Evaluation and Optimization of Hydraulic Fracture Treatments in Monell CO2 Flood Project

by

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Evaluation and Optimization of Hydraulic Fracture Treatments in Monell CO2 Flood Project

Approved by
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Dedication

To my parents, thank you for your continued support in everything I do and your unconditional love.
Acknowledgements

I would like to thank Anadarko Petroleum Corporation for the opportunity to report on hydraulic fracturing in an Enhanced Oil Recovery field. I would also like to thank Frank H. Lim for his continual support and mentoring throughout the length of the project.

A special thanks to be extended to The University of Texas at Austin and specifically to my supervisor Dr. Kamy Sepehrnoori for his guidance, encouragement and positive role modeling.

I would also like to thank the many colleagues at Anadarko and in the Patrick Draw field for sharing their expertise, working hard and safe, and genuine kindness.
Abstract

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By using the newly developed best practices in hydraulic sand fracturing in the Monell Unit, a decrease in the injection to production ratio will result. Diagnostics from pre and post fracture analysis and results from a three-dimensional hydraulic sand fracturing simulator are combined to discuss the best practices for hydraulic sand fracturing techniques. Hydraulic fracturing was utilized to decrease the injection to production ratio, without inhibiting sweep efficiency, in the five-spot forty acre spacing EOR Patrick Draw Field, located in Sweetwater County, Wyoming.
The preliminary step for this report was to collect various data type including rock properties and rock mechanics for the Monell Unit. From the field data different hydraulic fracturing techniques such as varying pump rates, varying sand concentrations, pumping different gelling fluids, and reducing the number of perforations where evaluated and simulated using FracproPT. Only the best techniques and procedures that resulted in a more effective hydraulic fracture were chosen to be used in the Monell Unit fracture jobs. The new techniques and procedures were tested in the field and again reexamined for any further improvement. The motivation behind finding the most effective hydraulic sand fracture job was to increase fluid volumes from an Upper Cretaceous Almond Formation, Mesotidal Embayment. The final production increase will be shown in a multitude of production plots. The current best practice for a hydraulic fracture in the Monell Unit include a limited entry oil diesel mixture with 20/40 and 20/40 resin coated sand.
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Chapter 1: Introduction

With oil demand and consumption at an all-time high in the United States and the world, it is imperative for oil companies to extract as much crude oil as possible with the least amount of cost and time expended. In an effort to meet this dramatic need for oil, a hydraulic fracturing program was initiated at the Patrick Draw field in Sweetwater County, Wyoming by Anadarko Petroleum Corporation. With only limited success in the first year of extraction, improvements were made to the hydraulic fracture design resulting in an increase in production. The present work examines best practices for hydraulic sand fracturing techniques utilized to decrease the injection to production ratio, without inhibiting sweep efficiency, in the five-spot forty acre spacing Enhanced Oil Recovery (EOR) Patrick Draw Field. A comprehensive study of rock properties and rock mechanics, production rates, tracer logs, research of published articles, and a three-dimensional hydraulic fracture simulator in the Monell Unit were utilized in an attempt to increase fluid volumes from an Upper Cretaceous Almond Formation, Mesotidal Embayment.

This report will illustrate the increase in production due to the hydraulic fracture program and address the current best practice for a hydraulic fracture in the Monell Unit utilizing a limited entry oil diesel mixture with 20/40 and 20/40 resin coated sand.

Chapter Two discusses the structural makeup, depositional characteristics, and reservoir properties of the Patrick Draw Field from its discovery in 1959 to current...
day EOR operations by Anadarko Petroleum Corporation. The various rock mechanical properties are assessed in Chapter Three. These rock properties are important throughout the report in representing how the reservoir will react to the hydraulic fracture. The FracproPT software by Pinnacle Technologies, which was used to model the hydraulic fracture jobs, is reviewed including the model assumptions in Chapter Four. Chapter Five is a step by step process of the different screens seen by the user in FracproPT. Accompanying the screenshots is an explanation of how the different fracturing properties of the Patrick Draw Field were used and improved upon in FracproPT. The conclusion and recommendation for improvements to the hydraulic fracture job proceeds in Chapter Six. Success in the fracture program to decrease the injection to production ratio is also illustrated in this chapter.
Chapter 2: Field History

The Patrick Draw field, located in the Greater Green River Basin in Southwest Wyoming as shown by Figure 2.1, was discovered by El Paso Natural Gas Company in 1959. Earlier production began within the basin's Almond formation by Texas Company Table Rock Unit 5 well in 1954. With the help of outcrops and limited surface data, the Almond sand was successfully drilled. Desert Springs and West Desert Spring fields were later discovered in 1958 and mid-1959 (C & C Reservoirs, 1999).

Texas Company Table Rock Unit 5 produced 41°API oil at 638 barrels of oil per day (BOPD) from the Upper Almond at a depth of 5172 feet. Infield drilling was quickly brought on and peak production in 1961 was recorded at 25,000 BOPD. First believed to be a massive field, Patrick Draw was estimated at 200-250 million barrels of oil (MMBO) (C & C Reservoirs, 1999). At the conclusion of the reservoir characterization studies recently performed this number dropped to 172 MMBO. The plunge in reserves was attributed to structural complexity and highly variable water saturations throughout the field. However, with remaining oil in place after primary and secondary recovery estimated at more than 113 MMBO, Patrick Draw field was still an economical target.

