A thesis submitted in partial fulfillment of the requirement for the degree

of

Bachelor of Technology

(Applied Petroleum Engineering-Upstream 2007-11)

"NPV analysis of Hydraulic Fracture Treatment Design for a Shale gas reservoir"

Under the Guidance of

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May 2011

Certificate

This is to certify that Project Report "**NPV analysis of hydraulic fracture treatment for a shale gas reservoir**" submitted to the University of Petroleum & Energy Studies, Dehradun by **Sugandha Thapliyal (R010207058), Gaurav Agarwal (R010207072) and Utkarsh Joshi (R010207063)** in partial fulfilment of the requirement for the award of degree of bachelor of technology in Applied Petroleum Engineering (Academic session 2007-11), is a bonafide work carried out by them under my supervision and guidance. This work has not been submitted anywhere else by anyone for any other degree or diploma.

9 May 2011

Signature

(Mr. Pradeep Joshi)

Abstract

The industry spends millions of dollars each year for fracture stimulation treatments. But the optimization of the fracture treatment is difficult to achieve as large number of critical variables are associated with the designing. These are the variables that have the largest impact on production obtained from any stimulation treatment. Identification of these factors is important for optimizing the treatment. This project concerns with evaluation of treatment design with variation in these critical factors. This method is used to optimize the design prior to spending any money for stimulation treatments. Also NPV analysis has been carried out for selecting the best possible design that promises maximum revenue. The project covers some general concepts of fracture economics and integrates net present worth with commonly observed producing performance decline profiles.

Acknowledgement

We would like to express our deepest gratitude to Dr. Shri Hari, Dean, COES, UPES for extending the opportunity for undergoing dissertation project, and providing necessary resources and expertise for this purpose.

We are grateful to our mentor **Mr. Pradeep Joshi**, for his kind attention and support and the valuable time he gave which led to the completion of the project.

We take this opportunity to express our gratitude towards Mr. Arvind Chittambakkam for his support which helped us to sustain our motivation.

We take this opportunity to express our immense gratitude towards **Mr. Arun Chandel** for allowing us to take stimulation as our major project a work which we always wanted to do.

We are greatly thankful to our faculty members for their altruistic teaching and continuous guiding throughout four years of our study.

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CHAPTER 1: INTRODUCTION

1.1 Project Background:

For optimum and economic development of unconventional reservoirs such as gas shales and CBM reservoirs conventional methods can't be employed. Due to the limited permeability of these reservoirs some type of stimulation process is required for economic recovery from wells drilled into these formations. A formation is said to be permeable if the pore spaces of the rock are interconnected and channels exist through which the oil can flow. The degree of permeability is said to be high if oil gas and water can easily flow through the existing channels and low in case the flow channels are very small and the fluid flow is restricted.

For highly permeable zones the drilling fluid may cause damage to the wellbore and the low permeable zones may not allow sufficient flow into the wellbore. In both the cases the production may not be commercial because the fluid flow is not at the desired optimum rate. A stimulation process (here Hydraulic Fracturing) is then used to increase the amount the amount of fluid flow into the wellbore. Hydraulic Fracturing creates an artificial channel that supports the very purpose.

The first industrial use of hydraulic fracturing dates back to the year 1903. However for oil & gas stimulation it was used in the year 1947 in the United States. The process is now widely accepted and is used annually in a large number of wells worldwide.

1.2 Project Aim

The project aims to design a hydraulic fracturing job for a shale gas and CBM reservoir and choose the best suited design according to the available parameters.

1.3 Project Objective

Hydraulic fracture treatment design varies with large number of parameters which can be chosen as a part of the treatment design. These design variables have been classified into three groups as:

Fracture fluid properties

Proppant properties

Injection schedules (volumes, rates and composition of each fluid stage)

Generally optimization of fracture treatment design is done by trial and error and/ or sensitivity analysis. But, the incorporation of all design parameters into one global optimization problem is impractical because the mechanistic simulation of hydraulic fracturing in conjunction with large scale optimization solvers is too computationally expensive. Since there are several operational and economical constraints in the fracturing treatment design, it is difficult to represent optimization problem with a single objective function. As there are a number of objectives and constraints, tradeoffs amongst these become complex.

The objective of this project is to achieve optimization for fracturing stimulation treatment

1.4 Project Scope

There are many commercial available programs that can be used too model a hydraulic fracturing job. In this project actual reservoir data has been used to design a hydraulic fracturing job.

1.5 Project Methodology

The project represents guidelines for simulation of a hydraulic fracturing job and it selects the best possible option based on NPV analysis i.e. a job that is economically viable.

1.6 Project Limitations

The simulation is done with the aid of computer generated programs and no actual mathematical solutions have been done manually so one has to rely upon the correctness of the results. Due to expertise and lack of data the results are not completely accurate but analysis has been done with the best possible purpose.

CHAPTER 2: LITERATURE REVIEW

2. Literature Review

2.1 Hydraulic Fracturing

It is the process of injecting fluid into the formation at a rate and pressure such that it opens up the formation. The process consists of transporting propping agents to the fracture that needs to be flowed out of well. The fracture creates a conductive path towards the wellbore. Fracturing also helps bypass the near wellbore damage and alters the flow of fluid in the formation. The main parameter to focus upon while considering the size of a fracturing treatment is the amount of proppant placed into the formation. More the proppant placed at the desired location increases the performance.

Application of hydraulic fracturing

- Enhance the flow rate of low permeability reservoirs in case of damaged wells
- For damaged wells the flow rate is increased.
- It helps natural fractures in a formation to communicate with the wellbore.
- The drainage area is increased.
- Pressure drop is reduced around the well in order to minimize the problem of asphaltene and paraffin deposition.

The fracturing job is completed in three stages:

Stage 1

Injection of pad fluid to initiate and propagate the fracture. This pad fluid is the fracturing fluid that does not contain any proppant.

Stage 2

Injection of proppant slurry. The concentration of slurry is increased with injection until it reaches a set value of solids at the end of the treatment.

Stage 3

Cleaning of fracture. This stage is also called back flowing stage in order to clean the fracture.

2.2 Formation Damage

It is the impairment of the reservoir permeability by any phenomenon, resulting in the decreased production / injection from the well is termed as formation damage.

- Fast production / injection decline of the affected well
- It leads to a reduced near well bore permeability

2.3 Damage Quantification

Skin value is used to calculate formation damage. It is denoted by S. The value of skin is given as:

$S=(k/k_s-1)\ln r_s/r_w$

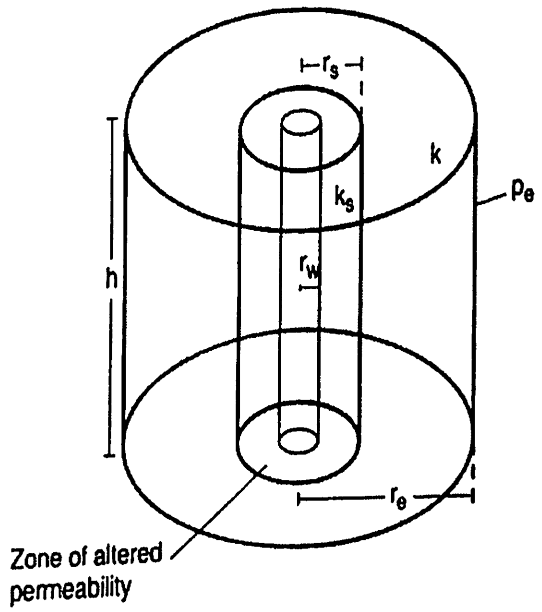


Figure 1. Well with a skin

2.4 Damage Characterization

To classify formation damage & its identification we should know:

- The Type of damage
- The Location of damage
- The Extent of damage
- Its effect on well productivity / infectivity

2.5 Types of Damage

Damages may be due to:

2.5.1 Drilling

Mud solids may block pores, natural or induced fractures. Mud filtrates may cause clay or other fines to flocculate, swell and move. Also pores or fractures near the wellbore may be plugged by the dynamic action of the drill string.

2.5.2 Casing

Cement or mud solids may plug large pores and natural fractures. Chemical flushed before cementing job may change clay properties. Filtrate from high fluid loss cement slurries may change formation properties.

2.5.3 Well Completion

Perforation may be plugged by the solids coming from perforation or completion fluid.

2.5.4 Production Initialization

Fluids that are not compatible with reservoir fluids may cause damage as well as clay or other fine entering the perforation, formation pores and fractures. Clean up of a well at high rate can result in severe plugging.

2.5.5 Stimulation

Formation and fractures can be plugged with solids while stimulating the well with mud or unfiltered oil or water. During hydraulic fracturing propped fractures may become plugged with fracturing sand fines.

2.5.6 Presence of paraffin's and asphalts

During the removal of paraffin's or asphalt from the tubing a portion of scrapped material will be pumped into perforations, pores and fractures adjacent to the wellbore.

2.5.7 Well Services and work over

Use of chemicals during work over may cause water blocks, oil wetting of formation or swelling of clay.

2.5.8 Production Phase

Screen or gravel pack may become plugged with silt, clay, mud scale or other debris. Change in fluid saturation will result in reduced permeability to oil.

2.5.9 Water Injection

If water is insufficiently filtered the fines may pug the formation. In some cases the injected water is not compatible with the reservoir fluid; this may cause drastic permeability reduction.

2.5.10 Gas Injection

Lubricating oil from the gas compressor may build up with oil saturation around the wellbore, oil wetting the injection zone and causing an emulsion in the formation.

2.6 Fracturing Fluid

It provides the hydraulic energy to initiate a fracture propagate or extend the fracture. It also transports propping agents to the fracture that needs to be flowed out after treatment.

