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Determination of significant parameters that drive fracture optimization in the Glauconite Formation, Southern Chile

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DETERMINATION OF SIGNIFICANT PARAMETERS THAT DRIVE FRACTURE OPTIMIZATION IN THE GLAUCONITE FORMATION, SOUTHERN CHILE

by

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ABSTRACT

The Glauconite Formation in the Magallanes Basin of Southern Chile is a clay- and silica-rich formation with low permeability. As with many of the unconventional resources, the Glauconite Formation requires a hydraulic fracturing operation to enhance the productivity of the wells in this area.

Data and pertinent information of fracturing, completion, and reservoir quality parameters along with post-fracture production data were collected to initiate a database of nearly 70 wells, to be used to develop a better understanding of the fracturing behavior, optimize the well stimulation, and overcome the major barriers in the hydraulic fracturing of the Glauconite Formation. The database of Glauconite wells was used in this study to identify the key parameters of the fracturing design, completion, and reservoir quality that have the greatest influence on well performance in this unconventional reservoir.

This study also attempts to identify the best treatment fluid to maximize well performance and the effects of different values of the major fracture treatments and completion parameters. Statistical and sensitivity analyses were applied to identify the most effective parameters on the initial production, early recovery, and Estimated Ultimate Recovery.

Results of this work show that water fracs are superior to hybrid fracturing fluids. Total fluid and proppant volumes strongly affect well performance. Other completion and reservoir parameters were found to have a lesser impact on well performance in the Glauconite wells of Southern Chile.

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NOMENCLATURE

Symbol	Description
Avg. Concentration	Average proppant concentration.
Avg. Press	Average pumping pressure
b	Parameter used for hyperbolic decline
CF	Cash Flow
D	Decline Rate (% day)
HCPV	Hydrocarbon pore volume
HHP	Hydraulic Horsepower
ISIP	Instantaneous shut in pressure
K	Proportionality Constant
Max Concentration	Maximum proppant concentration.
Max Press.	Maximum pumping pressure
n	Number of Periods
Number of Clusters	Number of perforated clusters/intervals.
Number of Perforations	Number of perforations shots/holes.
PV	Present Value
P-value	Confidence Factor
Q	Cumulative Production
q	Current production rate (STB/day)
r	Rate of Return
R^2	Correlation Coefficient
t-ratio	The ratio of the estimate to its standard error.
Total Fluid	The total volume of Pad, Fluid in slurry volume, and Flush volume pumped.
Total Perforations	Summation of perforated length.
Total Proppant	Total amount of proppant pumped
VIF	The Variance Inflation Factor

1. INTRODUCTION

1.1. UNCONVENTIONAL RESERVOIR

There are many definitions of the term "unconventional reservoir". However, most of the definitions are the same as what Meckel and Thomas used in their reservoir with permeability <0.1 md. (Temizel et al. 2015). They also mentioned in their work 2015 that the unconventional reservoir was described in other studies with an interpolation of petroleum system as "continues" or "basin centered" and lacked traditional traps. Other researchers related this term to product types (i.e., unconventional gas reservoir). Heavy oil and oil sand are considered unconventional resources, despite many of them in high permeability reservoirs that could potentially exceed 500 nd. (Temizel et al. 2015). In a different context, Cander (2012) explained his definition of unconventional resources as petroleum reservoirs whose permeability/viscosity ratio utilized the use of technology to modify either the rock permeability or the fluid viscosity to supply the petroleum at commercially competitive rates. King (2012) established a scale to divide the formation into unconventional, tight gas, and conventional based on the permeability magnitude in millidarcy, as shown in Figure 1.1 the reservoir is classified as unconventional when the permeability is less than 0.001 md. (King 2012)

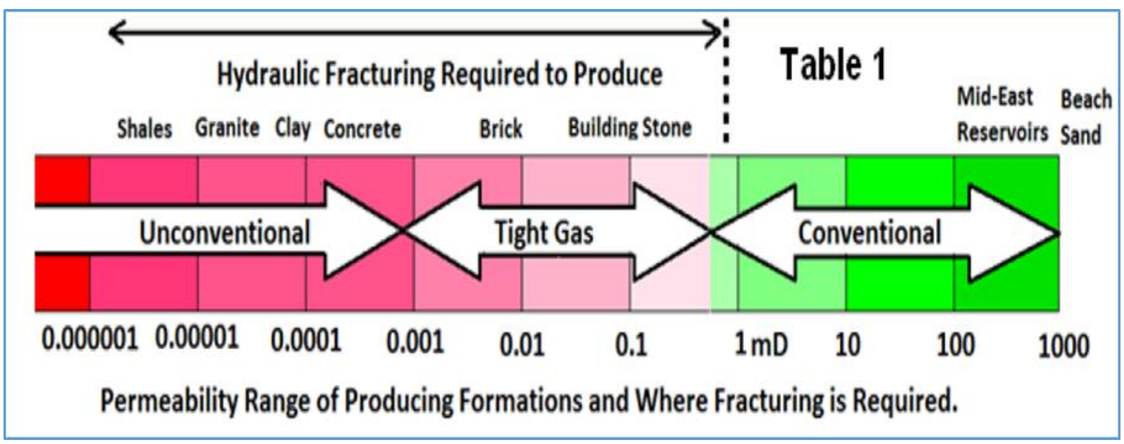


Figure 1.1. Permeability Range (King 2012)

Technically, unconventional reservoirs are known as the reservoirs that necessitate particular recovery operations outside the conventional operating practices. The following are unconventional reservoirs: tight-gas sands, gas and oil shales, coalbed methane, heavy oil and tar sands, and gas-hydrate deposits. These reservoirs require specific recovery solutions such as stimulation treatments or steam injection (“Unconventional Reservoir Wells” n.d). For economic reasons, these specific reservoirs cannot be profitably produced with conventional production methods.

The high development of technology in production from ultra-low permeability is facing difficulties and uncertainty accompanied with well performance characterization and analysis. Many lack the thorough understanding of the production mechanism and the parameters that control production rate, the physics of multi-stage completion, and the reservoir system’s behavior, which are the factors that cause uncertainty. Furthermore, the difficulty associated with building the long term production declined in this reservoir (Mangha et al. 2012).

Mangha et al. (2012) identified some of the challenges in characterizing unconventional reservoirs in the following points:

- Incapacity to tell the difference between hydraulic fractures and reservoir contribution from limited production/pressure history.
- Shortage of knowledge related to hydraulic fracturing geometry in horizontal wells.
- Uncertainty of determining the stimulated reservoir volume (SRV) contribution compared to the surrounding unstimulated reservoir volume.
- Deficiency in comprehension of petrophysics/reservoir properties.
- Linear flow as opposed to the conventional radial flow.
- Transient flow as opposed to the conventional boundary dominated flow.
- Pressure-dependent rock properties.
- Absorption in gas storage mechanics.

1.2. HYDRAULIC FRACTURING

Hydraulic fracturing is the well treatment method that is required to stimulate low permeability reservoirs. This process involved the injection fluid contained within the material to crack the formations (Yang et al. 2014). The term “hydraulic fracturing” is the process of creating fractures in the formations of rocks. Generally, the term “hydraulic” is used in applied science, which deals with the mechanical properties of liquids. For these considerations, the term “hydraulic fracturing” classifies all techniques that use liquid as a fracturing agent (Temizel et al. 2015).

The hydraulic fracturing process mainly consists of initiating a fracture in the formation using hydraulic pressure of the treatment fluid, the fracture propagation, and the proppant that holds the fracture open. These propped fractures represent the conductive pathway for the fluid to flow between the formation and the wellbore. To complete the procedure, hydraulic fracture design is composed of three main stages: the pad stage, the slurry stage, and flush stage. The pad stage includes injecting fluid without a proppant. The purpose of this stage is to initiate and propagate the fracture, develop adequate fracture width and provide enough fluid for leak-off. The slurry stage differs from other stages because the injection fluid does contain proppant, the aim of this stage is to place the proppant in the fracture. Therefore, the proppant concentration is constant through the length of the fracture at the end of pumping. The final stage is the flush, where the slurry is flushed to the perforation Figure 1.2 Shows the hydraulic fracture process and illustrates the placement of the proppant to establish a conductive pathway of the formation fluids. A hydraulic fracture operation could accommodate the production and/or production rate and increase the productivity of the reservoir by billions of barrels containing oil and trillions of cubic feet of gas. The hydraulic fracturing led to direct and indirect positive effect on the economy which was facilitated by increasing the energy sources of a variety of energy consumer facilities. Successful fracturing operations was required to collect necessary data in attempt to understand the overall processes and achieve optimal design strategy.

Jones and Britt (2009) presented a historical overview of hydraulic fracturing using the operations data to develop the fracture design. They stated that hydraulic fracturing was introduced by Stanolind (Amoco) in 1947. Thereafter, Godbye and Hoges (1958) recognized the significance of the pressure data. These data and its relation to in-situ stresses were used in a different model such as these by Khristianovic and Zheltov (1955). In 1978, a coordinated program of field data was collected and analyzed to boost the understanding of the fracturing mechanism. This program produced results such as the considerable work by Nolte and Smith (1981) that introduced the significant basis for the interpretation of pressure behavior during fracture treatment. Another work of Nolte (1979) introduced a procedure for quantifying the fluid-loss coefficient, fracture length and width, fluid efficiency, and time for the fracture to close from the mini-frac test, which was used in many designs (p.1-2).

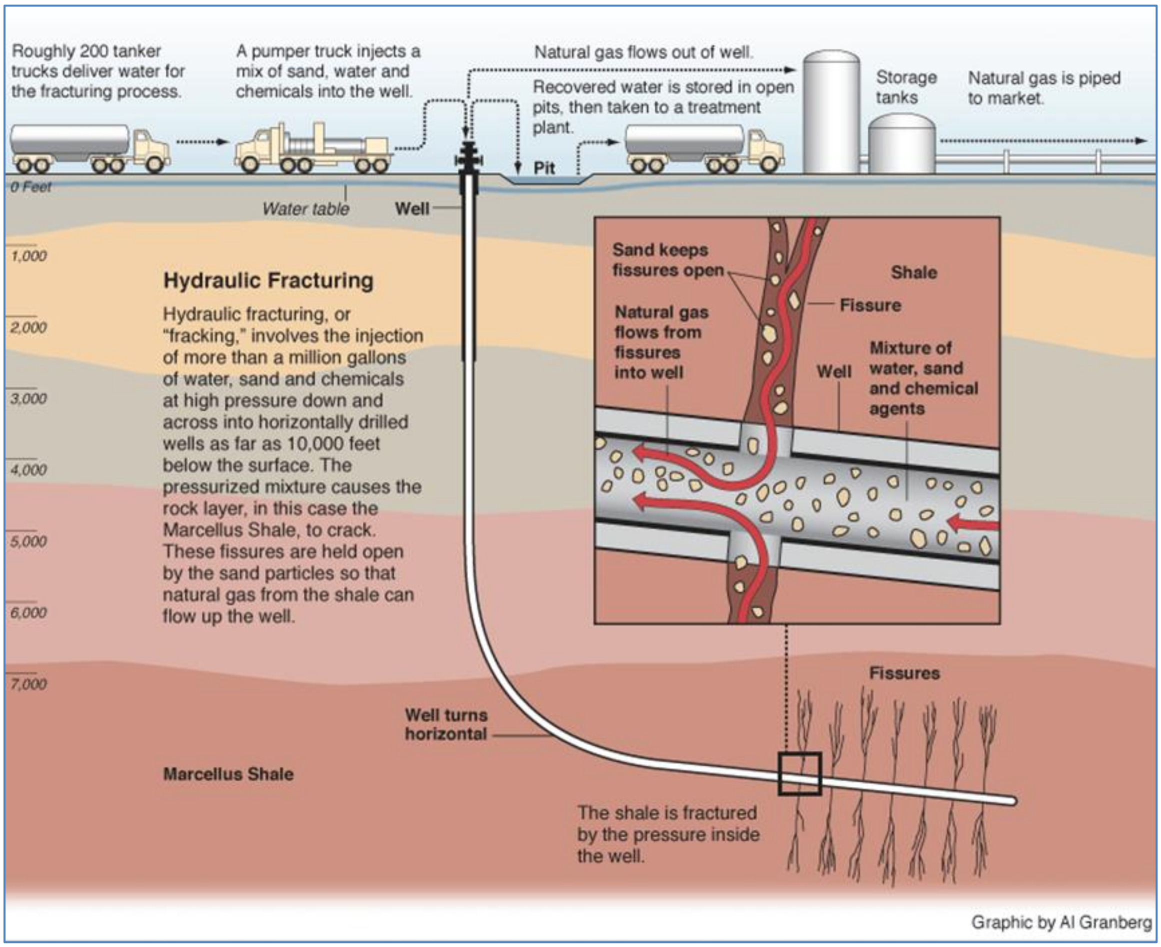


Figure 1.2. What is Hydraulic Fracturing? (Schmidt 2015)

1.3. THE GLAUCONITE FORMATION OF SOUTHERN CHILE

Britt et al. (2016) illustrated the characteristics and location of the Glauconite Formation in southern Chile. They defined the Glauconite Formation of the Magallanes Basin, as a tight gas sandstone and siltstone with notable percentages of glauconite, clay, and feldspar with a gross thickness of 50 to 150 meters. The hydrocarbons of the Glauconite Formation comes from the lower Cretaceous Estratos con Favrella and Lutitas con Ftanita Formation. The Magallanes Basin occupies about 200,000 square kilometers and is the southern most hydrocarbon-producing basin in the world (U.S.G.S 2015). The basin extends roughly 700 kilometers in length and 370 kilometers in width at the widest point. The Magallanes Basin is surrounded by the Patagonian Andes Fold-Thrust Belt to the west, the Rio Dungeness Arch to the north, and the Malvinas Basin to the east and northeast as shown in Figure 1.3 (Pinto et al. 2014). The figure also displays the Arenal Block (AR), which extends from Tierra Del Fuego onto the mainland. The portion of the block on Tierra del Fuego is the primary area of interest of this work.

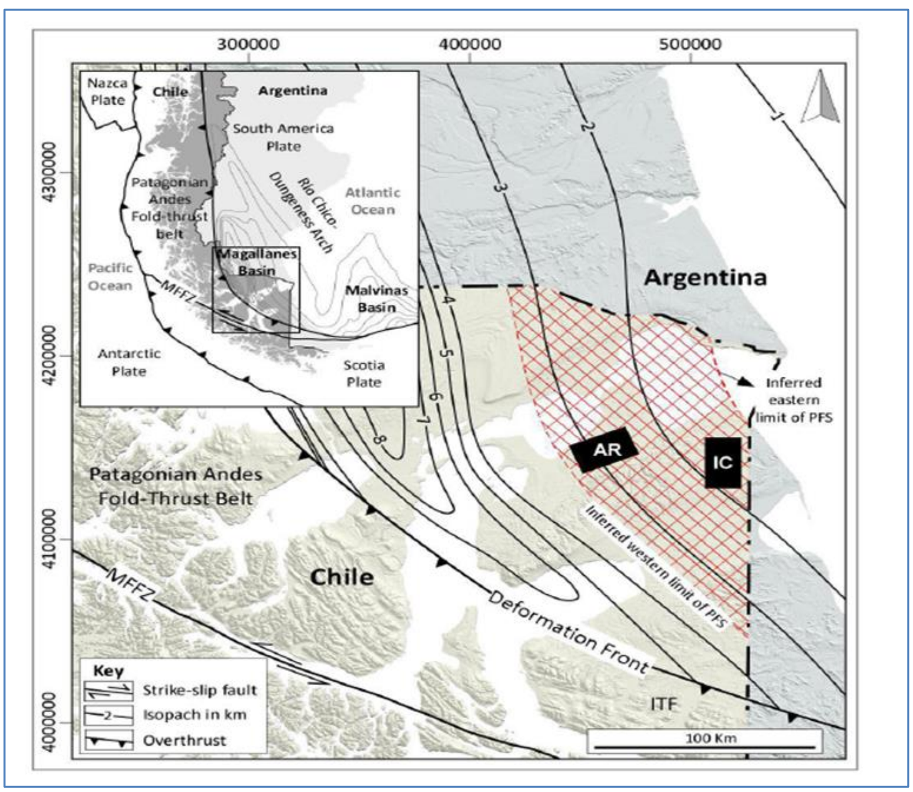


Figure 1.3. Map of the Magallanes Basin (Pinto et al. 2014)

Figure 1.4 presents a stratigraphic section located in Chilean part of the Magallanes Basin which is called "Austral Basin in Argentina" (Pinto et al. 2014). This figure demonstrates the stratigraphic nomenclature, typical fossil and mineral content, and the two polygon fault system. These fault systems extend through the rocks of the upper Cretaceous to reach and extend through the Glauconite Formation in the early Eocene.

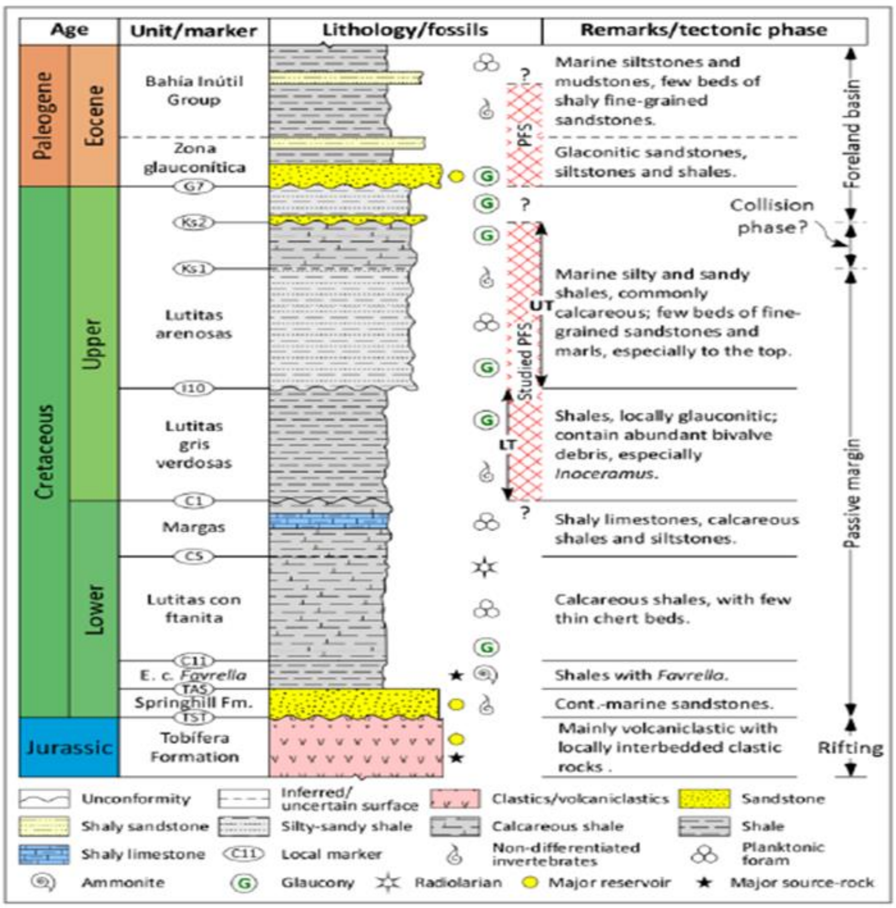


Figure 1.4. Generalized Geologic Section of the Magallanes Basin
(Pinto et al. 2014)

The mineralogy of the Glauconite Formation is complex; the composition of the formation contains quartz, clay, glauconite, and a small percent of tuff. Britt et al. (2016) identified the mineralogy content of the Glauconite Formation by examining three hundred and eight core plugs. The results are represented by ternary diagrams in Figures 1.5 and 1.6. Figure 1.5 shows the silicate (quartz and feldspars), carbonates, and clay glauconite content. The figure indicates that there is a small portion of carbonate in the Glauconite Formation. While Figure 1.6 exhibits components of quartz, feldspar, and clay and glauconite. The figure illustrates that the Glauconite Formation is composed of 23% quartz, 34% feldspar, and 43% clay and glauconite.

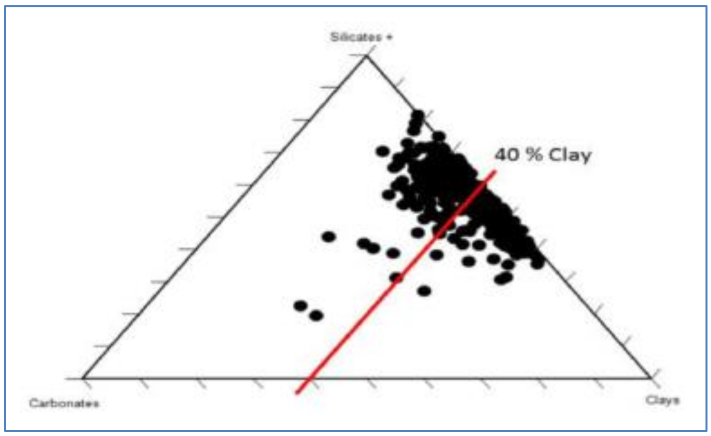


Figure 1.5. The mineralogical content of Glauconite Formation (silicate, carbonates, and clay glauconite) (Britt et al. 2016)

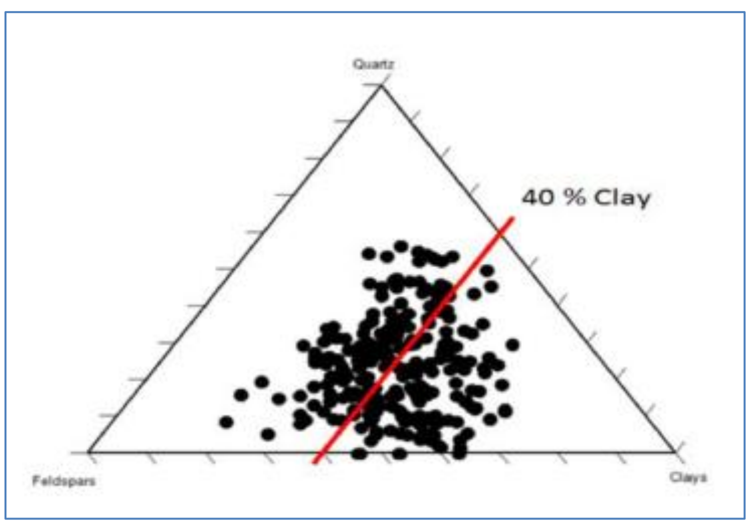


Figure 1.6. The mineralogical content of Glauconite Formation (quartz, feldspar, and clay and glauconite) (Britt et al. 2016)

1.4. THE OBJECTIVE OF THE STUDY

A database of nearly seventy wells contained two major sorts of treatments, Hybrid Treated Water and Linear Gel fracturing and Treated Water fracturing, which was based on the fracturing fluid type. The data contained a variety of fracturing, completion, and reservoir quality information. It also included post-fracture production data of the Glauconite Formation of southern Chile. The objective of this project was to use this data to identify which fracturing, completion, and reservoir parameters have the greatest impact on initial productivity, early recovery, and Estimated Ultimate Recovery for both stimulation types. Recognition of these parameters helps to address the factors that are required in the fracture optimization. Moreover, the work investigated the fracture type that more benefited to enhance the performance of the well in the Glauconite Formation. The project also tries to answer the following questions:

1. What are the effects of fracture parameters such as the proppant and the fluid?
2. How do the completion variables drive the post-fracture production?
3. What are the roles that could be derived from the well performance after fracturing?
4. What volume of proppant produce the highest economic benefit of the stimulated well in the Glauconite Formation.

2. LITERATURE REVIEW

Kazakov and Miskimins (2011) used a multivariate statistical method in a study on Jonah Field in Wyoming and The Barnett Shale in Texas. This study was conducted to investigate the possibility of prediction by using slick water parameters which can provide intuition into the design of the slick water treatment, and to use this multivariate method to discover the relation between stimulation parameters and the production. The authors used factor, cluster, and multiple regression methods to predict the (EUR) and cumulative water production in Barnett Shale, and a multiple regression method was used to predict (EUR) in Jonah Field. More specifically, a two relations were set up for the multiple regression. First, the relationship between the fluid pumped and the fluid recovered was established. Secondly, a relationship which calculated the amount of proppant used in Jonah Field stimulation from the total fluid and net pay was determined. The prominence of each parameter was established by comparing each one to other parameters using the multivariate analysis. The results demonstrated a weak correlation between EUR and slick water treatment parameters in both the Barnett Shale and Jonah Field. Also, the multiple regression shows a relationship between EUR and cumulative gas, whereby EUR was calculated based on decline curve analysis. The authors also determined a relation between the total fluid pumped and that recovered. This relationship was then used to predict the amount of fluid recovered in the Barnett Shale. The relationship had a regression coefficient of 92.8% and was determined between total fluid, total proppant, and net pay based on factor, cluster, and multiple regression analysis. This relationship can be used to predict the quantity of the proppant pumped in Jonah Field.