Driven by solution gas and gas cap expansion, primary production was best at thick intervals of pay and high oil saturation. However, the produced gas was re-injected into the formation in attempt to maintain reservoir pressure. Thereafter, a
five-spot forty acre spacing waterflood began and efficiencies declined in the northern part of the field due to heterogeneity, discontinuity of sand bodies and fluid flow barriers (C & C Reservoirs, 1999). Today the southern half of the Patrick Draw field is now in its third year of an Enhanced Oil Recovery (EOR) CO2 flood. The new wells are again on five-spot forty acre spacing offset from the original waterflood pattern to enhance sweep efficiency.
Figure 2.1: Map of Greater Green River Basin (C & C Reservoirs, 1999).
2.1: Structure

Soon after the deposition of the Almond Reservoir rock during the Late Cretaceous period, the favorable petroleum structure was formed in the Patrick Draw area. A stratigraphic trap was formed by an updip pinchout of the sandstone into coal-bearing shale and siltstone. The shale and siltstone are, in turn, capped by marine Lewis Shale. A cross-section is illustrated in Figure 2.2 below (C & C Reservoirs, 1999).

![Figure 2.2: The cross-section of the Patrick Draw formation illustrating the stratigraphic trap (C & C Reservoirs, 1999).](image)

In the 1900's, studies of previously acquired seismic, log and core data were evaluated to further investigate the presence of reservoir faulting. It was discovered that the majority of the faults strike W-E to SW-NE orientation and are offset on the order of 30° to the two most primary orientations seen in Figure 2.3. Normal faults
prevail as the dominant type with vertical non-sealing displacements of 10-50 ft (C & C Reservoirs, 1999).
Figure 2.3: Fault orientation of the Patrick Draw field. Unit boundaries defined by dashed lines (C & C Reservoirs, 1999).
2.2: Depositional Characteristics

The Upper Cretaceous shoreline formation, where the hydrocarbons in the Patrick Draw field are contained, is situated between the underlying Upper Cretaceous Ericson and overlying Lewis formation seen in Figure 2.4. Contained in the Rock Springs uplift, the hydrocarbon bearing formation known as the Almond Formation is composed of mixed marine and non-marine deposits which are believed to be the result of a western shoreline of the Cretaceous seaway (C & C Reservoirs, 1999).
The Almond Formation which ranges from 250 to 750 feet thick is divided into two parts. The Upper Almond is comprised of coal-bearing shale, siltstone, and sandstone deposited in an estuarine, littoral and shallow marine environment. The
lower formation is lithologically similar to the upper formation, but contains relatively more coal and is interpreted to have more of a dominantly fluvial environment. The Upper Almond is a typical mesotidal regime containing tidal inlet, tidal channel, and flood tidal delta facies boarded by tidal creek, tidal flat, swamp and lagoonal subfacies seen in the paleogeographic map in Figure 2.5 (C & C Reservoirs, 1999).
Figure 2.5: Paleogeographic map of the upper Almond Formation (C & C Reservoirs, 1999).
2.3: Reservoir Makeup

The Upper Almond consists of a total of eight vertically stacked sandstones commonly referred to as the UA-1 through the UA-8. Some of these layers are exposed to the west on the Rock Springs Uplift. Figures 2.6 A and B, illustrate the reservoir layers encountered in the Patrick Draw field. Figure 2.6 A represents a north-south view of the cross section where Figure 2.6 B represents a west-east depiction.

Figure 2.6: A). The reservoir layers of the Patrick Draw field in a north-south direction. B). The reservoir layers of the Patrick Draw field in the east-west direction (C & C Reservoirs, 1999).
The surface location of the above wells can be found on the isopach map in Figure 2.7. Note the pinch out of the UA-5A toward the eastern direction in the Patrick Draw field. This pinch out was also illustrated in the reservoir layers in Figures 2.6 A and B, but is much more subtle. Patrick Draw field is comprised of two vertically stacked mesotidal sand bodies, the UA-5 and UA-6, which dip to the southeast at 4° to the southern flank of the Wamsutter Arch.

The Patrick Draw Field is composed of two units, the northern Arch Unit and the southern unit is known as the Monell Unit. The main hydrocarbon bearing producing zones in the field are restricted to the UA-5 and UA-6; the UA-6 and UA-8 stringer sands throughout the field are gas-prone. The UA-5 has an average sandstone net pay of 20 feet, ranges from 0 to 40 feet gross thickness, and is present throughout the field, whereas the UA-6 is primarily found in the northern half of the field. UA-5 pay thicknesses are generally greater in the southern part of Patrick Draw. UA-5 was further divided into two pay zones called the UA-5A and UA-5B, with the UA-5B being the major pay zone. The division between the UA-5A and UA-5B is illustrated in Figures 2.6 through 2.8. The field was unitized, producing at depths ranging from 4,300 feet to 5,300 feet (C & C Reservoirs, 1999).