2.7 Desired Fluid Properties

Less (or controlled) fluid loss

Low value of friction in pipe

Sufficient viscosity to transport proppant

Yield viscosity quickly

- It should maintain viscosity at shear and temperature

Clean breaking

- Break after desired time at temperature
- Break to low viscosity and no yield-point

Non-damaging

- Leave no residue behind
- Do not cause capillary or phase trapping

2.8 Types of Fluids

- Water based
- Foam based
- Oil/ Diesel based
- Acid based
- Emulsion based

2.9 Types of Fractures

There are basically two types of fracture alignment:

2.9.1 Horizontal Fractures

- Pancake like geometry
- Shallow wells less than 3000 ft.
- Fracture gradient > 1psi/ft.

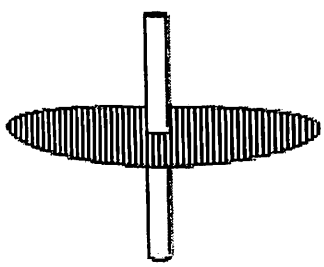


Figure 2. A Horizontal Fracture Geometry

2.9.2 Vertical Fractures

- Plane is perpendicular to earth's surface.
- Fracture gradient <0.8 psi/ft.

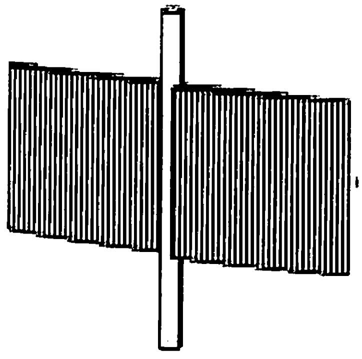


Figure 3. A Vertical Fracture Geometry

2.10 Orientation of the fracture produced

Fracture should occur along planes normal to the least principle stress; the minimum injection pressure should be equal to the least principle stress.

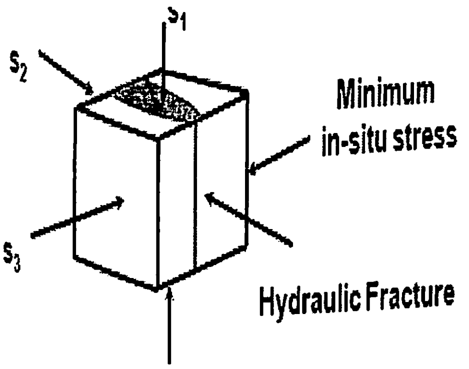


Figure 4. Orientation of Principal Stresses

2.10.1 Case 1

Region characterized by normal faulting

In such case vertical fractures should be formed with injection pressure less than the overburden pressure.

2.10.2 Case 2

Region characterized by thrust faulting

In such case horizontal fractures should be formed with injection pressure equal to or greater than the overburden pressure.

Note:-

In the particular case of horizontal fracturing, the total normal stress across the plane of fracture is equal to the fracture due to the total weight of the overburden, and therefore the minimum injection pressure, regardless of whether the fluid is penetrating or non-penetrating is also equal to the overburden pressure.

2.11 Rupture pressure

Rupture pressure is defined as the pressure which is required to initiate the fracture. In order to determine the rupture pressure, it is necessary to consider the properties of the rock to be fractured. The tensile strength of rock is a notoriously undependable quantity. It varies from zero for unconsolidated formation to several hundred pounds per square inch for the strongest rock.

In case of rocks which are intersected by one or more system of joints comprising partings with only slight normal displacement the tensile stress across these joint surfaces is essentially reduced to zero.

In any section of well bore it is probable that many such joint have been intersected. It appears likely, therefore, that the tensile strengths of most rocks that are subjected to hydraulic fracturing by pressure applied in the well bore is effectively zero, and that the pressure required to produce a parting in the rocks is only that required to reduce the compressive stresses across some plane in the walls of the hole to zero. As the pressure is increased, the plane across which the fracture will commence will be that across which the compressive stress is first reduced to zero.

In case of smooth cylindrical wellbore, this plane must be vertical and perpendicular to the least principle regional stress. The least compressive stress across a vertical plane at the walls of the hole varies from σ_A to zero. Therefore, the down-the-hole pressure required to start vertical fracture with a non penetrating fluid may vary from a value of twice the least horizontal regional stress to zero.

2.12 Design variables

2.12.1 Fracture half length

Productive fracture half length is always less than the propped length and it varies with permeability. Generally vertical variation in the permeability results in smaller fracture half length.

2.12.2 Fracture height growth

Fracture height growth depends upon the magnitude of in-situ stresses, stresses difference and fracture toughness in different layers.

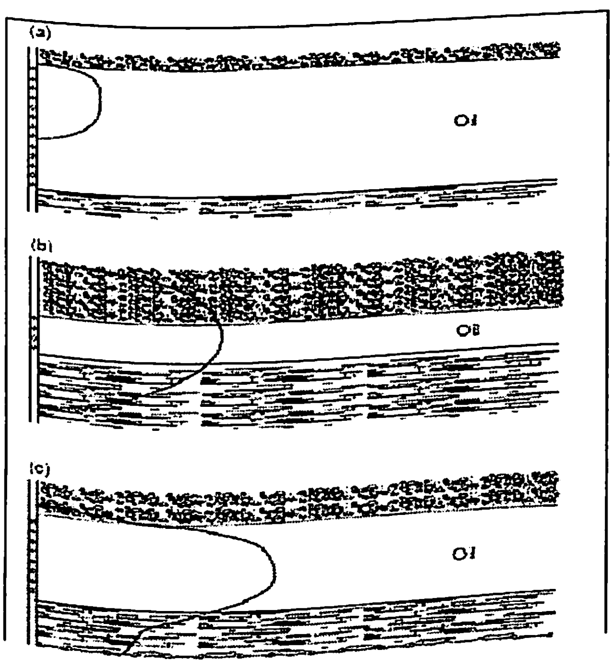


Figure 5. Fracture Height Growth

(a) In this case height of fracture is less than the height of entire zone.
(b) In this case the height of fracture is greater than the height of zone of interest as a result the fracture is contacting non reservoir rocks.
(c) In this case the fracture passes through oil/water contact and if propped will result in water production which is undesirable.

2.12.3 Fracture width

Fracture width depends upon:

- Fracture dimensions- height (h_f)and length of fracture (L)
- Net pressure inside the fracture
- Rock stiffness

2.12.4 Fracture conductivity

Fracture conductivity is defined as the ratio of ability of fracture to carry flow to ability of formation to feed the fracture.

Fracture conductivity C_{fd}:

$$C_{fd}=\frac{k_f w}{k x_f}$$

Value of fracture conductivity to be expected

- FCD>50 : Not preferred
- FCD=0.1: Not preferred

Therefore

- For an ideal steady flow condition FCD=1
- For peak flow conditions FCD=10

Prat's correlation

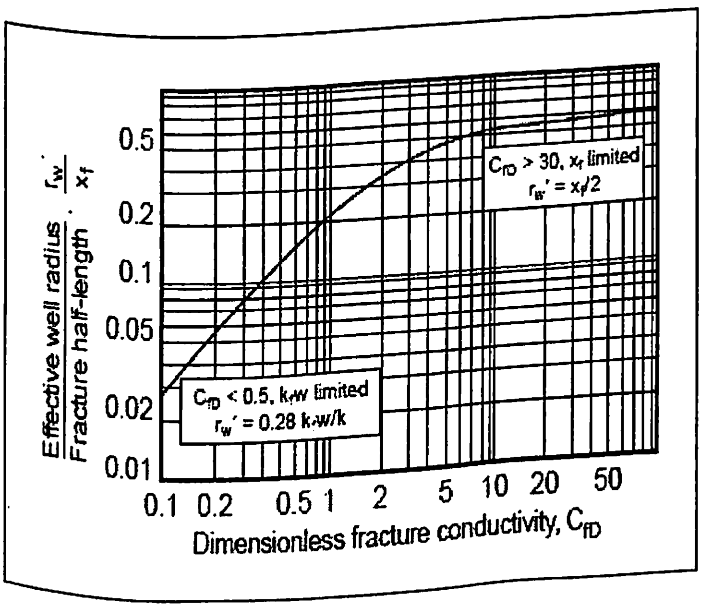


Figure 6. Prat's Correlation

2.13 Procedure to calculate fracture half length

Fracture half length can be calculated using volume material balance.

Fracture half length can be calculated using volume material balance.

Volume pumped

$V_i = q_i * t_p$

Fracture volume created

$V_f = h_f * w * 2L$

Volume lost during fracture

$V_{Lp} = 6h_L C_L L\sqrt{t_p} + 4Lh_L S_p$

Where

- C_L fluid loss coefficient (ft./min^1/2)
- h_L permeable fluid loss height (ft.)
- S_p spurt loss (gal/ft.^2)

Since volume is conserved

$V_i = V_f + V_{Lp}$

By substituting all the values we get:

$$L = \frac{q_i t_p}{2h_f * w + 6h_L C_L\sqrt{t_p} + 4h_L S_p}$$

2.14 Effect of net pressure:

Case1 if p_{net} is small

In such case vertical fracture growth is very small and hydraulic fracture is confined.

Case2 if p_{net} is high

In such case there is extensive height growth as a result radial or circular fractures are formed.

2.14.1 Maximum fracture width

$$w_{max} = \frac{2p_{net}d}{E'}$$

$$E' = \frac{E}{1-V^2}$$

- E' plane strain modulus
- D least dimension of fracture
- V Poisson's ratio

CHAPTER 3: OVERVIEW OF EQUATIONS AND METHODS USED IN CASE STUDY

3.1 Methodology

The critical parameters for optimization of stimulation results can be grouped into three categories. The three categories are 1) Reservoir and producing system parameters that determine the production response from the well 2) Stimulation parameters for the determination of fracture geometry 3) Economic parameters for optimum treatment.

