CANDIDATE WELL SELECTION FOR THE TEST OF DEGRADABLE BIOPOLYMER AS FRACTURING FLUID

A Thesis

by

YUN SUK HWANG

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

MASTER OF SCIENCE

December 2011

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee, Ding Zhu

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ABSTRACT

Candidate Well Selection for the Test of Degradable Biopolymer as Fracturing Fluid.

(December 2011)

Yun Suk Hwang, B.S., Seoul National University, Seoul

Chair of Advisory Committee: Dr. Ding Zhu

Hydraulic fracturing is a well-established technology of generating highly conductive flow path inside the rock by injecting massive amount of fracturing fluid and proppant with sufficient pressure to break the formation apart. But as the concern for environment and health effects of hydraulic fracturing becomes intense, many efforts are made to replace the conventional fracturing fluid with more environment-friendly materials.

The degradable biopolymer is one of the novel materials that is injected in the form of solid pellets containing proppant, which degrades in the presence of water to form a viscous gel fluid, leaving no gel residue or harmful material.

This work develops a methodology and computer program to determine the best candidate wells for the field test of degradable biopolymer as fracturing fluid. The unique properties of degradable biopolymer are captured in the selection of decision criteria such as bottomhole temperature and treatment volume as well as traditional hydraulic fracturing candidate well selection criteria such as formation permeability, productivity index.

DEDICATION

This thesis is dedicated to my family.

ACKNOWLEDGEMENTS

I would like to thank my committee chair, Dr. Zhu for her guidance, encouragement, continuous sense of humor and kindness. I also thank my committee members, Dr. Hill, Dr. Sun, for their guidance and support throughout the course of this research.

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Finally, thanks to God, for the guidance and strength given to me.

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CHAPTER I

INTRODUCTION

1.1 Background

Hydraulic fracturing is a well-established technology of generating highly conductive flow path inside the formation rock to produce hydrocarbon more efficiently by injecting massive amount of fracturing fluid and proppant with sufficient pressure to break the formation apart. The induced flow path not only bypasses the damaged zone near the wellbore, but also provides increased contact between the reservoir and the wellbore. Therefore, the production could be increased by several-folds.

Since the first use in US in 1947, hydraulic fracturing has been applied in more than 1 million wells (API 2011a) and it is believed that US would experience 17% reduction in oil production and 45% reduction in natural gas production by 2014 if fracturing were eliminated (API 2011b).

Because reservoirs are various in terms of permeability, pressure, temperature and rock composition, different types of fracturing fluids have been developed and used based on the reservoir properties.

As the concern for the environment and health effects of hydraulic fracturing becomes intense, many efforts are made to replace the conventional fracturing fluid or proppant with more environment-friendly and cost effective materials. The degradable biopolymer is one of those novel materials which could be used in place of conventional

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This thesis follows the style of *SPE Journal*.

fracturing fluid.

The degradable biopolymer could be applied to a large number of wells where small fracturing treatments, less than 50,000 lbs of proppant, is suitable. This small scale fracture treatments make up approximately 13,000 fracturing treatments per year or 40% of all fracturing treatment in the US (RPSEA Project #09123-20).

1.2 Objective and Outline

The objective of this work is to develop a methodology and software tool to best identify wells that are suitable for the field application of degradable biopolymer as fracturing fluid. In the process of this work, the understanding of unique properties of degradable biopolymer compared with conventional fracturing fluid is crucial in establishing decision criteria. This will be discussed in detail in Chapter II. After that, in Chapter III, the methodology and approach of selecting candidate well and the decision tree are introduced as well as the list of decision criteria. Chapter IV covers the development of candidate well selection program and step by step guidance for the application of the program. Finally, the conclusion of this research will be summarized and future work will be recommended in Chapter V.

CHAPTER II

LITERATURE REVIEW

2.1 Fracturing Fluids

The functions of fracturing fluids are to create hydraulic fracture when pumped at high enough pressure to crack the rock and transport the proppant into the fracture with the viscosity to hold the fracture open after fracturing. Fracturing fluids should also break easily and flow back to the surface once the treatment is over, so that the produced hydrocarbon can flow. The fluid leakoff into the formation needs to be controlled and the pressure loss due to friction inside the tubing needs to be low. The selection of fracturing fluid is complex because the fluids must simultaneously meet a number of requirements. The availability (especially for the case of water), cost, ease of mixing and use, compatibility with the formation rock, compatibility with the formation fluids, ability to be recovered from the fracture and safety are some of these requirements (Valko et al. 1998).

Fracturing fluids can be categorized as 1) water based fluids (linear, cross-linked, miceller and hybrid), 2) oil based fluids, 3) alcohol-based fluids, 4) foam fluids, 5) energized fluids. Fluid use started from gelled oil in the 1950s, passed the linear gelled water in the 1960s and crosslinked gelled water is the most commercially used since the 1970s (Holditch 2010). Since the environmental issues concerning hydraulic fracturing become a problem, the research to develop an environment-friendly fracturing fluid, including degradable biopolymer, has been conducted.

The viscosity of fracturing fluid is a function of polymer load. Polymers such as guar, which is a naturally occurring material, or hydroxypropyl guar (HPG) have been used in aqueous solutions to provide substantial viscosity to the fracturing fluid. The 40 lb/1000 gal HPG solution at 175°F has a viscosity of less than 20 cp (Economides et al. 1994). But when the viscosity is not high enough to transport the proppant (about 100 cp), crosslinking agents are used to boost the viscosity significantly. Borate, Titanate and Zirconate are the most common materials. They form bonds with guar and HPG chains, resulting in very high viscosity, therefore 40 lb/100 gal borate-crosslinked fluid has about 250 cp at 200°F (Economides et al. 1994).

Table 1 shows the summary of various fracturing fluids (Holditch 2010). In **Fig. 2. 1**, the structure of linear, branched and crosslinked polymers is compared conceptually as well as the process of polymer degradation.

Table 1 - Fracturing fluids summary (Holditch 2010)

Base Fluid	Fluid Type	Main Composition	Used For
Water Based	Linear Fluids	Gelled Water, GUAR< HPG, HEC, CMHPG	Short Fractures, Low Temperatures
	Crosslinked Fluids	Crosslinker + GUAR, HPG, CMHPG, CMHEC	Long Fractures, High Temperatures
Foam Based	Water Based Foam	Water and Foamer + N2 or CO2	Low Pressure Formations
	Acid Based Foam	Acid and Foamer + N2	Low Pressures, Water Sensitive Formations
	Alcohol Based Foam	Methanol and Foamer + N2	Low Pressure Formations With Water Blocking Problems
Oil Based	Linear Fluids	Oil, Gelled Oil	Water Sensitive Formations, Short Fractures
	Crosslinked Fluids	Phosphate Ester Gels	Water Sensitive Formations, Long Fractures
	Water External Emulsions	Water + Oil + Emulsifier	Good For Fluid Loss Control

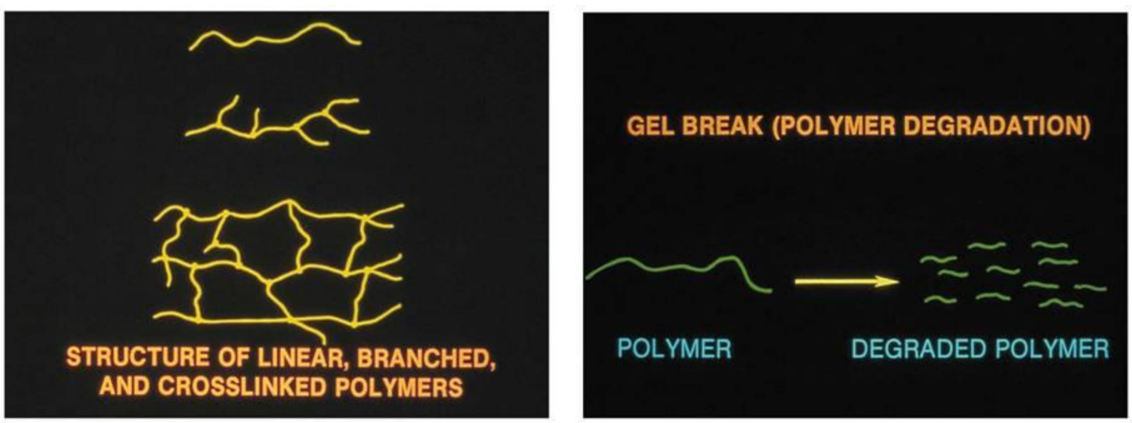

Fig. 2. 1 - Structure of polymers and gel break (Holditch 2010).

2.2 Gel Damage

To increase the viscosity for the transport of proppant, water soluble polymers are added to water and crosslinked with a metal like Borate or Zirconate. After the fracture treatment, the fracturing fluid should break down to less viscous fluid through polymer degradation by breakers or formation temperature. But some of the polymers do not break completely and leave insoluble gel residue in the formation and fracture. This residue causes problems known as gel damage.

Gel damage can largely be divided into two different categories: damage inside the fracture itself (proppant-pack damage) and damage normal to the fracture intruding into the reservoir (fracture-face damage). The first generally occurs because of the inadequate breaking of the polymer and the second occurs because of excessive leakoff of fracturing fluid into the formation and subsequent filter cake buildup (Economides and Nolte 2000).

The selection of fracturing fluids, polymer concentrations and breakers is critical. According to the research by Holditch (2009), the primary problem in hydraulic fracturing today is that the gel (guar based) left in the fracture. It is also concluded that incomplete breaking of the polymers in fracturing fluid is the most obvious cause of damage within hydraulic fractures, as well as the poor selection of proppant fracturing fluids (Brannon and Pulsinelli 1990). These damages are usually severe and cannot be improved with further matrix treatments.