Vertical fluid barriers in the Patrick Draw field are primarily based on swamp and lagoonal shales deposited during a regression between two transgressive phases. Other local lithologic fluid barriers include carbonate cementation and coquina deposits. These deposits were common on the island side of a shore barrier and are related to tidal delta or tidal channel deposits (C & C Reservoirs, 1999).
Figure 2.7: Isopach of the UA-5A in the Patrick Draw field and containing correlation of the reservoir layers in Figure 2.5 A and B (C & C Reservoirs, 1999).
Figure 2.8: Isopack of the UA-5B in the Patrick Draw field and containing correlation of the reservoir layers in Figure 2.5 A and B (C & C Reservoirs, 1999).
2.4 Reservoir Properties

The Upper Cretaceous Almond sandstone is composed primarily of fine to medium-grained feldspathic litharenites. Kaolinite, a clay mineral, accounts for between 3 to 5% of the bulk sandstone. Additional minerals include plagioclase, ankerite, calcite, k-feldspar, ankerite, and dolomite (C & C Reservoirs, 1999).

The reservoir sandstone is relatively homogeneous with average porosity and permeability to be 20% and 36 millidarcy (mD) respectively. As expected, the higher porosity and permeability areas correspond to the tidal inlet, tidal channel and tidal delta facies; in these areas the average permeability is 45 mD and the average porosity is 20%. These area facies are consistent with modeled reservoir sands where higher depositional energy corresponds to coarser grain size and lesser detrital clays. Other depositional areas such as the tidal flat, tidal creek, swamp and lagoonal facies, exhibit lower porosity and permeability. These areas demonstrate average permeability and porosity of 8.9 mD and 14% respectively; consequently this results in a greater and more variable porosity and permeability in the Arch Unit when compared to the Monell Unit (C & C Reservoirs, 1999). This less homogeneous area is caused by the environment of the deposition in the Arch Unit from a possible swamp or lagoonal type landscape. These different depositional environments can be seen again in Figure 2.5 while the distribution of mean permeability and porosity can be seen in Figure 2.9 and Figure 2.10.
Figure 2.9: Distribution of the mean permeability for the Monell Unit and Arch Unit in the Patrick Draw Field (C & C Reservoirs, 1999).
Figure 2.10: Distribution of the mean porosity for the Monell Unit and Arch Unit in the Patrick Draw Field (C & C Reservoirs, 1999).
The original reservoir temperature and pressure was 120°F and 2,000 psi respectively. Water saturation before the water flood stood at a respectable 46% then increased to 67% post waterflood. Initial oil saturation in the Monell Unit appears to be controlled by the structural dip. Oil produced from the Patrick Draw field is a light 42°API and low viscosity of .52 cp from the average depth of 4600 feet (O’Brien et al., 2004).

2.5: Reservoir Production

In 1960, as primary production began on an eighty acre well spacing, the reinjecting of produced gas was initiated. Reinjection supplemented with gas cap expansion resulted in the reservoir producing economically until 1977 (C & C Reservoirs, 1999).

Secondary waterflood recovery efforts began in 1967 and continued until 1986 on a five-spot forty acre well spacing. The waterflooding efficiency varied significantly with in the Arch Unit having only limited success compared to the Monell Unit. This inefficiency in the Arch Unit was the result of a high degree of heterogeneity (C & C Reservoirs, 1999), where water breakthrough was anywhere from less than one month to 100 months of water injection, with a short oil bank further substantiating the lesser homogeneous reservoir in the Arch Unit (Chang et al., 1993). Engineers speculated the cause of the early breakthrough to be either fractures in the carbonate-cemented sandstones or relatively high permeability tidal channel thief zones. The average per pattern waterflood recovery was 62.7 MBO in Arch Unit, compared to an average in Monell Unit of 321.7 MBO. The higher
average recovery represents Monell Unit's more homogenous reservoir structure and better interwell communication. Monell Unit waterflood saw longer breakthrough and oil bank period times between 70 to 90 months, and 50 to 75 months respectively (C & C Reservoirs, 1999). Therefore, the Monell Unit is seen as having much better sweep efficiency with a piston like sweep effect.

As initially stated, the original oil in place was over estimated with the current stock tank oil initially in place (STOIP) estimated at 60 MMBO in Arch Unit and 112 MMBO for Monell Unit. Through primary and secondary recovery approximately 59 MMBO have been produced in Patrick Draw with a tertiary recovery effort currently under way in the Monell Unit. The remaining oil in place for tertiary CO₂ flooding is estimated at 72 MMBO from Monell Unit and 41 MMBO from Arch Unit.
Chapter 3: Rock Mechanical Properties

Before beginning an EOR multi-well fracturing program in a five-spot forty acre spacing field, it is extremely important to know the rock mechanical properties of the reservoir. There are multiple techniques for determining such information with special logging tools and coring.

3.1: Properties Resulting from Logs

One type of logging tool is the cross-multipole array (dipole sonic) acoustilog. These logs can provide azimuthal anisotrophy of shear and compressional wave data for determination of present day reservoir stresses. Based on the measurements of maximum and minimum horizontal stresses, the growth direction of the fracture can be determined. According to Dutton et al. (1995), hydraulically induced fractures are commonly aligned parallel to the maximum horizontal stress; therefore, knowing the maximum stress direction is very important before implementing a fracture program. The importance of fracture alignment is discussed in Chapter 6.

