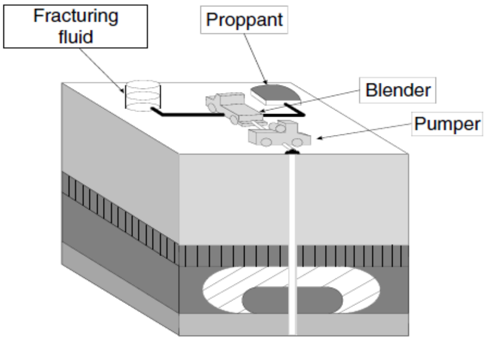


# HYDRAULIC FRACTURING DESIGN: BEST PRACTICES FOR A FIELD DEVELOPMENT PLAN

**Hafiz Mahmood Salman**

Thesis to obtain the Master of Science Degree in

**Energy Engineering and Management**

Supervisor: Prof. António José da Costa Silva

**Examination Committee**

Chairperson: Prof. Francisco Manuel da Silva Lemos
Supervisor: Prof. António José da Costa Silva
Member of the Committee: Prof. Maria João Correia Colunas Pereira

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## ABSTRACT

Unconventional oil and gas reservoirs are being explored significantly around the globe nowadays. The economical production of hydrocarbons from these unconventional oil and gas reservoirs requires very advanced and cost effective technologies. Hydraulic fracturing is such a technology which is being used in the oil and gas industry for many decades to create highly conductive channels in the formations having very low permeability values. Multistage hydraulic fracturing along with horizontal drilling has been proved to be a great achievement in oil and gas industry to enhance the production from unconventional reservoirs and massive shale gas production in the US is a successful example of it.

An effective hydraulic fracturing design is a key to achieve the expected results in terms of production from unconventional reservoirs such as tight gas, shale gas, coal bed methane or other very low permeability reservoirs. There are many factors which must be considered while designing and executing hydraulic fracturing operation. These factors are not only limited to pump rate, size and concentration of propping agent, fracture spacing or number of fractures, fracture geometry and conductivity but there may be more parameters such as flow back and shut in period, depth & thickness of reservoir, microcosmic events, faults and natural fractures which can play a significant role depending upon reservoir properties, rock properties, type of reservoir fluids etc. These parameters can vary significantly at different locations around the globe. There is no universal method of hydraulic fracturing which can be applied anywhere in the world without proper formation evaluation of underground formations containing hydrocarbons.

There are some concerns among our society about hydraulic fracturing regarding usage of huge amount of water and chemicals during the fracturing operation. A careful management of flow back fracturing fluid is necessary to avoid any potential problems associated with environment or human health. Therefore, an effective hydraulic fracturing design from pretreatment formation evaluation to environmental friendly and efficient management of fracturing fluid and waste water will be presented at the end of the study.

Keywords: unconventional hydrocarbons, hydraulic fracturing, formation evaluation, water management.

**RESUMO**

Actualmente, os reservatórios não convencionais de óleo e gás estão a ser explorados de forma significativa em todo o mundo. A produção económica destes reservatórios não convencionais de óleo e gás necessita a utilização de tecnologias avançadas e efectivas em termos de custo. Entre estas tecnologias inclui-se a fracturação hidráulica, sendo uma técnica utilizada há vários anos pela indústria do óleo e gás que se baseia na criação de canais muito permeáveis em formações que apresentam valores muito baixos de permeabilidade. Tendo em vista o aumento da produção dos reservatórios não convencionais, a fracturação hidráulica em múltiplas fases juntamente com a perfuração horizontal tem vindo a confirmar-se um êxito na indústria do óleo e gás, sendo a produção massiva do gás de xisto nos EUA um exemplo de sucesso da aplicação desta tecnologia.