Grieser et al. (1998) inspected the completion data consisting of 28 wells in the frontier zone of Fontanelle Field, WY, in 1996 and 1997. This information included porosity-ft, job size, total proppant, gel-system type, breaker quantity, and pH. These factors were used by the trend empirical analysis mode (TEAM) in their study. The object of this analysis was to examine the factors that have most influence on production. The parameters were listed without considering the fact if these parameters have control or not. During their research, they discovered that common parameters such as porosity and total proppant have a high impact on productivity. However, Parameters such as pH, breaker quantity per lb. of gel, ∆ lSIP1, and ∆ lSIP2 are had greater effect on for production. The most effective parameters during the 90 days of cumulative gas production were as follows: total lb of proppant/gal, gal of liquid pumped, ∆ ISIP, ratio of 16/30 proppant, and lb breaker/lb of gal. Increasing percentages of sand and ∆ISIP led to a decrease in the production.

Grieser et al. (2006) reviewed a database of 393-wells that was completed from 1993–2002 in the North Texas Barnett Shale. The data contained within this study included completion, reservoir, and production data. The initial review of the data before the authors made their analysis indicated that they were able to predict some the parameters' behavior in correlation with the stimulation of the Barnett Shale, such as the following:

- Barnett shale provides a commercial benefit in all situations.
- Slick water fracturing surpasses crosslinked fracturing because the last was damaging the Shale.
- Increasing fluid, proppant, and rate increases the production.
- Reservoir quality does not have significant effect on production.
- Stimulation parameters have clear effect on production.

Because the extensive distribution of the production data had been plotted with different completion and reservoir variables, the authors had to devise a method to extract the useful data and information. They used self-organizing maps (SOM) to limit the statistical errors and indicate the affecting parameters. As a result of this study, the authors indicated that slick water fracturing produced better results than crosslinked gel treatment in the Barnett Shale. The size of the treatment had the largest effect on production with total fluid volume is more important than the quantity of proppant.

Meyer et al. (2013) gave an outline of the number of necessary parameters and ideas that are significant in hydraulic fracture design and increase the productivity in unconventional reservoirs. Understanding these factors will help one build a gridline for optimization with multi-stages/multi-clusters of hydraulic fracturing in horizontal wells. The authors began with a discussion of some relevant multi-topics and researchers, such as design formula, mini-frac analysis, the impact of stress-dependent and Young's modulus on hydraulic fracture modeling, and technology integration—a methodology that enhances production. The authors addressed three key parameters for a successful hydraulic fracturing treatment and production enhancement. These parameters include the following:

1- Dimensionless fracture conductivity (and fracture penetration).

2- Production interference.

3- Mechanical interference.

Moreover, the authors introduced a method to optimize the spacing in multiple transverse vertical fractures in horizontal wells; this simple process was used to predict the production behavior in these kind of fractures.

The authors concluded with the following key points:

1. Dimensionless fracture conductivity and fracture penetration are the major factors that enhance the productivity.
2. Fracture conductivity greater than optimum value (Prats 1961) can enhance well performance in low permeability reservoirs.
3. Mechanical interaction of multiple parallel fractures produced a large impact on fracture slot for short-spaced parallel or transverse fractures.

Lafollette et al. (2014) used large data sets of completed wells in Eagle Ford, Texas that were analyzed using multivariate statistical analysis and input that data analysis into the geographic information system (GIS) application. This specific study used a special data mining method and GIS mapping in attempt to overcome some data gathering challenges to reveal impact of the key well, completion and stimulation factors on productivity and production efficiency. The authors divided the Eagle Ford Formation of southern Texas into three major producing areas. The areas were then researched thoroughly with mapping techniques, and each area was modelled using Boosted Trees.

The study yielded many important points displayed below:

1. Many wells, along with their completion and stimulation variables, are not normally distributed. Therefore, the boosted regression tree model could be a wiser technique to use to analyze this data than standard multiple linear regression.
2. The location of the wells was a significant predictor of the production.
3. Gas/Oil Ratio was a major predictor of production.
4. The impact of treatment size on production was larger than stage count.

5. A large treatment with more results yielded better productivity.

Yetkin et al. (2012) researched on developing a method to determine the important hydraulic fracturing parameters and measure their effect on EUR. In order to accomplish this study, the authors formed a comparison of reservoir simulation with probabilistic analysis methods. Following a history matching, the authors presented and defined the following parameters that control impact of hydraulic fracturing on the recovery which were:

- Matrix-Fracture exchange: the complexity of the fracture.
- Fracture conductivity: the permeability effective on the hydraulic fracturing.
- Fracture half-length.
- Job size: the size of the frac fluid volume injected during the hydraulic fracture.

The author used a particular technology in the study that created a response surface for the group of parameters. The technology combined an experimental design, response surface, and Monto Carlo analysis. History matching had played a major role in this study and was used to model the flow mechanism and geotechnical properties. The authors summarized and defined the parameters that were used in this parametric study as the following:

1- TEXMULT: Determines the magnitude of the matrix-fracture exchange which represents the complexity of the fractures determined by the surface area created in the matrix due to fracturing.

2- KXMULT: Determines the magnitude of the fracture conductivity in the major stress direction.

3- PVFMULT: Determines the volume of the hydraulic fracture fluid and represents the size of the hydraulic fracture job.

4- TYFMULT: Determines the magnitude of the communication in the opposite of the major stress direction within the hydraulic fracture.

5- NSREDUCTION: Determines the reduction factor to decrease TEXMULT, KXMULT, PVFMULT and TYFMULT in the opposite of the main stress direction away from the wellbore for a complex fracture geometry.

The study showed that NSREDUCTION had a larger effect on the EUR.

Mohaghegh et al. (2005) collected and analyzed data from more than 230 wells in the Golden Trend Field of Oklahoma. Through this analysis, the authors attempted to find the most influencing factors of some reservoirs, along with completion and stimulation parameters for production rate and ultimate recovery. However, this study was focused on identifying the best type of fluid, the optimal injection rate, and proppant concentration, which was applied for oil and gas bearing formations. The authors used a new methodology called "Intelligent Best Practices Analysis" to analyze large amounts of data in order to derive the information that required to achieve the optimum designs. The intelligent best practices analysis included two major steps. The first was descriptive analysis, where the productivity of the well is divided into several sets and the average of several parameters is calculated to examine the trend of the database. The second step was predictive analysis, where the data was thoroughly reviewed starting with whole field data and ending with a single well. Moving through these processes, the authors were able to conclude that in order to achieve better productivity, the two formations type, clastic and carbonate, should be isolated before the stimulation jobs. Additionally, the authors recommended using diesel oil as the main fracturing fluid for the clastic formations in the Golden Trend. It was also determined that while using acid as the main fluid in the carbonate formations, gas was mainly produced in the Golden Trend. Furthermore, the study showed that a low number of perforations enhanced the productivity for both types of formations. During their analysis, it was identified that using higher proppant concentration has a positive effect in the Golden Trend, and the recommended average injection rate was 0.2 BMP per foot of pay thickness.

Mathur et al. (1995) created a case study from the Gulf Coast to investigate the effects of fracture parameters such as fracture half-length and fracture conductivity on short and long time productivity by listing these parameters in relation to the degree of wellbore damage in a sensitivity analysis procedure. The study included various important considerations like the skin effect, well performance with cleanup and well test interpretation.

The following four points summarize the outcome of this case study:

1- In highly permeable formations, increasing the fracture conductivity has the highest advantage in terms of fracture design.

2- Initial productivity is important because fracture-face invasion will reduce over time.

3- Theoretically, seldom happened with a positive skin after proppant treatment, and if that did occur, it would be less than 5. High positive skin (more than 20) could result if the dimensionless conductivity less than 0.01.

4- Through an accurate well test, the fracture half-length, fracture conductivity, and magnitude of the fracture-face skin can be obtained.

Modeland et al. (2011) developed several assumptions in regards to building a database that contained 12 or more month's production or of the Haynesville shale reservoir. The authors applied a statistical analysis to predict the best completion methodology to improve the productivity of the stimulated wells. The authors stated that the productivity of Haynesville shale reservoir depended on several completion variables such as geographic locations, number of hydraulic fracture stages, perforations clusters, treatment rate, conductivity, and fluid type.

Several points were concluded for the statistical analysis that are as follows:

1. The location has a large effect on early production of Haynesville in eastern Texas and northern Louisiana.
2. The production can be enhanced by increasing the number of treatment stages across the Haynesville shale formation because the volume of the stimulated reservoir is increased.
3. Execution of the treatment within the 6-cluster stages should be performed with a higher rate to provide equivalent production to 4-cluster stages.
4. The conductivity that resulted from the proppant concentration and the total volume lead to the increase of the 12 month's production.
5. The crosslink fluid treatment defeated the treatments that did not contained the crosslink because the crosslink treatment contains higher proppant concentration.

Saldungaray et al. (2013) presented their work showing the relation between the fracture conductivity and productivity that is related to the effect of the proppant selection. In addition to showing the effects of transverse fracture, they showed proppant concentration and flow dynamics. The general idea is that fracture conductivity is taken into consideration less within the fracture design, which stimulated the author's thoughts to research in detail about the importance of the fracture. The work was based on the case study of the tight shale gas and liquid rich formations. In order to explore the broad range of parameters, the author divided them into four major categories:

- Wellbore placement band lateral length.
- Completion hardware and isolation.
- Fracture spacing or number of fracs.
- Fracture geometry and conductivity.

Many important points were concluded through the work related to the fracture conductivity; the proppant pack conductivity effected many parameters, including proppant particular size, proppant strength, proppant grain shape, and embedment into the faces, and fracturing fluid damage. Therefore, it is unusual to reduce the proppant pack conductivity more than two orders magnitude when compared to the American Petroleum Institute (API) and International Organization for Standardization (ISO). An individual must consider the optimal F_{CD} in the proppant selection for any given reservoir and be aware of other for potential effects such as flow convergence in transverse fracs and proppant transport in low viscosity during proppant selection for multi-stage fracs in horizontal wells. In proppant selection, one must give special consideration to the economic benefit by comparing each proppant option with their impact on well performance and the predicted production with each treatment cost. This work showed that the improved conductivity resulting from appropriate proppant has a great benefit in term of well performance and productivity in very low permeability formations.

Rafiee et al. (2012) realized that geomechanics play a major role in the success of the well stimulation process. The authors introduced an analytic model that predicts the changes in stress anisotropy around the fractures of different designs in elastic-static mediums. Moreover, they discovered the effect of geomechanic parameters on fracture geometry by using a numerical model based on the boundary element method. The boundary element method (BEM) is “a numerical computational method of solving partial differential equations that have been formulated in boundary integral form” (Rafiee 2012). The study was applied to a particular case, but the result of the survey could be used in other situations. The authors had to determine stress anisotropy, which is a method known to optimize the distance between the fractures in multi-stage stimulation.

The outcome of the study has been summarized into the following points:

- The stress anisotropy performs changes due to creating the two fractures. Therefore, the origin of change is at the middle of the distance between those fractures.
- If the exceeded stress anisotropy surpasses the original value, then stress reversal occurs.
- The width of the fracture is directly proportional to the net pressure and spacing between the fractures.
- The fracture created by the modify zipper fracture is more conductive than the fractures created by alternating fractures.

Shelley and Stacy (1997) published a benchmarking study of about 560 wells completed in the Cherokee Group of western Oklahoma. Through the study; the authors tried to collect enough information to achieve the optimum fracture design in this area. The study was applied to a large number in the production database from January 1, 1988, to January 1, 1989. This period of production was chosen because the data was more unadulterated and valid than before 1988. Additionally, a new technology was available, which added more appraisal. Different completion and stimulation methods resulted from the production data of a larger number of wells. Four main categories were applied in the statistical analysis within this work: the production data, well type, treatment volume, and fluid type. The analysis showed that the higher quality reservoirs overcame the low quality in a stimulation response. Also, the high-quality reservoir stimulated/reacted better with treatment containing 35% to 70% CO_2 fluids. Moreover, a large volume of medium-viscosity fluid enhanced the productivity, while high-viscosity fluid (crosslinked) damaged the well’s performance.

3. METHODOLOGY

3.1. DATABASE CONSTRUCTION

The database was initiated and developed by the previous work of Britt et al (2016). A valuable spreadsheet contains data of stimulation, completion, reservoir, and post production of the Glauconite Formation in Tierra del Fuego of Southern Chile. The stimulation data included the information on a preliminary fracture design, mini- frac tests, fluid additives, and actual fracture data. The important details of each category are listed below:

a) Preliminary fracture information for every well:
   i. Fracture type based on the fluid of the treatment.
   ii. Pump rate.
   iii. Pad volume.
   iv. Fluid volume.
   v. Quantity of sand and ceramic
   vi. Total proppant

b) Mini-Frac test data:
   i. Breakdown pressure.
   ii. Hydraulic horsepower.
   iii. Fluid type.
   iv. Fluid volume.
   v. Pump rate.
   vi. P*.
   vii. ISIP.
   viii. P closure (surface).
   ix. P closure (bottom hole).
   x. T closure.
   xi. Efficiency %.

c) Actual fracture data:
   i. Pad volume.
   ii. Slurry volume.

iii. Flush volume.

iv. Total fluid volume.

v. Maximum pressure.

vi. Average pressure.

vii. Average pump rate.

viii. Hydraulic horsepower.

ix. Final pressure.

x. ISIP.

xi. 10 minute pressure decline.

xii. Maximum concentration.

xiii. Quantity of sand, ceramic, and carbo-bond.

xiv. Total proppant pumped.

xv. Total proppant in the formation.

The completion data included information about the perforation interval as following:

a) Number of fractures.

b) Total perforations.

c) Number of perforation clusters.

d) Perforation diameter.

e) Number of perforation holes

The reservoir evaluation data included:

a. Net pay thickness.

b. Average porosity.

c. Average water saturation

d. Clay volume.

e. Reservoir pressure.

f. Hydrocarbon pore volume.

Table 3.1 displays the average value of stimulation, completion, and reservoir parameters as a function of fracture fluid type.

Table 3.1. Database Parameters and Averages as a Function of Fracture Fluid Type

Pump Rate, BPM	18.0	31.7	50.0	50.0	50.0
40/70 Sand, mlbs	0	0	306,483	370,167	438,711
20/40 Sand, mlbs	66,600	0	179,131	238,067	252,897
Total Sand, mlbs	66,600	0	470,547	608,235	691,610
20/40 Ceramic, mlbs	0	219,000	182,448	70,000	20,708
20/40 RC Proppant, mlbs	0	0	17,255	5,600	9,303
Total Ceramic, mlbs	0	219,000	199,703	75,601	30,012
Total Proppant, mlbs	66,600	219,000	686,476	683,835	721,622
Maximum Concentration, ppg	5.0	5.7	3.4	2.3	2.5

Mini-Frac Analysis	Cross-Linked	Linear Gel	Hybrid TW/LG	Modified TW	Treated Water
Number of Frac's	2	3	29	6	37
Breakdown Pressure, psi	4,470	2,713	2,686	2,852	2,889
P*, psi	1,531	768	765	855	738
ISIP, psi	1,897	1,911	2,012	2,028	1,999
P_{close}, psi	1,866	1,424	1,377	1,476	1,450
dP_s, psi	31	487	634	552	549
T_{close}, min	11.7	434.9	343.2	120.6	85.2
Efficiency, %	28.2	85.1	87.5	81.1	76.4

Completion Analysis:	Cross-Linked	Linear Gel	Hybrid TW/LG	Modified TW	Treated Water
Number of Frac's	2	3	29	6	37
Total Perforations, m	13.7	20.7	17.3	13.3	14.0
Perforation Interval, m	16.0	28.0	22.9	18.1	20.8
Perforation Clusters, m	1.0	4.0	2.6	2.7	3.5
Perforations, holes	53	NA	158	271	252
Perforation Diameter, in	0.405	NA	0.420	0.480	0.450
Perforation Phasing, degrees	60	60	60	60	60

Actual Frac Execution:	Cross-Linked	Linear Gel	Hybrid TW/LG	Modified TW	Treated Water
Number of Frac's	2	3	29	6	37
Average Pad Volume, BBls	476	590	522	467	808
Total Fluid Volumes, Bbls	1,782	2,482	10,892	12,794	14,387
Total Proppant, mlbs	66,598	229,500	646,400	659,633	720,054
Pump Rate, BPM	18.6	32.0	50.3	50.3	50.0
Maximum Pressure, psi	5,055	2,604	3,105	3,199	2,987
Average Pressure, psi	4,640	2,109	2,486	2,566	2,376
Final Pressure, psi	4,243	2,596	3,206	2,800	2,774
Hydraulic Horsepower, HHP	2,113	1,991	3,230	3,162	2,912
ISIP, psi	1,940	2,032	2,147	2,172	2,115
10 Min Pressure Decline, psi	NA	1,946	2,002	2,019	1,966
Maximum Concentration, ppg	5.0	5.0	5.4	2.5	2.7

Reservoir Evaluation:	Cross-Linked	Linear Gel	Hybrid TW/LG	Modified TW	Treated Water
Number of Frac's	2	3	29	6	37
Net Pay, m	8.0	13.7	15.2	18.4	15.9
Average Porosity, %	16.9	14.5	16.0	15.4	17.2
Average Water Saturation, %	46.5	45.3	47.9	49.6	51.1
Clay Volume, %	NA	35.8	34.2	31.8	30.6
Reservoir Pressure, psi	4,294.3	4,169.9	4,317.1	4,366.9	4,413.4
Hydrocarbon Pore Volume, ft	2.5	3.5	4.3	4.7	4.4
IP, Mm^3pd During Clean-Up	NA	NA	57.5	74.7	65.8

The production data included gas rate during clean-up, 3-month recovery, 6-month recovery, 9-month recovery, and 12-month recovery. Additionally, the database of Estimated Ultimate Recovery (EUR) was calculated and implemented by the company ENAP using rate transient analysis. This information was included in the overall database.

3.2. DIVIDING THE DATA BASED ON FLUID TYPE

In the previous section, the different fracturing, completion, and reservoir parameters were listed. These parameters were set as an independent variables and the aim of the project was to find their effect on the post-fracture production that determined the dependent variables.

Since there were two major types of treatment based on fluid types: (1) Treated Water Fracture and, (2) Hybrid Treated Water and Linear Gel Fracture, it was necessary to test the effect of the independent parameters on the dependent variables. The purpose of this step was to determine if the variables initiate a different behavior in each type of treatment. The total proppant and total slurry were observed within the scatter plot as independent variables, with the gas rate during flow back as a dependent variable. As an example to emphasize the purpose above. The plot showed that the proppant and slurry volume pose a different effect in each treatment, as shown in Figure 3.1 The software JMP was used for construct the scatter plots in the figure. The construction of the data table in the form of JMP tables was performed by importing the data Excel sheet or by copy and paste. The data table was constructed into many columns and rows. Each row represented the well name, while each column represented a different variable. Accordingly, the database was divided into subdatabases based on the treatment type, hybrid fracturing and water fracturing. Each data collection contains the same dependent and independent variable. The tool “Graph Builder” was used to create the graphs.

Figure 3.1 shows that the data as highly scattered, both in the water frac treatments (right side) and hybrid treatments (left side). The difference in the trends led to evaluating each fluid type separately in the study, and the high level of scattering led to the use of multivariate analysis to better identify trends in the data.

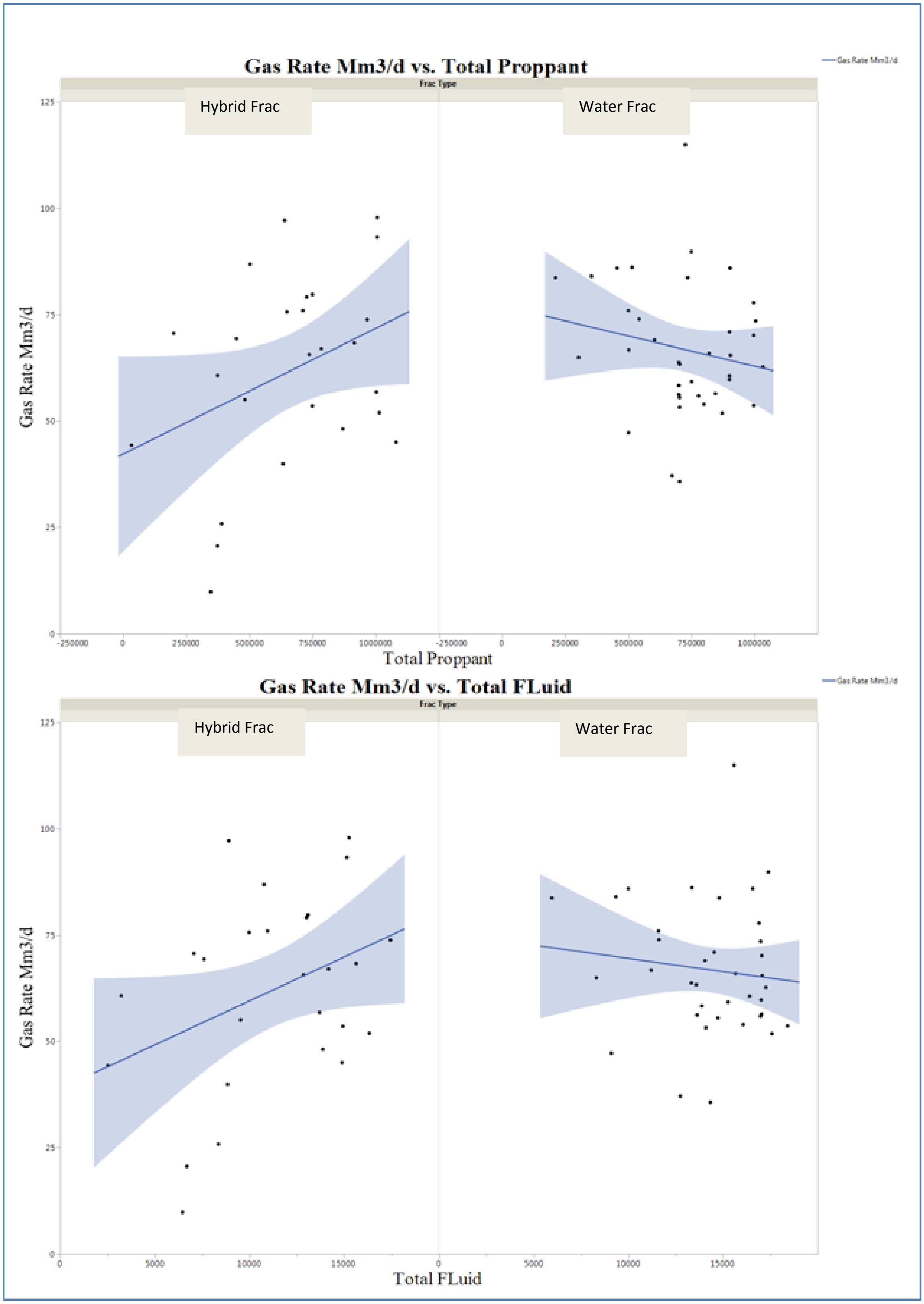


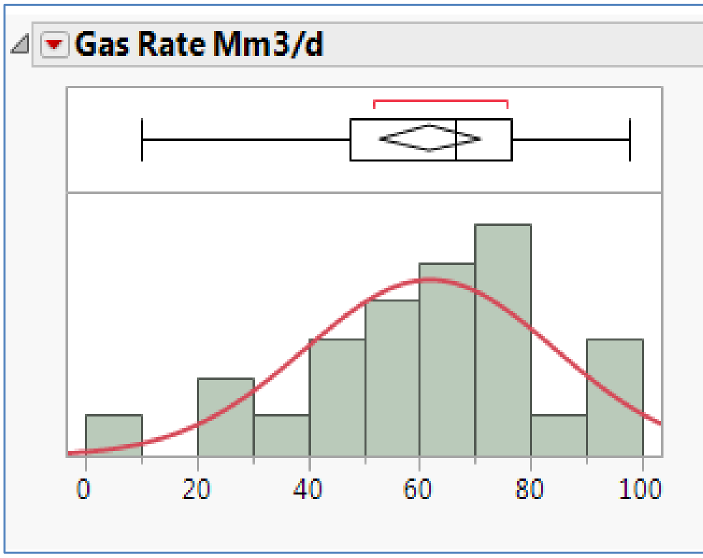
Figure 3.1. The different of proppant and slurry trend in each frac type

3.3. DATA FILTERING

The data from any statistical method utilized to analyze the pertinent data should be checked and filtered in order to ensure data reliability. Identifying a specific statistical problem like missing data and multicollinearity was a key point used to determine the modality of dependent and independent variable selection.