During the pilot phase before the full development program of the CO₂ project was initiated at the Monell Unit, dipole sonic logs were used to help identify the direction of minimum and maximum horizontal stresses. The Monell Unit 180-S1 was logged using the Baker-Atlas’s X-MAC Anisotropy Analysis. The X-MAC Anisotropy Analysis concluded that the maximum horizon stress orientation was north 60 degrees west. The log detailing this result is shown in Figure 3.1. The maximum stress orientation for this reservoir area was further confirmed in an earlier
study by Dutton et al. (1995) further validating the direction of a hydraulic fracture was in a northwest direction.
Figure 3.1: Baker-Atlas X-MAC Anisotropy Analysis from the Monell Unit (Anadarko Petroleum Corporation, 2006).
However, upon further analysis of the magnitude of the stress direction, the data revealed low horizontal stress anisotropy. This data was provided by running the Schlumberger DSI Waveform Analysis Shear Anisotropy Process. Low horizontal stress anisotropy results in a small difference between the maximum and minimum horizontal stresses as seen in Figure 3.2. Consequently according to Dutton et al. (1995) some possible implications of low stress anisotropy could result in multiple hydraulic fractures with shorter fracture length.
Figure 3.2: Schlumberger DSI Waveform Analysis for the Monell Unit (Anadarko Petroleum Corporation, 2006).
3.2: Properties Resulting from Coring

Other rock mechanical properties useful to hydraulic fracture design can also be found by coring. Multiple coring jobs were run throughout the Monell Unit to provide useful information about the formation throughout the field. The cores were sent to Omni laboratories for examination after drilling. Through various tests, the information obtained at the laboratory is represented in Table 3.1 and Table 3.2 which included the following: Young's Modulus, Bulk Modulus, Poisson's Ratio, bulk density, overburden pressure, fracture gradient, calculated fracture toughness, horizontal stress, and reservoir pressure.

<table>
<thead>
<tr>
<th>Sample No.</th>
<th>Sample Depth (ft)</th>
<th>Overburden Pressure (psf)</th>
<th>Reservoir Pressure (psf)</th>
<th>Biore's Parameter</th>
<th>Horizontal Stress (psf)</th>
<th>Fracture Gradient</th>
<th>Calculated Fracture Toughness (psi in 1/2)</th>
<th>Modified Ring Test</th>
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<td>2732</td>
<td>0.71</td>
<td>1264</td>
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</table>

*Biore's parameter
**Sample was failing off during test
***Average of two measurements (2245 psi in 1/2 and 2295 psi in 1/2)
**Average of two measurements (1935 psi in 1/2 and 1475 psi in 1/2)

Table 3.1: A typical fracture design parameters for the Monell Unit (Anadarko Petroleum Corporation, 2006).
Table 3.2: A typical ultrasonic velocities and dynamic elastic parameters for the Monell Unit (Anadarko Petroleum Corporation, 2006).

After the multiple rock mechanical properties were tested, an analysis was run on the cores' composition. Core composition analysis is vital to ensure the correct selection of chemicals used during the hydraulic fracture. Many chemicals have now been created to increase the effectiveness of a hydraulic fracture and are used based on the reservoir composition. Chemicals can combat clay swelling, assist with pH control, or control sulfate reducing bacteria depending on the reservoir makeup.

The multiple cores taken during drilling operations also provided the opportunity to ensure the correct calibration for future logging tools. The rock mechanical and composition properties determined from the cores were later used as parameters in the three dimensional hydraulic fracture simulator which will be discussed in Chapter 4.
Chapter 4: Hydraulic Fracture Modeling

Hydraulic fracturing was first used in the 1930's for acid stimulations, then in the 1960's the 150 frac was introduced which used 150,000 gallons of river water and 150,000 lbs. of sand pumping at a rate 150 barrels per minute (Mahrer et al., 1996). Since then, aided by advanced modeling, pressure analysis, and standard diagnostics, hydraulic fracturing has evolved. However, even with this increase in technology the exact fracture model cannot yet be predicted (Warpinski et al., 2001).

In the Monell Unit, hydraulic fracturing is being used to assist with the decreasing of the injection to production ratio. The fracturing program is concentrating on the production wells. The theory behind hydraulically fracturing the Monell Unit wells is to create a greater reservoir surface area resulting in higher flow rate thus leveling the injection to production ratio.

4.1: Modeling Application

Assisted by advancements in technology, an industry trusted three dimensional fracture simulator and analyzer was used to help design, improve and monitor the Monell Unit hydraulic fractures. FracproPT by Pinnacle Technologies was chosen because it is a fully integrated simulator complete with real-time analysis, data-acquisition and graphic representation of the hydraulic fracture.

The simulator allows the input of flow rates, mechanical rock properties, porosity, permeability, formation closure stresses, wellbore design, fluid parameters and proppant concentrations properties to compute expected hydraulic growth of a
Some of most popular output produced by FracproPT includes net pressure matching and time dependent fracture dimensions. This application is broken into four primary modules and was used extensively throughout the hydraulic fracture project at the Monell Unit on all wells that were pre-selected. However the fourth module was not used for this project and hence will not be discussed.

4.1.1: FracproPT Wellbore Transport Module

From the various input variables, the first module determines the change in pressures as the fluid flows down the wellbore. For this fluid flow, FracproPT assumes non-Newtonian fluid while correcting the densities and rheology for the effects of the proppant phases. FracproPT specifies the gel friction pressure by differentiating it at two different flow rates in a given test-loop section to determine the turbulent slurry friction. For friction variation created by the entrained proppant, FracproPT assumes a modified volume-fraction based Thomas equation multiplied by the gel friction (FracproPT, Pinnacle Technologies, GRI, 1999).