3.1.1 Reservoir and Producing System

- Effective Transmissibility ($k_e h_n/\mu$)
- Effective Mobility (k_e/μ)
- Effective permeability(k_e)
- Reservoir Pressure (psia)
- Net Producing Interval (h_n)
- Fluid Properties
- Reservoir Behaviour
- Surface and wellbore Plumbing Configurations
- Operating Conditions
- Stimulation Parameters

3.1.2 Fracture Stimulation Design

- Design Models
- Propping Agents Permeability(k_f)
- Closure Pressure on Proppants(psia)
- Fluid Loss
- Propped Fracture Width(w)
- Fracture Half Length(x_f)
- Created Fracture Height(h_g)

3.1.3 Economics

- Production Forecasting
- Net Discounted Production Revenue per BBL or MSCF
- Cost Of Stimulation Options

Transmissibility, mobility, pressure, permeability all affects the capability of a producing reservoir. Largely these variables cannot be changed and are the leading factors in certain stimulation design variables such as fracture half length, fracture width and proppant selection. A pressure transient test may be conducted to determine the reservoir variables. Transmissibility and mobility as unit terms is important for accurate production forecasting at the surface. Knowledge of fluid properties and identification of the net producing thickness are necessary to obtain mobility and permeability from the pressure transient analysis. Fluid properties are best obtained from PVT data. Net producing thickness can be obtained from log analysis.

The effects of the surface and wellbore plumbing configuration, as well as operating conditions, must be determined. This is done by available models to describe fluid flow through:

- Perforations
- Tubulars
- Flow lines
- Chokes
- Separators
- Artificial lift systems.

Fracturing stimulation is one of the alterations that can increase the production. The hydraulic fracturing process results in formation of fracture width and length. The resulting conductivity is one factor that determines the rate at which fluid will flow through the fracture to the wellbore. The effect of conductivity and length must be evaluated in conjunction with the total producing system.

Fracture half length is defined as the distance between the wellbore and tip of the fracture. Gross fracture height created during the fracturing treatment is the key parameter that needs to be determined. Optimizing fracture length and other critical parameters cannot be determined without knowing the gross fracture height. The fluid volume required to maintain the optimum fracture length in the formation increases as the fracture height increases. The amount of proppant thus required to obtain the desired conductivity also increases because the total area of fracture has increased.

Proppant selection is an important part of any fracture stimulation design. The fracture closure pressure helps select the propping agent that fits in with the conductivity required.

Fluid efficiency is a measure of how effective a specific fracturing fluid will be in creating the desired fracture geometry. It is dependent on the fracture fluid properties, injection rate, reservoir characteristics, area and fluid loss additives used. Here the fluid loss coefficient is a very critical parameter, the larger the value of fluid loss coefficient the less efficient the fracturing fluid system will be.

3.2 Obtaining variables

The term closure pressure is determined from an instantaneous shut in pressure by assuming that the closure pressure is equal to the bottom hole fracture pressure. It can also be obtained from a step rate test.

The total fluid loss coefficient and fluid efficiency terms are obtained insitu by performing a small injection test using the same fracture fluid and injection rate as done for the actual treatment.

The volume of fluid required is determined from previous experience. Gross fracture height is determined by a gamma ray survey.

The last variable to determine is the fracture geometry model. There are three models available that may be used:-

- 2D PKN model
- P3D model
- MLF model

Choosing the correct model for designing of an optimum stimulation treatment is very critical. Using accurate input data with previously established history and evaluating allows the verification or modifications that are applicable to a formation.

NPV analysis is the ultimate deciding factor for the total design process. It compares the revenue potential to the cost of treatment, plumbing system and operating conditions available. These modeling techniques forecast the effect each design option will have on the production potential. As the options vary the total system production potential will also change. Production forecast move hand to hand with revenue potential, if the net revenue per unit hydrocarbon is known, the present value can be calculated using a revenue discount factor. The economic design is one with the largest net present value. The other variables affecting optimum design are:-

- Duration of production forecast for which NPV is to be determined.
- The net discounted production revenue
- Investment for the design option

3.3 Method for optimum fracture stimulation design

3.3.1 Step 1

Forecasting production for fracture stimulation operating condition design and plumbing system.

Procedure

- Design, conduct and interpret via a pressure transient test for the determination of critical reservoir variables (transmissibility, permeability, mobility, reservoir pressure).
- Select plumbing system design options (tubing size, shot density and type, flow lines size and length, artificial lift).
- Select operating conditions (wellhead pressure, separator pressure, wellhead pressure).
- Select fracture design (fracture conductivity, fracture half length).
- With the help of modeling techniques forecast production for the total system design.

3.3.2 Step 2

Determine achievable fracture stimulation design.

Procedure

- Carry out injection tests to determine minimum stress and closure pressure.
- Carry out small non propped fracture treatment to determine total fluid loss coefficient and fluid efficiency.
- Carry out surveys to determine gross fracture height.
- Model the fracture geometry, determine the volume of fracturing fluid and proppant required to create the lengths and conductivity used in the forecast.

3.3.3 Step 3

Economic optimization of fracture stimulation treatment design.

Procedure

- From the production forecast determine cumulative production vs. time for each of the expected fracture stimulation designs.
- Calculate the present value of the production.
- Determine the investment required.
- Calculate the net present value for each of the options available.

- The economically reasonable, optimum fracture, stimulation treatment design has the highest net present value.

3.3.4 Step 4

Pumping and monitoring the desired fracture stimulation treatment

Procedure

- A treatment monitor vehicle is used to make sure the job is done as designed.
- Monitor and plot real time fracture growth data.

3.3.5 Step 5

Evaluate the fracture stimulation results.

Procedure

- Compare the results of step 4 to the production forecast model.
- If the forecast production and actual production are the same the system is operating properly and the stimulation treatment is successful.

3.3.6 Step 6

Detect the problem if the well is not performing as forecasted.

Procedure

- Undesired conditions are checked in the total producing system.
- Review the treatment data.
- A post fracture pressure transient test is conducted to determine the effective fracture length and conductivity.
- Any new condition should be updated to the production forecast.

3.3.7 Step 7

Design criteria for future fracture stimulation treatments in the area.

Procedure

- Use various models and simulators to create a new fracture geometry model, if desired.

3.4 Concepts of fracturing economics

Economic design has three basic requirements:-

- To evaluate what oil and / or gas producing rates and recoveries should be expected from various fracture lengths and conductivities of a reservoir.
- To determine the fracture treatment requirements to achieve the desired fracture lengths and conductivities.
- Combine the results and select the design that maximizes our economic returns.

3.5 Producing performance profiles

Profile of estimated producing rates or cumulative production must be determined for both fractured and unfractured cases. The approach depends on whether the performance behavior is following:

- Steady state (for K>10md)
- Unsteady state flow (k<1md)

3.5.1 Steady state or semi steady state behavior

When the reservoir has relatively high permeability and the performance condition s are established in a relatively short time, it is possible to determine production rate increase.

Performance decline studies have shown that the behavior falls into one of the three categories:-

- Constant percentage
- Hyperbolic
- Harmonic

The equation applicable to the above three forms is

$$s = -\frac{d}{dt}\ln q = -\frac{1}{q}\frac{dq}{dt} = bq^m$$

Where

- q producing rate
- t time
- b &m constants

The value of cumulative production N_p for the three forms is as follows:-

1. Constant percentage decline :

$$N_p = \frac{q_i - q}{s} = \frac{q_i(1 - e^{-st})}{s}$$

2. For hyperbolic decline :

$$N_p = \frac{q_i}{(1-m)s_i}\left[1 - (1 + ms_i t)^{\frac{(m-1)}{m}}\right]$$

3. For harmonic decline :

$$N_p = \frac{q_i}{s_i}\ln\left(\frac{q_i}{q}\right) = \frac{q_i}{s_i}\ln(1 + s_i t)$$

Where

- S constant percentage decline rate (cycles/month)
- s_i initial decline rate.
- t time
- q producing rate at time t
- q_i initial producing rate
- N_p cumulative production at time t

For economic optimization studies, the choice of approach and the choice for performance decline are very important and critical.

3.5.2 Unsteady state behavior

If the permeability of the reservoir is low transient flow prevails in early life of well. The type curves here provide a relatively fast and inexpensive method to predict the performance before and after fracturing.

3.5.3 General economic criteria

For the economics of fracturing one should consider the following:

- Present value of the cash flow from the well production and expense streams.
- The net present value of the net cash flow from the fracturing treatment.
- The payout time. (PO)
- Return on investment (ROI)
- The rate of return (ROR)

3.6 Present value

Present value (PV) is related to the future value (FV):

$$PV = D^{N}\,FV$$

Where

- N total number of compounding periods for the interest rate.
    - $D = \left[\frac{1}{1+\frac{i_A}{n_A}}\right]$ = discount factor

- i_A Annual interest rate
- n_A number of compounding periods per annum
- i_A/n_A periodic discount rate

3.6.1 Case 1

For discrete increments

$$PV]_l^L = \sum_{n=l}^{L} PV]_{n-1}^{n} = \sum_{n=l}^{L} D^n V]_{n-1}^{n}$$

3.6.2 Case 2

For continuous present value

$$D_c^n = \frac{1}{e^{n(i_A|n_A)}}$$

3.6.3 Case 3

For special cases

Constant percentage decline discrete case

$$PV]_l^K = \frac{A(e^s - 1)}{s}\left[\frac{1 - B^{K+1}}{1 - B} - 1\right] - E[D_k]$$

Constant percentage continuous case

$$PV]_0^{t_a} = \frac{A_l(B^{t_a} - 1)}{\ln B}$$

Hyperbolic decline discrete case

$$PV]_1^K = \frac{A}{(1-m)s_i} D - D^k[1 + ms_i K]^{\frac{m-1}{m}} + (D-1)\sum_{n=1}^{K-1} D^n(1 + ms_i)^{\frac{m-1}{m}} - E[D_k]$$

Harmonic decline discrete case

$$PV]_1^K = \frac{A}{s_i}\left[D^n ln[1 + s_i k] + (1 - D)\sum_{n=1}^{K-1} D^n \; ln[1 + s_i n]\right] - E[D_k]$$

Where

- K number of monthly increments
- i monthly interest rate
- u average net hydrocarbon value per unit produced
- E monthly operating expense
- E_l operating cost/bbl produced