The residue present in the pore spaces of the fracture will reduce the permeability of the proppant. Experimental test indicates that the residue will not be displaced from the fracture by production and will degrade slowly. Only a small amount of guar residue could be displaced at extremely high pressure (Cooke 1975). The residual gel is concentrated polymer and even if breaker has been added, in most cases, the broken gel will still have a static yield stress that cause problems with fracturing fluid cleanup (Wang et al. 2008). Poor fracturing fluid cleanup leads to the loss of effective fracture half-length. Effective fracture length is the part of a propped fracture that cleaned up and contributes to production.

Filter cake buildup at the fracture face, which may contain 10 to 20 times polymer concentration of the original fluid, might act as an obstacle against the pressure drop between the reservoir and wellbore, and therefore preventing the increase of productivity from hydraulic fracturing treatment.

When the fracture conductivity or the near fracture reservoir permeability is reduced, the fracture choke skin and fracture face skin increase (Cinco-Ley and Samaniego 1981). Fracture face skin may not be an important factor (Economides and Nolte 2000), but the fracture choke skin is an important factor in reducing the productivity (Le et al. 2010).

According to the experiment to understand the remediation of gel residue (Marpaung et al. 2008; Xu 2010), higher polymer concentration decreases cleanup efficiency and higher flow rate increases cleanup efficiency and the use of proper breaker increases cleanup efficiency up to 3.5 times.

2.3 Degradable Biopolymer as Fracturing Fluid

To overcome the near wellbore damage including previously discussed gel damage to restore the natural flow capacity of a well, various methods have been proposed but the efficacy of any method is not known (RPSEA Project #09123-20). As a method of insuring proppant in a fracture near a perforation, degradable biopolymer based fracturing fluid is developed. It can create a wide, propped fracture for a limited distance in low permeability, medium temperature formations.

The fracturing fluid is generated from dry biopolymer in the form of solid pellets, embedded previously with the proppant by responding the formation water inside the tubing/casing. Before the polymer degrades enough to allow proppant particles to settle, the proppant-containing gel is squeezed into the formation above fracturing pressure. The polymer continues to degrade to a clear aqueous solution, leaving no damage in the fracture (Cooke et al. 2012).

In this process, no additional water beside the formation water inside the tubing/casing is required, which is practical and economical for use in remote areas where water transportation is difficult or expensive. The degradable biopolymer is applicable when formation temperature is between 130 to 250 °F and permeability is larger than 0.1md.

This novel fracturing fluid has two key benefits over conventional fracturing methods in that it can achieve higher production rates than conventional treatment, and it has less impact on the environment (RPSEA Project #09123-20). The fluid breaks up easily, therefore enables fluid cleanup and leaves no permeability plugging residue. The process is also designed to deliver optimal proppant pack distribution resulting in more effective proppant pack.

It is environment-friendly in several ways. In the treatment process, substantially less fluid volume is used. It is anticipated that fluid volumes will be reduced by 60% to 80% when compared to the traditional treatments (RPSEA Project #09123-20). Also, the frac fluid itself is comprised of a biodegradable polymer that will hydrolyze in an aqueous environment to organic materials. This eliminates the need for metal crosslinkers, breakers and other commonly used chemicals for traditional crosslinked frac fluids. Additionally, the process does not require the normal levels of hydraulic horsepower and mixing equipment to perform treatment due to modified material placement technique, resulting in a smaller footprint. This will reduce the amount of equipment traffic, required foot print and number of roads necessary to provide for accessing the location for fracturing treatments (Cooke et al. 2012).

The fracture dimensions created by degradable biopolymer fracturing technology are small compared with conventional massive fracture treatment. This technology is aimed mainly at creating fractures to bypass deep formation.

2.4 Productivity Index

A well in a reservoir has a finite drainage area and most of the time it is produced at a stabilized flow regime, pseudo-steady state. During this production period, the productivity index (PI) of a well is defined as production rate per pressure drawdown. The productivity index for unstimulated well is given by (Economides et al. 1994)

$$J = \frac{q}{\Delta p} = \frac{kh}{141.2B\mu\left[\ln\left(\frac{0.472r_e}{r_w}\right) + s\right]}$$

For a fractured well, the stimulation effect can be calculated from

$$J = \frac{q}{\Delta p} = \frac{kh}{141.2B\mu\left[\ln\left(\frac{0.472r_e}{r_w}\right) + s_f\right]}$$

where, the skin factor can be obtained from the dimensionless fracture conductivity, which is expressed by

$$C_{fD} = \frac{k_f w}{kx_f}$$

where k is the reservoir permeability, x_f is the fracture half length, k_f is the permeability of proppant and w is the average fracture width.

The relationships between C_{fD} and s_f is presented in the **Fig 2.2** (Cinco-Ley and Samaniego 1981) and can be calculated simply by (Meyer and Jacot 2005) using Prats' effective wellbore concept (1961)

$$r_w^{'} = \frac{x_f}{\frac{\pi}{C_{fD}} + 2}$$

where $r_w^{'}$ is

$$r_w^{'} = r_w e^{-s_f}$$

Therefore, the after treatment skin factor is obtained by

$$s_f = -\ln \frac{r_w'}{r_w}$$

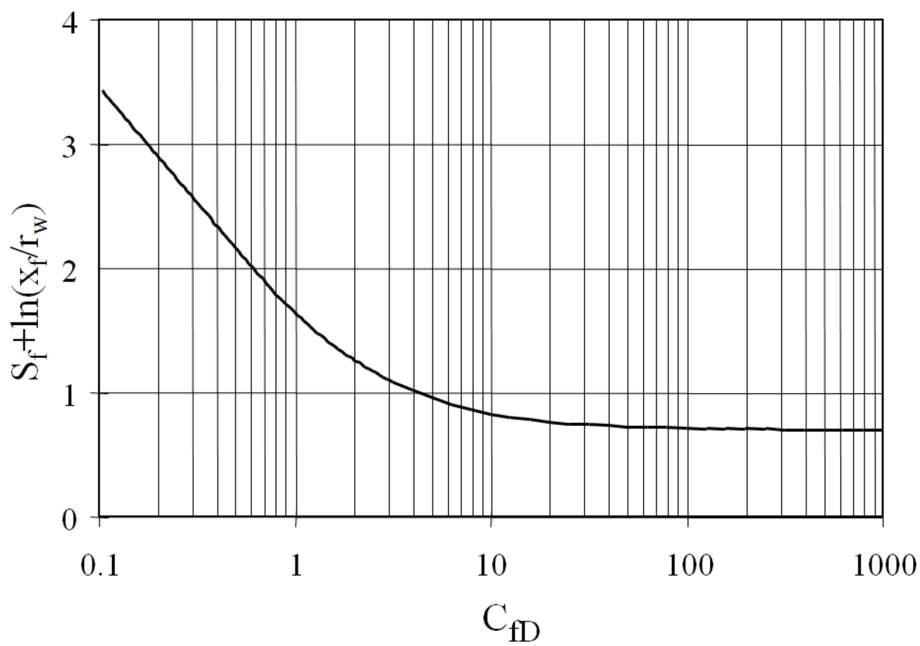

Fig 2.2 - Equivalent fracture skin, length and conductivity
(Cinco-Ley and samaniego 1981)

When the data is not available, as a quick and easy first-pass procedure, it is often useful to substitute values of s_f ranging from -4 to -6 to provide an idea of post-treatment production. This equation is a rough approximation only, as it applies to radial, pseudo-steady state flow, something that rarely occurs post-treatment (Martin and Economides 2010).

The effect of treatment on productivity is obtained by calculating productivity index ratio and comparing it between wells. Productivity index ratio indicates how much the productivity has been increased after the treatment compared to the production before the treatment. The higher the productivity index, the bigger the effect of the treatment. The productivity ratio is calculated by

$$PI\ ratio = \frac{J_{after\,frac}}{J_{beforefrac}} = \frac{\ln\left(\frac{0.472 r_e}{r_w}\right) + s}{\ln\left(\frac{0.472 r_e}{x_f}\right) + f} = \frac{\ln\left(\frac{0.472 r_e}{r_w}\right) + s}{\ln\left(\frac{0.472 r_e}{r_w}\right) + s_f}$$

CHAPTER III

METHODOLOGY AND APPROACH

3.1 Decision Tree

For the development of candidate well selection, decision tree was selected as a tool. Decision tree is one effective way to display an algorithm and is commonly used to help identify a strategy that most likely to reach a goal. Decision tree is simple to understand and interpret. It also requires little data preparation and can analyze large amounts of data in a short time.

Fig. 3. 1 shows the decision tree used for the candidate well selection program.

The decision tree is composed of 3 main parts ; Basic Screening, Productivity Index Calculation and Economic Analysis.

Basic Screening evaluates cases to identify if the technology can be applied. The main parameters are bottomhole temperature, formation fluid type, formation permeability and damage characteristics. Passing the Basic Screening, the next section calculates the well performance and assesses the improvement by the technology. The following section estimates the economic benefit.

The Part 1 Basic Screening starts from comparing the bottomhole temperature with the applicable temperature range of degradable biopolymer. If it is not met, the evaluation procedure aborts and the well is not considered as a candidate well. If the temperature condition is met, wellbore fluid type is evaluated next. If the main fluid inside the tubing/casing is water, the evaluation proceeds to the next session. If more than 50% of the fluid inside the tubing/casing is hydrocarbon, the degradable biopolymer cannot be broken into liquids, so the evaluation procedure stops.

Next, formation permeability is compared with the applicable permeability range of degradable biopolymer. If formation permeability is smaller than the permeability value of degradable biopolymer, the evaluation procedure stops and the well is not considered as a candidate well any longer.