3.3.1. Univariate Method. The first attempt to screen the data was done by using a histogram and boxplot. The procedure was applied to the dependent variables of the gas rate during flow-back, 3-month recovery, 6-month recovery, nine-month recovery, 12-month recovery, and Estimated Ultimate Recovery for three reasons. This procedure had three purposes: 1) to examine the normality of the data distribution which is mostly preferred in the data analysis, 2) to inspect the outliers, and 3) to collect important statistical information which are mean, standard deviation, standard error, and the number of elements. The option "Distribution" in the tool "Analyze" in the JMP software was used for this intent.

3.3.1.1 Hybrid treatment. Figure 3.2 demonstrates the histogram and some statistics, which list the values of mean, standard deviation, standard error, and the number of elements for gas rate during flow-back. The graph also indicates the distribution of the



Summary Statistics	
Mean	61.969231
Std Dev	22.552388
Std Err Mean	4.4228872
Upper 95% Mean	71.078338
Lower 95% Mean	52.860124
N	26

Figure 3.2. Histogram of Gas Rate during Flow-back / Hybrid Frac

data was very close to the standard normal distribution by fitting the normal distribution curve. Figures 3.3, 3.4, 3.5, 3.6, and 3.7 shows the histogram and summary statistics of 3-month, 6-month, 9-month, 12-month, and Estimated Ultimate Recovery respectively.

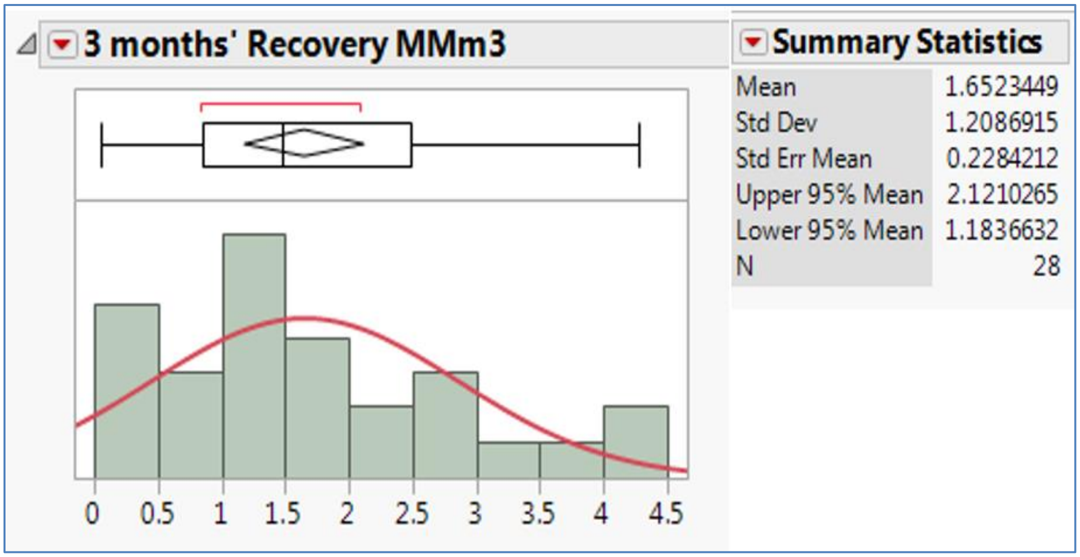


Figure 3.3. Histogram of 3-month Recovery /Hybrid Frac

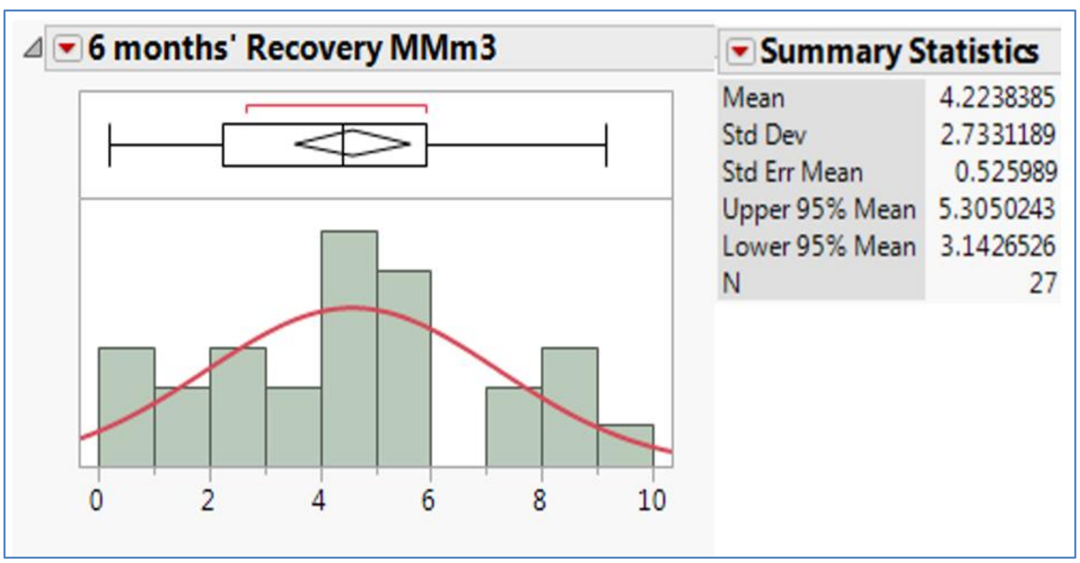


Figure 3.4. Histogram of 6-month Recovery /Hybrid Frac

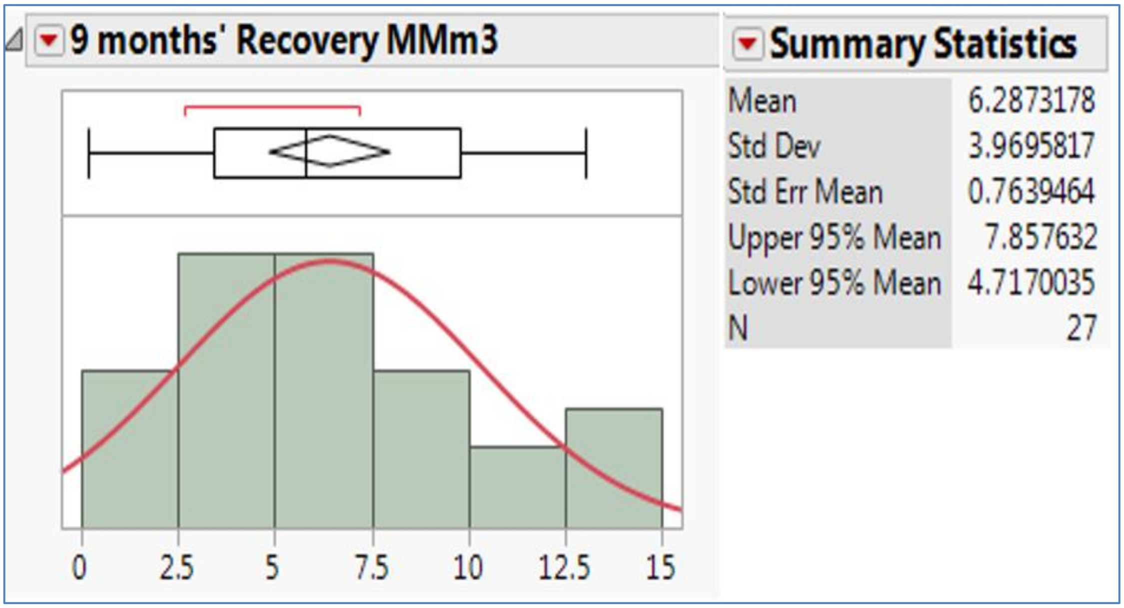


Figure 3.5. Histogram of 9-month Recovery /Hybrid Frac

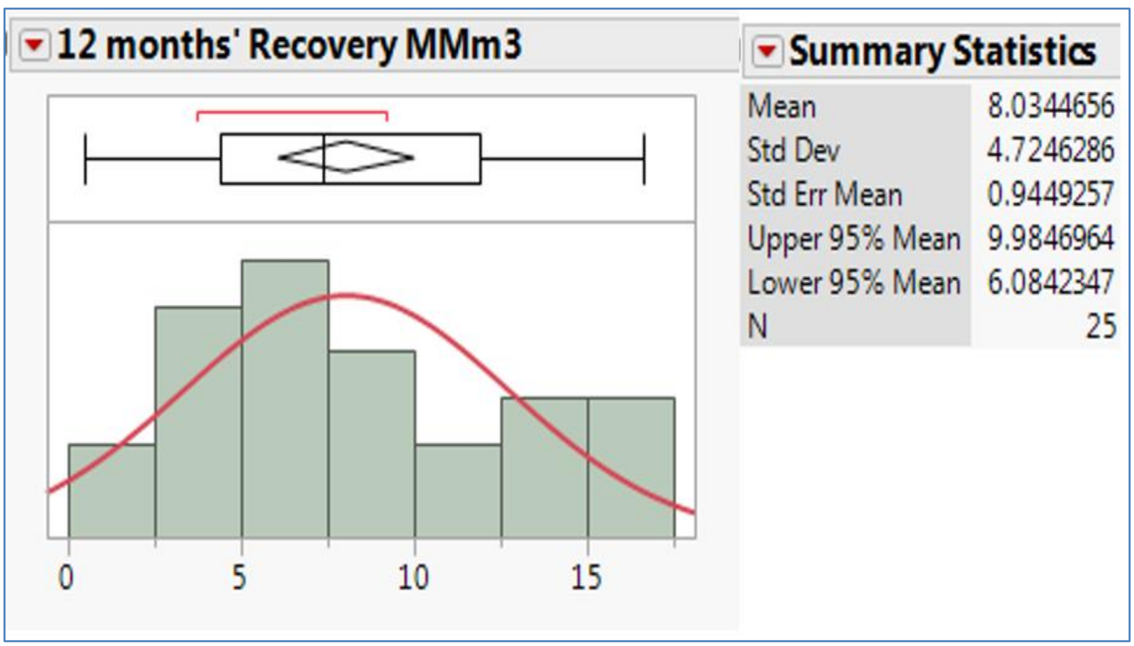


Figure 3.6. Histogram of 12-month Recovery /Hybrid Frac

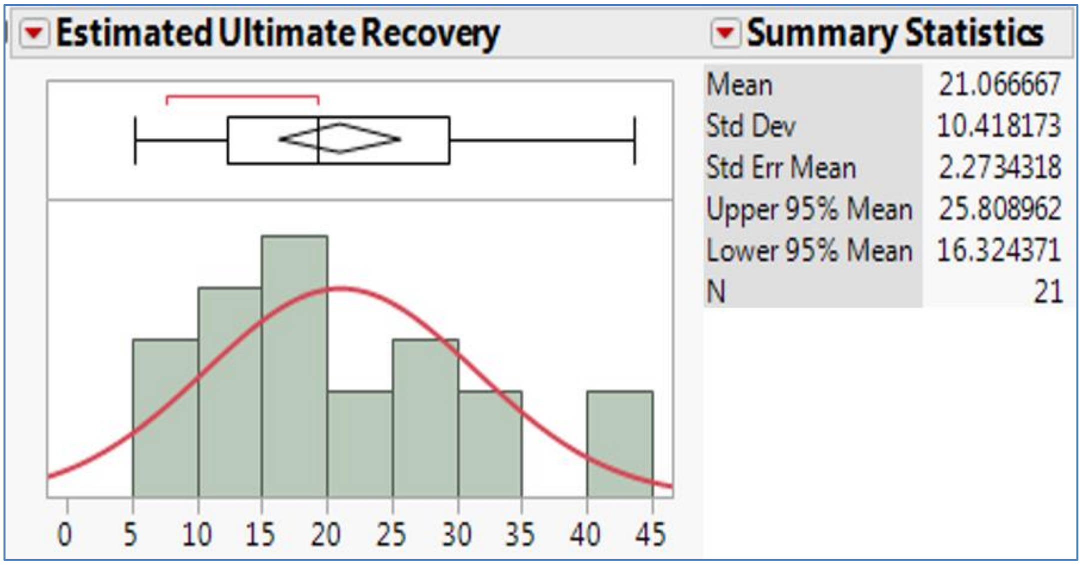


Figure 3.7. Histogram of Estimated Ultimate Recovery/ Hybrid Frac

3.3.1.2 Water treatment. The water frac data was analyzed similar to the hybrid fracturing data. Unfortunately, there were very limited data for cumulative recovery after 6 months production, because the water treatments were quite recent. Since there were insufficient data for statistical analysis, no analysis of cumulative recovery beyond 6 months is included in the study, except for EUR which has been calculated. Also, many of the treated water fracture stimulations were performed in multiple phase pads, whereas the recovery data required production distribution from limited production tests, resulting in an inaccurate estimate. However, the analysis was conducted on the available completed data, which are gas rate during flow-back, 6-month recovery, and estimated ultimate recovery. Figure 3.8 represents the histogram and a summary of statistics for gas rate during flow-back. In this figure, the boxplot area located in the top of the figure, shows that outlier data was evidently released, demonstrating the major role of the boxplot in identifying the outlier. After the function of the boxplot was utilized, the outlier point was excluded from this data table using the "hide and exclude" option in the software. Figure 3.9 and 3.10 exhibit the histogram of the 6-month recovery and estimated ultimate recovery respectively. Table 3.2 summarizes the statistical information for the gas rate during flow-back, 3-month recovery, 6-month recovery, 9-month recovery, 12-month recovery, and estimated ultimate recovery for each fracture type.

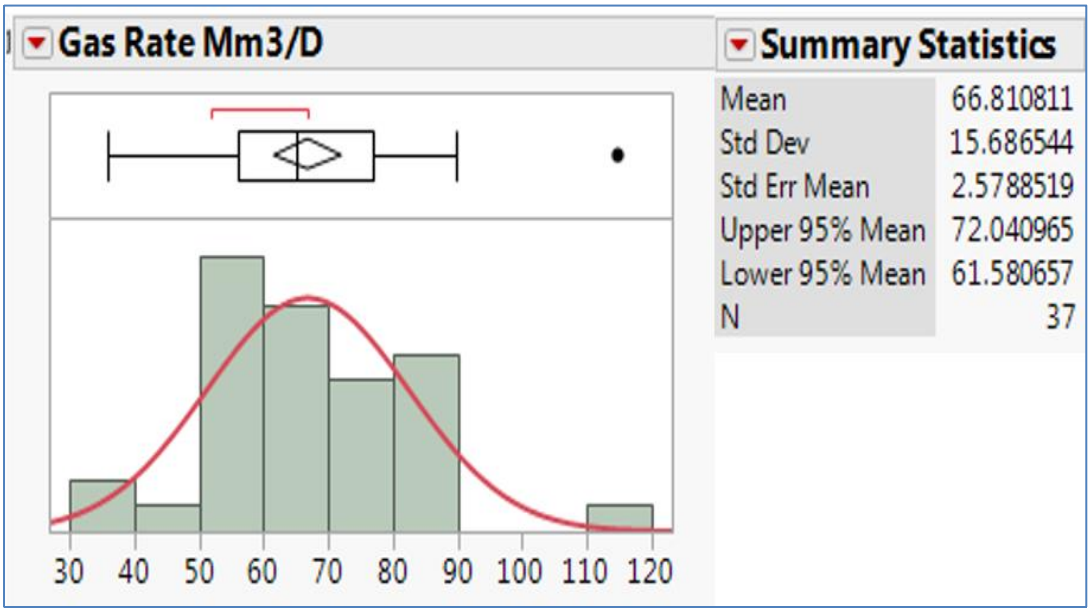


Figure 3.8. Histogram of Gas Rate during Flow-back / Water Frac

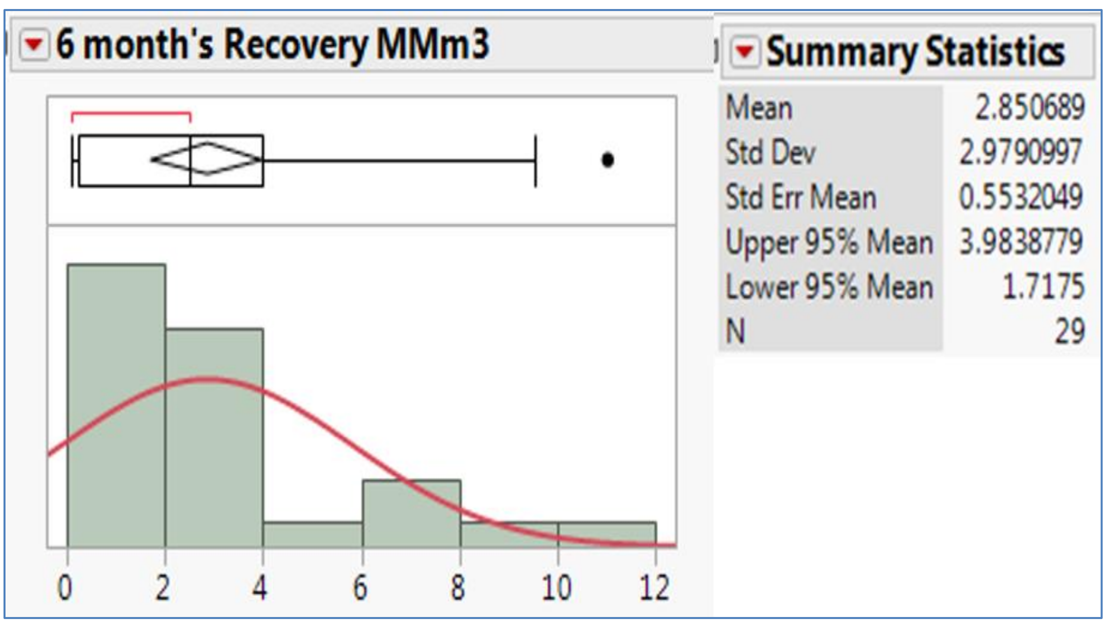


Figure 3.9. Histogram of 6-month Recovery /Water Frac

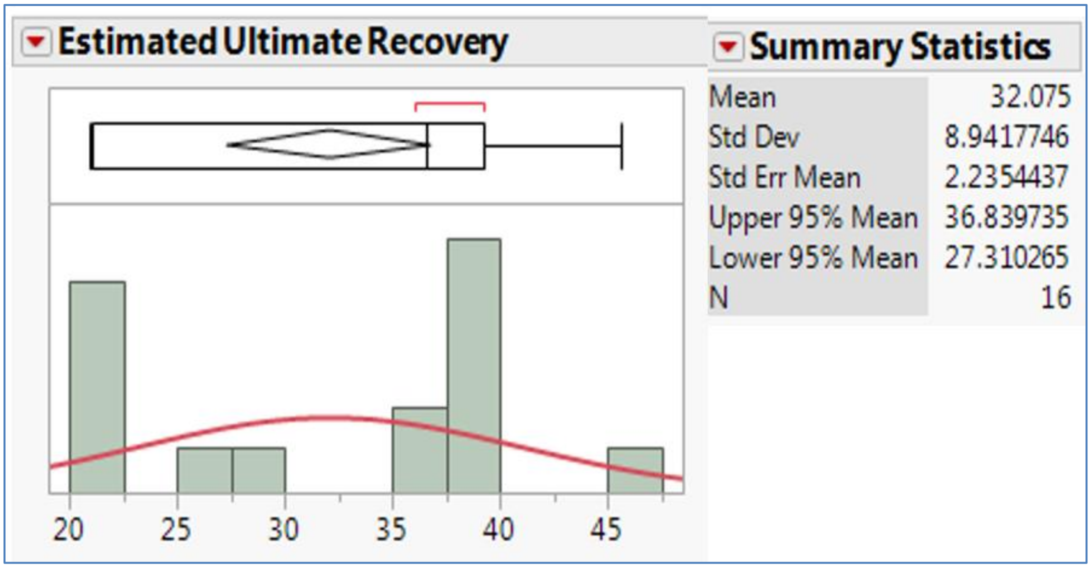


Figure 3.10. Histogram of Estimated Ultimate Recovery/ Water Frac

Table 3.2. Uni-Variate Results of Histogram Analysis

Description of Hybrid:	Number	Mean	Standard Deviation	Standard Error of Mean
Gas Rate During Flow-back	26	61.969	22.552	4.423
3-Month Recovery	28	1.652	1.209	0.228
6-Month Recovery	27	4.224	2.733	0.526
9-Month Recovery	27	6.287	3.969	0.764
12-Month Recovery	25	8.034	4.725	0.945
EUR	21	21.06	10.418	2.273
Description of Treated Water :	Number	Mean	Standard Deviation	Standard Error of Mean
Gas Rate During Flow-back	37	66.881	15.687	2.579
6-month Recovery	29	2.851	2.98	0.553
EUR	16	32.07	8.941	2.235

3.3.2. Multivariate Method. Since the data was limited, the previous method to test the independent variables was not highly recommended. There was a variety of independent variables used, and the exclusion of the outliers would have reduced the data even further. Therefore, a scatterplot matrix was best to examine the independent variables represented by stimulation, completion, and reservoir evaluation.

The purpose of this process is to find the correlation between the parameters and identify the multicollinearity, which is considered a potential problem in multiple regression analysis. Additionally, another advantage associated with this procedure is that provides the best evaluation of the data and elimination of the outliers through the Mahalanobis method. This method was performed once on the independent variables, and then to the independent variables and one dependent variable at each given time. A tool called multivariate which is an option located under the “Analyze” tab in the JMP software was used to perform this method.

3.3.2.1 Hybrid treatment scatterplots matrix. The scatterplot matrix was constructed for the hybrid treated water and linear gel fracture stimulations. Figure 3.11 shows the scatterplot matrix of the stimulation parameters of the hybrid fracture. As described previously, one purpose of the scatterplot is to determine the correlation between the parameters. These figures contained bivariate plots for each parameter with the 95% confidence ellipse, placing emphasis in red to symbolize the identification of outliers. Noted in the figure, the total fluid and, total proppant parameters had a correlation coefficient of 0.9275, which is an indication of multicollinearity. This circumstance will be discussed in detail at a later time. Figure 3.12 and 3.13 demonstrate the scatterplot matrix of reservoir quality parameters and completion parameters respectively.