3.7 Net present value

This term is used to study present value economics from a treatment.

$$NPV = (PV)_{af} - (PV)_{bf} - C_T$$

Where

- af and bf represent after and before fracturing
- C_T compounding period

3.8 Elements of fracturing treatment costs

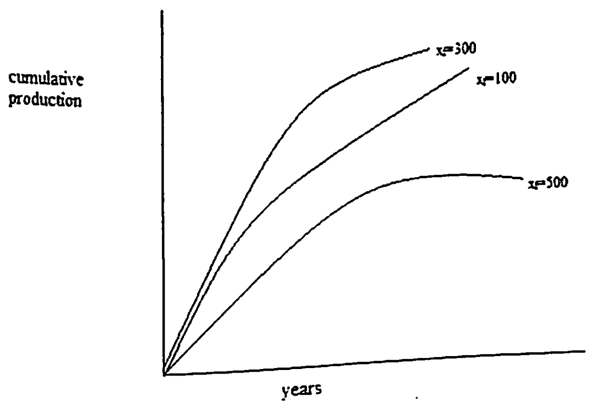
The Treatment cost usually includes the following:

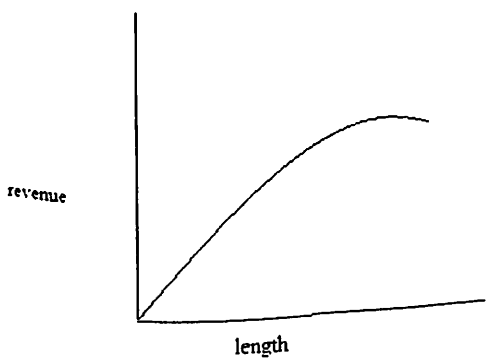
- Pressure multiplier pump charges
- Fracture pumping equipment charges
- Blender service charges
- Fracture material and material handling cost
- Propping agents pumping charges
- Slurry concentration service
- Material and equipment transportation costs
- Stimulation technical and laboratory help

- ➢ Various services and license charges
- ➢ Other associated costs

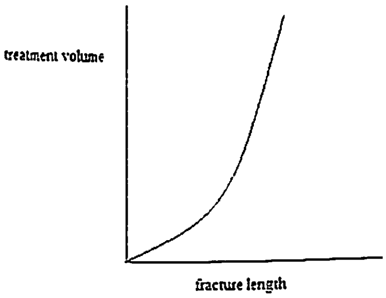
3.9 Fracture stimulation design: total concept of optimization

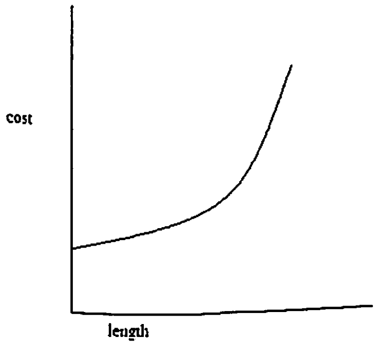
A reservoir performance simulator generates the following graphs:





Fracture simulator generates the following graphs:





With these data the net profit curve is generated as shown below:

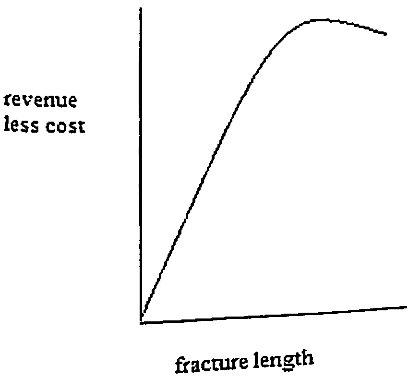


Figure 7. Total concept of optimization

CHAPTER 4: CASE STUDY ANALYSIS

4.1 CASE STUDY ANALYSIS

Reservoir and hydro fracturing data for the well is given in the following table.

	Name	Top TVD ft	Rock Type	Gross Height ft	Leakoff Height ft	Net Height ft	Number of Perfs	Perf Dia in	Fracture Gradient psi/ft	In-situ Stress psi	Young's Modulus psi	Poisson's Ratio	Reservoir Pressure psi	Permeability md	Porosity %
1	CLEAN-SANDSTO	1550.0	CLEAN-SANDSTONE	1000.0	1000.0	1000.0	0	0.400	1.010	2070	5.086E+06	0.23	1377	0.05	3.5
2	SHALE	2550.0	SHALE	500.2	500.2	500.2	0	0.400	0.910	2548	1.320E+06	0.35	1377	0.001	1.0
3	CLEAN-SANDSTO	3050.2	CLEAN-SANDSTONE	204.1	204.1	204.1	46	0.400	0.770	2427	5.086E+06	0.23	1377	0.05	3.5
4	SHALE	3254.3	SHALE	3.6	3.6	3.6	5	0.400	0.830	2703	1.320E+06	0.35	1377	0.001	1.0
5	CLEAN-SANDSTO	3257.9	CLEAN-SANDSTONE	103.6	103.6	103.6	13	0.400	0.770	2548	5.086E+06	0.23	1377	0.05	3.5
6	SHALE	3361.5	SHALE	104.5	104.5	104.5	0	0.400	0.830	2833	1.320E+06	0.35	1377	0.001	1.0
7	CLEAN-SANDSTO	3466.0	CLEAN-SANDSTONE	100.0	100.0	100.0	0	0.400	0.780	2742	5.086E+06	0.23	1377	0.05	3.5

T1. Reservoir and Hydraulic Fracture Data

The formation to be fractured is a potential shale gas producer formation.

A fracture half-length of 200 ft. (60.96 m) was chosen based on the data provided in the forecast. A fracture stimulation treatment was then designed for this 200 ft. However, the values for several critical variables (gross fracture height, closure pressure) necessary for realistic stimulation design were not accurately determined. A propped fracture length of 140 ft. (42.67 m) and apparent fracture length of 112 ft. (34.13 m) was assumed for base case.

The treatment was designed to use 39117 gal of total fracturing fluid to place approximately 51648 lb. of proppant. A pump rate of 40 bbl. /min was taken with fluid efficiency of 0.5. Total pad volume to be pumped was determined to be 16777 gal. Fracture lengths for various treatment volumes and rates were determined using a fracture propagation model.

The base case description is given below:

Fluid Type | Plot

	YF130.1HTD (base case)	
Hydraulic Xf	200.0	ft
Propped Xf	140.0	ft
Apparent Xf	112.0	ft
Fcd	121.47	
Radial Cum	82	MMscf
Frac Cum	291	MMscf
Pump Rate	40.0	bbl/min
Fluid Eff.	0.5	
Pad Vol.	16777	gal
Tot. Fluid	39117	gal
Tot. Prop	51648	lb
Est. Cost	4,778,999	$(US)
NPV	12,316,023 (optimum)	$(US)

T2. Base Case

4.2 Application of general concepts of fracturing economics

Economic design of fracture treatments has been done based on three basic requirements-

1) Evaluating what gas producing rates might be expected from various fracture lengths and conductivities. A reservoir performance simulator provided predictions of the production rates and recoveries for variation of fracture lengths as shown below:

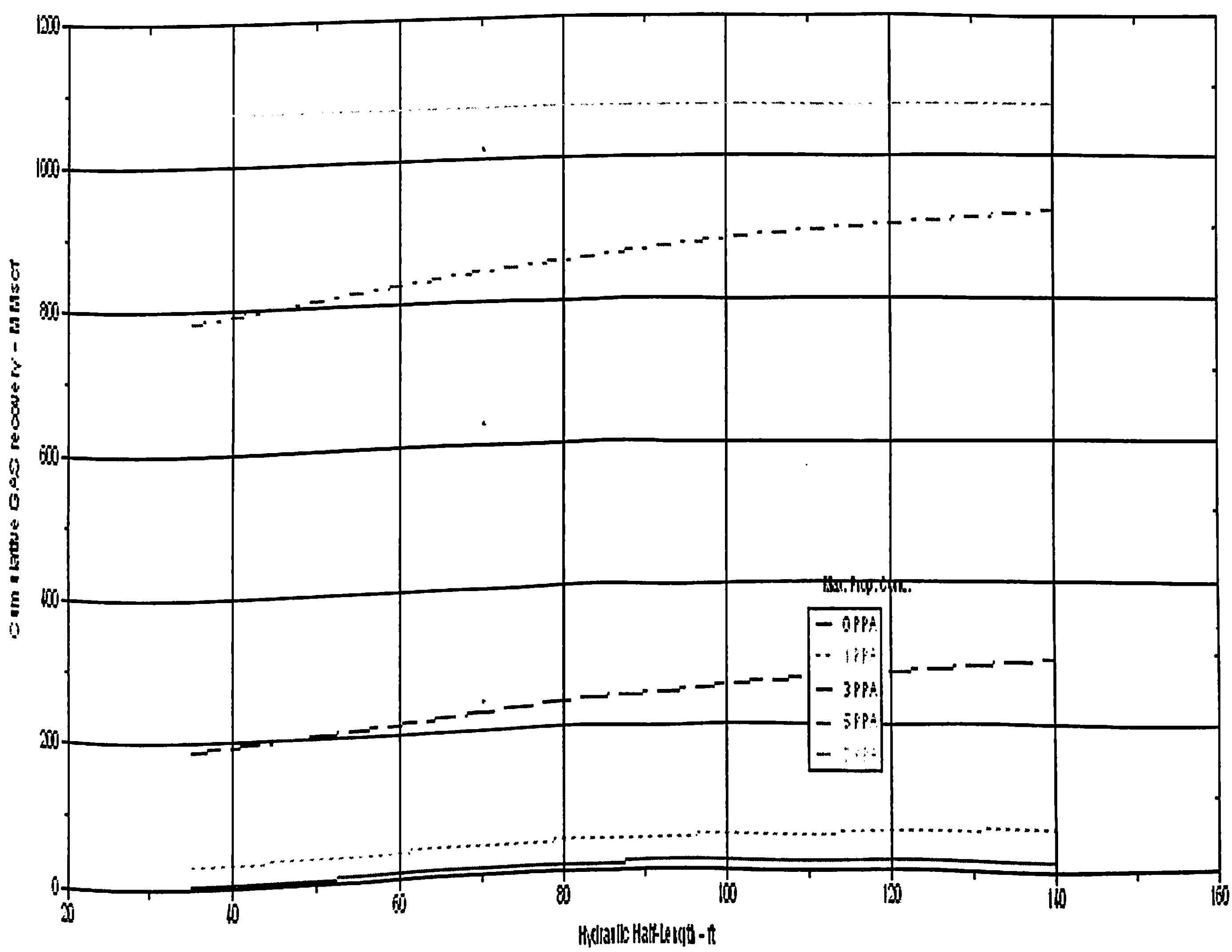


Figure 8. Plot of x_f vs. cumulative gas production

A revenue estimate was then developed for various fracture lengths. Revenue, as a function of fracture length is, usually not a linear relationship. It has been found that the rate of revenue growth diminishes with increasing fracture length and eventually reaches a flat slope.