The possible treatment volume is calculated from the liquid volume inside the tubing/casing. If the pre-defined target fracture half length and target fracture width cannot be achieved with the possible treatment volume, the target fracture half length and target fracture width is modified according to the possible treatment volume.

If the skin factor is negative, which implies the well has been treated before, the well is excluded from the candidate well for the test of degradable biopolymer. And if the damaged radius is very short, less than the pre-defined value, the well is still included in the candidate well and the evaluation proceeds to the next session but the matrix acidizing is also suggested.

For the next step, breakdown pressure is calculated for reference in fracture design. This step is for reference only and no well is excluded from the candidate well.

Last session in Part 1 deals with the operational check-points. The location and accessibility of the well, any HSE issues and any restrictions by law are those. If there is any of these issues, the well needs to be handled properly, therefore the well is still considered as candidate well, but the suggestion message is given to inform the user.

If the well meets all the requirements in Part 1, the productivity index is calculated in Part 2. After that, economic analysis is conducted in Part.

The list of decision criteria and the reason why they are selected as screening tool will be covered in the following chapters in detail.

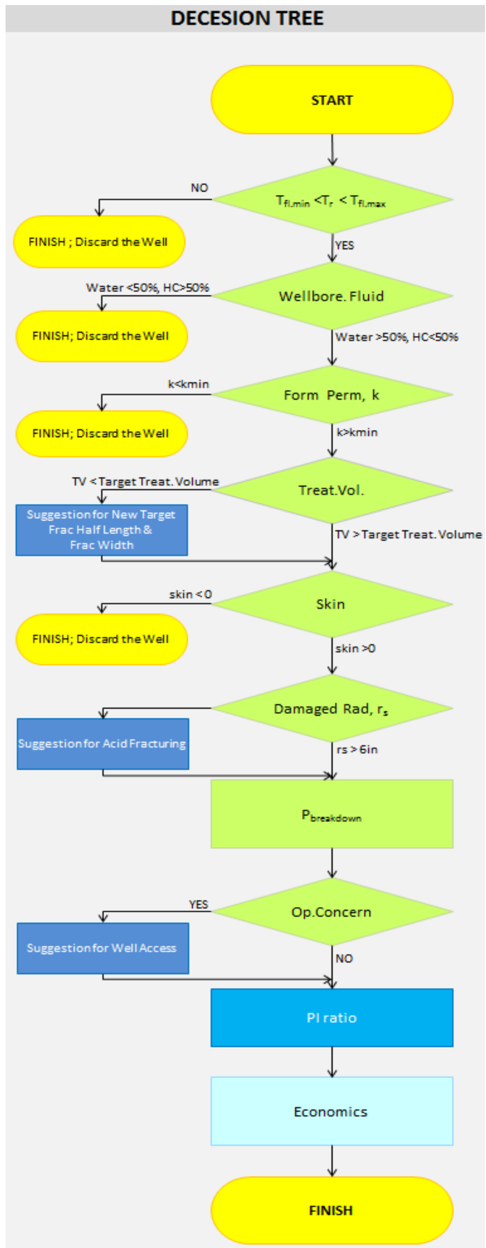

Fig. 3. 1 – Decision tree for candidate well selection

3.2 Selection Decision Criteria

It is a complicated problem to determine which well to hydraulic fracture because the conditions of every well are different and there is no exact answer. But it is certain that the best candidate wells for hydraulic fracturing are the wells which are in need of production increase due to the near wellbore damage and which is capable of production increase by having substantial volume of oil and gas in place. Therefore these aspects of productivity need to be considered when selecting possible decision criteria.

In selecting decision criteria, both the unique properties of degradable biopolymer and general hydraulic fracturing technique should be taken into account. Therefore, it is always preferable to have all kinds of data for the analysis of the candidate well selection for the test of degradable biopolymer, but the availability of data is always restricted in reality. **Table 2** is the list of data needed for the design of fracture treatment and its possible sources for the acquisition (Holditch 2010). The decision criteria for the development of candidate selection program were carefully chosen to reflect the importance of data and also the availability of the data.

Table 2 - Data needed for hydraulic fracturing design and the sources (Holditch 2010)

Data	Sources
Formation Permeability	Cores, Well Tests, Correlations,
Formation Porosity	Cores, Logs
Reservoir Pressure	Well Tests, Well Files, Regional Data
Formation Modulus	Cores, Logs, Correlations
Formation Compressibility	Cores, Logs, Correlations
Poisson's Ratio	Cores, Logs, Correlations
Formation Depth	Logs, Drilling Reports
In-situ Stress	Logs, Correlations, Well Tests
Formation Temperature	Logs, Correlations, Well Tests
Fracture Toughness	Logs, Correlations
Water Saturation	Logs, Cores
Net Pay Thickness	Logs, Cores
Gross Pay Thickness	Logs, Cores, Drilling Reports
Formation Lithology	Cores, Logs, Drilling Reports,
Wellbore Completion	Well Files, Completion Prognosis
Fracture Fluids	Service Company Information
Fracture Proppants	Service Company Information

3.2.1 Reservoir Temperature

Temperature is the most important parameter, and also the most complicated issue in this application. The viscosity of the biopolymer that coated the proppant is strongly dependent on the surrounding temperature. As formation depth increases, temperature increases, and at certain point, that will reduce the viscosity of the fluid.

When this happens, proppant will start settling in the fracture, and screen-out may occur at worst case scenarios. The criteria is set at 130 to 250°F from the laboratory test for the standard formula of the biopolymer. Therefore the well with reservoir temperature outside of this range will be excluded from the candidate well. The temperature data can be achieved by logging or well tests.

3.2.2 Wellbore Fluid Type

The degradable biopolymer reacts with the water inside the tubing/casing and breaks down into liquid and becomes viscous enough to transport the proppant embedded in the degradable biopolymer into the formation. Therefore the content of water inside the tubing/casing is detrimental for the application of degradable biopolymer. According to the laboratory test, the water content inside the tubing/casing needs to be more than 50% of the total fluid volume and hydrocarbon inside the tubing/casing needs to be less than 50% of the total fluid volume. Therefore the candidate well selection program will exclude the wells with wellbore fluid of less than 50% of water and proceeds only with the wells which have more than 50% of water.

3.2.3 Formation Permeability

There is no established range for the permeability in the literature, but it is generally accepted that oil reservoirs with permeabilities of 1 md or less are candidate for hydraulic fracturing (Heydarabadi et al. 2010). For gas reservoirs, permeabilities less than 0.1 md are believed to be favorable (Economides 1992).

Based on another classification, permeabilities of 5 md or less for oil reservoir and permeabilities of 0.5 md or less for gas reservoirs are considered appropriate for fracturing (Heydarabadi et al. 2010).

Jennings (1991) showed (**Fig. 3. 2**) the typical production increase curves. The available production increase relationship typically shows that little productivity improvement can be expected for hydraulic fracturing applications in moderate to high-permeability (k > 10 md) formations and that maximum benefit from fracturing occurs when formation permeabilities are less than 1.0 md.

The lower the formation permeability, the higher the production increase. But other than the productivity improvement, there exist the permeability range for the degradable biopolymer to successfully react in the formation. From the laboratory test, it was characterized that the degradable biopolymer works successfully in the reservoir permeability of larger than 0.1 md. Accordingly, the well with formation permeability of less than 0.1 md will be declined in the process of candidate well selection program.

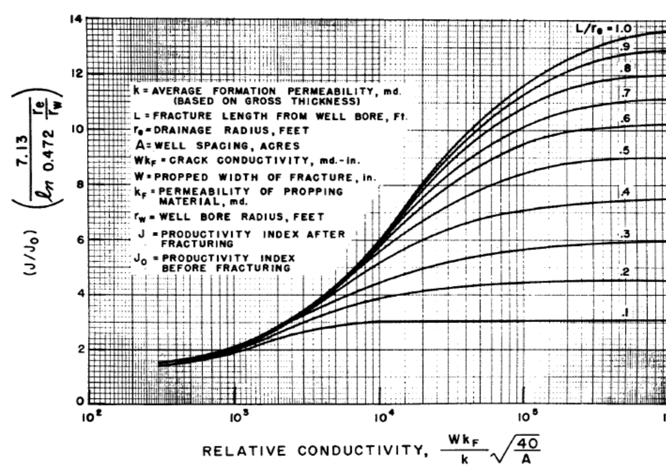

Fig. 2 — Increase in Productivity from Fracturing.

Fig. 3. 2 – The effect of formation permeability on productivity increase (Jennings 1991)

3.2.4 Treatment Volume

As describe above, the procedure of using degradable biopolymer is to set the material in the available well space, and push the fluid into the fracture after the biopolymer turns into viscous fluid. This means that the fracture volume is determined by the space available in the wellbore. If the volume is not enough, the propagation of fractures and keeping the fractures open by transporting the proppant would be limited or even impossible.

Because the settled down polymers during the degradation below the bottom of perforation will not be able to be used for the propagation of hydraulic fractures, only the inside casing volume between packer and bottom of perforation is included in the possible treatment volume. Usually, a plug is preferably placed just below perforations before pumping of polymer into the well commences, so that polymer pellets will accumulate in the casing over and above the perforations and not below the perforations (Cooke, 2005).

Therefore, the volume inside the tubing/casing is calculated based on the ID of tubing, ID of casing, the fluid level, packer depth and bottom of perforation depth using following relations

$$V_{posstreat} = \frac{\pi}{4} ID_{tubing}^2 \times (Packer\,Depth - Fluid\ Level) + \frac{\pi}{4} ID_{prodcasing}^2 \times (Bottom\,of\ Perforation\,Depth - Packer\,Depth\ )$$

The schematic for the calculation of possible treatment volume is in **Fig. 3. 3**.