3.3.2.2 Water treatment scatterplots matrix. Figure 3.14 represents the scatterplot matrix of fracture parameters for water treatment stimulations. This figure shows a good example of multicollinearity. The model is represented by the correlation between hydraulic horsepower (HHP) and Average Pressure. These two variables have a regression coefficient of just about 1 because the HHP is equal to the product of a constant, pump rate, and average pressure. For this data, almost all the hybrid fracture stimulations and water fracture stimulations were pumped at a rate of 50 BPM. As a result, the hydraulic horsepower (HHP) highly correlates with the average pressure. In other example, the relation between total fluid and total proppant with correlation coefficient is 0.9346, which indicates those two parameters are reliant on each other. Figure 3.15 illustrates the relation

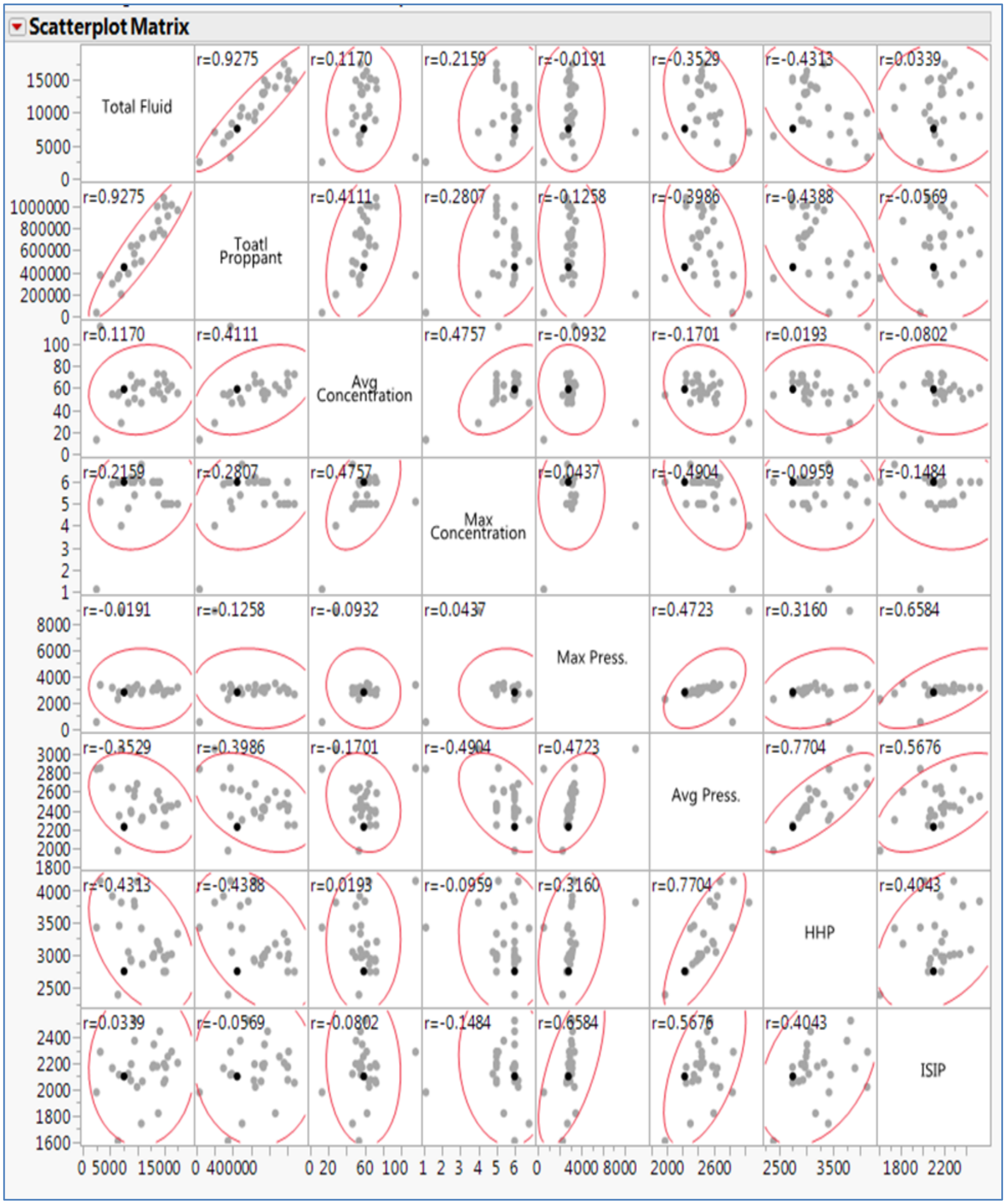


Figure 3.11. Scatterplot Matrix of Stimulation Parameters for Hybrid Treated Water & Linear Gel Frac

between the completion parameters of water treatment fracture, while Figure 3.16 exhibit the correlation of Reservoir quality parameters. As shown Figure 3.16, the hydrocarbon pore volume and net pay are significantly correlated.

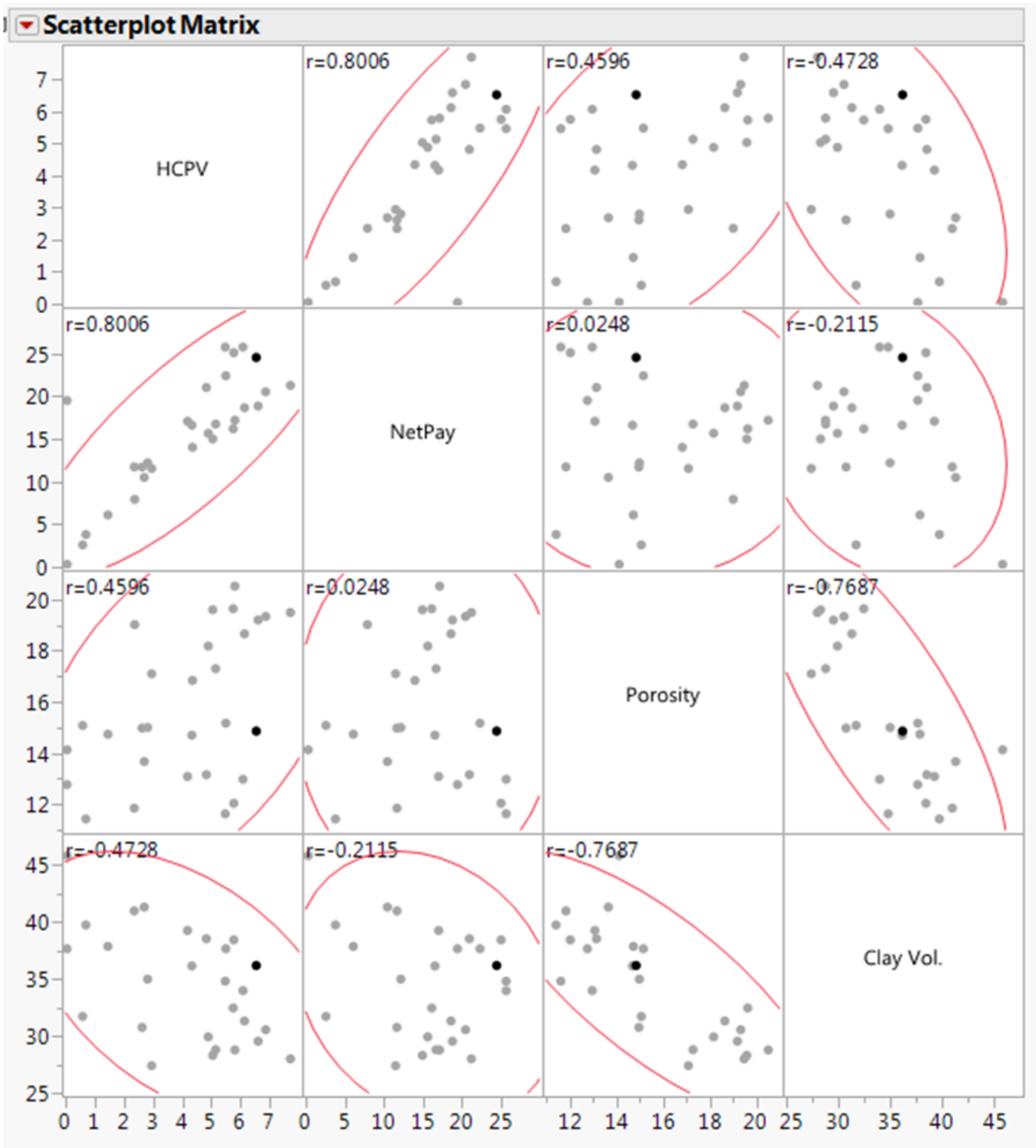


Figure 3.12. Scatterplot Matrix of Reservoir quality parameters for Hybrid Treated Water & Linear Gel Frac

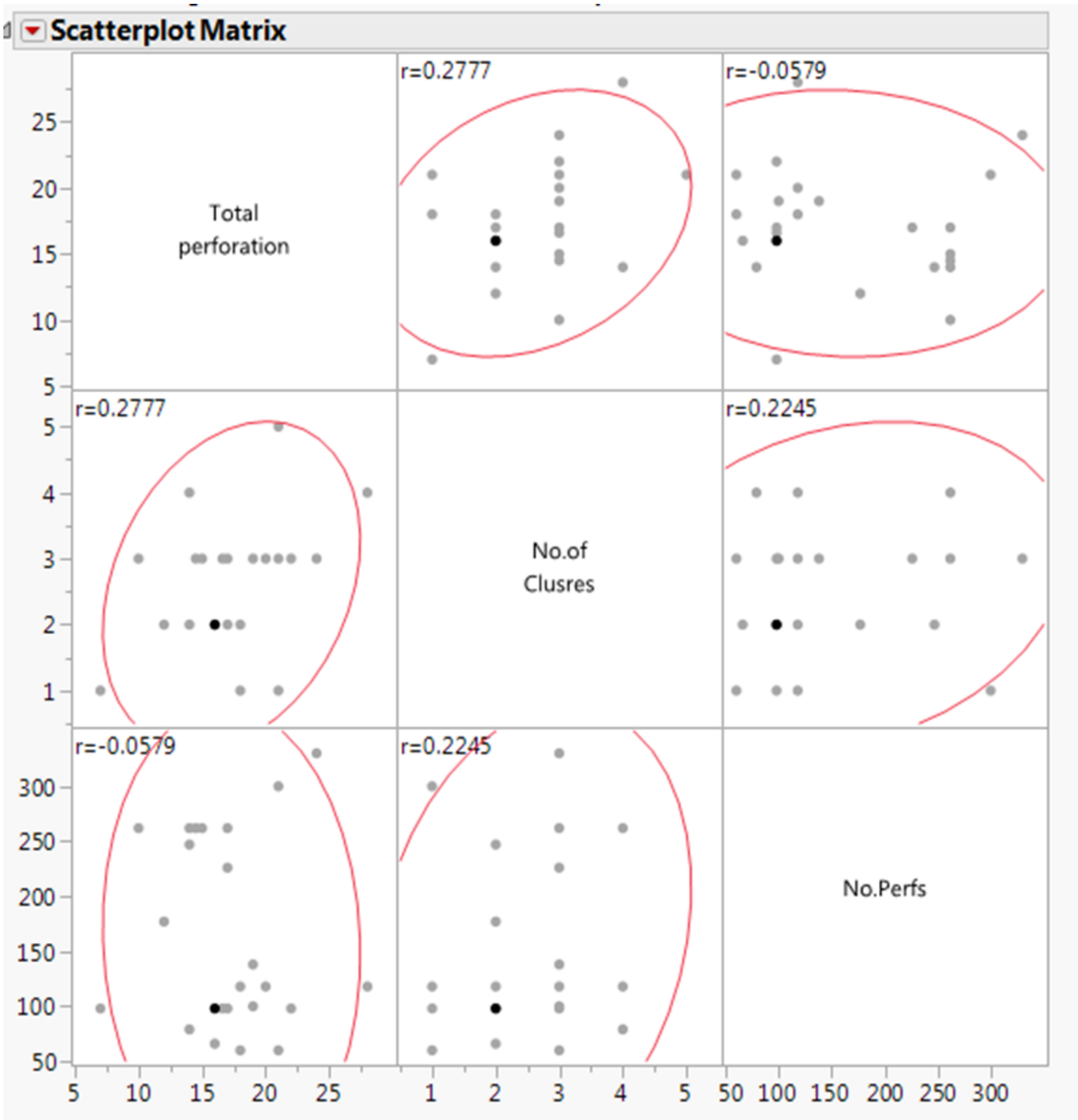


Figure 3.13. Scatterplot Matrix of Completions parameters for Hybrid Treated Water & Linear Gel Frac

3.3.3. The Results of the Scatter Plots Play a Vital Role in the Determination of Multiple Regression Variables. As previously mentioned, the existence of multicollinearity could cause an issue in the multi-regression analysis. Multicollinearity is the situation of where there are two or more variables in a multiple regression analysis are highly correlated; this phenomenon could skew the outcome of the analysis. The scatterplot matrix of stimulation parameters for both water treatment fracture and hybrid treatment fracture shows that total fluid and total proppant was highly correlated. This collinearity could mislead the results of the analysis. This was discussed by Alqatrani et al. (2016). However, in the evaluation of hydraulic fracture stimulations one would like to have both the fluid and proppant pumped represented in the analysis. Given that these parameters likely reflect information regarding fracture dimensions. For example, it may be viewed that proppant pumped may be more representative of fracture conductivity while the fluid pumped may be more representative of fracture length at least as related to treated water fracture stimulations and the early parts of the hybrid treatments. To this end, a series of multi-variate analyses were performed to determine various statistical properties to assess whether total fluid, total proppant, or both total fluid and proppant could be included in the analysis without detrimentally impacting the multi-variate statistical analysis. The results of this assessment showed that for nearly all dependent parameters the correlation coefficient was improved by including both the total fluid and proppant as independent variables in the analysis. A review of the confidence factors and the Variance Inflation Factors for the total fluid case, total proppant case, and the combined fluid and proppant case suggests little effect of multi-collinearity of the analysis. Additionally, it was determined that net pay be utilized as the pay quality parameter rather than hydrocarbon pore volume and that neither hydraulic horsepower nor average pressure had a sufficiently low p-value to be of significance to the analysis (Alqatrani 2016).

In other circumstances, the scatterplot matrix of reservoir quality parameters showed that as the clay volume increases, the hydrocarbon pore volume, net pay, and porosity decreased which is considered reasonable consequences. On the other hand, the scatterplot of the reservoir quality for water treatment indicated that as the clay volume increased the hydrocarbon pore volume and the net pay increased, while the porosity decreased as anticipated. The two different scenarios and the irrational relation between clay volume and the other pay quality variables led to the decision that clay volume was not preferred to be included in the multivariate analysis.

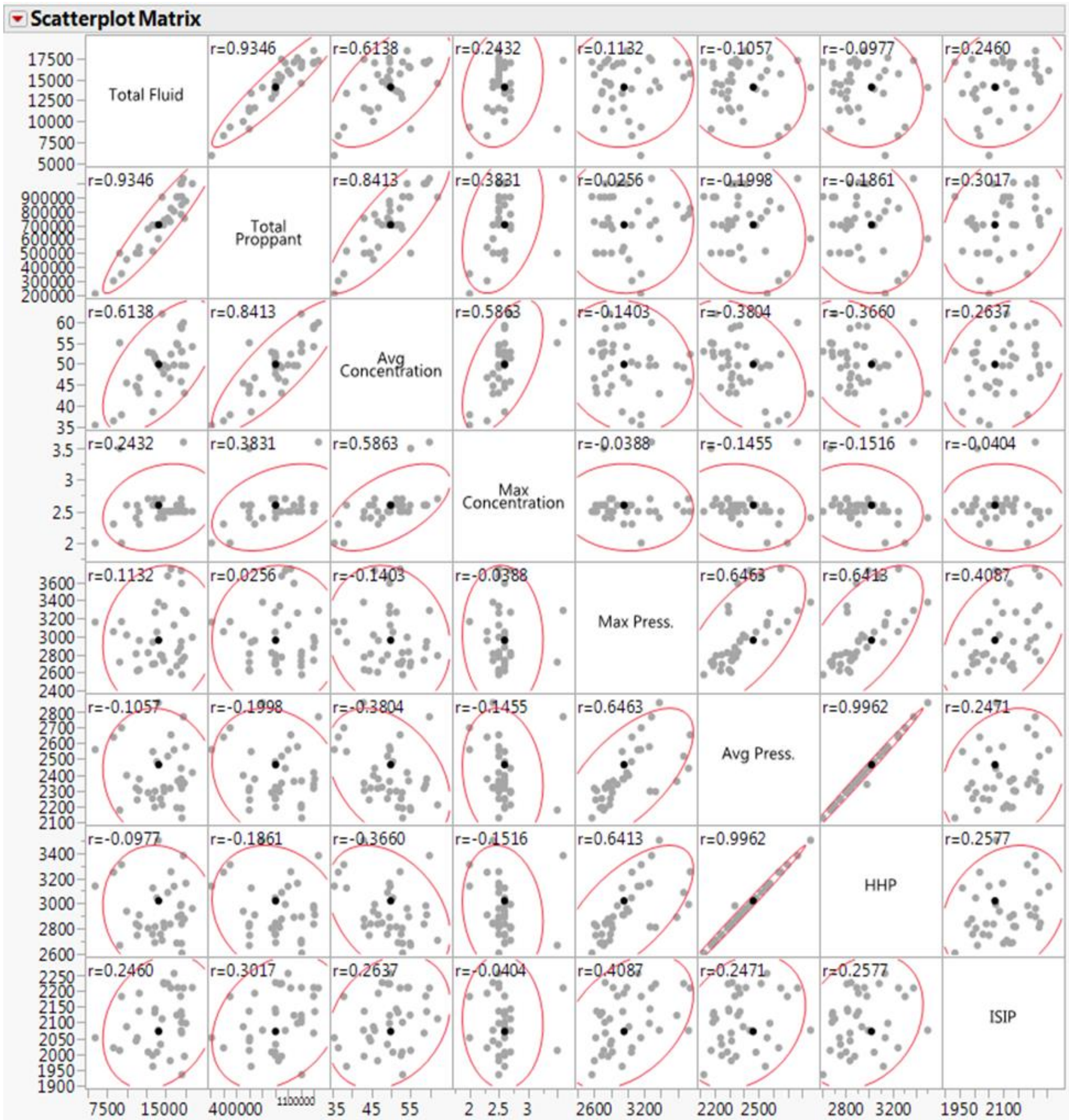


Figure 3.14. Scatterplot of Stimulation Parameters Matrix for Treated Water Frac

3.4. MULTIPLE REGRESSION ANALYSIS

Multiple regression analysis is a statistical method used to predict the value of an independent variable based on two or more other dependent variables. Using this approach, an analysis was conducted on the relation between the multiple independent parameters that were discussed in Section 3.1 and dependent variables represented by gas rate during flow-back, 3-month recovery, 6-month recovery, 9-month recovery, 12-month recovery, and estimated ultimate recovery (EUR). This method was used to predict the dependent variables of the production/recovery from the independent variables, which included pre-fracture mini-frac data, fracture data, completion data, and reservoir quality data. The objective of this technique is to maximize the predictive capabilities of the independent variables. In addition, the analysis shows the relationship and the degree of the relationship between the dependent variables and independent variables. The outcome of the procedure

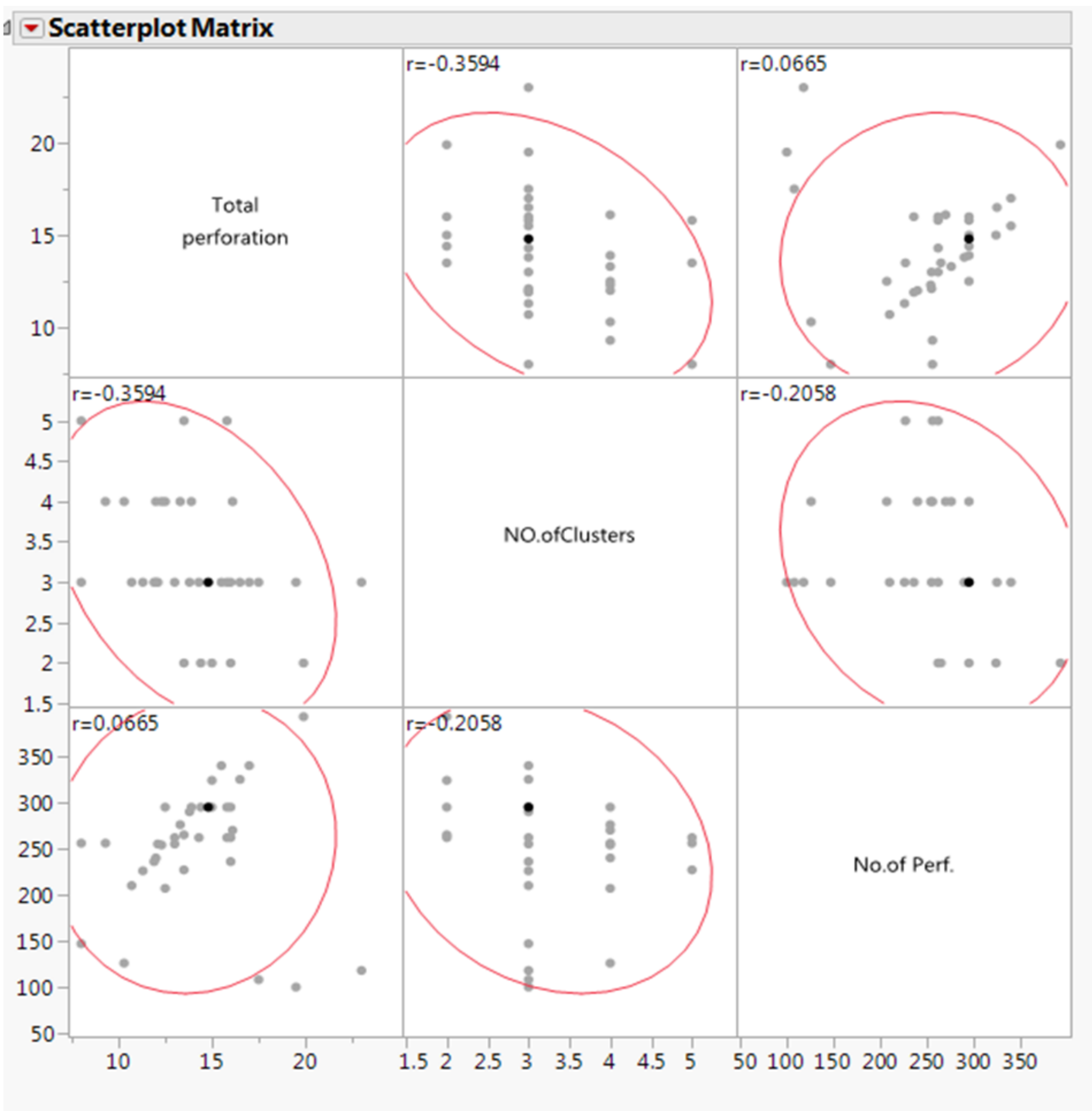


Figure 3.15. Scatterplot of Completion Parameters Matrix for Treated Water Frac

was represented by an equation and plots to show the strengths of the relation between the predictive value and the real values. The standard least squares estimation was selected in the analysis, and the dependent variables test was determined. A single independent variable was selected, and the confidence level was set at 0.05. The independent parameters that may potentially be included in the final equation should have a p-value less than 0.05 to be considered significant. In addition, statistical evaluation parameters such as Variance Inflation Factors and standard errors were used to assess the value and predictive capability of the independent variables.

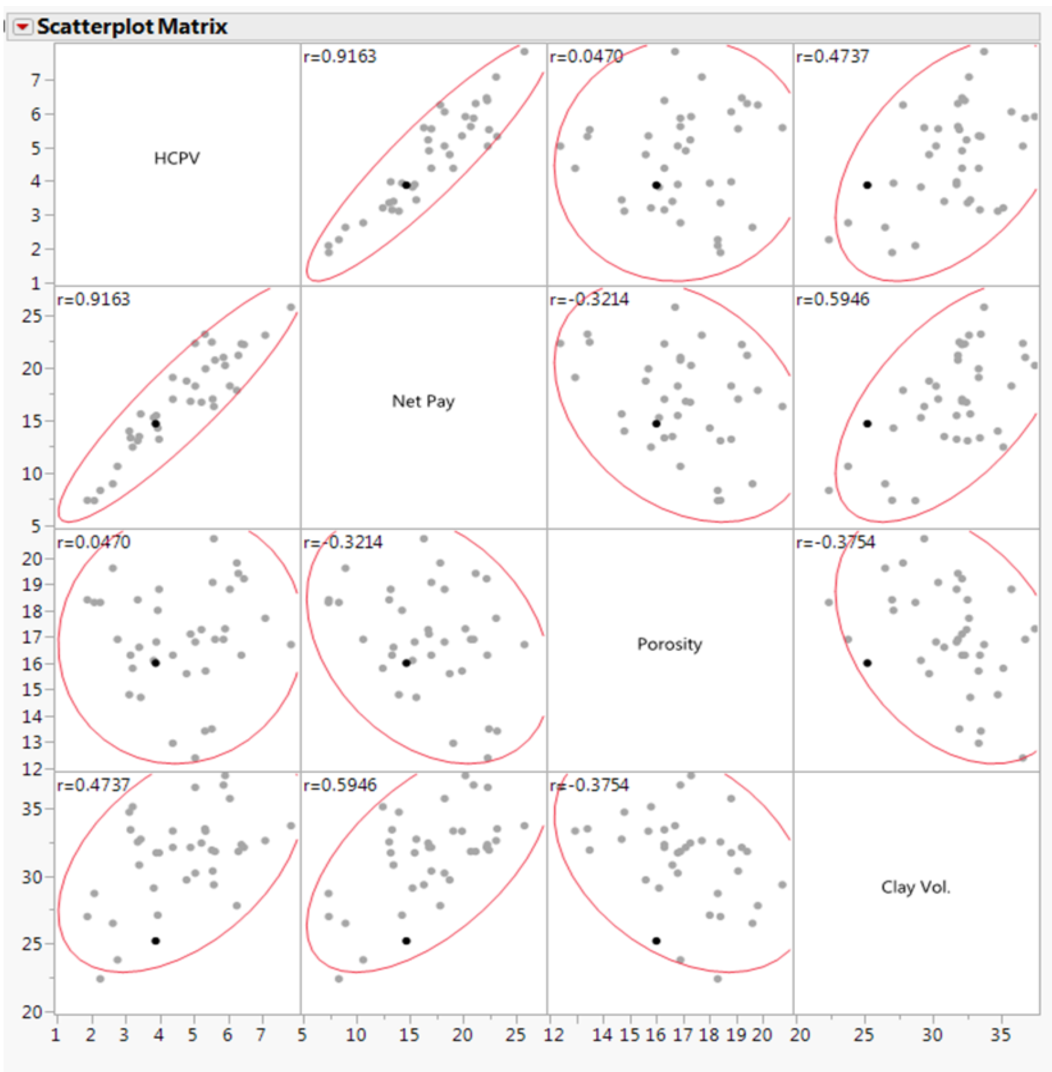


Figure 3.16. Scatterplot of Reservoir quality Parameters Matrix for Treated Water Frac

Finally, a sensitivity analysis was used to generate a visual method to present the independent variable parameter estimates that would sort the parameter estimates and plot these parameters into a tornado chart. The equations that were estimated through multiple regression analysis were the basis to establish the tornado charts using commercial software. The goal of this operation was to show the final result of the most effective parameters estimation. The figures showing the multi-regressions and the sensitivity are presented in the results section.