4.1.2: FracproPT Fracture Growth Module

For an accurate depiction of a three-dimensional model, FracproPT uses reservoir stress, pressure, flow distribution and modulus for spatial variations. To simplify the fracture dimension calculation, FracproPT integrates the effects into coefficients of the dominant differential equations. Fluid loss in the fracture follows Darcy's law and takes into account the compressible reservoir fluid. The escaping flow is perpendicular to the fracture face and modeled in one dimension. The model
also accounts for the rise in confining stress. The assumptions for heat transfer into
the reservoir again assume one dimensional influence function with a cubic fit
temperature division between the fracture face and the end of the heated region
(FracproPT, Pinnacle Technologies, ORI, 1999).

4.1.3: FracproPT Fracture Growth Module

While there are multiple options for the effects to transportation and
placement of proppant into the fracture, only one effect was modeled during the
simulations on the Monell Unit for consistency. The settling module was chosen to
be modeled which is assumes the fluid is a non-Newtonian fluid and having a slowed
settling rate but with a settled bank buildup. In the convection like model, proppant is
carried into the fracture and allowed to settle throughout the different proppant
concentrations stages (FracproPT, Pinnacle Technologies, GRI, 1999).
Chapter 5: Fracture Design Improvements

Researching, consulting and modeling the initial hydraulic fracture design at the Monell Unit caused the fracture program to improve and evolve. Different iterations resulted in continuous improvements and enhancements to the base model used at the Monell Unit in an effort to use the most effective fracturing techniques. Ultimately, the enhancements decreased the injection to production ratio.

5.1: Model Type Selection

As stated in Chapter 4, FracproPT has many options for the formation of the modeled fracture in the reservoir. Convection is used as the model for the transport of proppant because it takes into account the deceleration created by fracture offsets, multiple fractures and extremely viscous fluids in the fracture. It is suggested by FracproPT to use this option when working with cross linking gel treatments.

Heat transfer effects were modeled to calculate the bottomhole temperature of the pumped fluids which is then passed onto the fracture model. It is in the fracture model that any additional heat transfer between the reservoir rock perimeters and the pumped fluids is calculated. FracproPT default options were selected for remainder of options.
5.2: Well Selection

Soon after it was decided to hydraulically fracture the wells in the Monell Unit, a well selection process commenced. Wells lying within close proximity to faults or injectors were immediately disregarded. It was thought that fracturing near these wells would ultimately lead to premature CO₂ breakthrough. A wellbore evaluation was also done on all remaining wells. All attempts were made to pump the hydraulic fracture jobs through 5 1/2 inch casing since this creates a safer environment. Pumping down 5 1/2 inch casing gives the service company crew extra reaction time to instant downhole pressure increases as well as decreased pumping pressures. Wellbores with casing damage or previous wellbore repairs were packed
off and the fracturing fluid was pumped down 2 7/8 inch production tubing. From the remaining wells, the poorest producing wells were selected to hydraulically fracture first. FracproPT accommodates the many variations in wellbore size by providing a table where the user enters the wellbore size. A screenshot of this can be seen in Figure 5.2. On the occurrence the hydraulic fracture was pumped through 2 7/8 inch tubing this change in wellbore size can be made to the screen seen in Figure 5.3.

Figure 5.2: Screenshot of casing setup in the FracproPT simulation (FracproPT, Pinnacle Technologies, GRI, 1999).
5.3: Completion Practice

As the hydraulic fracture designs were enhanced, the completion practices were augmented. A perforation technique known as limited entry was initiated. Limiting the number and size of the perforations during a hydraulic fracture causes a substantial pressure drop from the wellbore out into the fracture. With this concept in mind as discussed by McDaniel and McMechan (2001), the Monell Unit well

Figure 5.3: Screenshot of tubing setup in the FracproPT simulation (FracproPT, Pinnacle Technologies, GRI, 1999).
completion changed from a 6 shot per foot with 90° phasing to 2 shots per foot with 120° phasing. Reducing the number of shots per foot not only reduces the probability of near wellbore tortuosity but also increases the likelihood of creating multiple main fractures. Changes to the number of perforations were also updated in FracproPT. Figure 5.4 is the screenshot of the input screen for the perforation intervals in FracproPT.

Figure 5.4: Screenshot of the perforation intervals in the FracproPT simulation (FracproPT, Pinnacle Technologies, GRI, 1999).
5.4: Rock Properties

As mentioned earlier, careful investigation of the reservoir rock properties was undertaken. This data was able to provide a firm base of rock properties parameters in FracproPT. The data was correlated to the different layers from which it came and was inputted into the different screens seen in Figure 5.5 and Figure 5.6.