Fig. 3. 3 – Schematic for the calculation of possible treatment volume

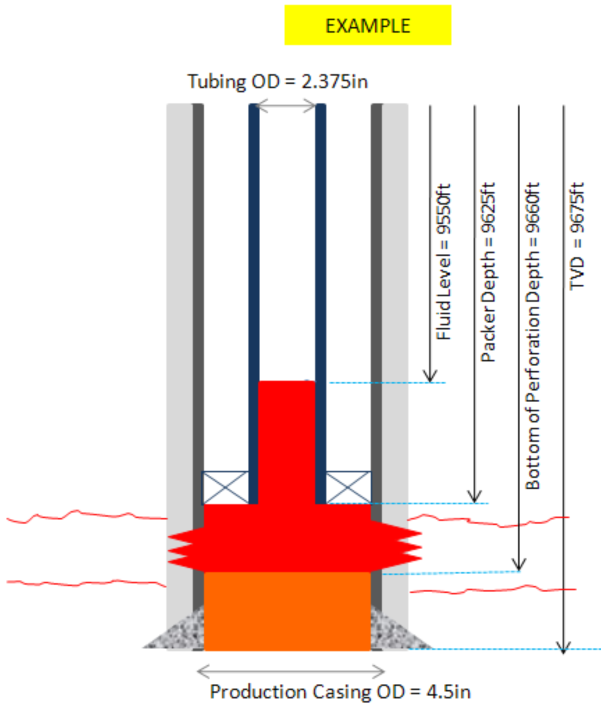

Fig. 3. 3 – Schematic for the calculation of possible treatment volume

After calculating possible treatment volume, penetrable height is calculated for given target fracture half length and target fracture width. Usually the target fracture half length for this degradable biopolymer is 20 ft and target fracture width is 0.5 in, which is wider and shorter than conventional hydraulic fractures.

When the penetrable height is smaller than payzone thickness, which means the possible treatment volume is not enough to achieve target geometry, the target fracture half length and target width are modified based on the ratio of penetrable height and payzone thickness. Since achieving wide fracture width is more important than having long fracture length, fracture width was modified to half of the original target width and fracture half length was modified using the ratio of penetrable height and payzone thickness.

$$ratio = \frac{penetrable\ payzone\ thickness}{payzone\ thickness}$$

$$w_{new} = 0.5 * w_{oldtarget}$$

$$x_{f,new} = \frac{ratio}{0.5} * x_{f,oldtarget}$$

When the penetrable height is greater than payzone thickness, which is enough to achieve target fracture half length and target fracture width, the original target values are used in subsequent calculations.

Optimum fracture half length and optimum fracture width are calculated using the concept of optimal fracture conductivity based on the proppant mass. The optimum fracture geometries are presented for reference purposes, which could be compared with the target fracture geometries and provide user an idea of how the target geometries could be modified if operation and economics allow. In many situations, the optimal condition cannot be achieved because of pumping limit. This is more common in higher permeability formation compared with low permeability unconventional resources.

The optimum fracture half length and optimum fracture width are calculated using following equations (Economides et al. 2002).

$$x_{fopt} = \left(\frac{k_f V_p}{2C_{fD,opt} k h} \right)^{0.5}$$

$$w_{opt} = \left(\frac{C_{fD,opt} k V_p}{2 k_f h} \right)^{0.5}$$

3.2.5 Damage Assessment

According to Matthews and Russell (1967), invasion of drilling fluids, dispersion of formation clays, presence of a mudcake and cement, partial well penetration, limited perforation, turbulence effects in the wellbore and perforation plugging can cause skin near the wellbore. Positive skin factor results in additional pressure drop in the vicinity of the well and this indicates permeability reduction in the formation near the wellbore. Therefore, positive skin is a good indicator that the well needs to be hydraulic fracture treated.

Negative skin factor occurs when the well had already been treated (matrix acidizing treatment or hydraulic fracturing treatment) or there is a natural fracture (Schechter 1992). Even when the matrix acidizing had already been treated and the productivity increase is not enough, hydraulic fracturing can be treated additionally. Therefore it is not a good idea to automatically exclude the well with negative skin from the candidate well. Instead, it is necessary to carefully examine the treatment history before making any decision.

But because our work focuses on finding a well which has not been treated before, positive skin factor was selected as one of the decision criteria. Positive skin factor means the well has been damaged before, therefore it is expected that it would give large productivity increase when treated. The well with negative skin factor will be excluded from the candidate well.

Besides the skin factor, the damaged radius is also considered. Matrix acidizing is a production enhancement technique by injecting acid into the formation to dissolve present minerals, and therefore, increase the permeability in the near-wellbore vicinity. For the very near-wellbore damage, matrix acidizing can be an alternative treatment for hydraulic fracturing. Therefore for the damaged radius of less than 6 in, the well is still included in the candidate well but matrix acidizing is additionally suggested as a possible option.

The relationship between the skin factor, damaged radius and damaged permeability is obtained by Hawkins' formula (1956).

$$s = \left(\frac{k}{k_s} - 1 \right) \ln \left(\frac{r_s}{r_w} \right)$$

The skin factor can be calculated from pressure build-up (PBU) test.

3.2.6 Pressure

In this session, several kinds of pressures are discussed. And the purpose of this session is to figure out breakdown pressure and not to screen out the candidate wells.

The fracturing pressure, also known as in-situ stress or minimum horizontal stress, is the pressure required to propagate a fracture. Breakdown pressure is the pressure required to initiate a fracture from the wellbore. Due to the effect of the stress induced by the wellbore, the breakdown pressure is usually greater than the fracturing pressure. An expression for the breakdown pressure has been given by Terzaghi(1923) and for a vertical well this pressure, p_{bd}, is expressed as follows (Economides et al. 1994)

$$p_{bd} = 3\sigma_{H,\min} - \sigma_{H,\max} + T_0 - p_p$$

where, $\sigma_{H,\min}$ and $\sigma_{H,\max}$ are the minimum and maximum horizontal stresses, respectively, T_0 is the tensile stress of the rock, and p_p is the reservoir pressure.

Usually the fracturing pressure is known from log or step-rate test, but the data for maximum horizontal stress is not always provided. Therefore, the maximum horizontal stress was assumed to be higher by 700 psi than the minimum horizontal stress inside the program in the calculation of breakdown pressure. This is rough estimation only and as further data becomes available, it can be modified.

3.2.7 Operational Check-points : Accessibility, HSE Issues, Restrictions by Law

Since most wells are located in remote area, the well location and accessibility becomes an important factor in determining the availability of treatment. During the treatment, large amount of proppant and fluid additives are used. Therefore, the well should be located and accessible at least by a full-size heavy-duty truck and provide enough room on location for the truck. Therefore the accessibility is chosen as one of the decision criteria and if the well doesn't meet this requirement, the program shows a suggestion message that it is better for the well to be accessible by truck.

As the hydraulic fracturing becomes widespread practical operation in shale gas production, the HSE concerns such as the contamination of ground water, risks to air quality, the migration of gases and hydraulic fracturing chemicals to the surface and the potential mishandling of waste are highly expressed. The waste disposal of flowback and sometimes the injected fracturing fluids are regulated by U.S. Environmental Protection Agency (EPA) under the Safe Drinking Water Act and Clean Water Act. And local regulations also tend to support stronger regulation of hydraulic fracturing. Therefore the well which has specific issues regarding HSE regulation is informed to the user.

Besides the regulations from the EPA, many states have comprehensive laws and regulations for hydraulic fracturing to protect drinking water sources and for safe operation such as Louisiana, Alabama, Texas, Oklahoma, Utah and Wyoming. There sometimes exist regulations at city level regarding hydraulic fracturing to protect their own environment, such as lakes which serves as the source of drinking water. Therefore the well which has specific issues regarding law enforcement will receive a suggestion message before proceeds to the next session.

3.3 Additional Considerations for Decision Criteria

The following parameters were not used as screening criteria for the development of candidate well selection program, but they are also important factors and should be discussed according to the data availability.

3.3.1 Potential for Water Production

Fracturing into a water bearing zone can significantly affect the post treatment production. When a fracture penetrates the water zone, the water production will increase substantially at the cost of oil and gas production. Therefore, it needs to be considered if there exist a water-bearing formation above and beneath the target formation in the context of fracture height growth and the treatment size needs to be modified accordingly (Martin and Economides 2010).

To prevent unwanted height growth, the understanding of in-situ stress field is essential. Not only the several layers in the pay zone which we intent to create hydraulic fracture but also several feet of upper and lower layers that coinside with the payzone.

3.3.2 Consideration for Equipments

Martin and Economides (2010) took into account the operational equipments when choosing candidate well for hydraulic fracturing. Pressure limitations of tubing/casing, packer, valves, gas lift mandrels as well as wellhead isolation tool are those factors which need to be considered to endure the fracturing pressure. The quality of tubular is also important to prevent a treatment from being under-performed. The quality of cement bond needs to be considered to initiate the fractures where the perforations are, not somewhere else.

3.4 Productivity Index

To investigate the technical effect of the fracture treatment, productivity index were calculated before and after treatment and productivity index ratio was also obtained. The wells which satisfy all the basic screening criteria are compared based on the productivity index ratio. Productivity index ratio could be from slightly larger than 1 to several dozen and the higher the productivity index ratio, the bigger the effects of the treatment. But about 2 to 5 folds of increase is the most common range.