4. ANALYSIS AND RESULTS

4.1. MOST EFFECTIVE PARAMETERS ESTIMATION

Tornado charts were built to specify the effect of the independent parameters, which were represented by fracturing, completion, and reservoir quality, on the dependent variables represented by the production/recovery. During a multivariate analysis procedure, the significant parameters were considered and usually kept in the analysis, while the variables that were not statistically significant were eliminated from the models. This elimination was based on the p-value (less than 0.05). For both fracturing types (hybrid treated water and linear gel fracture stimulation and treated water fracture stimulation) the independent variables that were kept in the analysis are total fluid, total proppant, total perforation (top to bottom), the number of perforation clusters, and net pay. These factors fell into the significant level of p-value (less than 0.05) for almost all the multiple regression analysis of the independent variables along with the dependent variables.

4.1.1. Hybrid Treated Water Linear Gel Fracture Stimulation. A regression analysis was conducted on the dependent and independent variables of the hybrid fracture stimulation. The results of this analysis of the gas rate during the flow-back, 6-month recovery, and the Estimated Recovery will be discussed in this section; while the results of the 3 Month Recovery, 9 month Recovery, and 12 Month Recovery have been included in the Appendix.

4.1.1.1 Most effective parameters on gas rate during flow-back. A tornado chart was generated based on the multivariable equation of gas rate during the flow-back as a dependent variable. The independent variables in addition to the total perforation, total fluid, total proppant, number of perforation cluster, and net pay were statistically significant. Figure 4.1 shows a tornado chart of the independent variables that have the greatest impact on the gas rate during flow-back. The degree of its effect has been sorted as the largest impact beginning at the top to the lowest impact on the bottom of the plot. As shown, the total perforations and the total proppant pumped had the biggest impact on the gas rate during the flow-back, and both are positive. In simplest terms, increasing the total perforation and total proppant led to an increase in gas rate during flow-back using hybrid treated water fracture in the Glauconite Formation of southern Chile. The plot also demonstrates that the total fluid (pumped) followed by the number of perforations clusters had a lesser impact. However, the effect on both of these parameters was negative, which means increasing the fluid and the number of perforations clusters resulted in lower gas rate during flow-back. Lastly, the remaining parameter indicated that the net pay had a positive effect on gas rate during flow-back although the impact was the smallest.

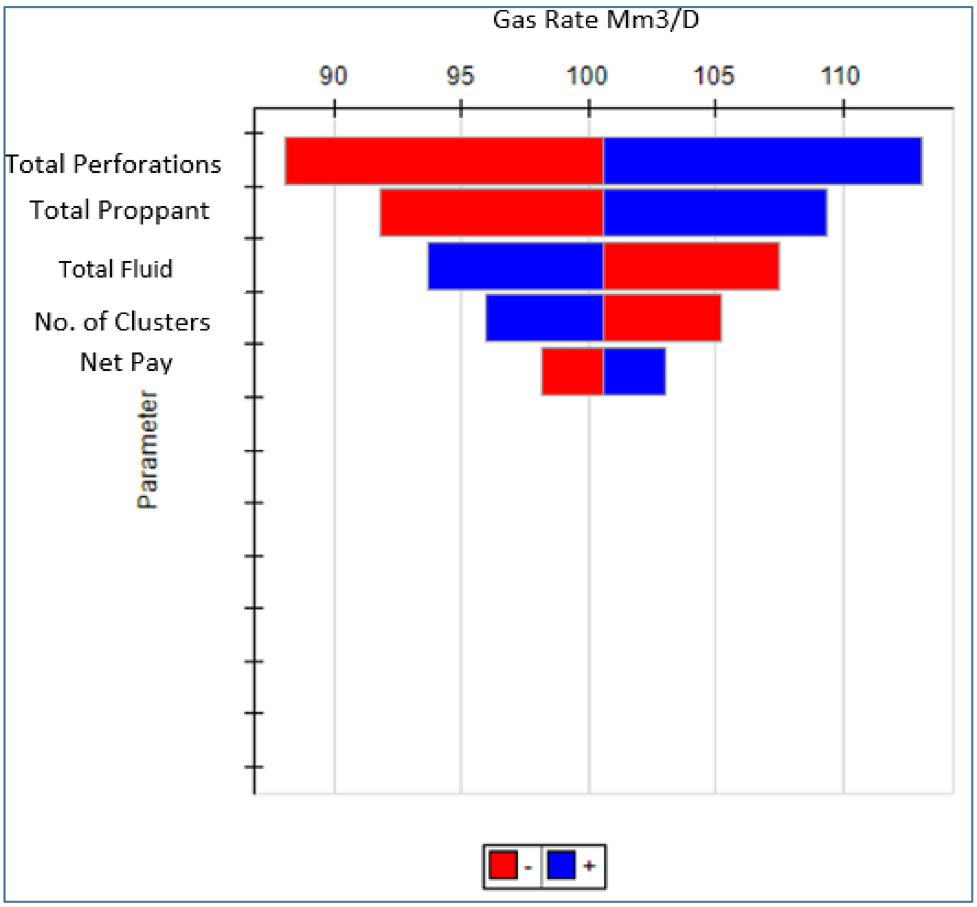


Figure 4.1. Tornado Plot of Sorted Parameter Estimates (Hybrid) For Gas Rate during Flow-Back

4.1.1.2 Most effective parameters on 6-month recovery. The multiple regression analysis was also conducted for the dependent variable of 6-month production. The analysis indicated that the independent variables of the total number of perforations, total proppant pumped, total fluid, number of perforation clusters, and net pay were statistically significant. The equation of the regression was used in the sensitivity analysis to initiate the tornado chart (Figure 4.2). The plot illustrates the impact of these parameters on the 6-month recovery. The figure shows that the total number of perforations and the number of perforation clusters had the largest effect on the 6-month recovery for hybrid fracture treatments. Even so, the total number of perforations resulted in a positive effect, while the number of clusters had a negative effect. Total proppant and total fluid had a smaller impact than the total number of perforations and number of clusters. Both the total proppant pumped and total fluid had a positive effect on the dependent variables of 6-month recovery. Once again, the net pay had the least impact on the output, although the impact proved to be negative.

4.1.1.3 Most effective parameters on estimated ultimate recovery. Finally, the tornado plot was created to sort the estimated effective parameters on the Estimated Ultimate Recovery based on the multi-regression equation. In this analysis, the total number of perforations was not significant, unlike in the other evaluations. Figure 4.3 displays a tornado chart of the independent variables, impact on the estimated ultimate recovery (the dependent variable). The plot demonstrates that total proppant and total fluid had the largest impact on EUR. However, the total proppant utilized had a positive effect on EUR, and the total fluid pumped had a negative effect. The number of the perforation clusters had less impact than the proppant and the fluid used, and the influence was negative. Last of all, net pay had the least impact and its impact, was negative with respect to the estimated ultimate recovery.

4.1.1.4 The tornado charts summary of hybrid fracture. In the tornado charts of the hybrid fracture, it noted that the total meters of perforations had the biggest positive impact on initial production and early recovery. However, the number of perforation clusters had a significant and negative effect on initial production and early recovery. The results look unclear since both total perforations and number of perforation clusters are completion parameters and their effects are in direct opposition. This could be improved if the perforation interval were positioned in a longer interval instead of dispersed into shorter intervals. This situation could also possibly explain the negative effect of the net pay. A relative point to consider is the pay of the Glauconite Formation in Tierra del Fuego which is made up of thin sporadic intervals with an average of about 15 meters spread out over 23 meters of gross formation interval

In the same context, total fluid pumped and total proppant pumped had a close impact of the initial production, early recovery, and Estimated Ultimate Recovery. However, the trend of their influences were opposite the majority of the time. The multicollinearity issue may have played a major role in this scenario, as was mentioned before with the correlation between the total fluid and total proppant. Either way, this outcome could be accounted for since the hybrid fracture treatment had significant height growth, and was to add more proppant to prop the created fracture height. This assumption is supported by three dimensional finite element fracture simulations conducted on the Glauconite fracture stimulation designs and post appraisals as shown in Figure 4.4.

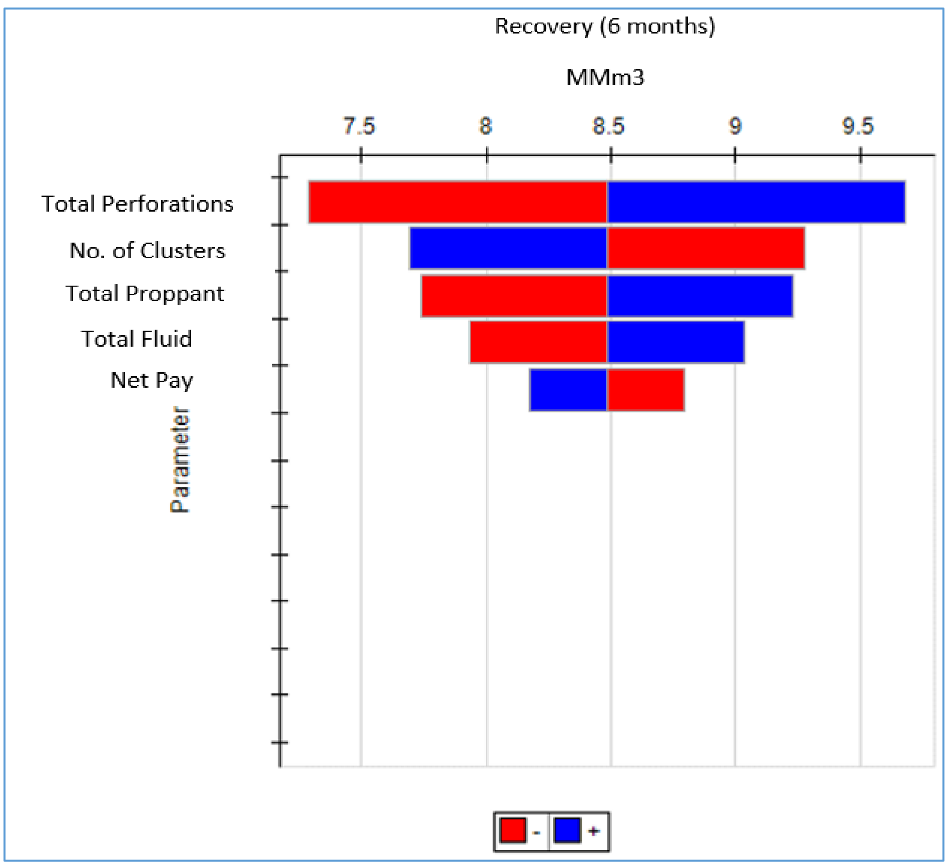


Figure 4.2. Tornado Plot of Sorted Parameter Estimates (Hybrid) for 6-Month Recovery

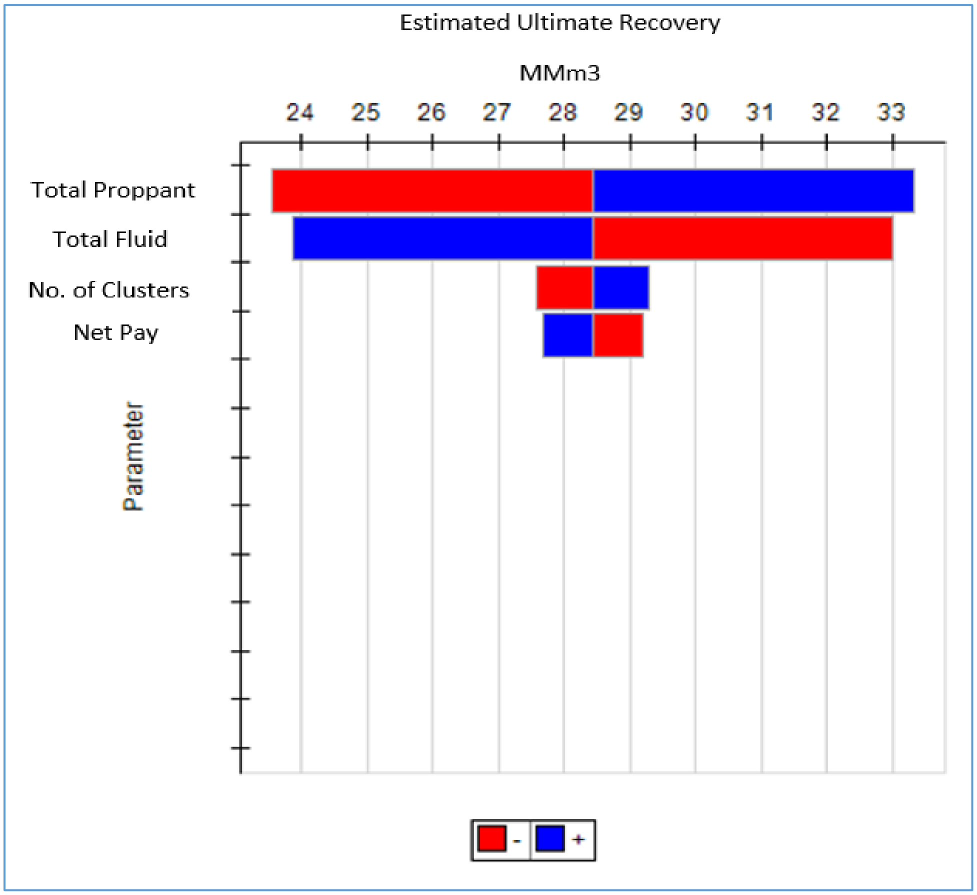


Figure 4.3. Tornado Plot of Sorted Parameter Estimates (Hybrid) For EUR

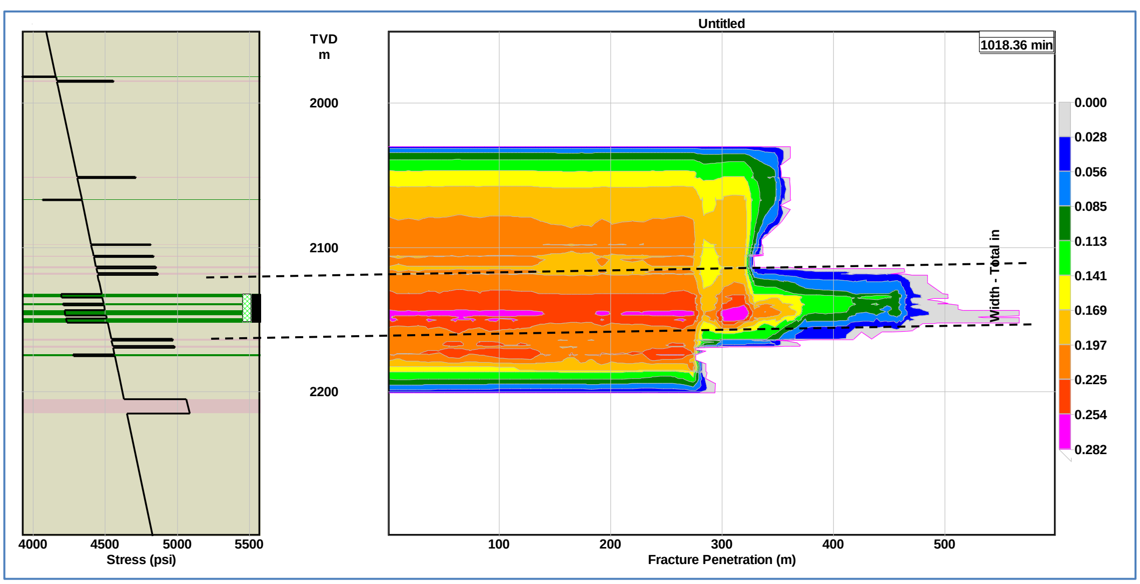


Figure 4.4. Hybrid fracturing Simulation shows a height growth

4.1.2. Treated Water Fracture Stimulation. Multiple regression was performed to investigate the most effective independent parameters on the dependent variables of production and recovery for treated water fracture. This analysis was limited by the shortage of the production data after six months of production. Therefore, the analysis was conducted on gas rate during flow-back, 6-month recovery, and Estimated Ultimate Recovery.

4.1.2.1 Most effective parameters on gas rate during flow-back. The sensitivity analysis was completed using the multiple regression equation of water fracture as gas rate during flow-back as a dependent variable. In the regression, the significant independent variables with p-value less than 0.05 were total proppant, total fluid, total perforation, number of perforation clusters, and net pay. A tornado chart (Figure 4.5) was generated as a result of the sensitivity analysis to show the sorted parameter estimates. The plot demonstrates that the total fluid and total proppant pumped had the greatest impact on the gas rate during flow-back, although the total fluid had a negative effect and total proppant had a positive effect. The total number of perforations, the number of perforation clusters, and net pay all had a negative effect. However, these three parameters had the smallest effect on the gas rate during flow-back.

4.1.2.2 Most effective parameters on 6-month recovery. Figure 4.6 shows the tornado plot for 6-month recovery and it is clear that the total fluid pumped and the total proppant pumped had the largest effect, although the total fluid impact was negative and the total proppant impact was positive. The parameters with less effect are total number of perforations, the number of perforation clusters, and net pay. These variables had a positive effect on the 6-month recovery with water fracture treatments.

4.1.2.3 Most effective parameters on estimated ultimate recovery. Finally, the multi-regression analysis was applied to the independent variables represented by stimulation, completion and reservoir quality variables. The dependent variable was Estimated Ultimate Recovery. Once the relation was determined by an equation, this equation was used to build the estimated parameters in the tornado chart shown in Figure 4.7. The plot shows that total fluid had the largest positive impact on the estimated ultimate recovery. Net pay, number of clusters, and total proppant had the second largest effect, but the effect was negative. Finally, total perforation had a lower effect with a positive sign.

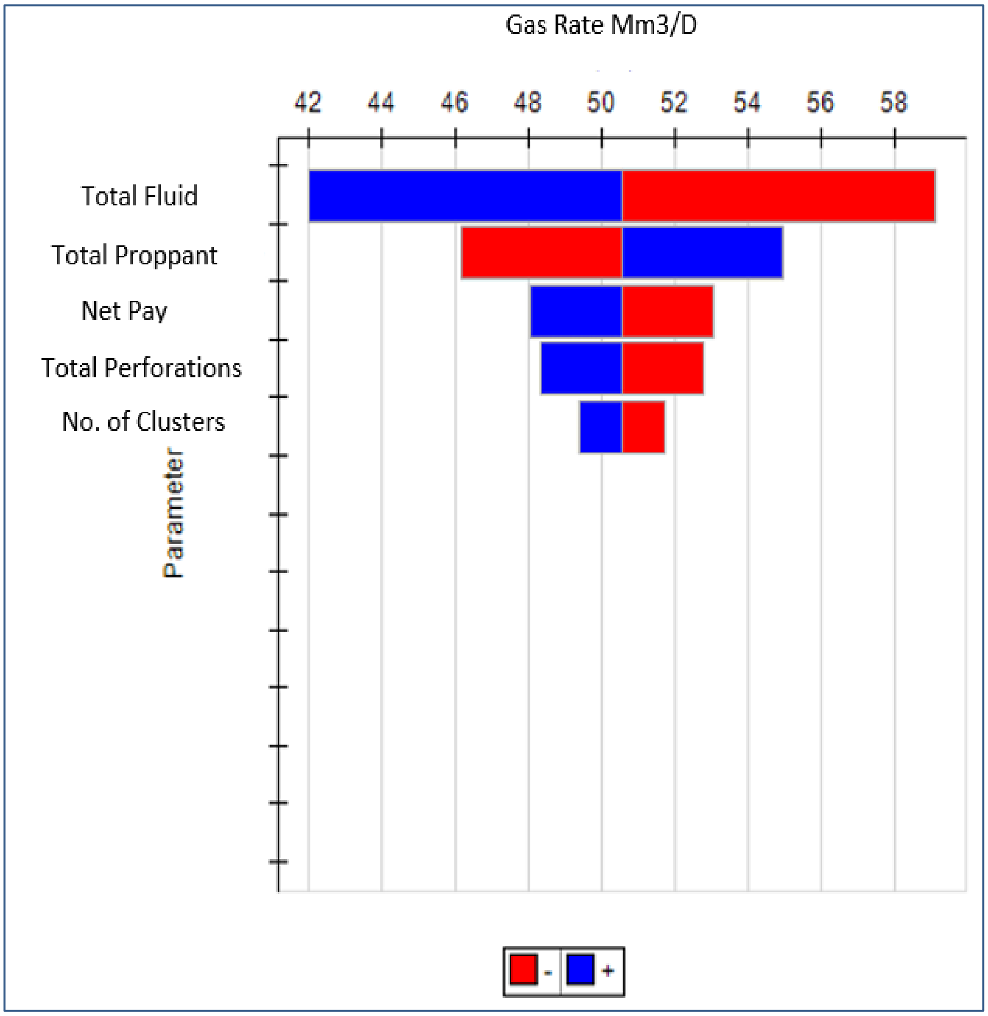


Figure 4.5. Tornado Plot of Sorted Parameter Estimates (Water) For Gas Rate during Flow-Back

4.1.2.4 The tornado charts summary of treated water fracture. Tornado charts were prepared for first production, 6 month recovery and EUR for treated water stimulations. This analysis shows which parameters impact early production versus ultimate recovery. The total fluid, net pay, total perforation, and number of clusters all had a negative impact on the early production. The impact of the total proppant on the EUR is negative, while the effect of total fluid pumped was positive. This may occur because the water fracture stimulations are contained in-zone, so increased proppant leads to an increase in conductivity. Conversely increasing the total fluid pumped increases the fracture length (less high growth) and provides excellent proppant transportation. High conductivity is beneficial to early production, while a long fracture supports the estimated ultimate recovery. This assumption is supported by three dimensional finite element fracture simulations conducted on the Glauconite fracture stimulation designs and post appraisals as shown in Figure 4.8.

