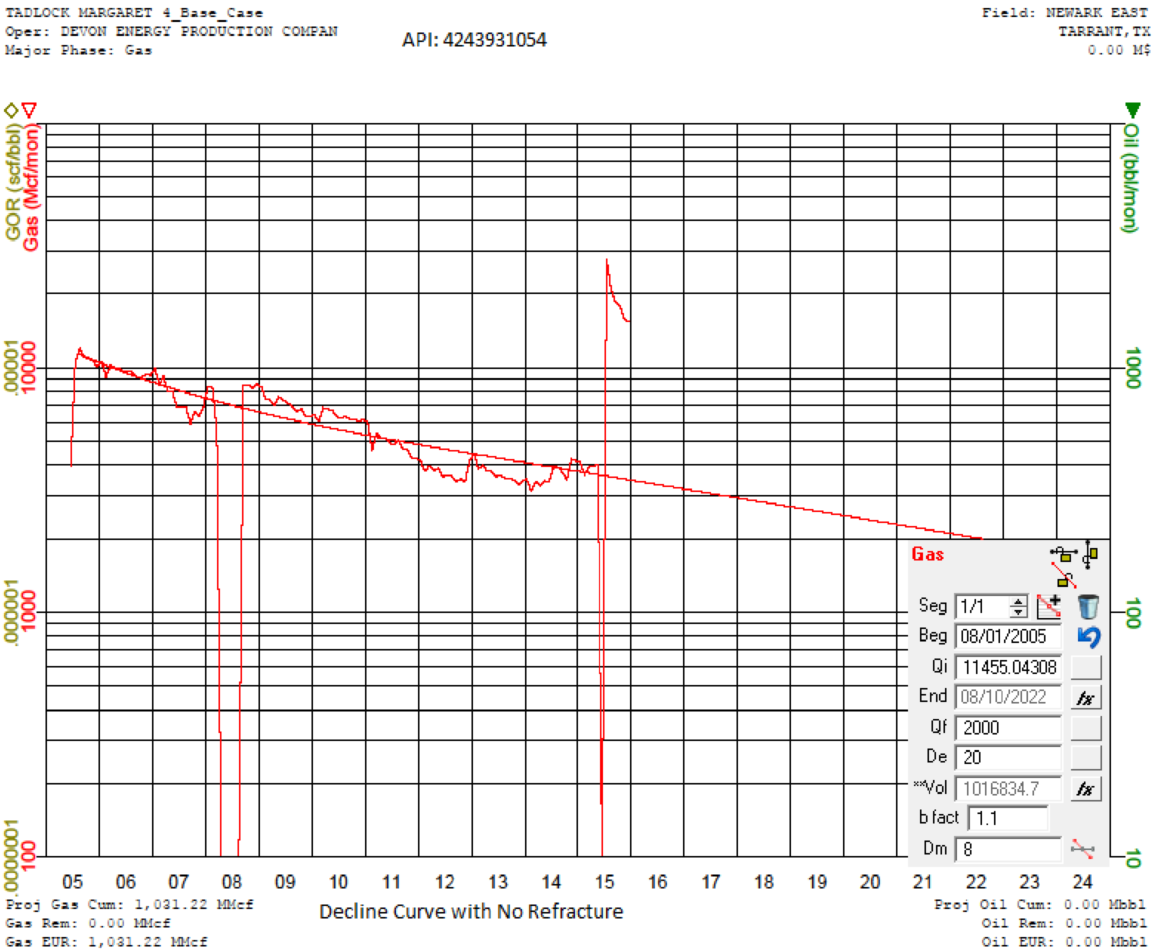
Refracture Decline Curve Applied



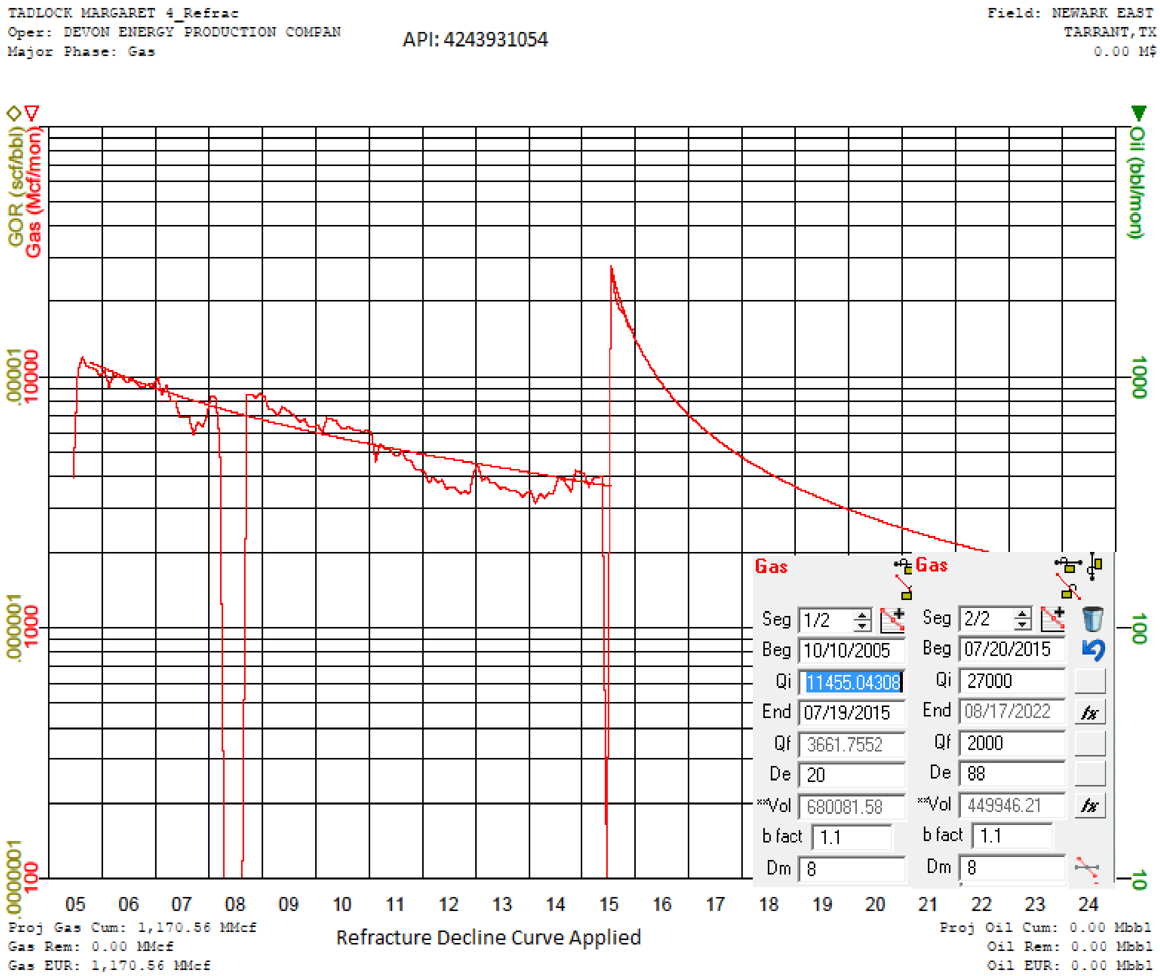
Decline Curve with No Refracture



Refracture Decline Curve Applied



Decline Curve with No Refracture


TADLOCK MARGARET 4_Refrac
Oper: DEVON ENERGY PRODUCTION COMPAN
Major Phase: Gas
API: 4243931054
Field: NEWARK EAST
TARRANT, TX
0.00 M$
GOR (scf/bbl)
Gas (Mcf/mon)
Oil (bbl/mon)
10000
1000
100
05 06 07 08 09 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Gas
Seg 1/2
Beg 10/10/2005
Qi 11455.04308
End 07/19/2015
Qf 3661.7552
De 20
**Vol 680081.58
b fact 1.1
Dm 8
Gas
Seg 2/2
Beg 07/20/2015
Qi 27000
End 08/17/2022
Qf 2000
De 88
**Vol 449946.21
b fact 1.1
Dm 8
Proj Gas Cum: 1,170.56 MMcf
Gas Rem: 0.00 MMcf
Gas EUR: 1,170.56 MMcf
Refracture Decline Curve Applied
Proj Oil Cum: 0.00 Mbbl
Oil Rem: 0.00 Mbbl
Oil EUR: 0.00 Mbbl