3.5 Economic Analysis

Because the candidate well will be actually tested in the field, the proper analysis of economics is crucial in the candidate well selection program. For the quick and easy understanding of the economics, additional expected daily revenue from hydraulic fracture treatment is calculated, which does not consider the time value of money and assumes constant pressure drawdown.

$$Additional\ Expected\ Revenue = (J_{after\ frac} - J_{before\ frac}) \times Pressure\ Drawdown \times Oil\ Price$$

And then the payback period is obtained using the revenue and the treatment cost.

$$Pay\ Back Period = \frac{Treatment\ Cost}{Additional\ Expected\ Revenue}$$

CHAPTER IV

DEVELOPMENT OF CANDIDATE WELL SELECTION PROGRAM

4.1 Introduction

Candidate well selection program was developed using Microsoft-Excel VBA for easy application. The program is composed of input section and output section. After user finishes data input on input worksheet, program automatically delivers the summary of evaluation and relevant graphs on other worksheets.

The input section composes of 3 different parts as discussed before. Part 1 is the basic screening to decide whether the well is suitable for candidate well. In part 1, the each different decision criteria, divided by sessions, is evaluated in sequence by inputting appropriate data. In part 2, the productivity index ratio is calculated. Lastly, the economic analysis is conducted.

The output section consists of 3 main parts. First, the various input data are summarized and the results of evaluation for each session are also summarized. Second, for the effective visualization, the evaluated results are presented on the decision tree. Finally, several graphs are presented for given input data to show the sensitivity analysis. Inflow performance relationship (IPR) curves according to various skin factor, productivity index versus skin factor, optimum fracture geometry for a various proppant mass are some of the examples.

4.2 Test Run of Candidate Well Selection Program

It is interactive between the user and the program in that the program will generate candidate selection results based on the information provided by the user through a questionary. From following section, the steps to run the candidate well selection program will be explained in detail with an example.

Table 3 is the summary of input parameters used in the test run of the program.

Table 3 – Summary of input parameters

Well Name	TAMU-1
Bottom Hole Temperature, °F	190
Formation Permeability, md	50
Tubing OD, in	2.375
Casing OD, in	4.5
Fluid Level,ft	6410
Packer Depth,ft	6420
Bottom of Perforation Depth,ft	6450
TVD,ft	6465
Pay Thickness,ft	15
Drainage Radius,ft	745
Proppant Permeability,md	10,000
Damaged Zone Radius, in	12
Damaged Permeability, md	10
Fracture Gradient, psi/ft	0.62
Tensile Stress, psi	0
Pore Pressure Gradient, psi/ft	0.42
Formation Volume Factor, rb/STB	1.1
Formation Fluid Viscosity, cp	0.9
Oil Price,$	85
Treatment Cost, $	250,000
Bottom Hole Pressure, psi	1000

4.2. 1 Part 1 : Basic Screening

<u>Session 1 : Bottomhole Temperature and Wellbore Fluid Type</u>

Figure. 4. 1 shows the beginning of the basic screening part. The well name, bottomhole temperature are asked to be typed in by the user. And user can easily select the wellbore fluid type from the combo box, either "Water > 50% & HC < 50%" or "Water < 50% & HC > 50%" because the wellbore fluid type essentially determines whether the fracturing fluid can be used or not . After finishing the data input, user can click the "End of Session1" command button to check the results for session 1. The results are shown on the blue box under the data input box, either proceeding to the next session or stopping the evaluation. If the result is stopping the evaluation, the message shows which criteria, either bottomhole temperature or wellbore fluid type, does not meet the requirements so that the user can understand the reason. In this case, both temperature and fluid type satisfy the criteria, so we move to the next session.

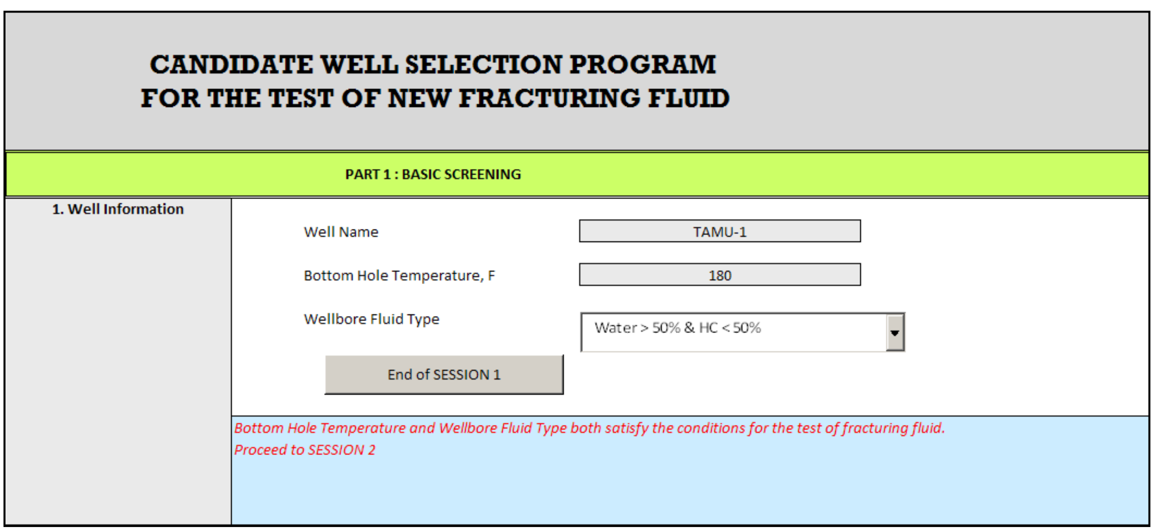

Fig. 4. 1 – Part 1 Basic screening : Session 1 checking bottomhole temperature and wellbore fluid type

Session 2 : Formation Permeability

Figure. 4. 2 is the formation permeability session. If the input formation permeability is in the range of degradable biopolymer fracturing, the message of "Proceed to Session 3" appears when user clicked the "End of Session2" button. If not, the evaluation abortion message pops up and it shows necessary permeability range for the treatment. In this case, the permeability is 50md, so it satisfies the criteria.

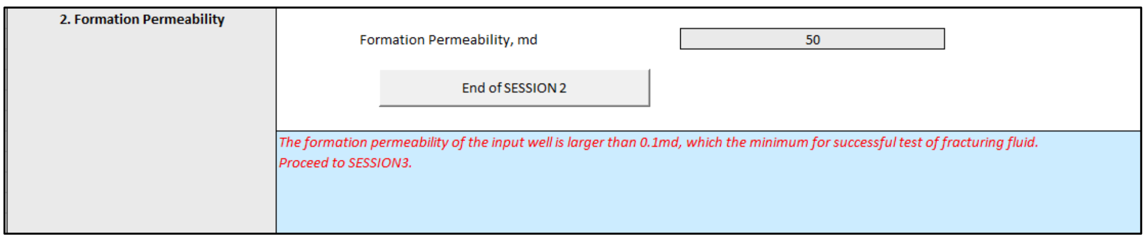

Fig. 4. 2 – Part 1 Basic screening : Session 2 checking formation permeability

Session 3 : Treatment Volume

In **Fig.4.3**, the treatment volume is calculated. The user can select the tubing and production casing sizes from the list boxes which were pre-developed according to the API standards. The fluid level inside the tubing, packer depth, bottom of perforation depth, true vertical depth (TVD) and the payzone thickness need to be provided. If the "End of Session 3" button is clicked, the results are shown for either proceeding to the next session or proceeding to the next session with the modification of target fracture geometries. In addition, the possible treatment volume is presented and modified target fracture half length and target fracture width are also presented if the possible treatment volume is not enough to achieve the desired target fracture geometry. Optimum fracture half length and optimum fracture width are also provided for the reference.

In this case, possible treatment volume is 22.17 gal, which is not enough to achieve the target fracture half length (20 ft) and target fracture width (0.5 in), so the new target fracture half length of 4.74 ft and new target width of 0.25 in were set. Optimum fracture half length is 11.40 ft and optimum fracture width is calculated as 1.12 in. These optimum values can act as a reference for user in designing the new target fracture geometries when necessary.

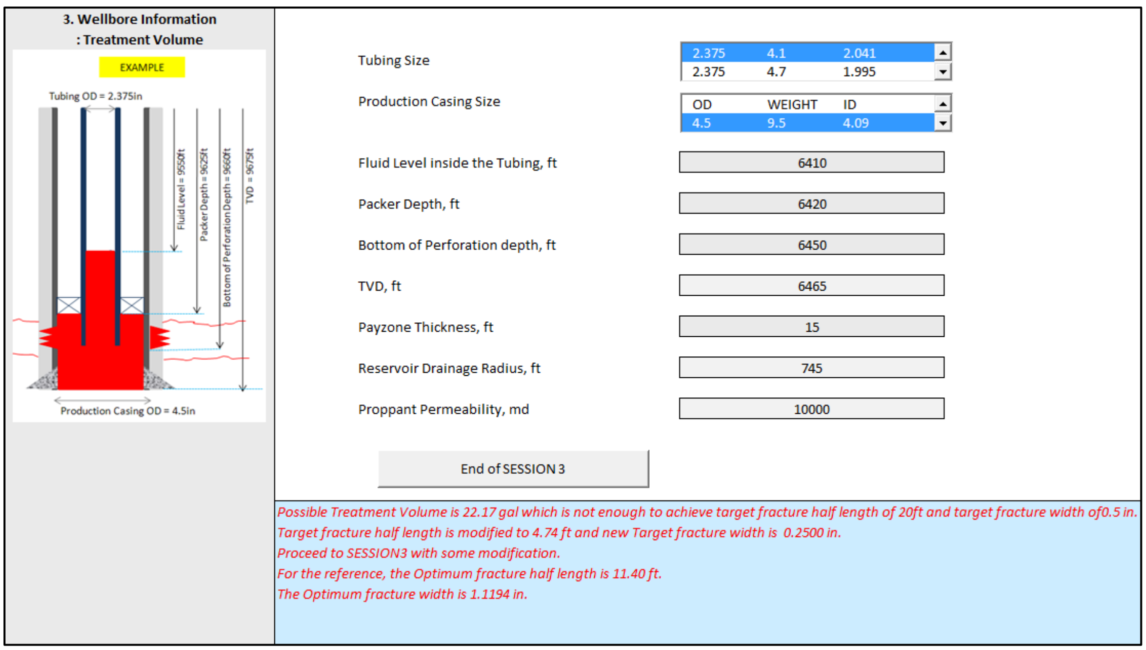

Fig. 4. 3 – Part 1 Basic screening : Session 3 checking treatment volume

Session 4 : Damage Assessment

Skin factor and the radius of damaged zones are evaluated next such as in **Fig. 4. 4**. If the calculated skin factor is positive and the damaged radius is larger than the pre-defined limit, the "Proceed to Session 4" message appears. If the skin factor is negative, the evaluation aborts and the message of "This well is does not need by-pass fracture treatment." is shown. If the skin factor is positive but the damaged radius is smaller than the pre-defined limit, the suggestion of matrix acidizing is presented.