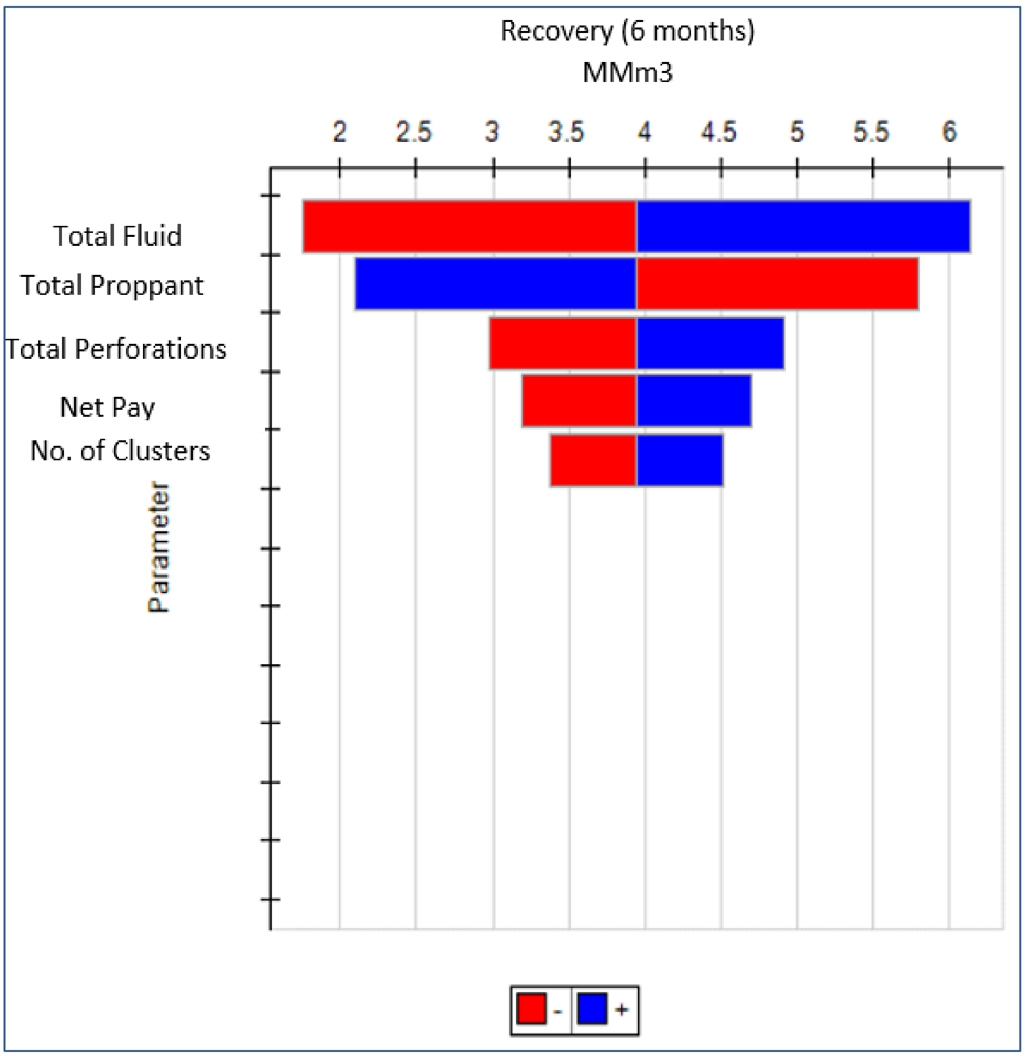


Figure 4.6. Tornado Plot of Sorted Parameter Estimates (Water) 6-Month Recovery

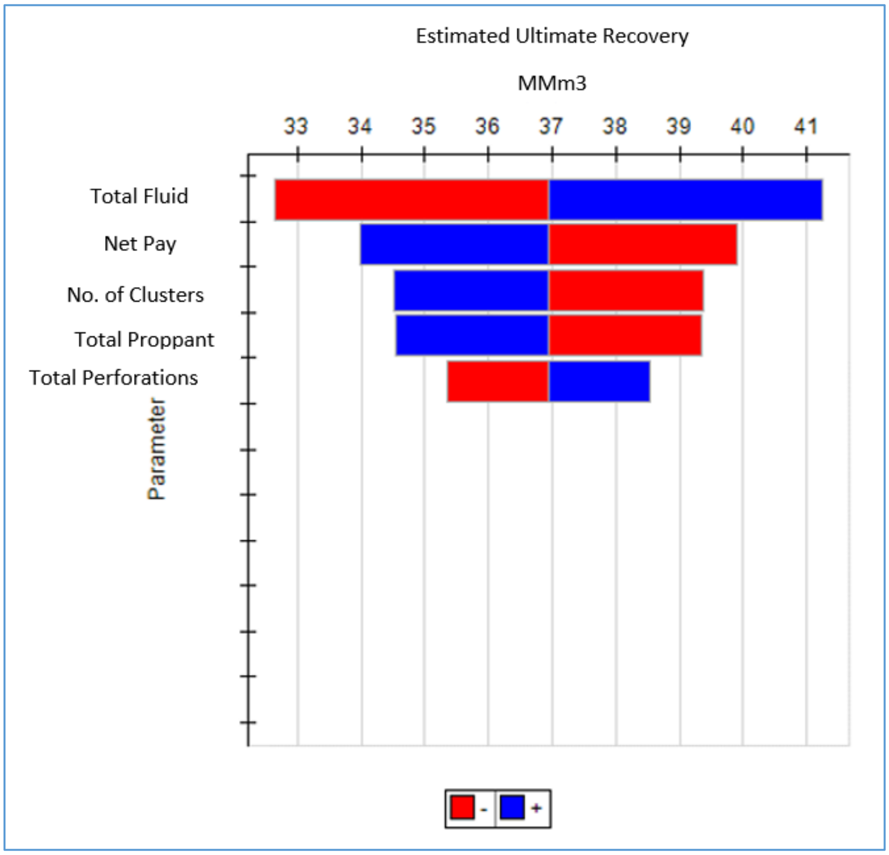


Figure 4.7. Tornado Plot of Sorted Parameter Estimates (Water) Estimated Ultimate Recovery

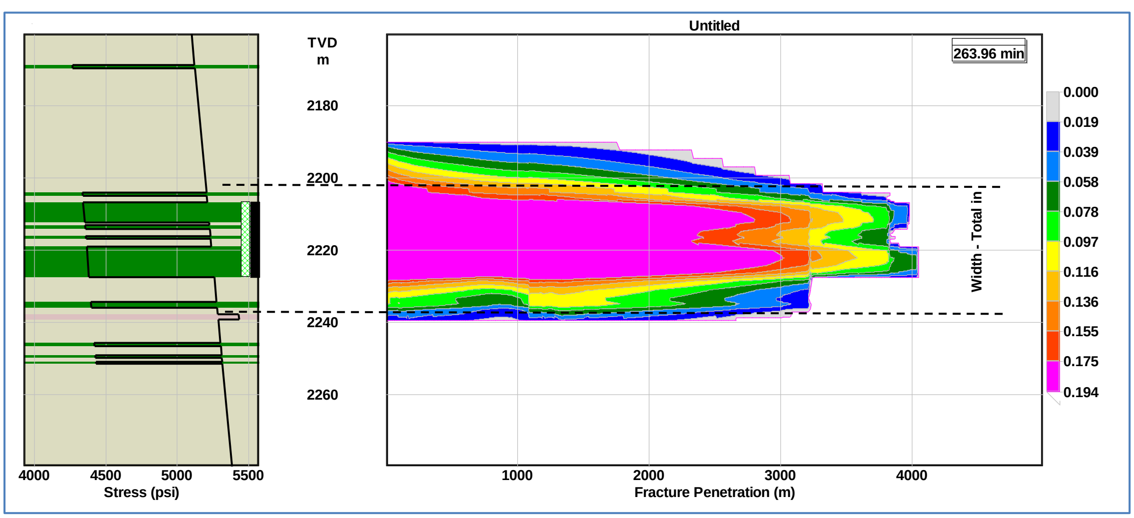


Figure 4.8. The Water Fracture Simulation Shows Relatively Contained Fracture

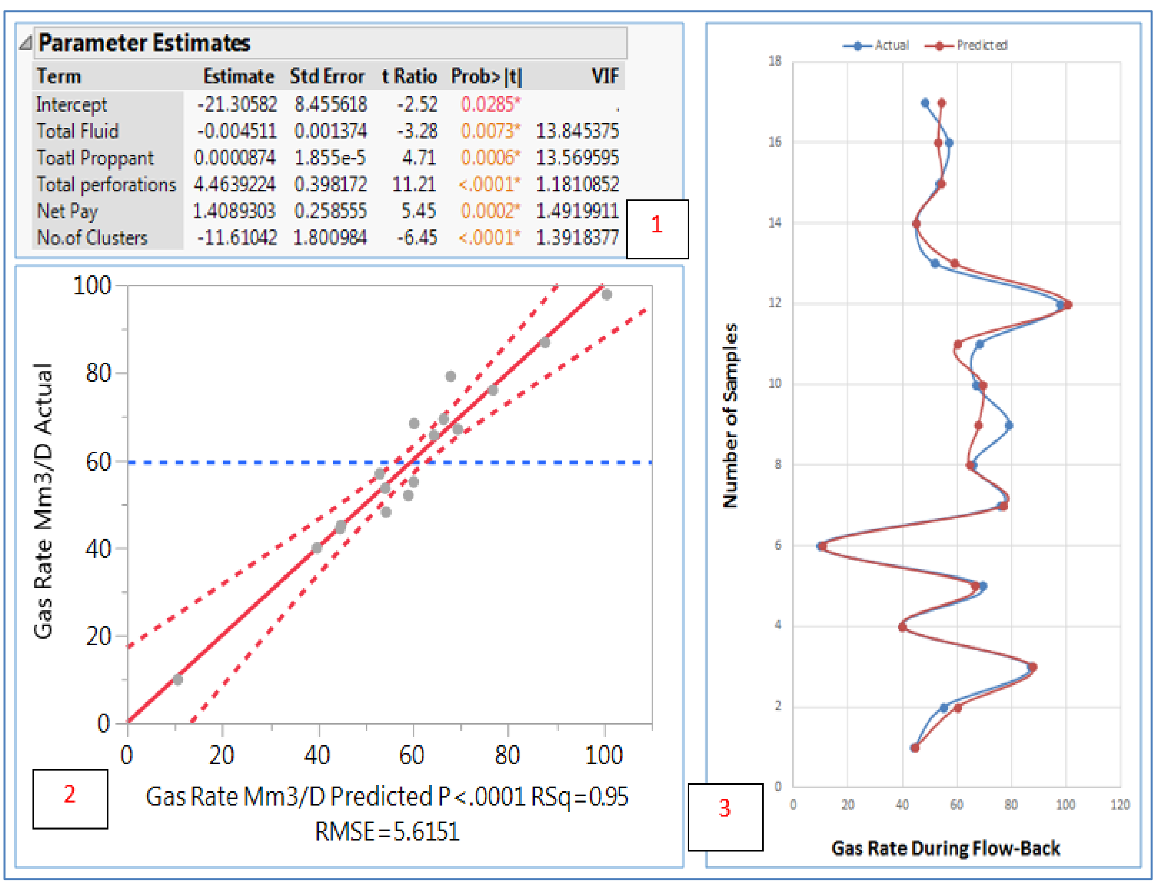
4.2. THE VALIDATION OF PREDICTION EQUATIONS

A variety of equations were established to represent the relation between the independent variables of stimulation, completion, and reservoir quality with dependent variables such as gas rate during flow-back, 6-month recovery, and Estimated Ultimate Recovery. The relation of the estimated sorted parameters and their effect on the output dependent variables have to be trusted in order to be used in the fracture optimization and production/recovery prediction. When the multi-regression was used, there were many factors taken into consideration to measure the reliability of the predicted variables. Some statistical measurement points were used to evaluate the strength of the regression equation and to predict the production/recovery based on the stimulation, completion, and reservoir quality parameters

4.2.1. Hybrid Treated Water and Linear Gel Fracture Stimulations. The analysis was conducted on the equations of hybrid treated water and linear gel stimulation Figure 4.9 includes three parts, each containing evidence to prove the validation of the multi-regression equation of the independent variables with the gas rate during flow-back for hybrid fracture as the dependent variable. The top left part in Figure 4.9 (part 1) contains a table with the significant parameters in the regression. In other words, the final independent variables were kept in the analysis since the other parameters were excluded from the operation because they were not statistically significant with 95% level of confidence, as was discussed in Section 3. Also, the table shows the estimates of the model coefficients, the standard error of each of the estimated parameters, the t-ratio, the p-values, and the Variance Inflation Factor (VIF) for each term in the model. The model coefficients define the multiple regression equations, the standard error, t-ratio, and p-values and show the level of the confidence and the significance. The VIF was used to test the collinearity between the independent variables. The most important factor in selecting the significant parameters is the p-value, and the table shows that all five parameters had a p-value less than 0.05, which coupled with the level of confidence (95%). The t-ratios are all above 2, which support evidence that they are significant. The variance inflation factor indicated a multicollinearity issue with total proppant and the total fluid term as was recognized and discussed in Section 3. The operation was repeated for each parameter at a time and it was found that the VIF was slightly lower than all of the parameters together but still relatively high. Therefore, both total fluid and total proppant were kept in the regression. Additional reasons were discussed in Section 3 (3.3.3).

Figure 4.9 also includes a leverage plot (part 2) which shows the model fit, the confidence region, and whether the model was significant or not. The curves crossed the mean (the horizontal line), which is an indication that the model was significant. Also, the R^2 is equal to 0.95, which is a very high correlation coefficient for the model.

The last part of Figure 4.9 is labeled number 3. This plot compares the predicted variables for a number of dependent samples with the actual data variables. The graph shows the predicted values of the gas rate during flow-back based on the estimated equation described in the sorted parameter table. As shown, the model prediction is very close to the actual values indicating the model's high accuracy predicting the gas rate during the flow-back whenever the dependent variables are obtainable.

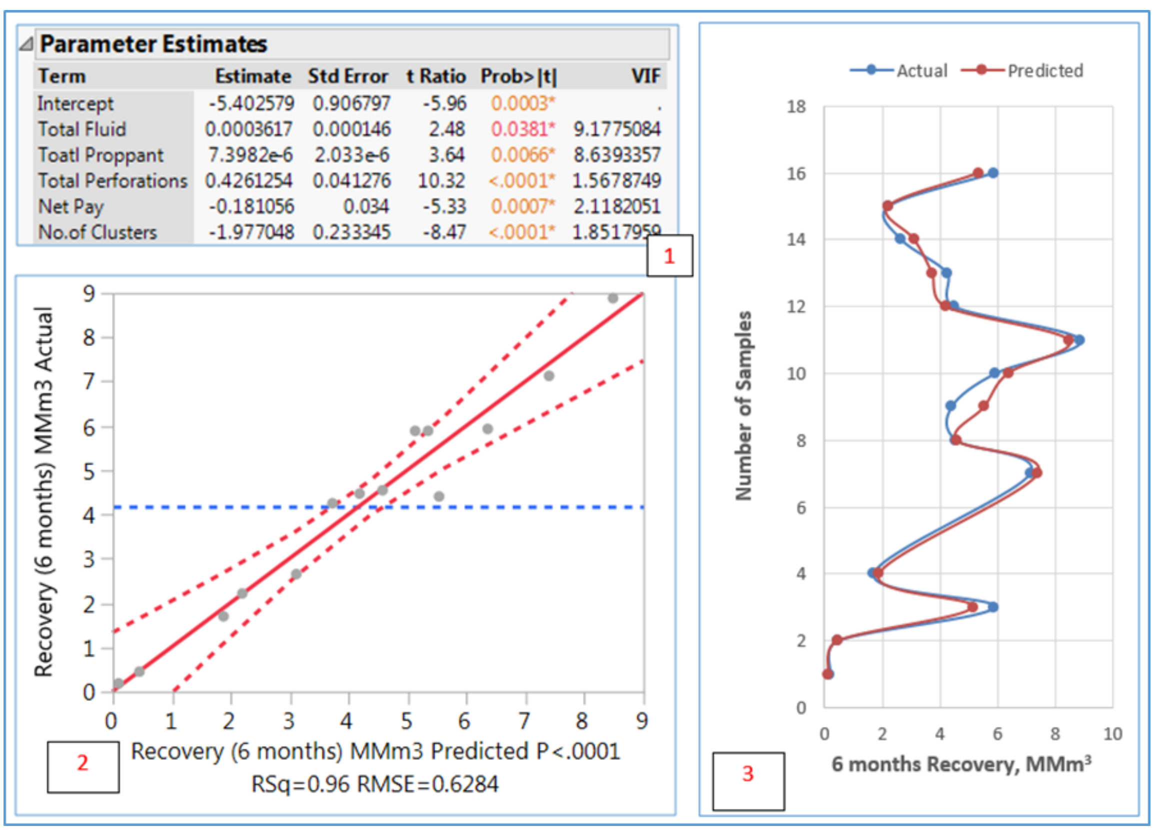


Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	-21.30582	8.455618	-2.52	0.0285*	.
Total Fluid	-0.004511	0.001374	-3.28	0.0073*	13.845375
Toatl Proppant	0.0000874	1.855e-5	4.71	0.0006*	13.569595
Total perforations	4.4639224	0.398172	11.21	<.0001*	1.1810852
Net Pay	1.4089303	0.258555	5.45	0.0002*	1.4919911
No.of Clusters	-11.61042	1.800984	-6.45	<.0001*	1.3918377

Figure 4.9. Parameter Estimates & Predictions (Hybrid) for Gas Rate during Flow-Back

This evaluation was also conducted on the hybrid treated water and linear gel fracture treatments to determine the significant independent variables to be used to predict the dependent variable of 6-month recovery. Figure 4.10 illustrates the three parts of the multi-regression evaluation of 6-month recovery as dependent variable for the hybrid treated water and linear gel fracture stimulations. Part 1 represents the table that contains the estimated independent parameters of stimulation, completion, and reservoir variables. The linear coefficient of each variable is shown with the standard error and the t-ratio. Also, the table highlights the p-value of each significant variable and as is shown, all the terms have a p-value less than 0.05. The t-ratio of each variable above 2 also indicated that all of the variables are significant. The variance influence factor again shows that total fluid and total proppant may have collinearity but to a lesser degree. However, when each of these variables were analyzed separately, the VIF was still relatively significant and for this reason it was decided to keep both independent variables in the analysis.



Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	-5.402579	0.906797	-5.96	0.0003*	.
Total Fluid	0.0003617	0.000146	2.48	0.0381*	9.1775084
Toatl Proppant	7.3982e-6	2.033e-6	3.64	0.0066*	8.6393357
Total Perforations	0.4261254	0.041276	10.32	<.0001*	1.5678749
Net Pay	-0.181056	0.034	-5.33	0.0007*	2.1182051
No.of Clusters	-1.977048	0.233345	-8.47	<.0001*	1.8517959

Figure 4.10. Parameter Estimates & Predictions (Hybrid) for 6-Month Recovery

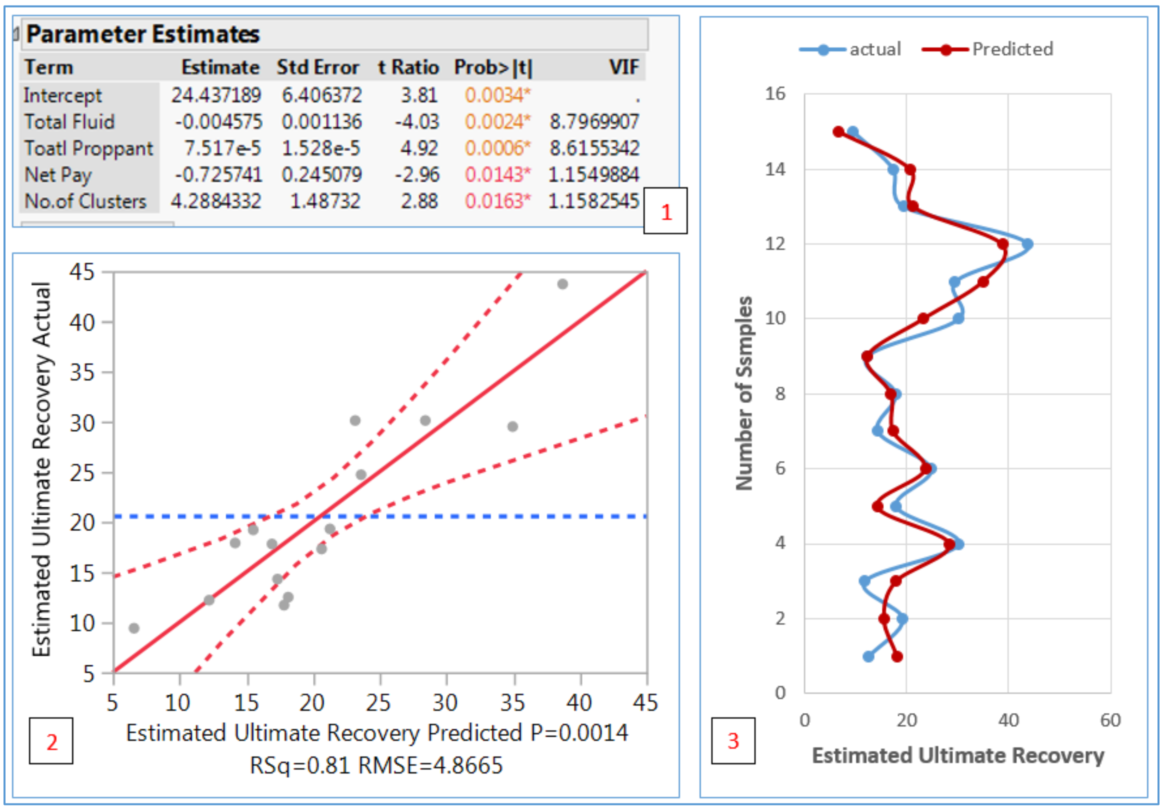
Figure 4.10 includes a leverage plot (part 2) that specifies whether the multi-regression analysis is significant with 5% level of confidence. The plot indicates that the model is significant since the curves cross the mean line (horizontal). Additionally, it is shown that the residual is small and the correlation coefficient,R^2, is 0.96 which is nearly a perfect fit.

Finally, part 3 of Figure 4.10 indicates graphically how much the predicted values of 6-month recovery are close to the actual collected data. That would enforce the accuracy of the multiple regression models to be used to predict the 6-month recovery from the estimated independent parameters. As shown in the graph, the predicted values corresponded with the actual data nearly in all tested samples

As the models of the gas rate during flow-back and 6-month recovery for the hybrid treated water and liner gel fracture stimulation were examined, the assessment was applied on the multi-regression analysis equation of the EUR as well. Figure 4.11 displays the table of estimated parameters, the leverage plot of actual versus predicted data, and the graph illustrating the accuracy of the predicted estimated ultimate recovery compared with the real data. The table at the top left of Figure 4.11 (number 1) shows statistically estimated independent parameters of stimulation, completion, and reservoir variables based on the least square analysis method. As provided in the table, the parameters are statistically significant and their existence in the model decreases the probability of the event to occur by chance. Also, the t-ratio for all variables is above 2, which supports their significance. The coefficient of each estimated term in the equation was included in the table as well as the standard error. Finally, the Variance Influence Factor (VIF) was determined, and it conveyed that the total fluid and total proppant were less likely to have the collinearity issues than both previous analyses had indicated.

The second part in Figure 4.11 (number 2) is the leverage plot, which is a graphical expression used to observe whether the analysis was significant or not. The curves crossing the mean line (the horizon) indicate the fit model is significant. Also, visible in the plot are the residuals which provides evidence of the models accuracy. Finally, the R^2 of 0.81 is still satisfactory although not as high as the prior models for the hybrid treated water and linear gel fracture stimulations.

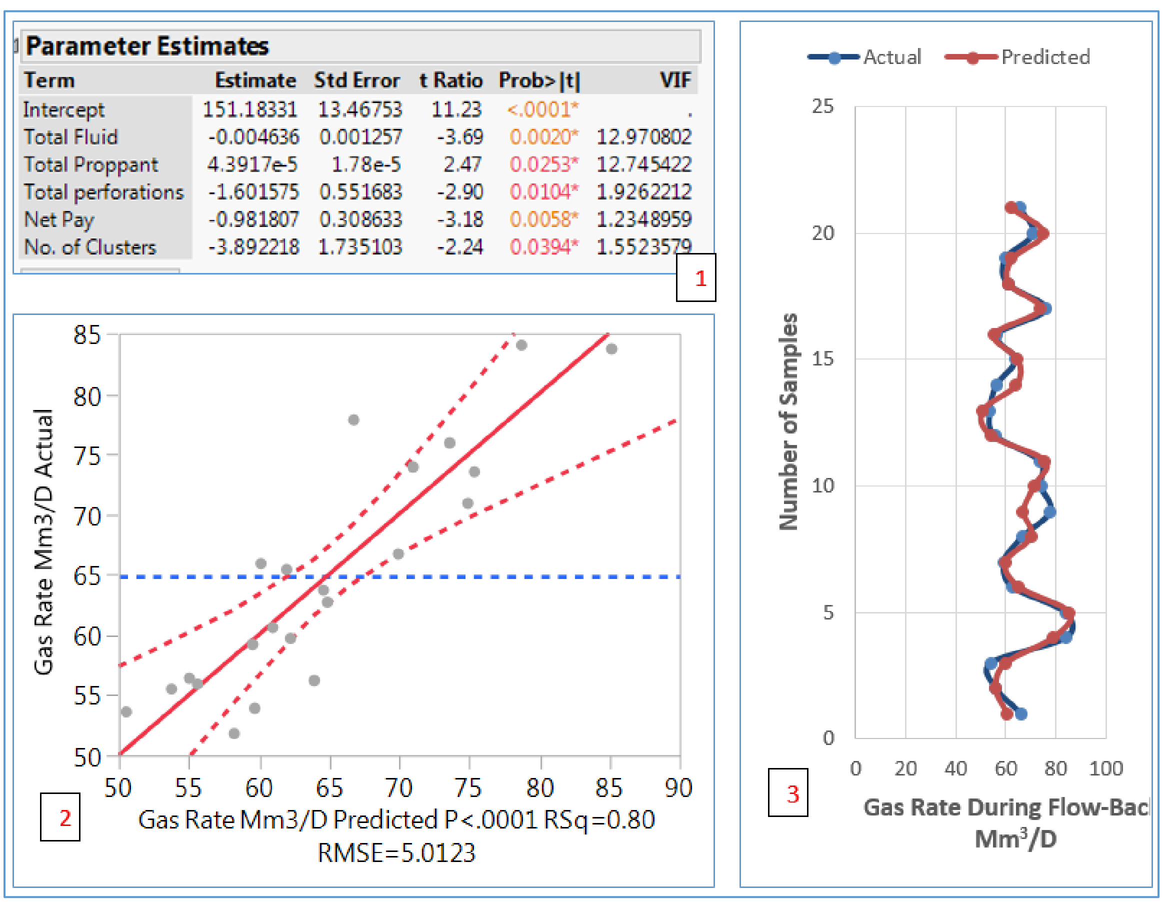
The last part of Figure 4.11 (number 3) is the graph that demonstrates the exactness of the predicted EUR by using the multi-regression equation described in the table and comparing the predicted values with actual values that came from the database. As revealed, the predicted EUR is very close to the actual data for the same independent data point, which increases the credibility of the prediction equation and the analysis.



Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	24.437189	6.406372	3.81	0.0034*	.
Total Fluid	-0.004575	0.001136	-4.03	0.0024*	8.7969907
Toatl Proppant	7.517e-5	1.528e-5	4.92	0.0006*	8.6155342
Net Pay	-0.725741	0.245079	-2.96	0.0143*	1.1549884
No.of Clusters	4.2884332	1.48732	2.88	0.0163*	1.1582545

Figure 4.11. Parameter Estimates & Predictions (Hybrid) for Estimated Ultimate Recovery

4.2.2. Treated Water Fracture Stimulation. The previous analysis was also applied to the treated water fracture stimulations to validate the models of the gas rate during flow-back, 6-month production, and EUR. The first check was applied on the multi-regression of the gas rate during flow-back as the dependent variable and stimulation, completion, and reservoir quality as the independent variables. Figure 4.12 displays three parts of investigation of the accuracy of the multi-regression equation of gas rate during flow-back for the treated water treatments. The first part shows a summary table of the multi-regression analysis. The table includes the significant parameters and the coefficients of each parameter in the equation. The standard error, t-ratio, and p-value are also included in the table. The absolute value of the t-ratio for each variable is higher than 2, and the P-value is less than 0.05, indicating that these parameters are all significant and have produced an effect in the analysis. The last column comprises the values of VIF of each significant parameter. By highlighting the VIF of the total proppant and total fluid, these two values mark a possibility of a collinearity issue with these two independent variables. However, when each of these parameters was tested separately, the VIF was still high even though it was slightly lower than the combined case. Therefore, the parameters were kept together in the analysis.



Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	151.18331	13.46753	11.23	<.0001*	.
Total Fluid	-0.004636	0.001257	-3.69	0.0020*	12.970802
Total Proppant	4.3917e-5	1.78e-5	2.47	0.0253*	12.745422
Total perforations	-1.601575	0.551683	-2.90	0.0104*	1.9262212
Net Pay	-0.981807	0.308633	-3.18	0.0058*	1.2348959
No. of Clusters	-3.892218	1.735103	-2.24	0.0394*	1.5523579

Figure 4.12. Parameter Estimates & Predictions (Water) for Gas Rate during Flow-bac

The second part in Figure 4.12 is a leverage plot. This plot is a test to prove whether the analysis is significant. As shown, the curves crossing the mean line represents significance and the residual is small. The correlation coefficient, R^2, is 0.8 which indicates a good fit.

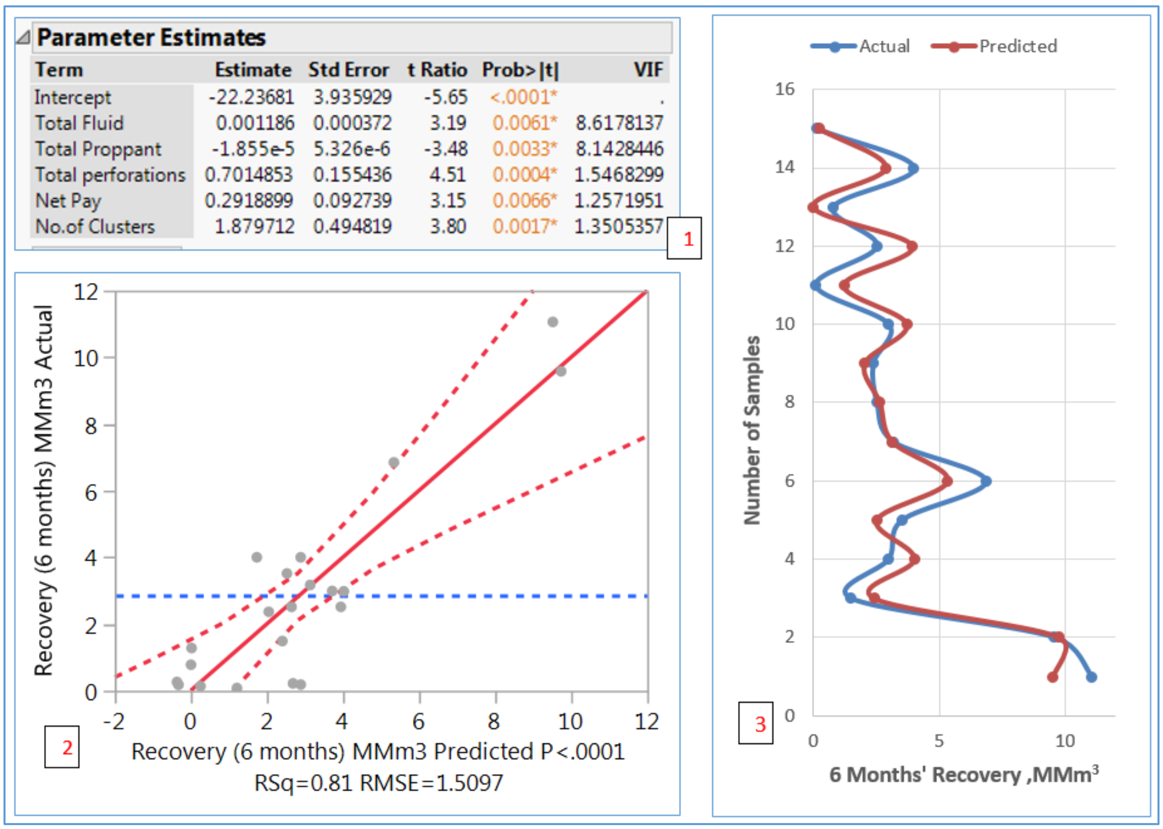
The third part of Figure 4.12 is a graph constructed based on the equation of the multi-regression analysis. This plot examines the equation described in the sorted parameter table by comparing the predicted dependent variable of the gas rate during flow back with actual gas rate during the flow-back. As shown in the plot, the predicted and the actual gas rate during flow-back matched very well.

The analysis was also conducted for the estimated dependent variable of 6-month gas recovery for the water treatments. Figure 4.13 exhibits the first part in the table of estimated significant parameters that had an impact on the 6 month recovery. The table includes the confidence, the standard error, t-ratio, p-value, and the VIF for each factor. As revealed, the t-ratio absolute value above 2 and p-value is below 0.05 indicating that the independent variables are all significant. The VIF indicates that the total fluid and total proppant may have collinearity issues. Despite the possibility of the collinearity, the total proppant and total fluid were both kept in the analysis because when these two parameters were tested separately, the VIF, although lower, was still significant.

Secondly, the leverage plot indicates that the analysis is significant at 5% level by showing the confidence region for the fit line, where the curves cross the mean line (horizontal blue line) and the residuals are small. Additionally, the R^2 is 0.81, which indicates a good fit.

Figure 4.13 includes a plot constructed using the equation that represents the 6-month recovery as the dependent variable. The figure shows the accuracy of the estimated relation of predicted 6-month recovery from multi regression analysis to actual production. As shown, the predicted values are very close to the actual values of the samples.

Lastly, the evaluation method was applied to the treated water fracture stimulation in order to test whether the significant independent variables can be used to predict the EUR via the relation found by the least squares method of the multiple regression analysis. Figure 4.14 includes a table that contains the estimated significant independent variables with the standard coefficient, the t-ratio, the p-value, and the VIF. The t-ratio is above 2 and p-value is below 0.05 which indicated that the parameters are all statistically significant. The VIF indicates that total fluid and total proppant could again have collinearity issues. However, when each of total proppant and total fluid was examined separately, although lower, there was still a relatively significant VIF. Therefore, these two parameters were kept together in the analysis.



Parameter Estimates

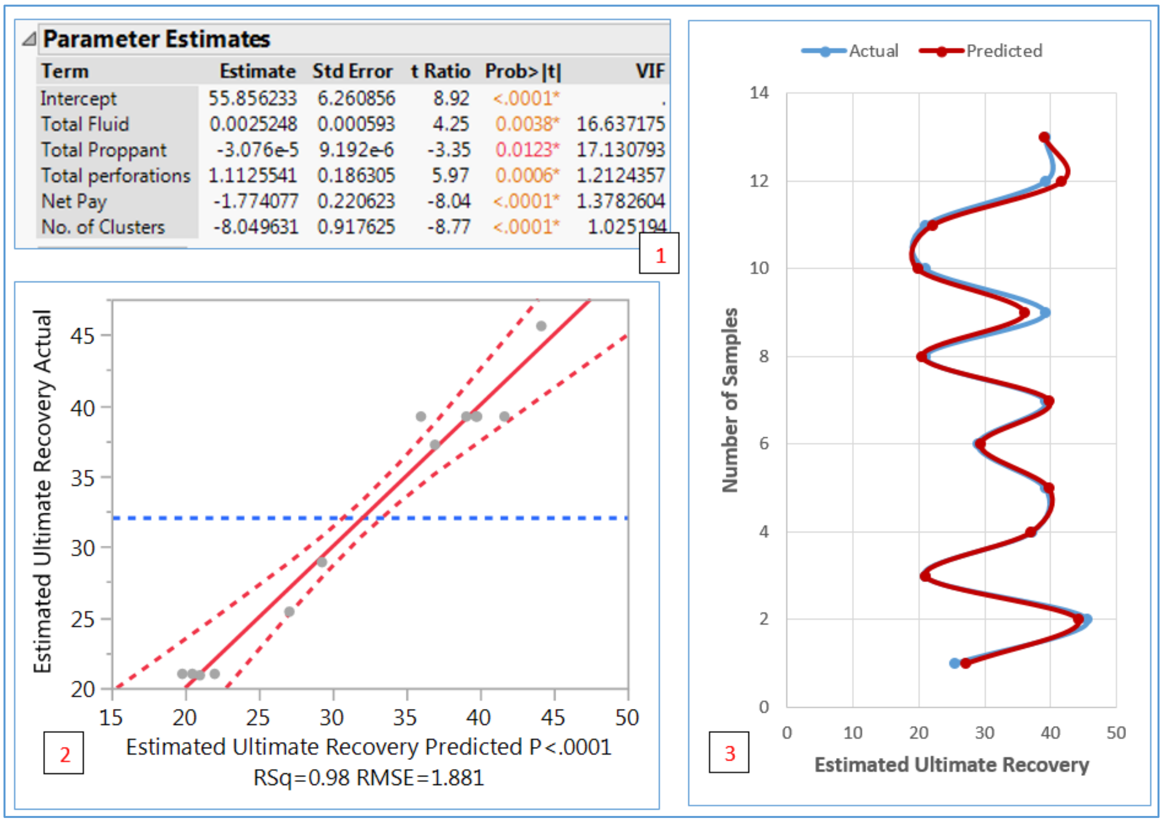
Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	-22.23681	3.935929	-5.65	<.0001*	.
Total Fluid	0.001186	0.000372	3.19	0.0061*	8.6178137
Total Proppant	-1.855e-5	5.326e-6	-3.48	0.0033*	8.1428446
Total perforations	0.7014853	0.155436	4.51	0.0004*	1.5468299
Net Pay	0.2918899	0.092739	3.15	0.0066*	1.2571951
No.of Clusters	1.879712	0.494819	3.80	0.0017*	1.3505357

Figure 4.13. Parameter Estimates & Predictions (Water) for 6-Month Recovery

The second part of Figure 4.14 is a leverage plot to test whether the analysis is significant at 5% level. The plot shows the confidence region for the fit line. The curves cross the mean line (horizontal), and the residuals are small indicating that the analysis is significant. The R^2 is 0.98 indicating a nearly perfect fit.

Finally, the third part of Figure 4.14 shows a plot initiated by using the equation described in the sorted parameters table to calculate the EUR as the dependent variable.

The plot compares the predicted values of the EUR to the actual EUR contained in the database. As shown, the predicted and the actual values are extremely similar, indicating the accuracy of the estimated equation in predicting the EUR from the five independent variables in the table. This also explains why the R^2 is 0.98.



Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|	VIF
Intercept	55.856233	6.260856	8.92	<.0001*	.
Total Fluid	0.0025248	0.000593	4.25	0.0038*	16.637175
Total Proppant	-3.076e-5	9.192e-6	-3.35	0.0123*	17.130793
Total perforations	1.1125541	0.186305	5.97	0.0006*	1.2124357
Net Pay	-1.774077	0.220623	-8.04	<.0001*	1.3782604
No. of Clusters	-8.049631	0.917625	-8.77	<.0001*	1.025194

Figure 4.14. Parameter Estimates & Predictions (Water) for Estimated Ultimate Recovery

5. FRACTURE OPTIMIZATION

5.1. HYBRID TREATED WATER AND LINEAR GEL FRACTURE OPTIMIZATION

The objective of this study was to conduct an optimization analysis which considers both the productivity and the economic benefit of the fracture treatment and determines which fracture design parameters could be adjusted for a greater benefit. The analysis was based on the equations previously developed by multiple regression analysis. The independent variable gas rate during flow-back was taken to represent the initial productivity and the Estimated Ultimate Recovery was used to represent the long-term productivity.

The first process in the optimization was an attempt to understand the effect of the controlled parameters of hybrid fracture stimulation on the early production, and the Estimated Ultimate Recovery. As previously discussed, in the hybrid fracture stimulation, the total proppant, total perforations, and net pay all have a positive impact on the gas rate during flow-back, while total perforation and number of the clusters have a negative effect. But how much is the effect of the number of clusters in a reasonable condition? To answer this inquiry, an average well was taken with average net pay with 15 meters. It was assumed that this interval was all perforated (total perforation 15 meters), with an average proppant of 650,000 lbs. and average fluid volume of 11,000 bbls. By verifying the number of the clusters (between 2 to 5), it was found that increasing the number of perforation clusters cost about 11.6 Mm^3pd of gas during the flow-back per cluster. The method was repeated to investigate the effects of total proppant and total fluid as stimulation parameters and total perforation as a completion parameter. The analysis yielded that for every 100,000 lbs of proppant pumped, the gas rate increased 8.75 Mm^3pd. Also, for every 1,000 bbls of fluids pumped, the gas rate decreased nearly 4.5 Mm^3pd. Finally, for every 2 m of additional perforations, the gas rate was increased by nearly 9 Mm^3pd, which indicates that increasing the perforations can be accomplished without additional clusters.

The analysis was applied to the equation of the Estimated Ultimate Recovery for hybrid fracturing. As discussed previously, the total proppant and number of perforation clusters had a positive impact on EUR, while total fluid and net pay yielded a negative impact. Further analysis shows that the EUR would be increased by 7.5 MMm^3 by pumping an extra 100,000 lbs of proppant and increased by about 4.3 MMm^3 by adding just one more perforation cluster. In the other analysis, the EUR decreased 4.5 MMm^3 for each 1,000 bbls of fluid pumped. Table 5.1 below summarizes this assasment, where the (+) and (-) signs describe the increase and decrease respectively.

Table 5.1. The Multi regression equations of Hybrid Treated Water and Linear Gel Fracture Described by Realistic Values

The Independent parameters	Total Proppant (lb)	Total Fluid (bbl)	Total Perforation (m)	Number of Clusters
The quantity added for each parameter / The dependent variables	100,000	1,000	2	1
Gas Rate During The Flow-Back (Mm^3/D)	+8.75	-4.5	+9	-11.6
Estimated Ultimate Recovery (MMm^3)	+7.5	-4.5	x	+4.3

5.2. TREATED WATER FRACTURE OPTIMIZATION

The multiple regression equation of the dependent variables of the gas rate during flow-back and Estimated Ultimate Recovery was utilized in the treated water fracture optimization. The gas rate during flow-back represents the initial production, and the EUR represents the long-term recovery.

A quick review of the parameter estimates and their effects on the gas rate during flow-back indicated that the total proppant pumped has a positive impact while total fluid, the total number of perforations, the number of perforation clusters, and the total net pay have negative effects. These results once again illustrate how much effect the number of perforation clusters has on the gas rate during flow-back. A typical Glauconite well was used with an average net pay of 15 m assuming the entire interval was perforated. The average of total proppant and total fluid of 700,000 lbs and 14,000 bbls, respectively (the proppant concentration in the treated water fracture is confirmed from 0.5 to 2). The assessment conducted that for each perforation cluster added, the gas rate during flow-back decreased by 3.9 Mm^3. This analysis was also performed to find the impact of total fluid and total proppant. The analysis showed that adding an additional 1,000 bbls of fluid caused a reduction in gas rate by around 4.6 Mm^3pd. The next analysis showed for each 100,000 lbs of proppant added, the gas rate increased by approximately 4.4 Mm^3pd. The analysis provided the completion parameters, which are critical, as well as the stimulation parameters. For two additional meters of perforation, the gas rate was reduced by about 3.3 Mm^3pd.

This analysis was applied to the treated water fracturing equation for EUR with a typical average well. The results showed that for every additional 100,000 lbs of proppant pumped the EUR was decreased by 3 MMm^3, while with the additional 1,000 bbl added of fluid led to an increase in the EUR by 2.5 MMm^3. In relation to the completion parameters, it was determined that 8 MMm^3 of EUR was lost by increasing the number of perforation clusters by a cluster. Alternatively, EUR was improved by 5.5 MMm^3 for every 5 m perforated, indicating that the perforation clusters should be as long as possible. Table 5.2 below summarizes this assessment, where the (+) and (-) describe the increase and decrease, respectively.

Table 5.2. The Multi regression equations of Treated Water Treatment Described by Realistic Values

The Independent parameters	Total Proppant (lb)	Total Fluid (bbl)	Total Perforation (m)	Number of Clusters
The quantity added for each parameters / The dependent variables	100,000	1,000	2	1
Gas Rate During The Flow-Back (Mm^3/D)	+4.4	-4.6	-3.3	-3.9
Estimated Ultimate Recovery (MMm^3)	-3	+2.5	+2.22	-8

5.3. EXPLORATION OF THE BEST FRACTURING TYPE

After analyzing the models for initial production and ultimate recovery for hybrid fracturing and water fracturing, the roles of the stimulation parameters (such as total fluid and total proppant) need to be investigated. In other words, does increasing the proppant prove to be more beneficial, or should the proppant concentration be decreased to enhance the wells performance in Glauconite Formation? The equations of the gas rate during flow-back and real values for the independent variables (total proppant, total fluid, total perforations, number of the clusters, and net pay) were used to test the difference in the production rate for the hybrid fracture treatments and treated water fracture stimulations. Figure 5.1 shows the initial production for a typical well, one stimulated by hybrid fluids and the other by treated water.

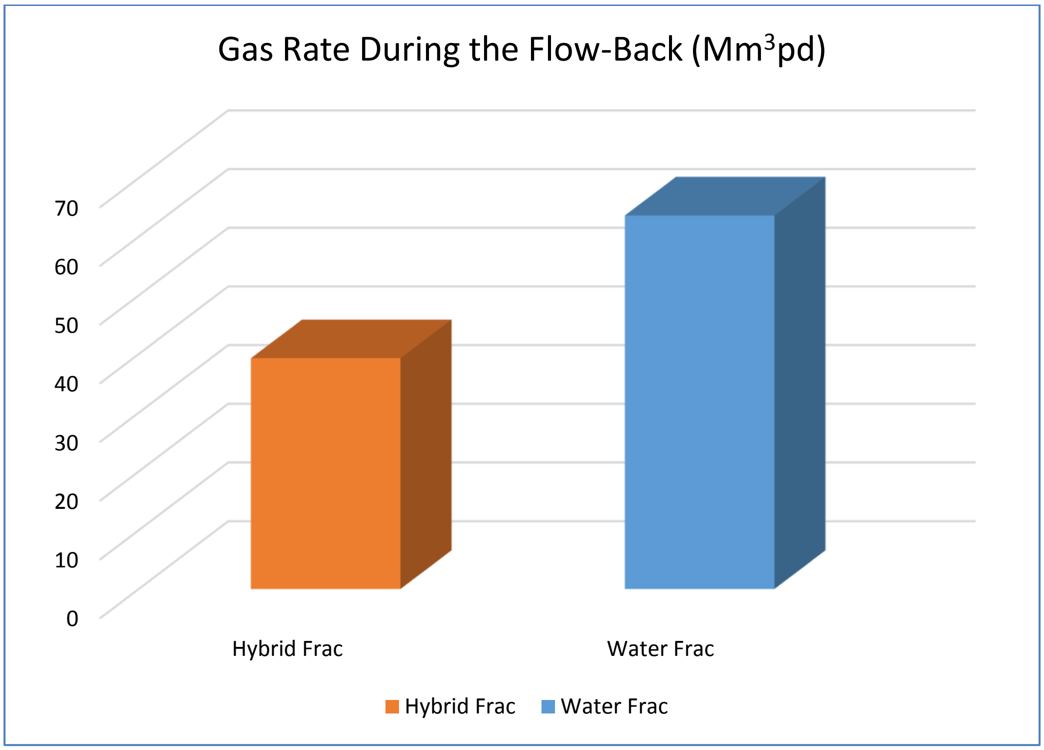


Figure 5.1. The difference in the gas rate during flow-back based on fracture type

As illustrated in Figure 5.1, the gas rate during flow back in a fracture treated by water is higher than the rate from a well fractured with a hybrid fluid. The investigation produced similar results when applied to 6-month recovery to represent an average recovery period. Figure 5.2 displays the difference in the 6-month recovery of the two wells, one fractured by treated water and the other by a hybrid treatment. As shown, the water fracture treatment produced more initially than the hybrid fracture treatment.