![Figure 5.5: Screenshot of the rock properties used in the FracproPT simulation (FracproPT, Pinnacle Technologies, GRI, 1999).](image-url)
5.5: Gelling Agent

There are multiple ways to increase the performance of a fracture. One such way is using a transporting liquid that will hold the sand yet not inhibit flowback. In the initial period of frac design at Monell the gel loading weight was 25 pounds per 1000 gallons of fluid. However, with no flowback volumes, questions soon began as to the heaviness and possible formation damaging effects of the gel. Therefore, a decrease of the gel loading was instituted and the gel loading weight was lightened to 17 pounds per 1000 gallons of fluid. Results from using the 17 pound gel loading...
were not substantial. Flowback returns were still minimal and concerns that formation damage was occurring were still considered. Upon further investigation and research into non-formation damaging fluids, it was concluded that an oil and diesel mixture could lessen the effect of formation damage while proving an adequate water-based gel substitute. Furthermore, the oil and diesel mixture would have very little effect on the clays and the kaolinite in the formation. Thus, after a few fracture treatments the oil and diesel mixture was proven to be less damaging resulting in faster and greater flowback compared to the gel-based fracturing liquids. The first oil and diesel fracture was in September of 2006 and continued throughout the rest of the project. In FracproPT the oil-diesel mixture is a named by BJ Service Company as Super Rheo 4. For each gelling agent, FracproPT calls for the different fluid properties. The fluid properties for Super Rheo 4 are captured in Figure 5.7.
5.6: Sand Type

The initial design called for 20/40 Ottawa sand, which is common in this type of formation with the presented reservoir characteristics, throughout the 4 stages. The regular 20/40 Ottawa sand was later revisited based on the amount of sand seen in the flowback of the fracture job. The initial fracture design called for a 1 pound mixture in the first stage, 3 pound mixture in the second stage, 4 pounds in the third stage and a 6 pound per gallon concentration in the final stage. To solve the high sand return...
issues upon flow back seen in the launching of the project, a resin coated 20/40 sand was introduced into the fourth stage of the design. When heated or contacted with a certain chemical, resin-coated sand forms a bond with other resin-coated sand particles. When pumped in the last stage, the sand forms a barrier between the sand from the first stages of the frac and the wellbore. The success of the technique used in Monell indicated that the barrier helps prevent the flow back of sand particles. This, in turn, eliminates the need for costly coil tubing cleanouts and swabbing jobs after a fracture job. Both data proppant properties screen can be seen in Figure 5.8 and Figure 5.9. In FracproPT, the resin coated sand is called Super LC-20/40.
Proppant data taken from Proppant Library.

Identifier: 20/40 Ottawa Northern white sand

Description:
- Ottawa Northern white sand
- Unimin

Cost: $0.11 (per lb)

Bulk Density: 1.0000 (lb/ft³)

Packed Density: 0.30

Specific Gravity: 2.65

Turbulence Coefficient a: 1.25

Turbulence Coefficient b: 0.33

Diameter: 0.022 (in)

Width at 2 PSF: 0.000 (in)

Width Correction a: 1.86e-06 (in/psi)

Width Correction b: 4.90e-03 (in)

Figure 5.8: Screenshot of the proppant properties for Ottawa-20/40 sand used in the FracproPT simulation (FracproPT, Pinnacle Technologies, GRI, 1999).
5.7: Sand Volume

As mentioned earlier in this report, fracture growth is important especially in a secondary or tertiary recovery field. In most primary production wells, hydraulic fracturing is used to produce the largest possible reservoir fracture. The larger the fracture that is created in the pay zone, the larger amount of resulting surface area is created in increased production. However, in a five-spot forty acre tertiary field, the longest possible fracture is neither effective nor economical. It is also important that the main fracture growth is not in the direction of the injector. If indeed the main
fracture growth is in the direction of the injector, the producer will experience premature fluid breakthrough which will cause poor sweep efficiency. Van den Hoek (2004) has defined a fracture that grows parallel to opposing well (producer parallel to an injector) as a favorable fracture orientation seen in Figure 5.10.

This type of fracture growth is what is expected in the Monell Unit based on the logging results by Baker-Atlas's X-MAC Anisotropy Analysis. According to Van den Hoek (2004), the ideal half length for a five-spot forty acre spacing fracture is on the order of 318 feet or 25% with respect to its maximum length of the pattern unit cell size.

Figure 5.10: Layout of a favorable fracture orientation (van den Hoek, 2004).

Initially, the fracture job consisting of fifty thousand pounds of 20/40 sand were used in the four stages of the fracture for Monell Unit wells. But after modeling the 50,000 pound fracture jobs, the fracture length appeared not to be reaching the desired length as suggested by Van den Hoek (2004). Therefore, it was decided to increase the 20/40 sand in the first three stages to 68,000 pounds. With this increase of sand and other variable affected by the increase of sand, a fracture length reaching just over 300 feet modeled by FracproPT which was closer to the desired length.
FracproPT, the sand volume is calculated by the multiplication of the flow rate of the fluid by the proppant concentration of each stage seen in Figure 5.10. Also seen in Figure 5.10, is the chosen proppant for each stage. The treatment schedule screenshot in Figure 5.11 are the results of an actual oil diesel 78,000 pound hydraulic sand fracture in the Monell Unit.

Figure 5.11: Screenshot of the treatment schedule for an actual hydraulic fracture in the Monell Unit in FracproPT (FracproPT, Pinnacle Technologies, GRI, 1999).

Van den Hock (2004) also studied the recovery effects of fracturing the reservoir at the 25% with respect to its maximum length of the pattern unit cell size.
His studies concluded that indeed fracturing the well would increase the recovery per pore volumes injected and the most optimal length was undeniably at 25%. Figure 5.12 illustrates the different recovery volumes for the different length of fractures. It is important to point out the more recovery improvement in a well, the increase in the net present value for the well occurs.