In this case, the calculated skin factor is 17.02 and damaged radius is long enough for hydraulic fracturing.

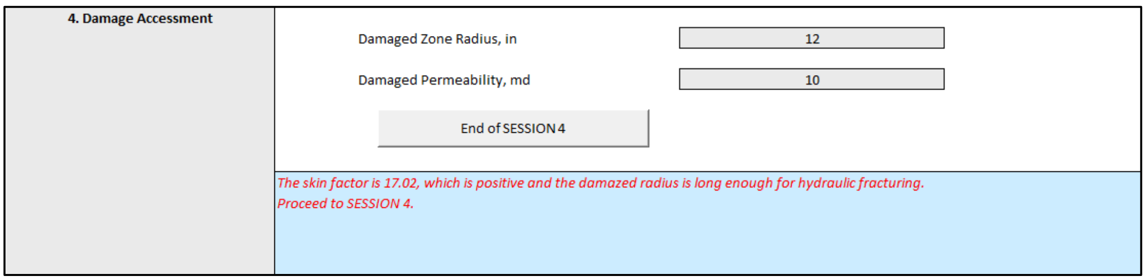

Fig. 4. 4 – Part 1 Basic screening : Session 4 checking damage assessment

<u>Session 5 : Pressure</u>

Figure 4. 5 shows the session for calculating breakdown pressure based on the input fracture gradient, tensile stress and pore pressure gradient. In this session, the screening process is not made, just the calculation of breakdown pressure is conducted. Reservoir pressure and in-situ stress are also presented for the reference.

In this case, the minimum in-situ stress is 4008 psi and reservoir pressure is 2715 psi. The breakdown pressure for the initiation of fracture at the wellbore is calculated as 4601 psi.

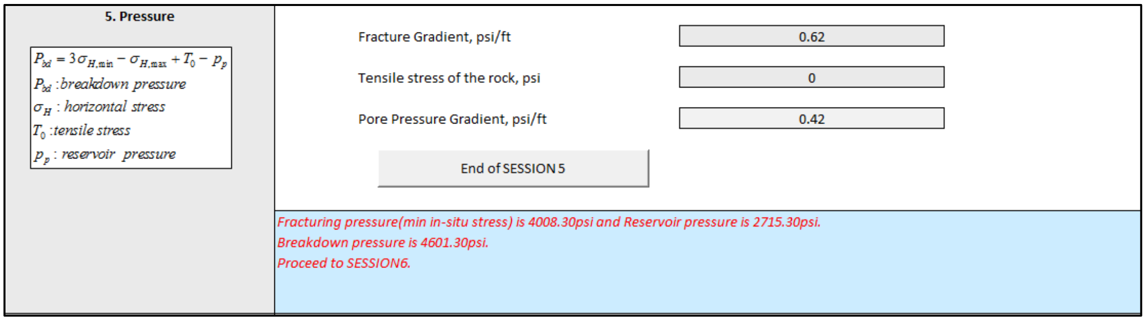

Fig. 4. 5 – Part 1 Basic screening : Session 5 checking pressure

<u>Session 5 : Well Location & Accessibility, HSE Issues, Restrictions by Law</u>

Last session is for checking the various operational considerations (**Fig. 4. 6**). The user can select "Yes" or "No" from the option button for each 3 questions. The "Yes" option for the "Well is easy to access by truck" question means there is no special concerns needed. On the other hand, the "No" buttons for the "Health, Safety and Environmental issues regarding this well" and "Any special restrictions by local/state law" mean there is not any issue which has to be further considered. If one of 3 questions has some restriction, a suggestion message, that it's better not to have any issue/restriction, appears.

In this case, well is accessible by truck and any special HSE issue or law restriction does not exist.

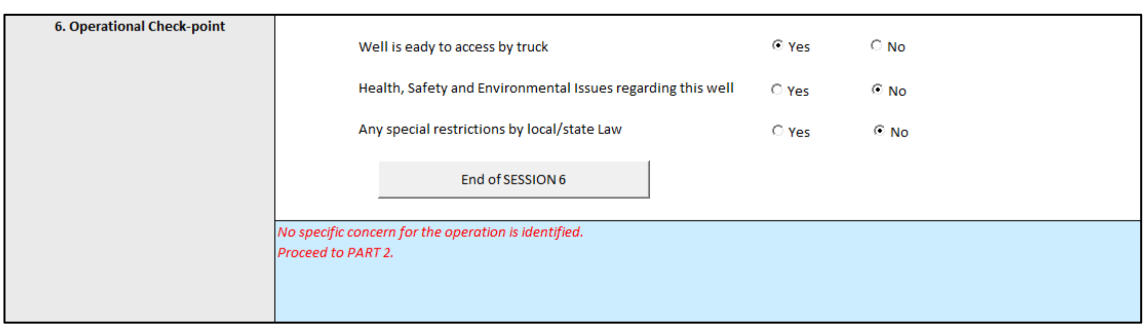

Fig. 4. 6 – Part 1 Basic screening : Session 6 checking operational check-points

4.2. 2 Part 2 : Productivity Index

The productivity index calculation part is shown in **Fig. 4. 7**. For the calculation, the data for the formation volume factor, formation fluid viscosity are needed. After clicking the "End of Part 1" button, the results of evaluation is shown on the blue box and the computed productivity indexes of before and after treatment are provided. The productivity ratio is also displayed.

In this case, the productivity index before treatment is 0.22 and after treatment is 0.89 and productivity index ratio is 4.08.

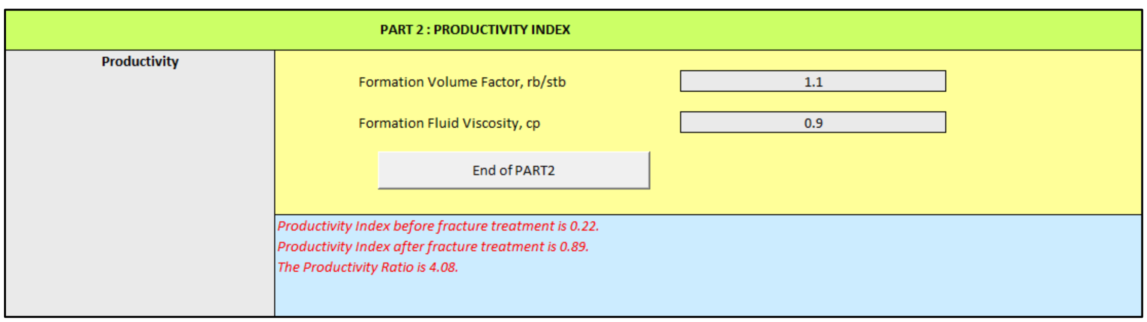

Fig. 4. 7 – Part 2 Checking productivity index

4.2. 3 Part 3 : Economic Analysis

Figure. 4. 8 shows the economic analysis. After inputting oil price and the estimated treatment cost, the calculated additional revenue due to the treatment and payback period are presented on the message box.

In this case, the additional revenue expected from treatment is $97,785 and payback period is 2.56 days.

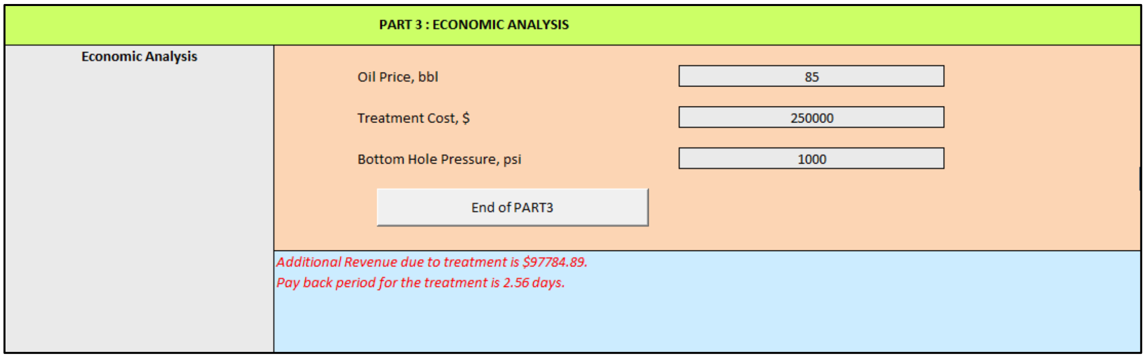

Fig. 4. 8 – Part 3 Checking economic analysis

4.3 Evaluation Summary

After user followed all the sessions and provided all the input data, the program runs to generate the evaluation results. If the user clicks "End of Program Run. Review the Results" button located at the very bottom of the worksheet, the results worksheet is added and the results are summarized. Starting from the list of all the input data, the evaluation results for each session are summarized (**Fig. 4. 9**)

Figure. 4.10 is the decision tree for the evaluated case results. On the decision tree, the results of evaluation for each session are represented as thick red arrows, so the user can easily figure out which decision criteria are satisfied.