O desenho eficaz da técnica de fracturação hidráulica representa uma chave para atingir os resultados esperados no que diz respeito à produção dos reservatórios não convencionais tais como o *tight* gas, gás de xisto, metano de jazidas de carvão (CBM)ou outros reservatórios com permeabilidades bastante reduzidas. Muitos factores devem ser tidos em conta aquando o desenho e execução de uma operação de fracturação hidráulica. Estes factores não estão limitados apenas pelo fluxo da bomba, dimensão e concentração do propante, espaçamento, número, geometria e condutividade das fracturas, mas também podem existir outros parâmetros tais como a reversão do fluxo e o tempo de fecho do poço, profundidade e espessura do reservatório, fenómenos microscópicos, falhas e fracturas naturais que poderão desempenhar um papel significativo dependendo das propriedades do reservatório e da rocha, tipo de fluidos do reservatório, entre outros. Estes parâmetros podem variar consideravelmente em diferentes localizações do globo. Não existe um método universal para a aplicação da técnica de fracturação hidráulica em qualquer região do mundo. Esta não pode ser realizada sem a avaliação adequada das formações subterrâneas que contêm hidrocarbonetos.

Existem algumas preocupações na nossa sociedade relativamente à fracturação hidráulica, nomeadamente, a utilização de grandes quantidades de água e químicos durante as operações de fracturação. Uma gestão cuidadosa no escoamento revertido de fluidos de fracturação é necessária de forma a evitar quaisquer potenciais problemas associados com o ambiente e saúde humana. Assim, um desenho eficaz da técnica de fracturação hidráulica desde a avaliação do pré-tratamento da formação até à gestão eficaz e amiga do ambiente dos fluidos de fracturação e água residual irá ser apresentado no final deste estudo.

Palavras chave: hidrocarbonetos não convencionais, fracturação hidráulica, formação avaliação, gestão de água.

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## ABBREVIATIONS

CDI – Capacitive deionization water treatment technology

FDP – Field development plan

FO – Forward osmosis

FWL – Free water level

HF – Hydraulic Fracturing

HHP – Hydraulic horse power

KGD – Geertsma and de Klerk

MD – Measured depth

MVR – Mechanical Vapor Recompression

MVC – Mechanical Vapor Compression

NWB – Near Wellbore

NCS – Net confining stress

NPV – Net present value

OWC – Oil water contact

PKN – Perkins and Kern

PVT – Pressure, volume and temperature

SEM – Scanning electron microscope

TVDSS – True vertical depth subsea

VSEP – Vibratory shear enhanced process

## SCOPE

This study is focused on real field data analysis obtained from ten delineation wells of a field. Production, stimulation, logging and core analysis data was obtained to carry out this study. The delineation wells were drilled to know the boundary of field to design and propose a cost effective field development plan. All of these delineation wells were hydraulically fractured. The company had some concerns regarding the hydraulic fracturing operation performed on these wells, which ultimately are the objectives of this study. There are precisely five objectives of my thesis which have been discussed in the objectives section below.

In short words, the scope of the thesis is to present an effective hydraulic fracturing design from pretreatment formation evaluation to environmental friendly and efficient management of fracturing fluid and waste water.

## OBJECTIVES

The objectives of this study are to:

1. Find out, what we should know before performing hydraulic fracturing operation on any well or why proper formation evaluation is important before hydraulic fracturing.

2. Propose an effective hydraulic fracturing treatment design.

3. Point out the reasons of lost circulation or mud losses.

4. Investigate the effect of long time shut-in period on production, after short time initial production.

5. Provide an environmental friendly solution for fracturing fluid and waste water management.

## STRUCTURE

Thesis has been divided into six chapters. The first chapter includes the introduction of hydraulic fracturing, hydraulic fracturing process and a discussion about available fracturing technologies. Different sources of data acquisition and importance of pretreatment formation evaluation are presented in chapter 2. Chapter 3 focuses on HF treatment design from proppant, fluid and model selection to production forecast and NPV analysis. Chapter 4 is dedicated to X field introduction, production and stimulation data analysis and finally the problems and their solutions are presented in the last part of the chapter. Then fracturing fluid and wastewater management technologies and options are discussed in chapter 5. Finally the conclusions, recommendations and future work are presented in chapter 6 which is the last chapter of the thesis.