Figure 5.12: Recovery verse pore volumes injected base of different fracture lengths (van den Hoek 2004).
5.8: Pumping Rates

Throughout the length of the project, flow rates were held relatively constant. These were on average 15 bbls/min fracturing through 2 7/8 inch tubing and 30 bbls/min if fracturing through 5 1/2 inch casing. However, while carefully monitoring the pressures during the hydraulic fracture job for any abnormally high or low responses, slight changes to the rate were made for maximum results. These real time adjustments were based on live pressuring readings, gelling time, viscosity, max pressure, and initial formation break pressure. Monitoring of these pressures occasionally resulted in changes to the rate and sand concentrations in order to prevent a screen out. The pumping rates can also be seen from the treatment schedule in Figure 5.11.

5.9: Quality Control

During the first two years of the fracture program, very minimal onsite quality control action was taken. However starting in June of 2006, a company engineer was onsite for quality control. The onsite company engineer validated everything from quantity of chemicals on hand and used during the fracture job to measuring the sand size seen in Figure 5.13. The engineer routinely visually inspected the cross-linking of the fluid being pumped every five minutes during the fracture job. Days before the oil diesel fracture jobs, tanks containing the mixed fluid were checked by the company engineer multiple times for water breakout and weathering. Samples were also taken into the service company lab for further testing for cross-linking capabilities.
Figure 5.13: Proppant quality control from an oil diesel fracture job in the Monell Unit (BJ Services JobMaster Program, Anadarko Petroleum Corporation, 2006).

Downhole quality control can also be performed. This ensures the fracture sand is indeed entering the reservoir at the perforation zone and leads to better understanding the near wellbore fracture height. One of the many ways of investigating is by adding an isotope tracer to the proppant and then pumping it down the hole during the last stage of the fracture job. Soon after the fracture job is complete, a logging tool and SpectraScan by Core Lab is run down the hole and logs the placement of the isotope or in this case, iridium. The placement of the isotope is later used to determine the near wellbore height of the fracture created during the job.
and ensuring the sand is indeed fracture the correct zone. In Figure 5.14 the near wellbore proppant placement is almost perfect. As stated earlier, the zone of interest is the UA-5 where it was perforated at 5016 feet to 5044 feet, is bound by a thick shale layer above followed by a thin layer of coal and thicker sandy shale below. These shale and coal create good fracture barriers.
5.10: Pre-Fracture Analysis

Before each fracture job was finalized and sent to the service company for initiation, multiple FracproPT simulations were developed, studied and improved. Although modeling is a computer-generated three-dimensional representation of a
hydraulically induced fracture is, it does help create expected pressures, rates, ratio and possible fracture length. With this data, a graphic three-dimensional representation of the fracture can be created by FracproPT. This simulation can then be further analyzed and changes in the fracture schedule can be made. Figure 5.15 is a modeled fracture in the Monell Unit using all discussed values and improvements.

Figure 5.15: A FracproPT representation of the hydraulic fracture from pre-fracture analysis.

Occasionally pre-fracture analysis was done in what was thought to be the tighter areas of the reservoir as well as wellbores with a high number of perforations per foot. The pre-fracture analysis consisted of step up step down rate test. The step rate test consisted of stepping up the pump rate at 2 barrels a minute until formation break pressure occurred then stepping down the pump rate one pump at a time until all pumps were off line. The step up rate test was used to analyze the fracture treating...
pressure while the step down test analyzed near wellbore effects such as tortuosity. Unfortunately, many times this analysis was not run due to the lack of fluid volume on site, the cost of the fluid volume and during the step up rate test there was no clear sign of a break in the formation.

5.11: Post-Fracture Analysis

Post-Fracture analysis was conducted by the onsite company engineer and the service company’s hydraulic fracture engineer. All volume, pressure and rate plots were reviewed in great detail seen in Figures 5.16 through Figure 5.19. During the fracture job it is necessary to know the current volume that has been pump and how much volume remains. Figure 5.16 is a representation of actual values that were pumped during the hydraulic fracture job. This graph is useful when a limited amount of liquid volume is on hand to pump similar to the Monell Unit environment. Figure 5.17 represents the different pressures and rates seen at various inline points and is valuable in recognizing possible sand conditions. The Nolte Plot (Nolte and Smith, 1980 and Rogers, 1989) in Figure 5.18 can be used to interpret the hydraulic fracture characteristics. The slope of line can determine the type of growth in a hydraulic fracture where in Figure 5.18 represents a radial hydraulic fracture. The plot seen in Figure 5.19 is effective in determining the different chemical ratios in the hydraulic fracturing fluid at any point during the fracture job. Guaranteeing the right chemicals are in the correct ratios is essential for the gel to carry the sand downhole into the fracture and then break the bond and return to the surface. These plots are useful in determining how the reservoir is responding to the fracture job and are
watched very carefully throughout the job in real time. Both positive and negatives results were discussed after the job and improvement for the next hydraulic fracture job were noted and put into action.