REVIEW ON CANDIDATE WELL SELECTION	
Summaries of Input Data	
Well Name	**TAMU-1**
Formation	
Formation Permeability, md	50
Payzone Thickness, ft	15
Formation Volume Factor, rb/stb	1.1
Formation Fluid Viscosity, cp	0.9
Reservoir Drainage Radius, ft	745
Well Diagram	
Wellbore Fluid Type	Water > 50% & HC < 50%
Tubing Size(ID), in	2.041
Production Casing Size(ID), in	4.09
Fluid Level inside the Tubing, ft	6410
Packer Depth, ft	6420
Bottom of Perforation Depth, ft	6450
TVD, ft	6465
Bottom Hole Temperature, ft	190
Wellbore Radius, ft	0.17
Reservoir Pressure, psi	2715.3
Pore Pressure Gradient, psi/ft	0.42
Treatment	
Fracture Gradient, psi/ft	0.62
In-situ stress, psi	4008.3
Proppant Permeability, md	10000
Operational Check-point	
Location Accessibility	TRUE
HSE Issues	FALSE
Loca/State Law Restrictions	FALSE
Summaries of Evaluation	
Part1	
Bottom Hole Temperature	Passed
Wellbore Fluid Type	Passed
Formation Permeability	Passed
Treatment Volume	Passed but some modifications were made on target frac length & width
Skin, Damaged Zone Radius	Passed
Pressure	Calculated
Operational Check Points	Passed
Part2	
Productivity Index before Treatment	0.218
Productivity Index after Treatment	0.888
Productivity Index Ratio	4.081
Part3	
Additional Revenue, $	97,784.89
Payback Period, days	2.56
Additional Calculation	
Possible Treatment Volume, gal	22.17
New Target Frac Half Length, ft	4.74
New Target Frac Width, in	0.25
Skin before fracture treatment	17.02
Skin after fracture treatment	-1.59
Optimum Fracture Half Length, ft	11.4
Optimum Fracture Width, in	1.1194
Breakdown Pressure, psi	4601.3

Fig. 4. 9 – Summary of program run

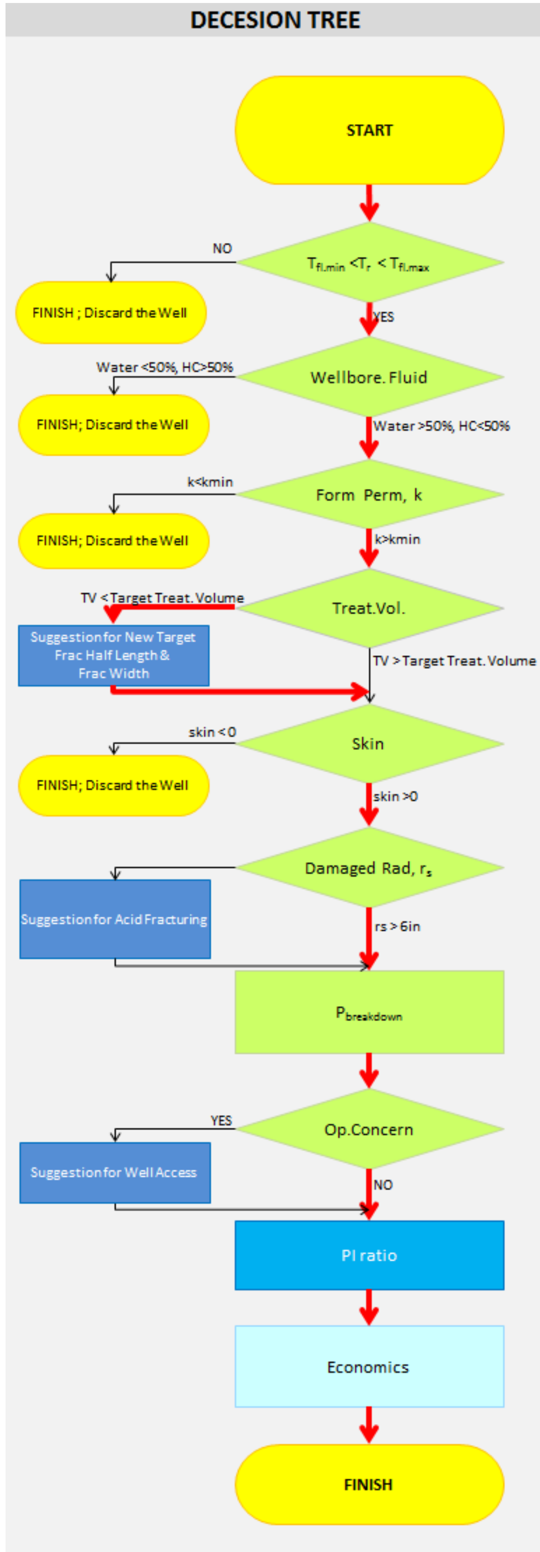

Fig. 4. 10 – Decision tree with the results of program run

4.4 Graphic Output

Figure. 4. 11 shows the graphs of the evaluation. Inflow performance curves are presented to compare the flow rate before the treatment and after the treatment. Also, for the sensitivity analysis of the skin factor, IPR curves for different skin factor (before treatment) are provided.

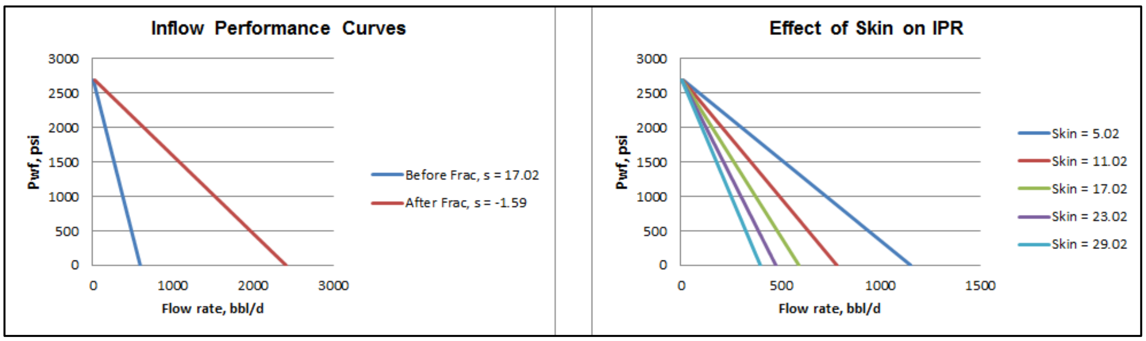

Fig. 4. 11 – IPR curves for various skin factors

And to investigate the effect of before treatment skin factor on the calculation of productivity index and on the calculation of productivity index ratio (**Fig. 4. 12**), graphs are displayed. The red dots on the graphs represent the calculated results from the program run and the blue curves are the results of sensitivity analysis. Therefore, even when the user has only a rough estimate of the input values, he/she can still use the candidate well selection program and can obtain the general idea of how the results would be.

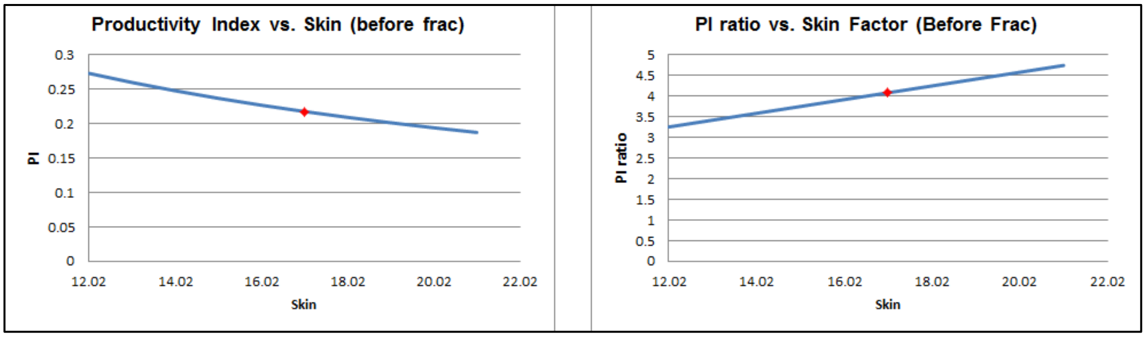

Fig. 4. 12 – PI/PI ratio curves for various skin factors (before treatment)

The effect of after treatment skin can be also examined by **Fig. 4.13**.

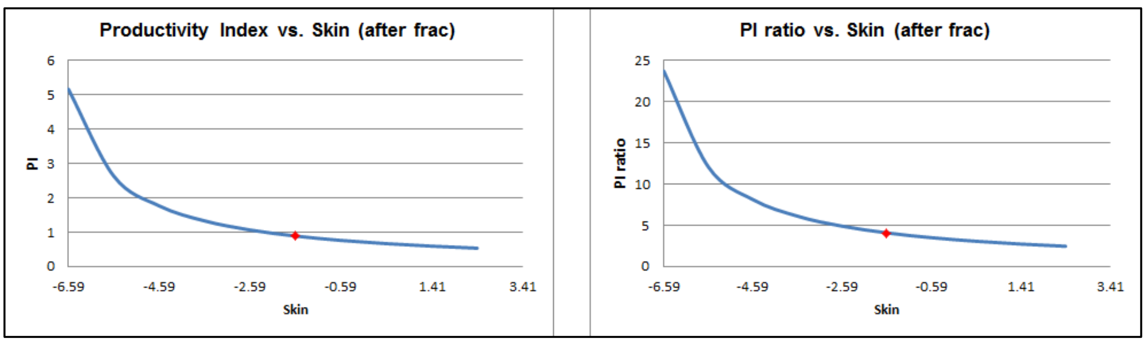

Fig. 4. 13 – PI/PI ratio curves for various skin factors (after treatment)

The sensitivity analysis for proppant permeability, fracture half length and fracture width are also presented. The red dot for proppant permeability is the input value and for fracture geometries, the modified target fracture half length and target width were used (**Fig. 4. 14**).