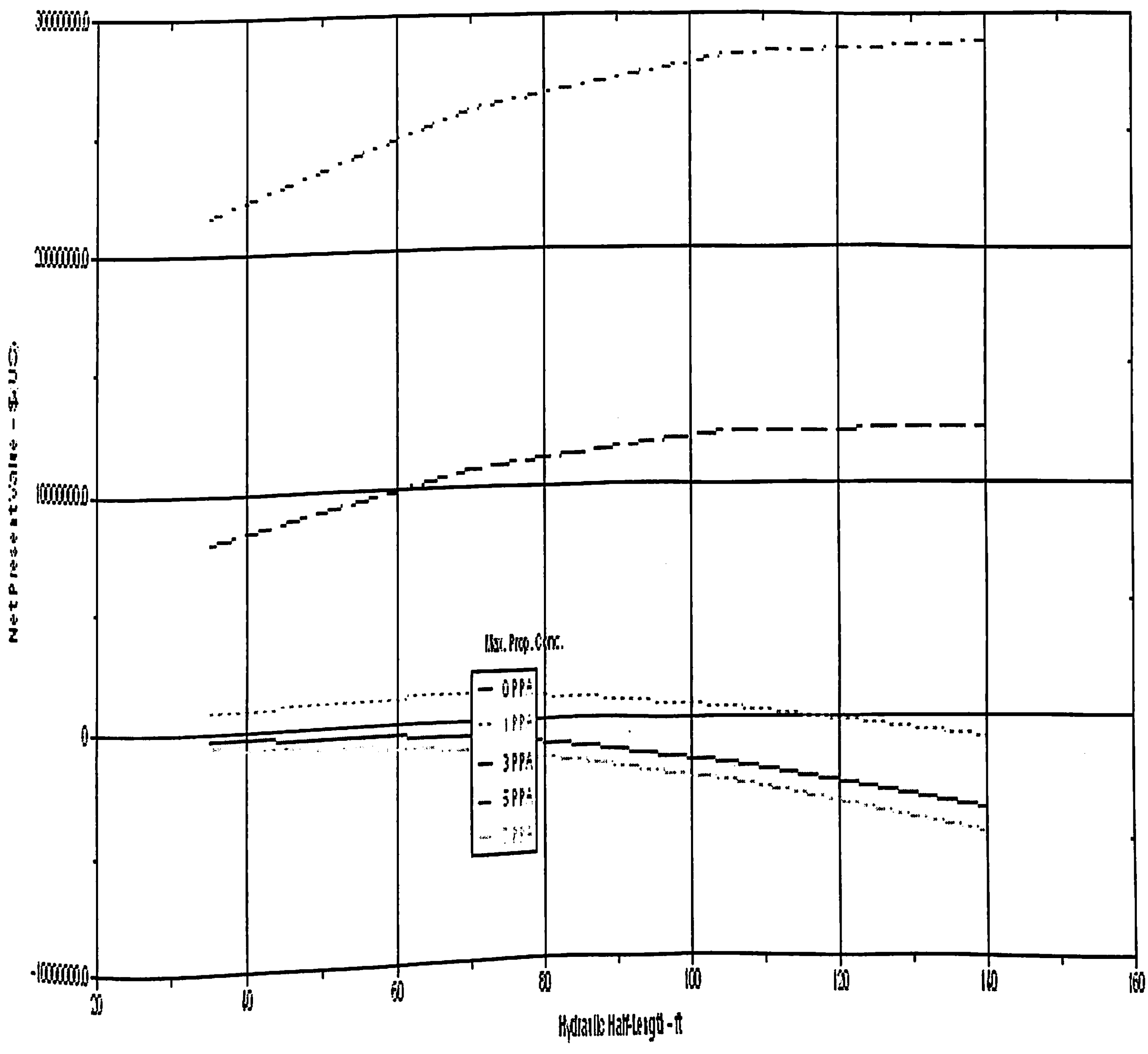


Figure 9. Plot of x_f vs NPV

2) A hydraulic fracture simulator has been used to compute treatment volumes, types of material and pumping schedules necessary to achieve various fracture lengths and conductivities.

Stage Name	Pump Rate bbl/min	Fluid #	Fluid Name	Gel Conc. lb/mgal	Fluid Volume gal	Prop. #	Prop. Conc. PPA	Prop. Mass lb	Slurry Volume bbl	Pump Time min
pad	25.0	2	YF130D	30.0	5000	0	0.0	0	119.0	4.8
0.5 ppg	25.0	5	YF130.1H	30.0	5000	2	0.5	2500	121.7	4.9
1 ppg	25.1	5	YF130.1H	30.0	5500	2	1.0	5500	136.9	5.5
1.5 ppg	25.0	5	YF130.1H	30.0	6000	2	1.5	9000	152.5	6.1
2 ppg	25.1	5	YF130.1H	30.0	6500	2	2.0	13000	168.8	6.7
2.5 ppg	24.7	5	YF130.1H	30.0	7000	2	2.5	17500	185.5	7.5
3 ppg	20.1	2	YF130D	30.0	7500	2	3.0	22500	202.8	10.1
flush	15.0	4	WF250	50.0	2978	0	0.0	0	70.9	4.7

T3. Pumping Schedule

With these data a relationship between fracture lengths and treatment costs can be generated.

3) The sensitivity of net present value to various parameters has been analyzed as shown in plots below:

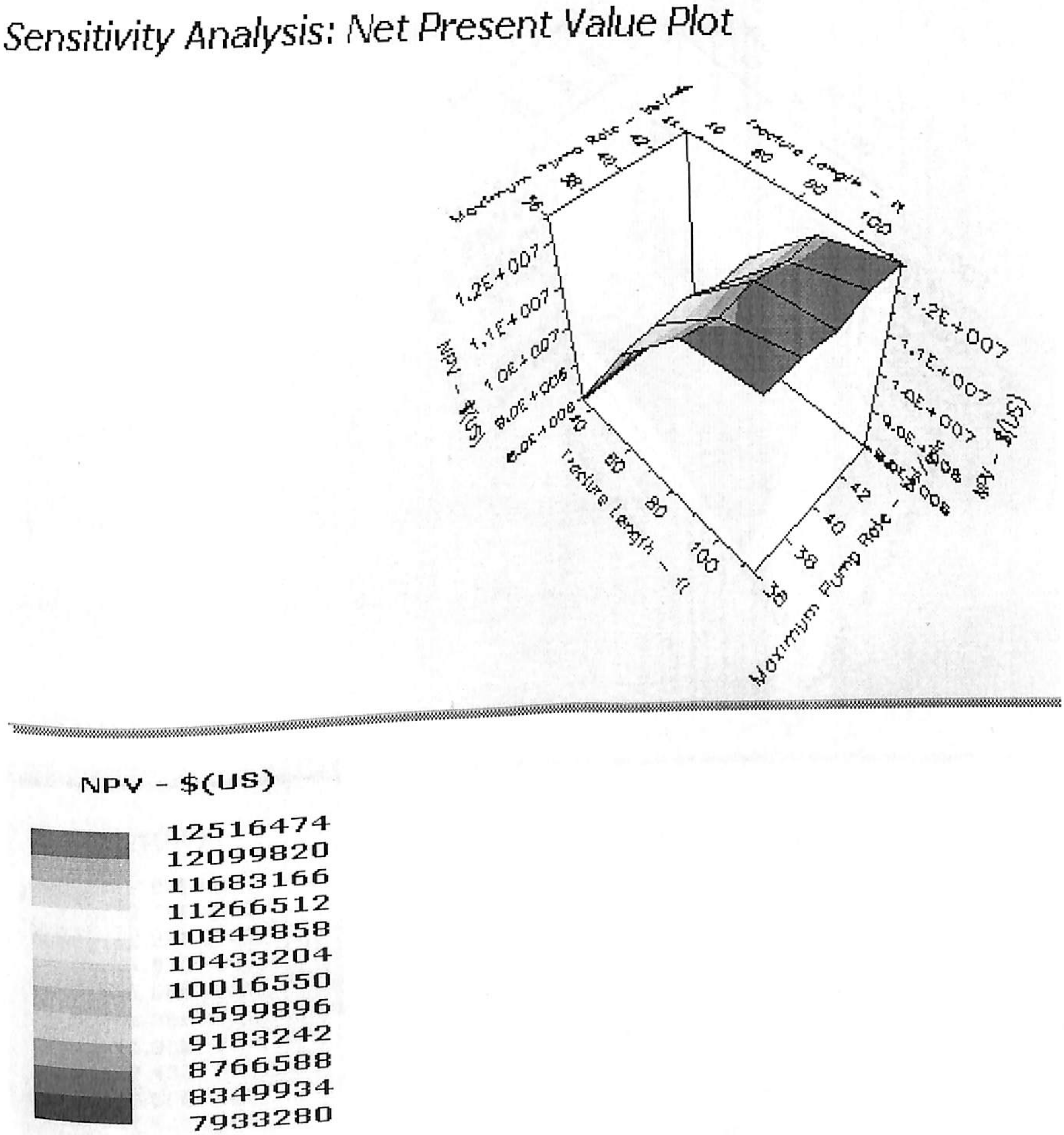


Figure 10. Plot of NPV vs. x_f and maximum pumping rate

Sensitivity Analysis: Net Present Value Plot

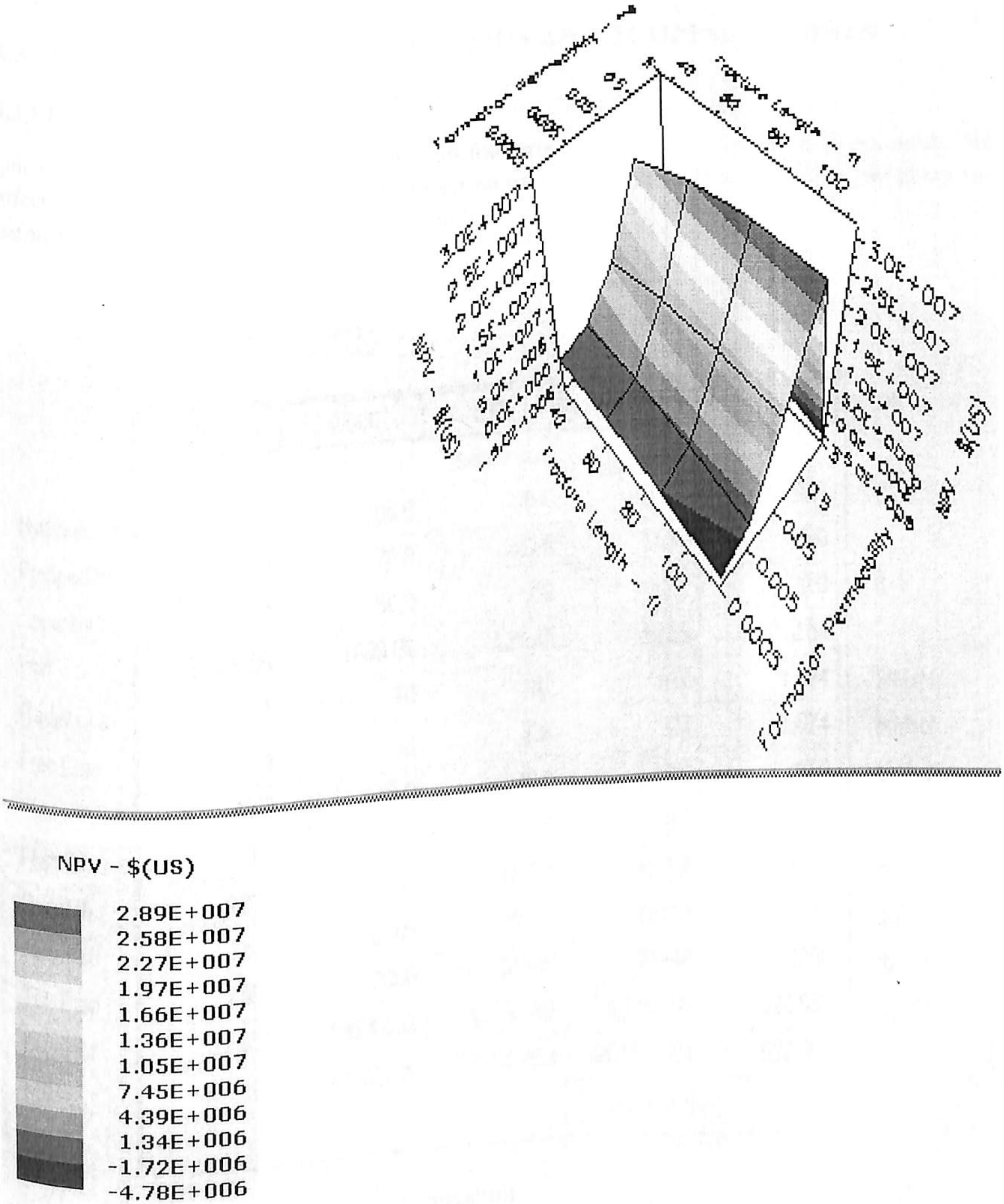


Figure 11. Plot of NPV vs. k and x_f

This revenue curve exhibits some optimal points at which the cost to achieve longer fractures exceeds the revenue generated by production from the additional length. This identifies a range of treatment designs that maximize economics (i.e. optimal treatments).

4.3 ECONOMIC ANALYSIS METHODS AND SCOPING STUDIES

4.3.1 FORMATION PERMEABILITY

One of the more important considerations in fracturing economics is formation permeability. Its effect on producing rates has a major impact on cash flow and economics. Cases are given for permeability of 0.0005, .005, .05, .5 and 5 md:

Formation Permeability

Plot

	0.0005	0.005	0.05 (base case)	0.5	5	md
Hydraulic Xf	50.0	100.0	200.0	200.0	50.0	ft
Propped Xf	35.0	70.0	140.0	140.0	35.0	ft
Apparent Xf	28.0	56.0	112.0	112.0	28.0	ft
Fcd	25405.90	1609.06	121.47	12.15	2.54	
Radial Cum	1	10	82	512	1,074	MMscf
Frac Cum	5	38	291	923	1,074	MMscf
Pump Rate	40.0	40.0	40.0	40.0	40.0	bbl/min
Fluid Eff.	0.6	0.5	0.5	0.5	0.6	
Pad Vol.	1219	3497	16777	16777	1219	gal
Tot. Fluid	3271	8600	39117	39117	3271	gal
Tot. Prop	4990	12008	51648	51648	4990	lb
Est. Cost	522,851	1,164,532	4,778,999	4,778,999	522,851	$(US)
NPV	-208,407	1,192,745	12,316,023	28,851,004 (optimum)	-522,851	$(US)

T4. Variation of NPV with Formation permeability

4.3.2 FRACTURE CONDUCTIVITY

Achieving appropriate fracture conductivity is an important part of fracture design. The decision to use sand versus higher strength manufactured synthetic proppant, the proppant size concentration play a significant role in economics. The manufactured proppant are considerably more costly than sand and their use often requires economic justification. This justification has been provided below:

	20/40 Ariz	Sand	20/40 Brad	20/40 C-Li	20/40 Carb	
	(base case)					
Hydraulic Xf	200.0	200.0	200.0	150.0	150.0	ft
Propped Xf	140.0	140.0	140.0	105.0	105.0	ft
Apparent Xf	112.0	112.0	112.0	84.0	84.0	ft
Fcd	136.11	138.03	135.58	325.51	212.53	
Radial Cum	124	124	124	124	124	MMscf
Frac Cum	432	432	432	393	392	MMscf
Pump Rate	40.0	40.0	40.0	40.0	40.0	bbl/min
Fluid Eff.	0.5	0.5	0.5	0.5	0.5	
Pad Vol.	14647	14647	14647	8875	8873	gal
Tot. Fluid	37598	37598	37598	24486	25234	gal
Tot. Prop	53496	53496	53496	36976	37846	lb
Est. Cost	4,935,982	5,470,945	5,470,945	6,017,635	6,347,090	$(US)
NPV	20,326,322	19,794,804	19,790,378	15,988,251	15,636,516	$(US)
	(optimum)					

T5. Variation of NPV with Proppant type

The relationship between fracture half-length and fracture conductivity is shown in following figure:

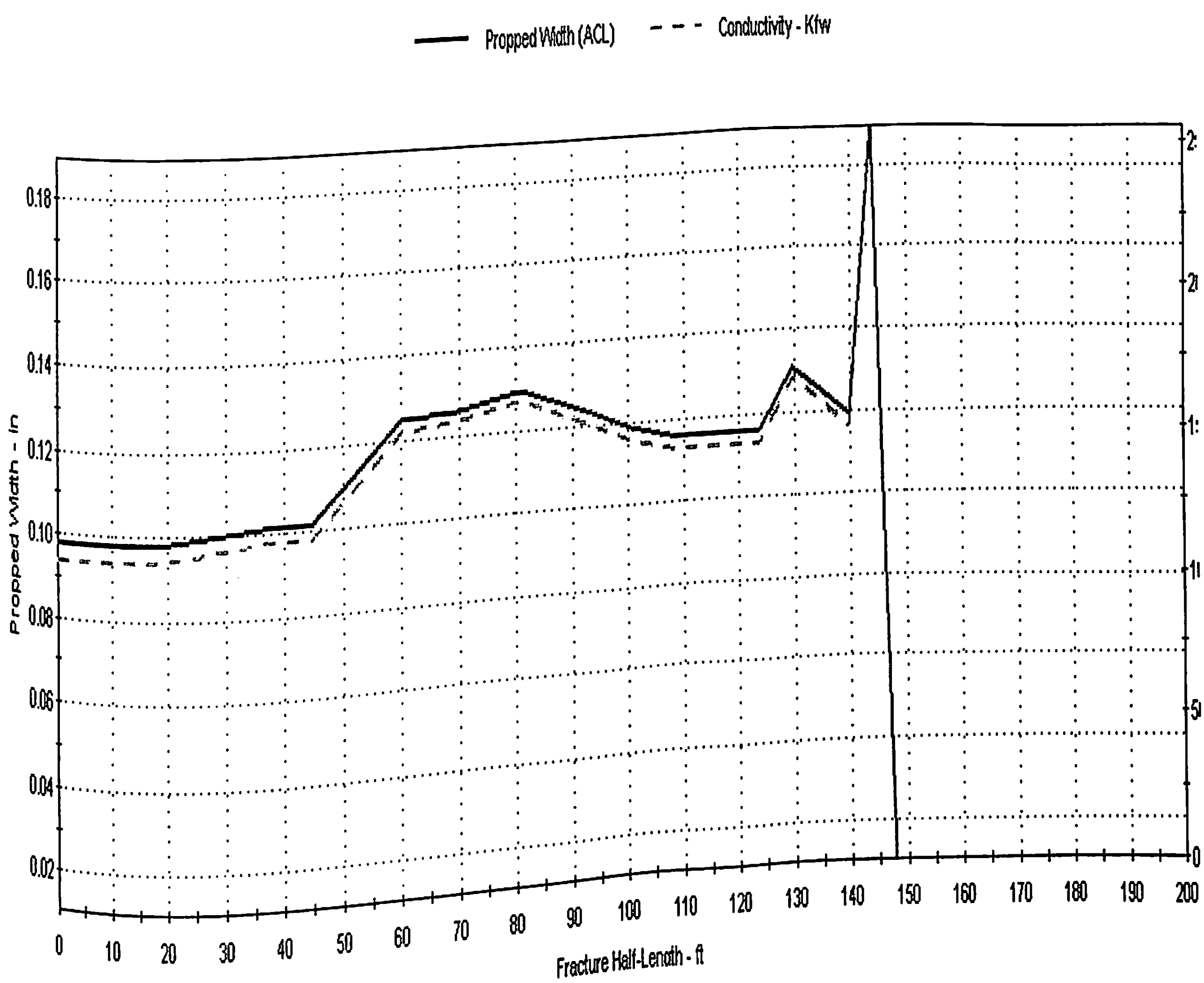


Figure 12. Plot of x_f vs. Propped width and FCD

The end of job fracture half-length with well depth has been shown as follows:

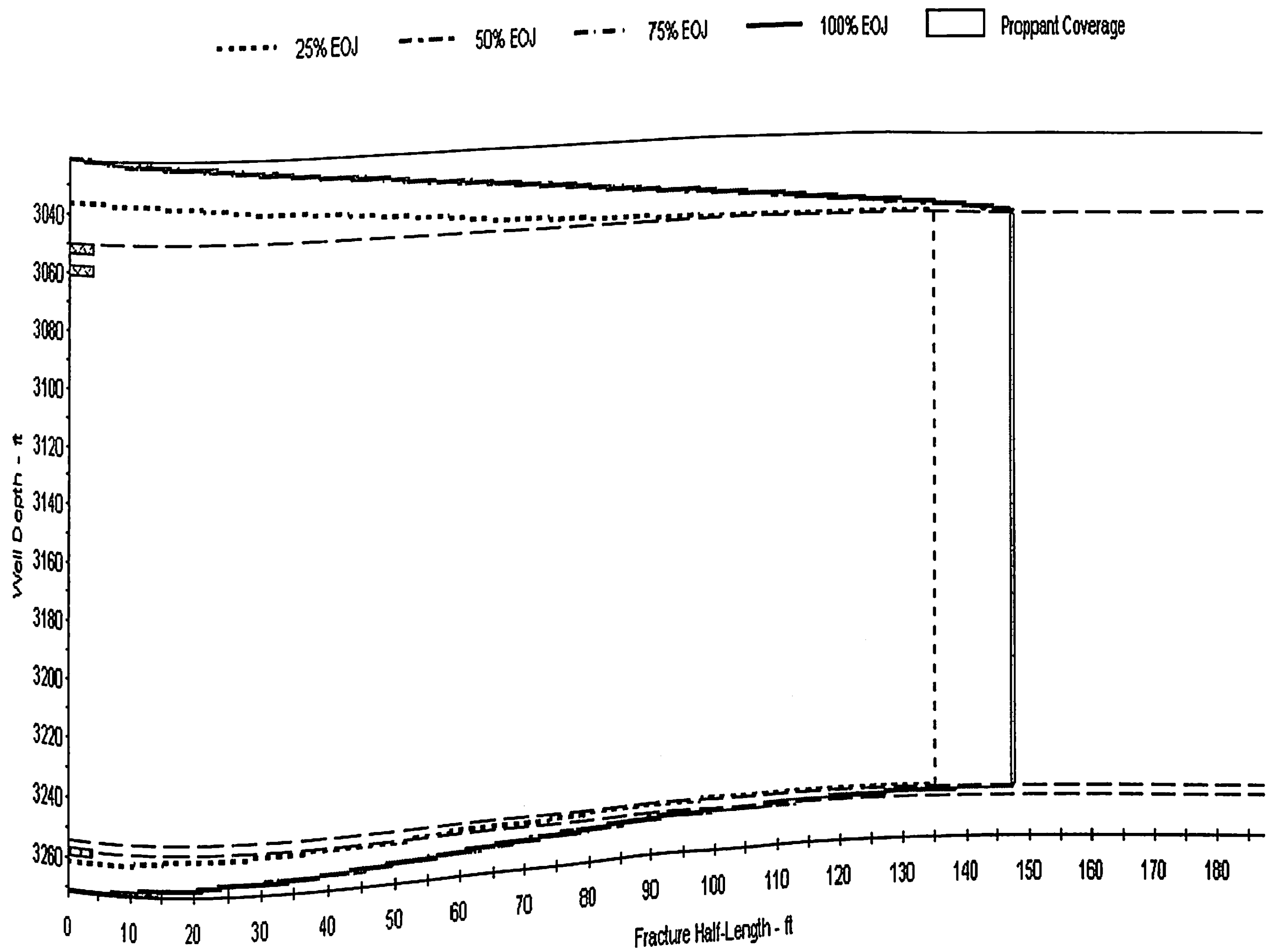


Figure 13. Fracture growth with well depth

Maximum proppant concentration required for achieving optimum NPV has been analyzed as follows:

Max. Prop. Conc.

Plot

	0	1	3 (base case)	5	7	PPA
Hydraulic Xf	50.0	200.0	200.0	150.0	150.0	ft
Propped Xf	35.0	140.0	140.0	105.0	105.0	ft
Apparent Xf	28.0	112.0	112.0	84.0	84.0	ft
Fcd	0.00	42.28	121.47	229.48	300.96	
Radial Cum	82	82	82	82	82	MMscf
Frac Cum	81	288	291	264	264	MMscf
Pump Rate	40.0	40.0	40.0	40.0	40.0	bbl/min
Fluid Eff.	0.5	0.5	0.5	0.5	0.5	
Pad Vol.	340116	15875	16777	8810	8793	gal
Tot. Fluid	4122611	39624	39117	21676	20147	gal
Tot. Prop	17	18628	51648	48950	59831	lb
Est. Cost	6,243,758	1,807,439	4,778,999	4,510,737	5,488,205	$(US)
NPV	-6,332,067	15,056,114 (optimum)	12,316,023	10,335,156	9,365,117	$(US)

T6. Variation of NPV with maximum proppant concentration

4.3.3 NET PAY

Net pay is usually not highlighted in parametric fracturing studies where the focus is on formation permeability, fracture conductivity and fracture penetration requirements, and sometimes net pay is normalized out of performance trends. Therefore, its impact has been overlooked here.

4.3.4 PUMPING RATE

The primary economic factors associated with pumping rate are hydraulic horsepower costs and fluid leak off to the formation. Pumping rate compensates for fluid leak off to the formation. However, pumping rate does not usually compete economically with fluid loss additives to overcome leak off. The optimization of pumping rate with NPV has been shown below:

	36	38	40 (base case)	42	44	bbl/min
Hydraulic Xf	200.0	200.0	200.0	200.0	200.0	ft
Propped Xf	140.0	140.0	140.0	140.0	140.0	ft
Apparent Xf	112.0	112.0	112.0	112.0	112.0	ft
Fcd	136.85	135.81	136.11	141.44	140.08	
Radial Cum	124	124	124	124	124	MMscf
Frac Cum	432	432	432	433	433	MMscf
Pump Rate	36.0	38.0	40.0	42.0	44.0	bbl/min
Fluid Eff.	0.5	0.5	0.5	0.5	0.5	
Pad Vol.	16536	15694	14647	15033	14613	gal
Tot. Fluid	43049	39105	37598	43603	38918	gal
Tot. Prop	60804	54694	53496	65267	57567	lb
Est. Cost	5,594,809	5,042,495	4,935,982	6,007,945	5,311,504	$(US)
NPV	19,668,832	20,219,268	20,326,322 (optimum)	19,263,674	19,957,810	$(US)

T7. Variation of NPV with pumping rate

Stress distribution and fracture growth distribution with depth is illustrated as follows:

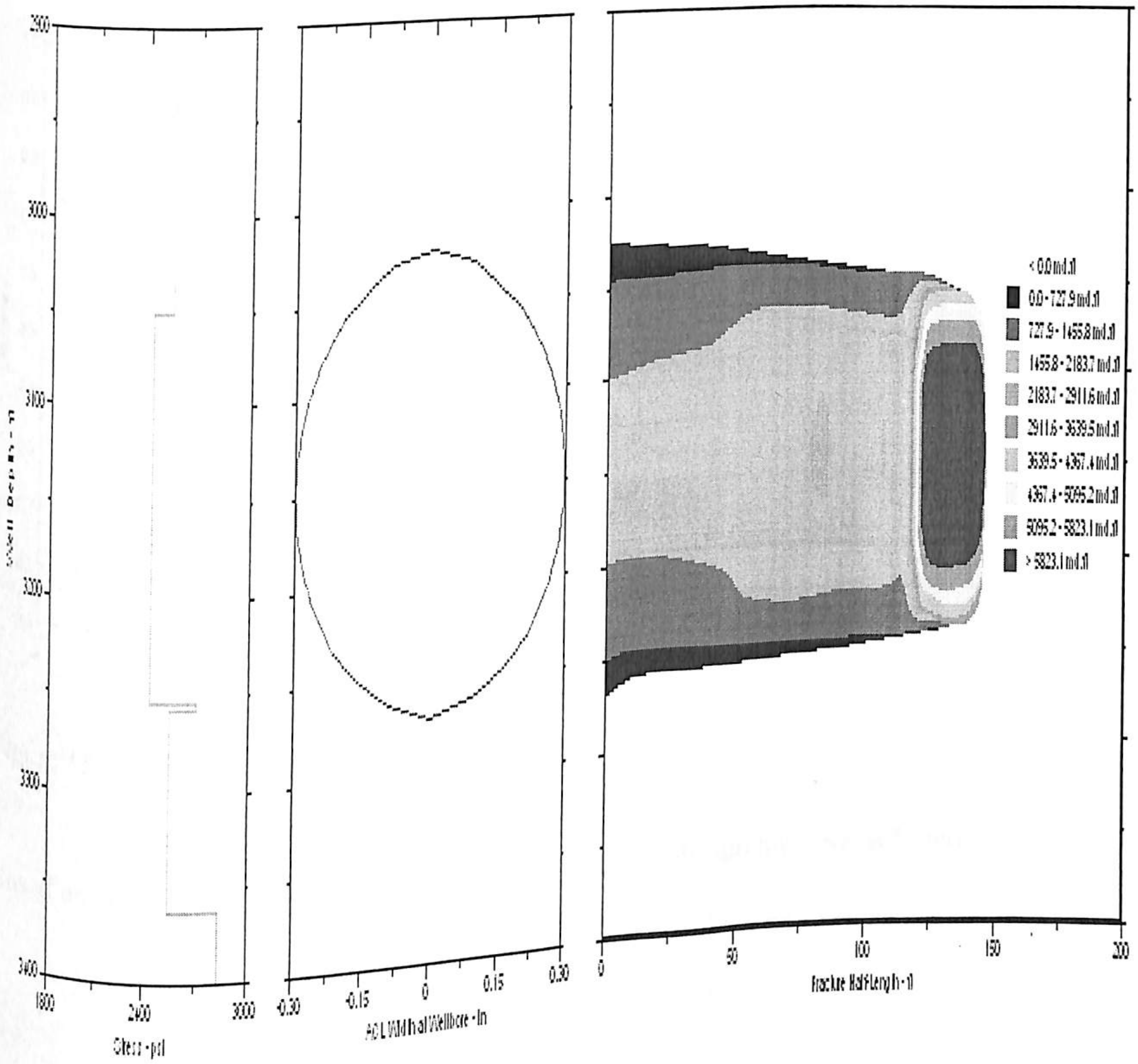


Figure 14. Stress distribution

The efficiency of fracture job with treatment time is given below:

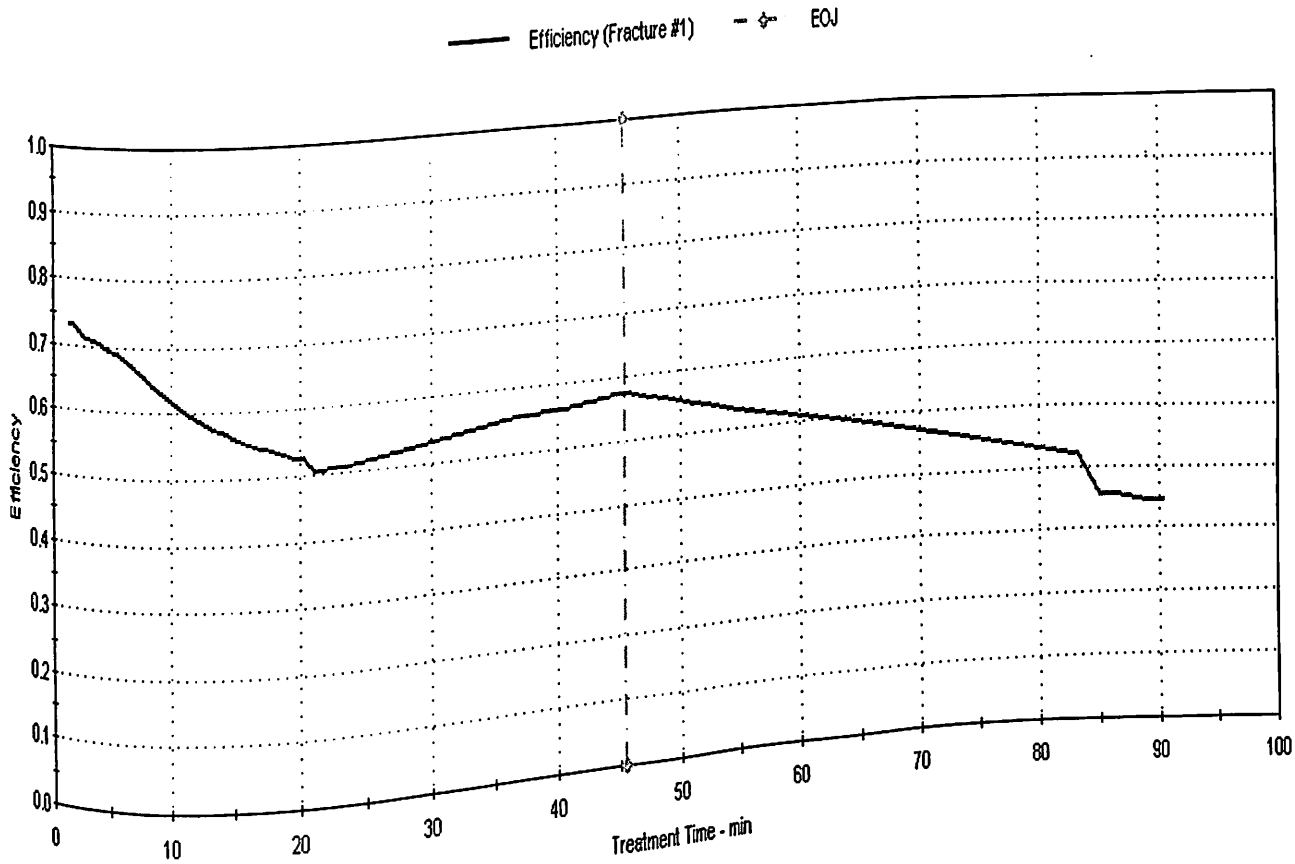


Figure 15. Plot of efficiency vs. treatment time

Based on above design considerations, optimum fracture design has been selected.

CHAPTER 5: RESULTS AND DISCUSSION

5.1 RESULTS AND DISCUSSIONS

Using the concept of optimizing fracturing treatments design, end of job simulated results have been found. An efficiency of 57.6 % has been achieved with effective conductivity of 294.2 and propped fracture half-length of 147.8 ft. Other EOJ parameters are presented below:

Max Hyd Frac Half-Length	171.9 ft
Propped Frac Half-Length	147.8 ft
EOJ Hyd Frac Half-Length	147.3 ft
EOJ Hyd Height at Well	250.5 ft
EOJ Hyd Width at Well	0.669 in
Propped Width at Well	0.097 in
Average Propped Width	0.114 in

EOJ Net Pressure	364 psi
Efficiency	0.576
Effective Conductivity	1702 md.ft
Average Gel Concentration	705.0 lb/mgal
Effective Fcd	294.2
Max Surface Pressure	1510 psi
Estimated Closure Time	45.0 min

T8. End of job simulated results

We have varied design options (i.e. x_f, k_{fw} etc.), the total system production has also changed. It has been observed that Production forecasts are synonymous with revenue potential.

CHAPTER 6: CONCLUSIONS AND RECOMMENDATIONS

6.1 CONCLUSIONS AND RECOMMENDATIONS

The following conclusions & recommendations can be drawn from the performed analysis:

- Accurate identification of critical variables allows a realistic economic optimization of the fracture stimulation.
- There is sensitivity of economics to certain fracture design parameters.
- Optimum design corresponds to the maximum net present value.
- Prior to an expenditure for a fracture simulation treatment economic optima can be determined.
- Success of a fracture stimulation treatment can be quantified in exact terms by using NPV analysis.
- For more accurate treatment design, impact of parameters as net pay, closure stress can also be included.

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Nomenclature

A	Area (ft^2)
A_b	Fracture area with settled proppant (ft^2)
A_f	Fracture area (ft^2)
A_s	Fracture area with suspended proppant (ft^2)
B	formation volume factor (bbl/STB)
C_{fd}	Fracture conductivity
FCD	Fracture conductivity
C	Compressibility (psi^{-1})
C_L	Fluid loss coefficient (ft/min^1/2)
c_o	Compressibility of oil (psi^{-1})
c_p	Compressibility of rock (psi^{-1})
c_t	Total Compressibility (psi^{-1})
c_w	Compressibility of water (psi^{-1})
C	Proppant concentration (PPA)
C_L	Leakoff coeeficient (ft/min^{-2})
d	Diameter (in)
d_p	proppant diameter (in)
E	young's modulus (psi)
E'	plane strain modulus (psi)
g	Acceleration due to gravity (ft/sec^2)
h	reservoir thickness (ft)
h_f	Fracture height (ft)

h_L	permeable fluid loss height (ft)
K	Permeability (md)
K_f	Fracture permeability (md)
K_p	Proppant permeability (md)
K_{ro}	Oil relative permeability (md)
K_{rw}	Water relative permeability (md)
K_s	skin permeability (md)
K_H	Horizontal permeability (md)
K_v	Vertical permeability (md)
L	Formation length (ft)
L_{perf}	Perforation channel length (ft)
N_p	Oil cumulative production (bbl)
P	Pressure (psi)
P_{net}	net pressure (psi)
Psi	per squre inch
Pc	closure pressure (psi)
P_i	Initial reservoir pressure (psi)
R	Fracture radius (ft)
r_s	radius of damaged zone (ft)
S	Skin factor (dimensionless)
S_P	Spurt loss (gal/ft^2)
t_c	closure time (hr)
t_p	pumping time (hr)
T	Absolute temperature (^oR)
μ	viscosity (cp)

V	Poisson's ratio
v_l	volume pumped
v_f	Fracture volume created
v_{Lp}	volume lost during fracture
w_{max}	maximum fracture width
Xf	Fracture half length (ft)
PVT	Pressure Volume Temperature