<table>
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<tr>
<th>Design</th>
<th>Actual</th>
<th>Stage</th>
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<tr>
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<td>945.1</td>
<td>Slurry</td>
</tr>
<tr>
<td>78004</td>
<td>71731</td>
<td>Sand</td>
</tr>
<tr>
<td>190.5</td>
<td>208.9</td>
<td>01. Pad</td>
</tr>
<tr>
<td>99.5</td>
<td>95.9</td>
<td>02. 1# 20/40 White</td>
</tr>
<tr>
<td>216.3</td>
<td>104.4</td>
<td>03. 3# 20/40 White</td>
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<tr>
<td>281.2</td>
<td>268.3</td>
<td>04. 4# 20/40 White</td>
</tr>
<tr>
<td>50.7</td>
<td>61.9</td>
<td>05. 6# 20/40 Super LC</td>
</tr>
<tr>
<td>118.8</td>
<td>118.7</td>
<td>06. Flush</td>
</tr>
</tbody>
</table>

Figure 5.16: Graph illustrating the design and actual volumes from an oil diesel fracture job in the Monell Unit (BJ Services JobMaster Program, Anadarko Petroleum Corporation, 2006).
Figure 5.17: Various pressures versus elapsed time from an oil diesel fracture job in the Monell Unit (BJ Services JobMaster Program, Anadarko Petroleum Corporation, 2006).
Figure 5.18: The Nolte Plot from an oil diesel fracture job in the Monell Unit (BJ Services JobMaster Program, Anadarko Petroleum Corporation, 2006).
Chemical Rates

Figure 5.19: Chemical ratio rates from an oil diesel fracture job in the Monell Unit (BJ Services JobMaster Program, Anadarko Petroleum Corporation, 2006).

FracproPT also has the functionality of creating a simulation of the hydraulic fracture based on the results from the fracture job. With the live data provided by the service company, FracproPT can use the actual data to generate a three-dimensional graphical representation of a hydraulically induced fracture. This is with the help of net pressure matching, all imputed data, and FracproPT calculations and assumptions. The representation can then be analyzed by the engineering and changes can be made to the fracture program if deemed necessary. Figure 5.20 shows the three-dimensional simulated fracture for a Monell Unit well. The fracture job was using an
oil diesel mix with limited entry and 78,000 pound 20/40 and 20/40 resin coated sand pumped down 5 1/2 inch casing.

Figure 5.20: A FracproPT representation of the hydraulic fracture from post-fracture analysis.
Chapter 6: Conclusion and Recommendations

The main objective of hydraulically fracturing the Monell Unit was ultimately to increase production which would cause a decrease in the injection to production ratio. With just 45 wells fractured, analysis shows the hydraulic fracture program is helping to decrease the injection to production ratio. A high confidence in the program caused the hydraulic fracture program to be integrating into the completion procedures on all new wells. This decision was based on the optimization of the design and latest production results.

6.1: Production Rate

In the initiation of the fracture program it was important to accurately test the production of a well before fracturing in order to determine whether it needed stimulation. Reliable production tests would also allow observation of the increase in production increase. Unfortunately due to mechanical difficulty with equipment in the Monell Unit, accurate tests were only carried out 3 times a year in 2005 and continuing on to the first half of the year in 2006. For this reason, only a portion of the wells that were hydraulically fractured are represented in the Figure 6.1. In Figure 6.1, the initial and post production rates are illustrated along with the percent change from pre to post fracture production. The percent change is represented by a dashed line and is representative of a success with the average well increasing more than an 88% in production.
6.2: Production and Injection Ratio

Plotting the injection to production ratio was also considered when researching the success of the fracture program at the Monell Unit. Figure 6.2 reveals the ratio is indeed on the decline in the Monell Unit. This is another indication that the hydraulic fracture program in Monell is helping increase production. Again in Figure 6.3, the results of current monthly production point out the production rates are on the incline. It is also seen in Figure 6.3 an increase in CO2 injection. This is due to the initiation of new CO2 injectors in the field but no real bearing on the

Figure 6.1: Initial and post production rates of hydraulically fractured wells for the Monell Unit.
injection to production ratio since the increase is minor compared to the increase in production.

Figure 6.2: Monthly injection to production ratio for Monell Unit.
Therefore, after research, modeling and analyzing hydraulic fracture jobs in the Monell Unit, it is recommended that a limited entry oil diesel mixture with a total of 78,000 pounds 20/40 and 20/40 resin coated sand be utilized to achieve the greatest fracture length without inhibiting the sweep efficiency in a forty acre five-spot pattern. Although the exact length and path of the fracture is unknown, new technology is able to reduce the uncertainty. Unfortunately, due to capital restraint, a newer technology proposed by Warpinski et al., (2004) called microseismicity technology which records and displays microseismic events from around a hydraulically induced fracture was unavailable. However, with the increase in
production and the decrease in the injection to production ratio the objective in the Monell Unit fracture program has been reached. It is such a success that all new wells will be fractured using the specifications provided in this report.
REFERENCES


Vita

Nathan Goodman was born in River Falls, Wisconsin on April 20, 1977, the son of Thomas R. Goodman and Jacquelyn R. Goodman three years after his older sister, Khrisslyn. Upon graduation from Georgetown High School, Nathan began his freshman year at Texas Tech University. He studied petroleum engineering and spent his summers at Pioneer Natural Resources and Merit, but ultimately graduated with a B.A. in Management Information Systems. Working for Anadarko Petroleum Corporation after graduation, he soon began to miss the engineering side of the business. In the spring of 2005, Nathan was accepted into the Graduate School of The University of Texas at Austin for Petroleum Engineering. He continued to work for Anadarko Petroleum Corporation and is expected to graduate from The University of Texas in May of 2007.

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