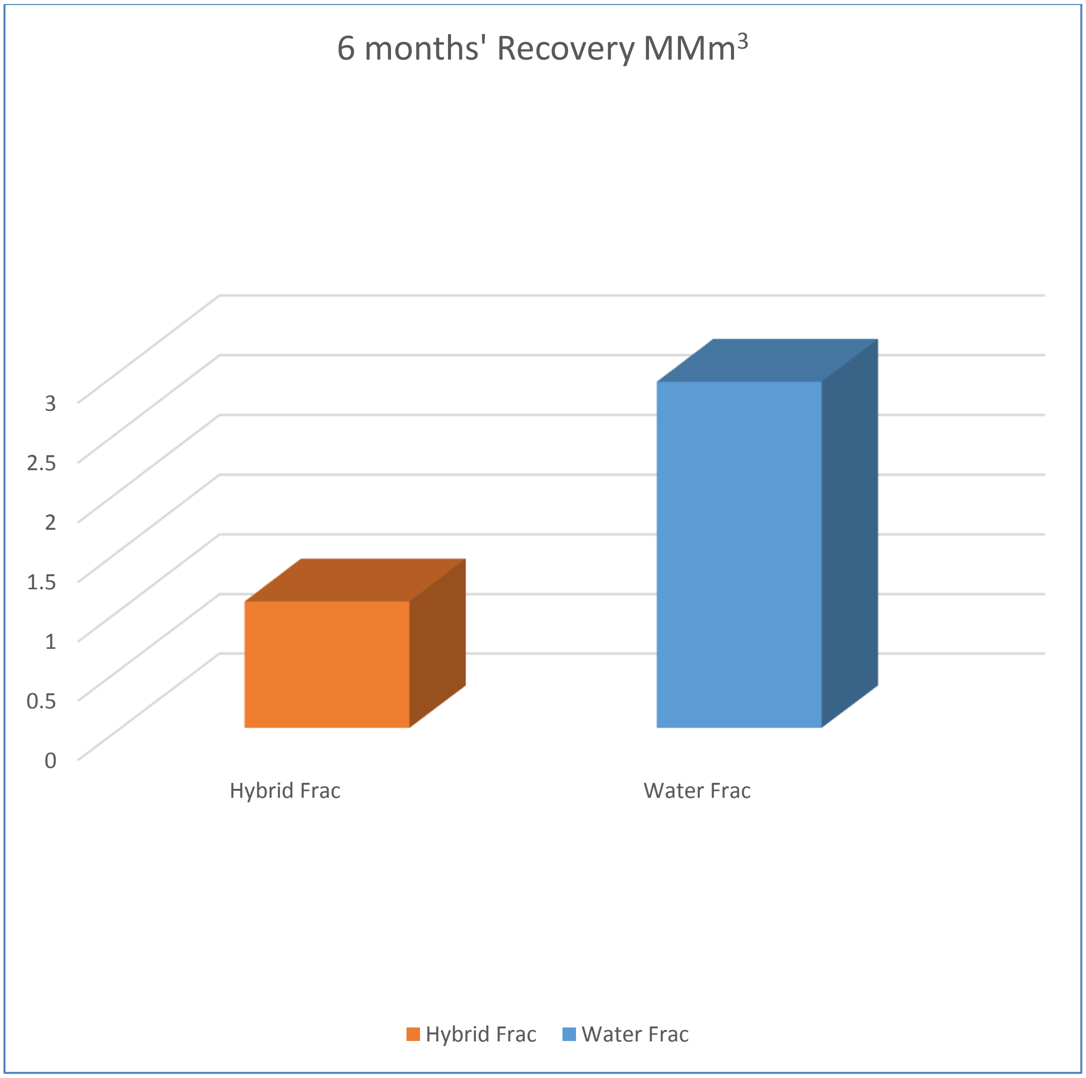


Figure 5.2. The difference in 6-Month recovery based on fracture type

These two figures (Figure 5.2) show that treated water fracture stimulation could potentially enhance the productivity of the wells in Glauconite Formation. However, the economic benefit should be considered before the final recommendation is made. For this purpose, the hyperbolic rate decline relationship was used to calculate the production rate for each year within a 20-year time period:

$$q = q_i \frac{1}{(1 + \mathrm{b}D_i t)^{\frac{1}{b}}} \tag{1}$$

The cumulative production also was then calculated for each year (1 to 20 years) using the hyperbolic equation:

$$Q = \frac{q_i^b}{(1-b)D_i}\,(q_i^{1-b} - q^{1-b}) \tag{2}$$

Next, the cash flow and present value were calculated:

$$PV = \frac{CF}{(1+r)^n} \tag{3}$$

The fracture cost was subtracted from the present value cumulative gas sales to provide the net present value of the investment. The fracture cost was calculated based on proppant price and service company pump charges in the fracturing operations in southern Chile. The calculation was applied to hybrid fracture and treated water fracture stimulations in a 1 to 20-year period with various proppant concentrations. For hybrid fracturing, the proppant concentrations used were 3, 4, 5, and 6 ppg; whereas, it was 0.5, 1, 1.5, and 2 for treated water fracturing. In addition, for each concentration the proppant quantity varied from 100,000 lbs. to 1,100,000 lbs. These variations in the concentration and the proppant were applied to capture any possibility that could happen since the proppant concentration was dependent upon the proppant quantity and fluid volumes. At the end, the analysis indicated that average treated water fracture in the Glauconite Formation was more economically beneficial than the average hybrid treated water and linear gel fracture stimulation. Figure 5.3 Shows that Treated Water Fracture with a proppant concentration of 2 ppg results in higher net present value than Hybrid fracturing. This benefit can be improved by decreasing the proppant volume through decreasing the fracture cost (Figure 5.4). Additionally, that could enhance the well performance in the long term recovery (review Figure 4.6).

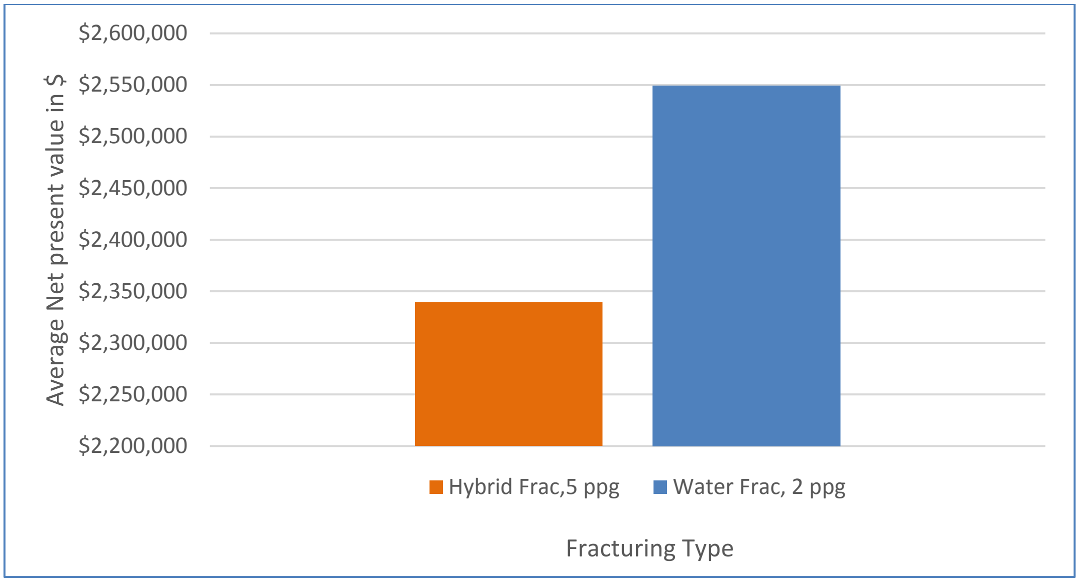


Figure 5.3. Treated Water Fracturing Yield Higher Profit than Hybrid Treated Water & Linear Gel Frac

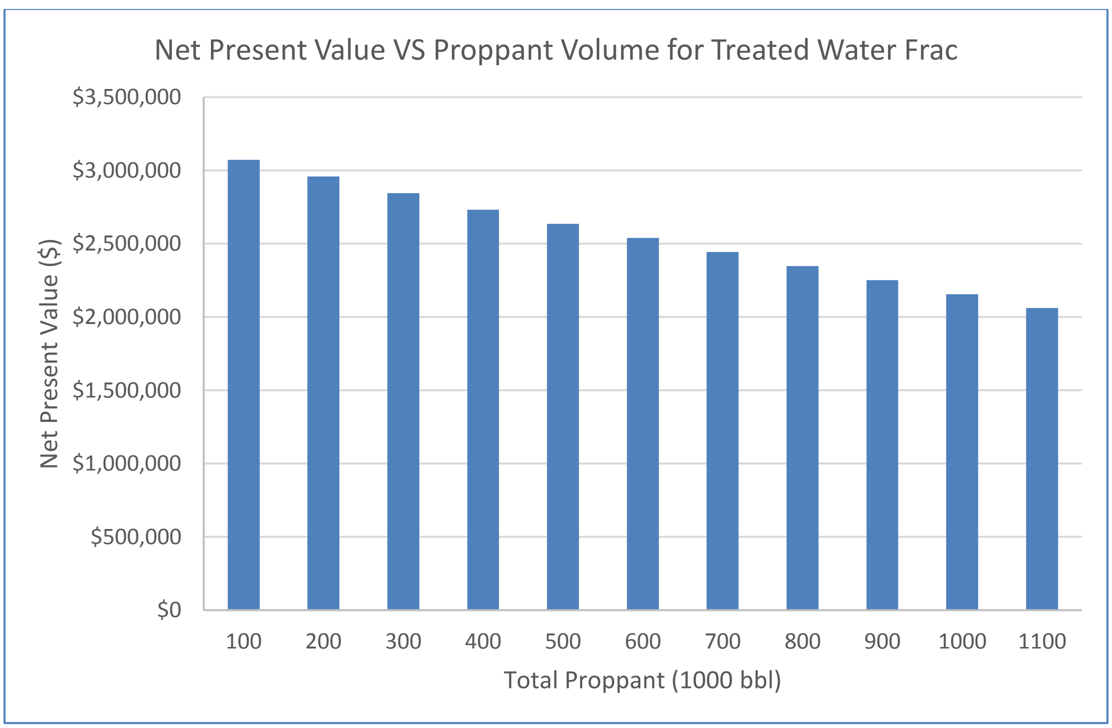


Figure 5.4. Increasing Fracturing Net Present Value by Decreasing Total Proppant in Treated Water Fracturing

6. SUMMARY AND CONCLUSION

Since hydraulic fracturing stimulation operations began in the southern Chile to enhance the gas production from the Glauconite Formation, much information related to the fracturing, completion, and reservoir quality have been collected, and a database has been constructed. The database was used in this work to identify the most effective parameters of stimulation, completion, and reservoir quality on the early production, early recovery, and Estimated Ultimate Recovery. The data was separated according to treatment fluid type as Hybrid Treated Water and Linear Gel, and Water Fracture Stimulation. In the analysis the initial production is represented by the gas rate during the flow-back, and the early recovery is represented by the recovery at 6 months. Multiple regression analysis was used to generate relations between the gas rate` during the flow-back, 6 month recovery, and EUR as dependent variables and the fracturing, completion, and reservoir quality as independent variables. Finally, a sensitivity analysis was utilized to identify the independent parameters which had the greatest effect on early productivity, recovery, and EUR and determine how they effect. The work resulted a several observations which are summarized as follows:

1. The significant independent variables that were estimated out of the many fracturing, completion, and reservoir parameters are the total number of perforations, the number of perforation clusters, total fluid, total proppant, and net pay.
2. In The Hybrid Treated Water and Linear Gel Fracture Stimulations, the number of total perforations had the most impact on initial production (gas rate during the flow back) and early recovery. The impact of the total number of perforations was positive indicating that the gas rate or the recovery can be increased by increasing the total number of perforations. The number of perforation clusters also had a significant influence on these two dependent variables but its effect was negative. However, it had a small positive effect on the Estimated Ultimate Recovery. The total fluid and total proppant had nearly the same impact level in the three cases. Nevertheless, the impact of the total proppant pumped on initial production and Estimated Ultimate Recovery was positive and the effect on these parameters of

total fluid pumped was negative. This contrary effect of the total proppant pumped and total fluid pumped could be because the well fracture stimulated with hybrid treated water and linear gel had high growth and more proppant was needed to cover the excessive fracture height. It is worth to mentioning in this tight gas formation that higher conductivity has more benefit to the early production and can be achieved by pumping more proppant while a longer fracture would have more benefit to the EUR which can be improved be injection of more fluid. Finally, the net pay had less impact on initial production, recovery, and Estimated Ultimate Recovery.

3. For Treated Water Fracture Stimulations, the total proppant pumped had a positive influence on early production while its impact was negative on Estimated Ultimate Recovery. On the other hand, the total fluid pumped had largely opposite effects on all the three production and ultimate recovery cases. This could be because the treated water fractures are more contained in height so increasing the proppant increases the fracture conductivity which supports the initial production and more fluid produces longer fractures enhancing the EUR as mentioned previously. The total number of perforations had negative effect on initial production but a positive effect on early recovery and EUR. The number of perforations clusters and net pay had negative consequences on both initial production and EUR.
4. An evaluation was conducted to investigate the best treatment type based on the fracturing fluid which indicated that Treated water fracture stimulation could improve the initial production rate, early recovery, and the EUR more than with the hybrid treated water and linear gel fracture stimulations in The Glauconite Formation. These treated water fracture stimulations could also provide an economic benefit which could be even further enhanced by decreasing the total proppant.
5. The statistical analysis could produce multiple and conflicting results without a physical understanding of the fracturing process. Therefore, a further investigation may be required to explain the statistical analysis using different method such as three dimensional finite element fracture simulations.

7. FUTURE WORK

The standard least square method used in the multiple variant analysis has been used in this study. It is suggested that a Generalized linear model could also be evaluated to compare statistical methods and their results.

Since the fracturing operation in the Glauconite Formation of southern Chile still continues, more data can be collected, especially the production data from treated water fracturing. Building an even larger database and repeating the analysis with more data will help to validate conclusions of this work.

Using wells logs, mini-frac, and fracturing information to build 1-D or 3-D stimulation models, can clarify the fracture behavior and identify the fracture dimensions and their effects on the post-fracture production.

It is also suggested to create a database of geomechanical information and determine how the geomechanic parameters control the fracture dimensions in the Glauconite Formation.

APPENDIX

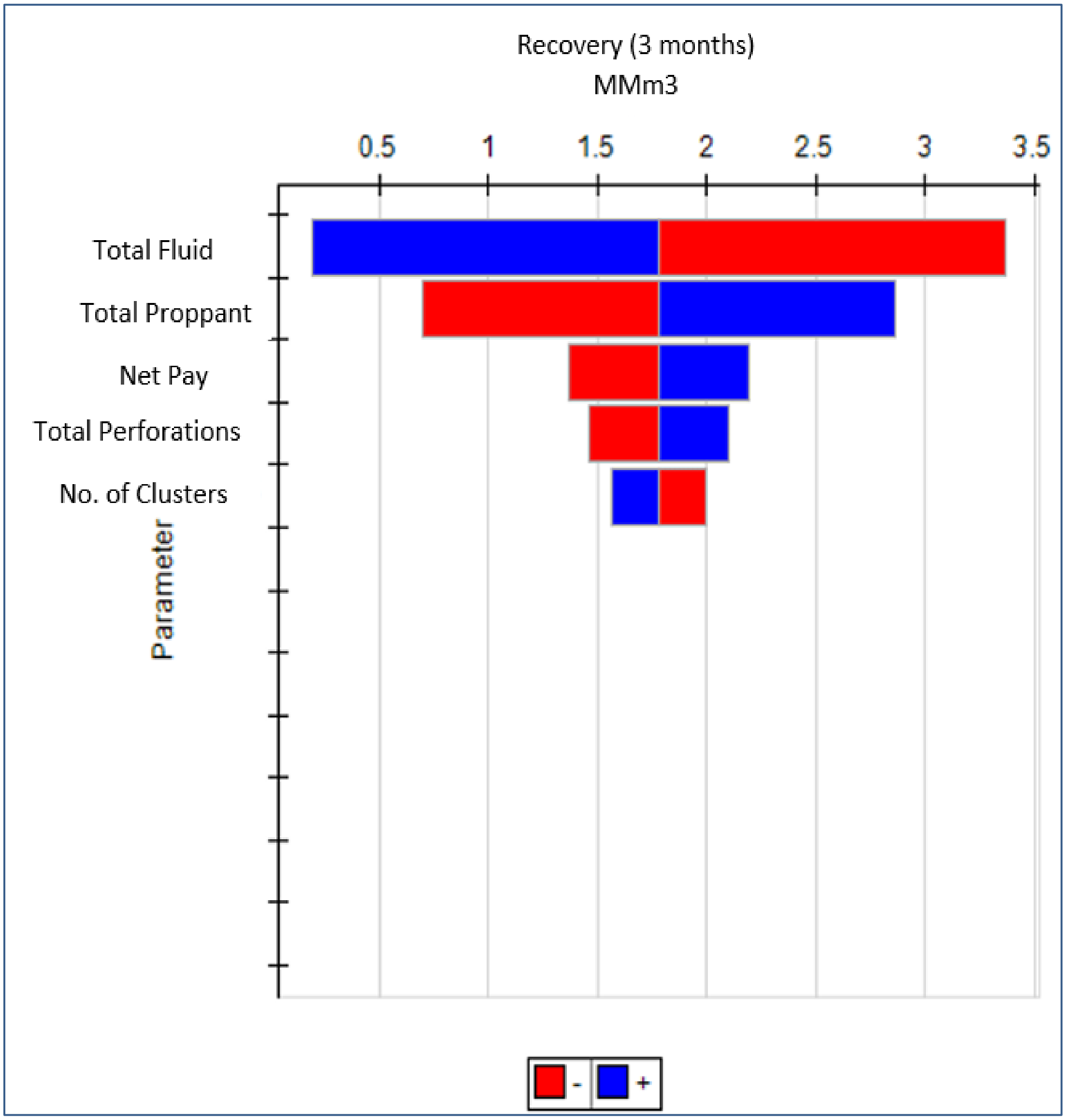


Figure A.1. Tornado Plot of Sorted Parameter Estimates (Hybrid) For 3-Month Recovery

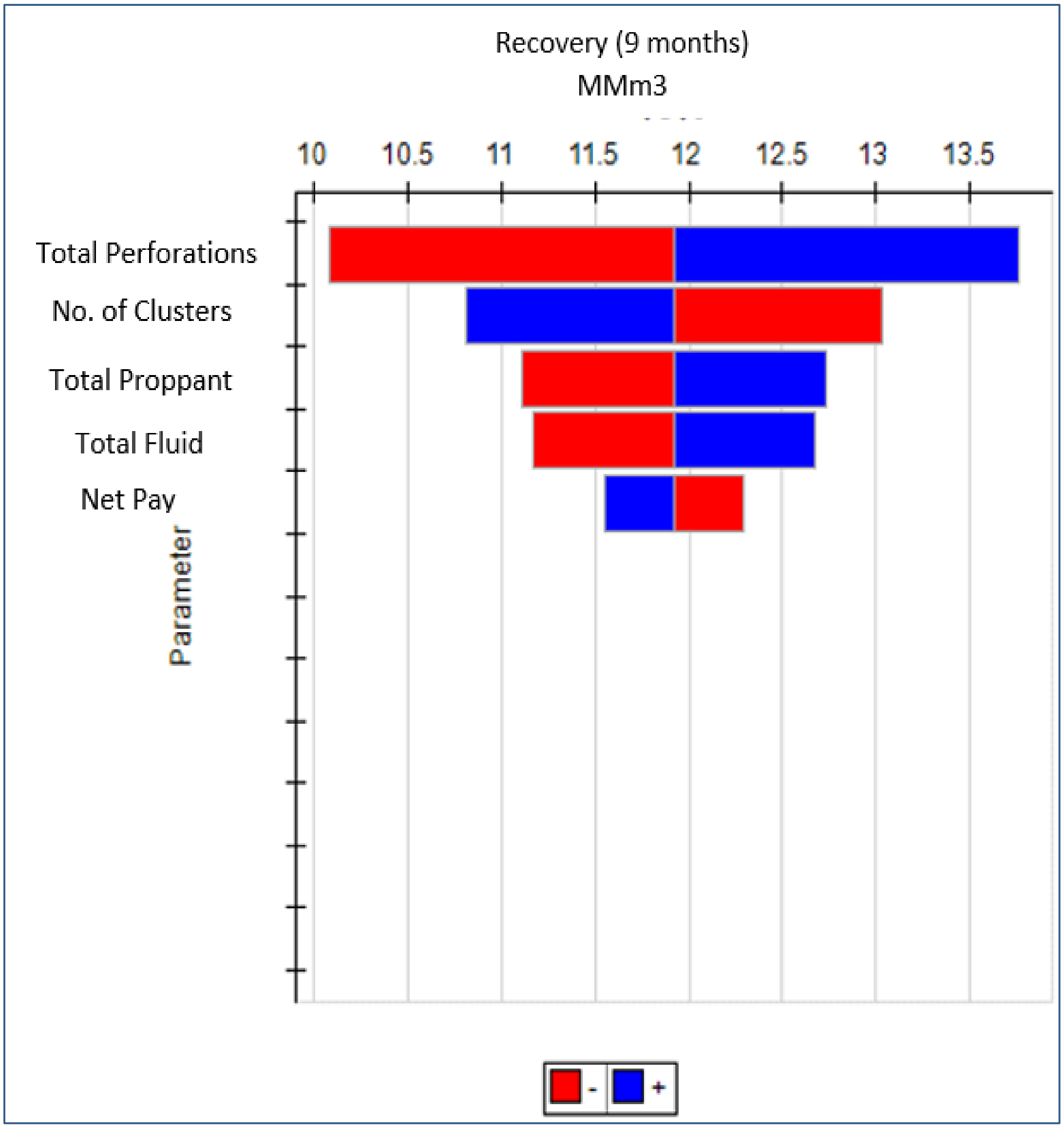


Figure A.2.Tornado Plot of Sorted Parameter Estimates (Hybrid) for 9-Month Recovery

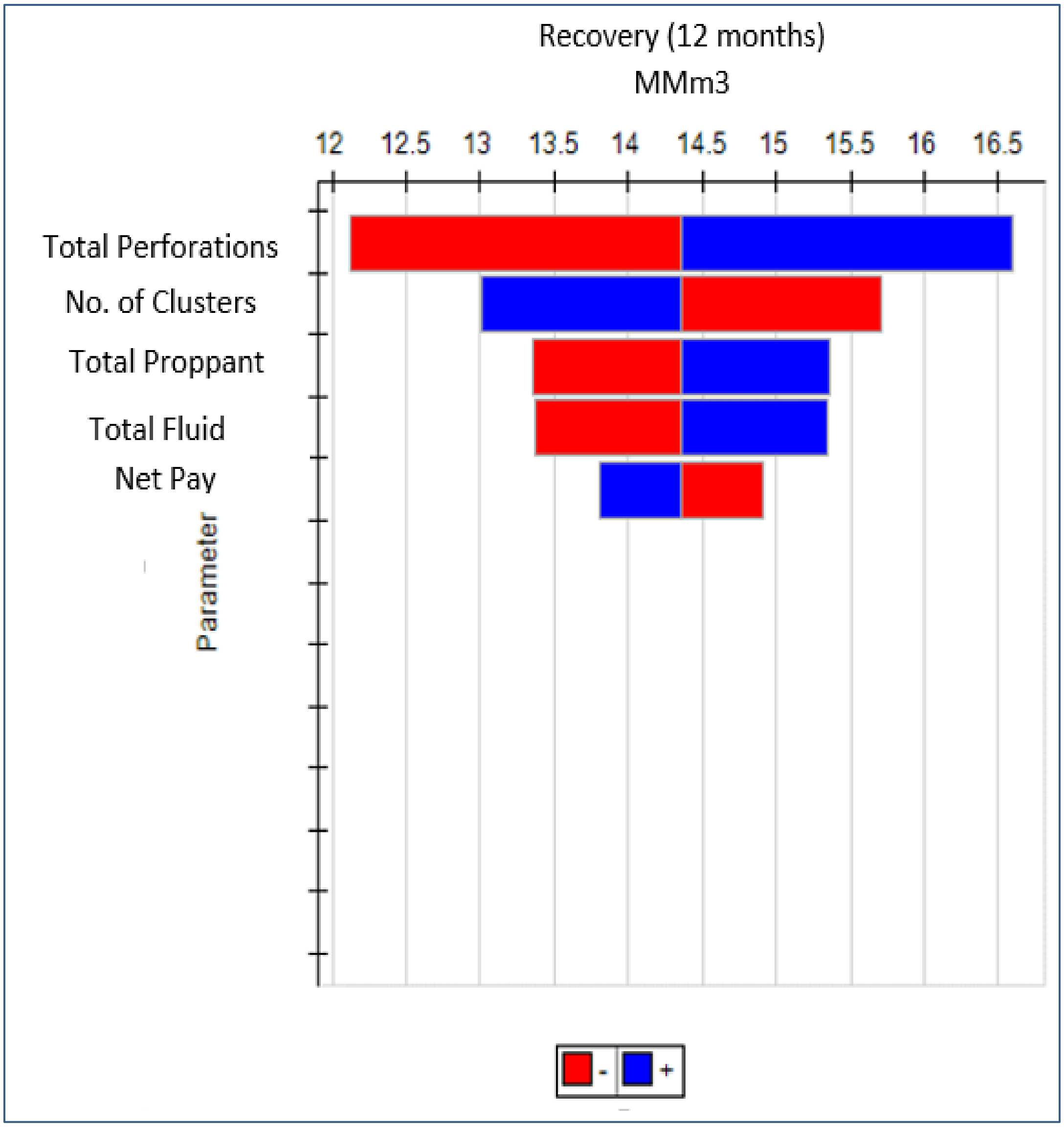


Figure A.3. Tornado Plot of Sorted Parameter Estimates (Hybrid) for 12-Month Recovery

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VITA

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