## CHAPTER 1: HYDRAULIC FRACTURING: AN OVERVIEW, PROCESS AND AVAILABLE TECHNOLOGIES

### 1.1. Introduction

Hydraulic fracturing is not a new technology in the oil and gas industry. It has been deployed in the oil and gas industry since 1947. The first intentional hydraulic fracturing process for stimulation was performed at Hugoton gas field in western Kansas, in 1947 as shown in the figure 1. The Klepper well no.1 was completed with four gas producing intervals. The fluid used for this job was war-surplus napalm which is an extremely hazardous material. The amount of fluid pumped in each formation was 3000 gals. Although, post-treatment tests showed that acidizing is a better technique than hydraulic fracturing to enhance the production from limestone formations. Since that first treatment in 1947, hydraulic fracturing has become a standard treatment for stimulating the productivity of oil and gas wells. Many fields produce only because of hydraulic fracturing process. Applications of first-generation of fracturing were primarily small treatments to bypass near-wellbore drilling fluid damage to formations with permeability in the millidarcy range.

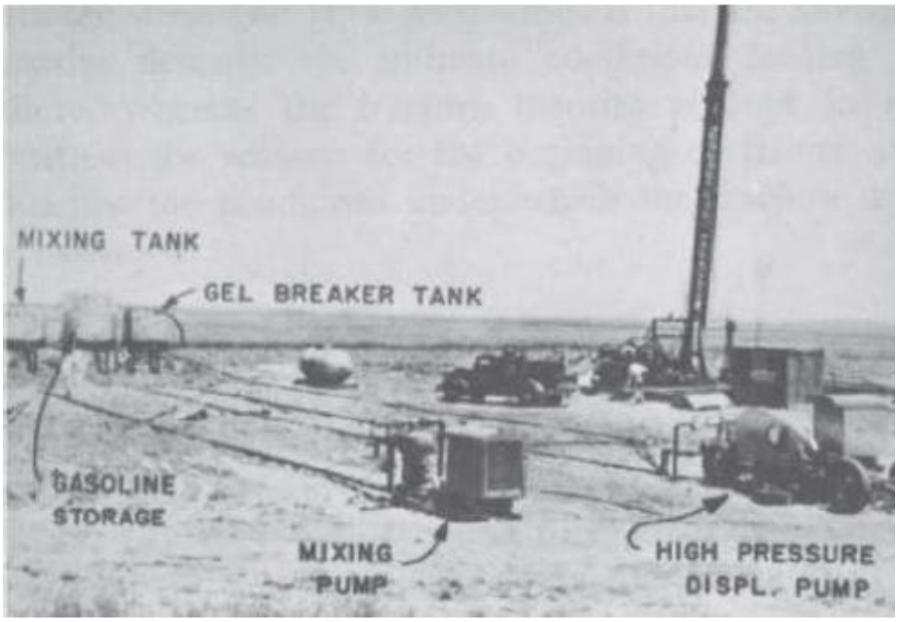



Figure 1.Klepper Well No.1, Hugoton gas field, Kansas (Michael J. Economides, T. M. 2007).

Nowadays, hydraulic fracturing has become very common technique especially in North America to extract natural gas from unconventional reservoirs such as coal beds, tight sands and shale formations. A large amount of shale gas production in North America has become possible due hydraulic fracturing treatments. The cost of the fracturing operation ranges from less than $20000 for small skin bypass fracs to over $1 million for massive hydraulic fracturing treatments. (Michael J. Economides T. M., 2007). The definition of a "tight gas" reservoir is a function of many physical and economic factors, and it applies to many types of reservoirs. The best way to define a tight gas reservoir is that "*the reservoir cannot be produced at economic flow rates or recover economic* *volumes of natural gas unless the well is stimulated by a large hydraulic fracture treatment, a horizontal wellbore, or by using multilateral wellbores*” (A.Holditch, 2006).

### 1.1.1. Objectives of Hydraulic Fracturing

In general, hydraulic fracture treatments are used to increase the productivity index of a producing well or the injectivity index of an injection well. The productivity index defines the volumes of oil or gas that can be produced at a given pressure differential between the reservoir and the wellbore (United States Environmental Protection Agency, 2004).

$$Productivity\ Index = PI = J = \frac{Flow\ rate}{Drawdown} = \frac{q}{\Delta P} = \frac{q}{P_e - P_{wf}} \quad (1)$$

There are many different objectives of HF depending upon certain situations. For instance, HF is used to:

1. Increase the flow rate of oil and/or gas from low permeability reservoirs
2. Increase the flow rate of oil and/or gas from wells that have been damaged
3. Connect the natural fractures in a formation to the wellbore
4. Decrease the pressure drop around the wellbore
5. Increase the area of drainage or the amount of formation in contact with the wellbore
6. Connect the full vertical extent of the formation to the wellbore

### 1.3. Hydraulic Fracturing Process

Hydraulic fracturing jobs are carried out at well sites, using heavy equipment including truck-mounted pumps, blenders, fluid tanks, and proppant tanks. A simplified equipment layout in hydraulic fracturing treatments of oil and gas wells is illustrated figure 2. A hydraulic fracturing job is divided into two stages: the pad stage and the slurry stage as shown in figure 3. In the pad stage, only fracturing fluid is injected into the well to break down the formation and to create a pad. The pad is created because the fracturing fluid injection rate is higher than the flow rate at which the fluid can escape into the formation.

After the pad grows to a desirable size, the slurry stage is started. During the slurry stage, the fracturing fluid is mixed with sand/proppant in a blender and the mixture is injected into the pad/fracture. After filling the fracture with sand/proppant, the fracturing job is over and the pump is shut down. Apparently, to reduce the injection rate requirement a low leak-off fracturing fluid is essential. Proppants are used to keep the fractures open and should have a compressive strength that is high enough to bear stresses from the formation. (Boyun Guo, 2007).

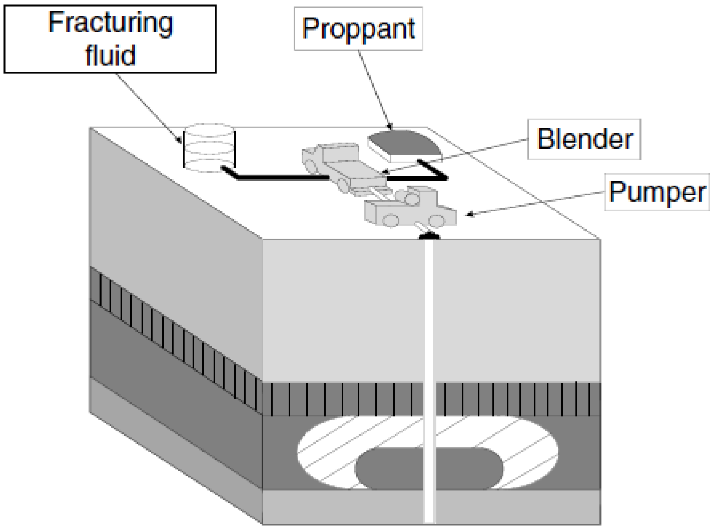



Figure 2.A schematic to show the equipment layout in hydraulic fracturing treatments of oil and gas wells (Boyun Guo, 2007).