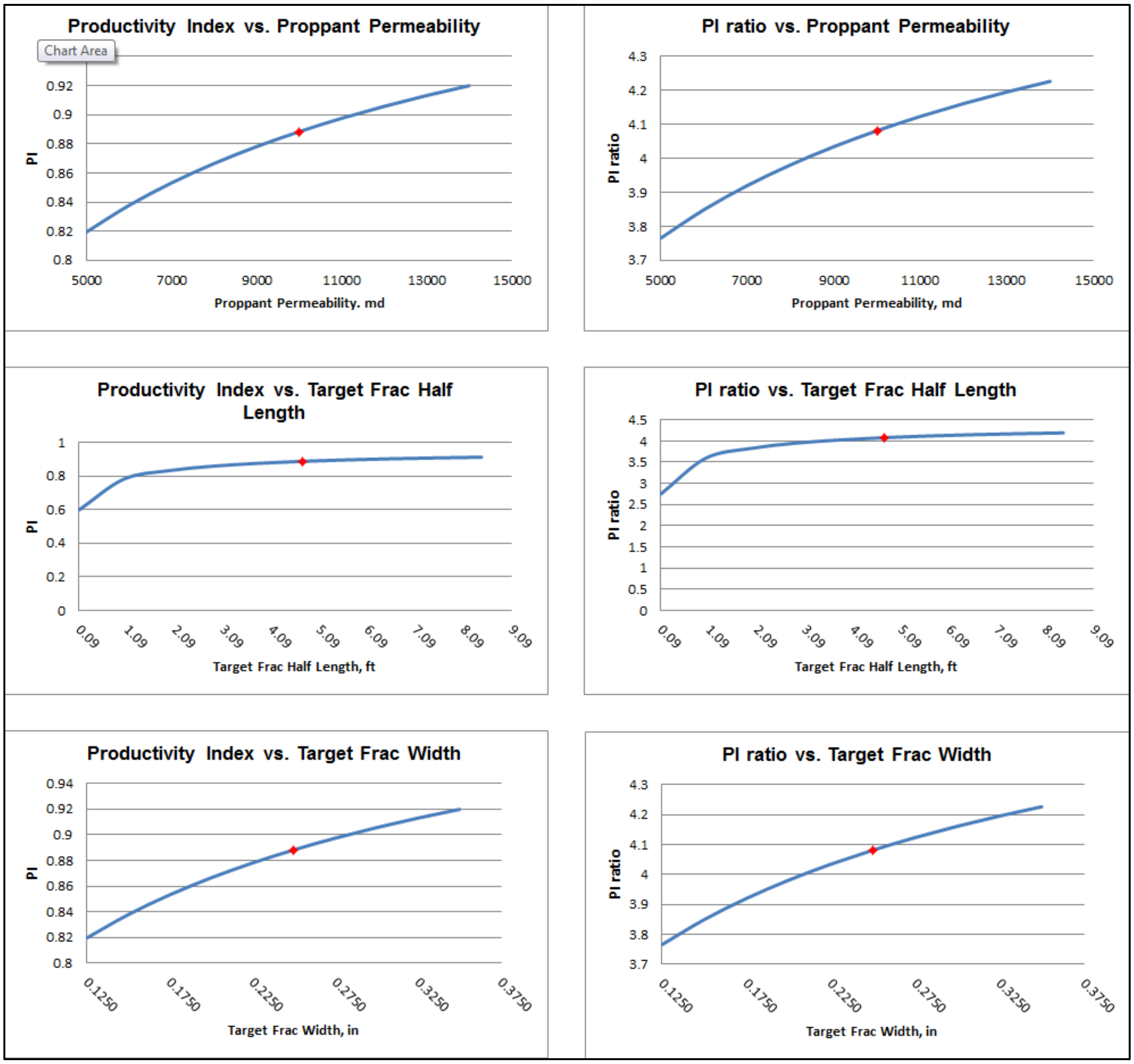

Fig. 4. 14 – PI/PI ratio curves for the various parameters

Additionally, the optimum fracture geometries for the different proppant mass are displayed (**Fig. 4. 15**). As the more proppant is used, longer fracture half length and wider fracture width can be achieved. But the proppant mass is directly related to the treatment cost, therefore the decision of how much proppant to use is a complex question. By providing the different fracture geometries for various proppant mass, the user can better understand the relationships of proppant mass and fracture geometries and use it as a reference.

In this case, the red dot shows the calculated proppant mass and other markers are for the sensitivity analysis.

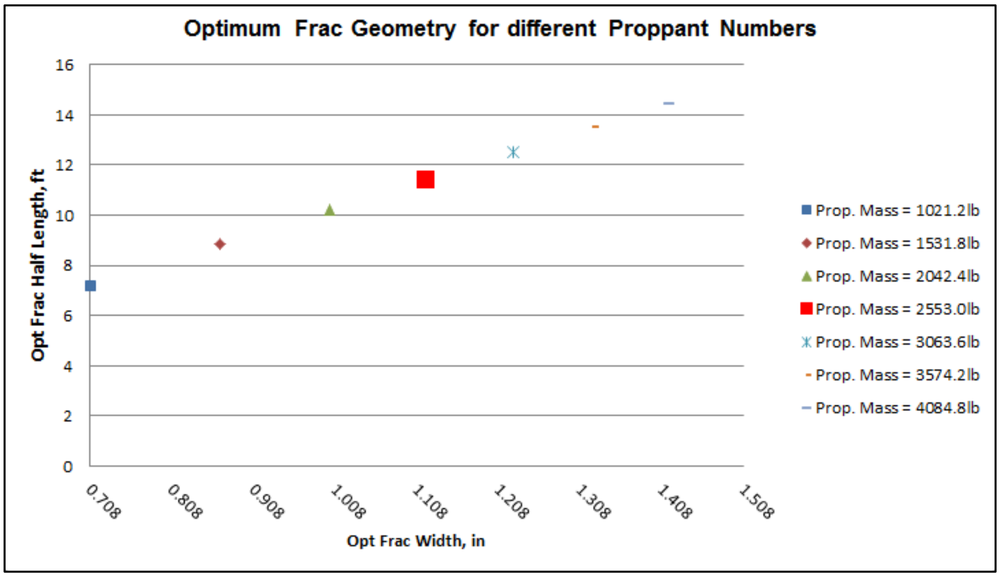

Fig. 4. 15 – Optimum fracture geometry for various proppant mass

CHAPTER V

CONCLUSION AND RECOMMENDATIONS FOR FUTURE WORK

5.1 Conclusion

This thesis is about the process of building a user-friendly candidate well selection program for the test of degradable biopolymer as fracturing fluid. Conclusions drawn from this thesis include:

- The decision criteria were carefully selected to incorporate the unique properties of degradable biopolymer as fracturing fluid. The field data availability and the benefits of each data were examined as well
- The decision tree for the selection of candidate well was developed to reflect the selected decision criteria. The decision tree helps the user to understand the procedure of the selection process and easily figure out which data are used and how the data are sub-grouped together to provide meaningful results
- The selection process is comprised of 3 main parts. Basic screening part is the part which screens out unsatisfactory wells by applying several decision criteria by sequence
- After basic screening part, productivity index is calculated to help user to understand the productivity increase by comparing productivity index before and after the treatment

- Economic analysis is conducted after productivity index. Additional expected revenue and payback period are calculated to provide economical impact of the treatment
- For the reference, optimum fracture geometries are presented from given proppant mass
- Several graphs including IPR curves, productivity index curves and productivity index ratio curves depending on several independent parameters are presented for the sensitivity analysis. This will enable the user to have the general idea of how input values affect the results of evaluation

5.2 Recommendation for Future Work

Though the candidate well selection program was made in the best possible way while reflecting the properties of degradable biopolymer and the requirements for hydraulic fracturing, the program can be much more improved by:

- Test with real field data. By doing so, the program can be more practical and effective with necessary modification
- Update the properties of degradable biopolymer as new information becomes available. By newly conducted laboratory test for the degradable biopolymer, new aspects of decision criteria can be added or the existing ones can be modified

NOMENCLATURE

B	formation volume factor, res bbl/STB
C_{fD}	dimensionless fracture conductivity
$C_{fD,opt}$	optimum dimensionless fracture conductivity
f	f-factor
h	payzone thickness, ft
ID	inner diameter, in
J	productivity index
k	formation permeability, md
k_f	proppant permeability, md
k_s	damaged permeability, md
q	flow rate, STB/d
p	pressure, psi
p_{bd}	breakdown pressure, psi
p_p	reservoir pressure, psi
r_e	drainage radius, ft
r_w	wellbore radius, ft
$r_w^{'}$	effective wellbore radius, ft
r_s	damaged zone radius, ft

s skin factor (before treatment)

s_f skin factor (after treatment)

T_o tensile stress of the rock

TVD true vertical depth, ft

V_p propped fracture volume contain within the payzone (2-wing)

w fracture width, in

w_{opt} optimum fracture width, in

x_f fracture half length, ft

$x_{f,opt}$ optimum fracture half length, ft

μ viscosity, cp

ν Poisson's ratio

$\sigma_{H,\max}$ maximum horizontal stress, psi

$\sigma_{H,\min}$ minimum horizontal stress, psi

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