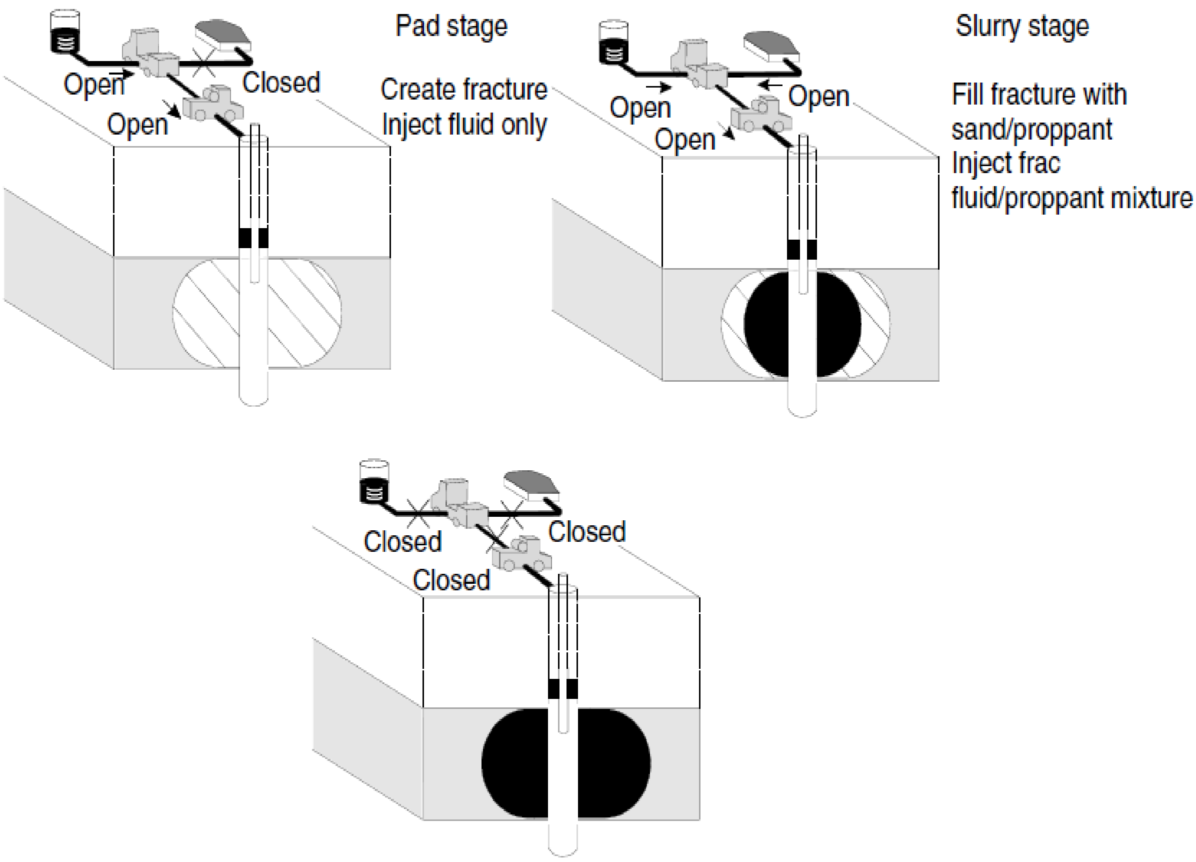



Figure 3.A schematic to show the procedure of hydraulic fracturing treatments of oil and gas wells (Boyun Guo, 2007).

## 1.4. Hydraulic Fracturing Technologies

There are many technologies of formation stimulation which are in use in oil and gas industry and hydraulic fracturing is one of them. Massive hydraulic fracturing treatments can cause risks to the environment. For example, high usage of water, methane infiltration in aquifers, aquifer contamination, extended surface footprint and induced local seismicity are some of the major risks associated with hydraulic fracturing treatments. Therefore, industry is continuously focusing on developing the new technologies which can reduce the impact on the environment.

As an example, foam technologies are more expensive than water based stimulations but they do offer an alternative to reduce the use of water in during stimulation. There is one thing to remember that there is no universal stimulation technique which can be applied anywhere in the world. The technologies to be used for stimulation heavily depend upon the location, formation characteristics, stress regime, environmental regulations, etc. This topic covers the different techniques available in the market. The main technologies being used in the industry can be dived into four major categories as described below.

### 1.4.1. Hydraulic fracturing

Water based, foam based, oil based, acid based, alcohol based, emulsion based and cryogenic liquid based technologies are all included in the category of hydraulic fracturing.

### 1.4.2. Pneumatic Fracturing

Air or nitrogen based technologies are termed as pneumatic fracturing technologies.

### 1.4.3. Fracturing with dynamic loading

This category includes explosives based and electric fracturing technologies.

### 1.4.4. Other fracturing techniques

This category includes thermal fracturing, mechanical cutting etc (Gandossi, 2013).

## CHAPTER 2. PRETREATMENT FORMATION EVALUATION

### 2.1 Introduction

In this section, different considerations will be discussed in details which are very helpful in designing and executing an efficient hydraulic fracturing operation. There are many considerations that should be focused upon before performing a hydraulic fracturing operation such as geologic considerations, petrophysical and well testing considerations and these are combined to get a complete understanding and description of the reservoir. The findings from these different considerations are illustrated in the following figure 4. (John L. Gidley, 1990). It is recommended to consult John L. Gidley's book" Recent Advances in Hydraulic Fracturing" for further knowledge about pretreatment formation evaluation.

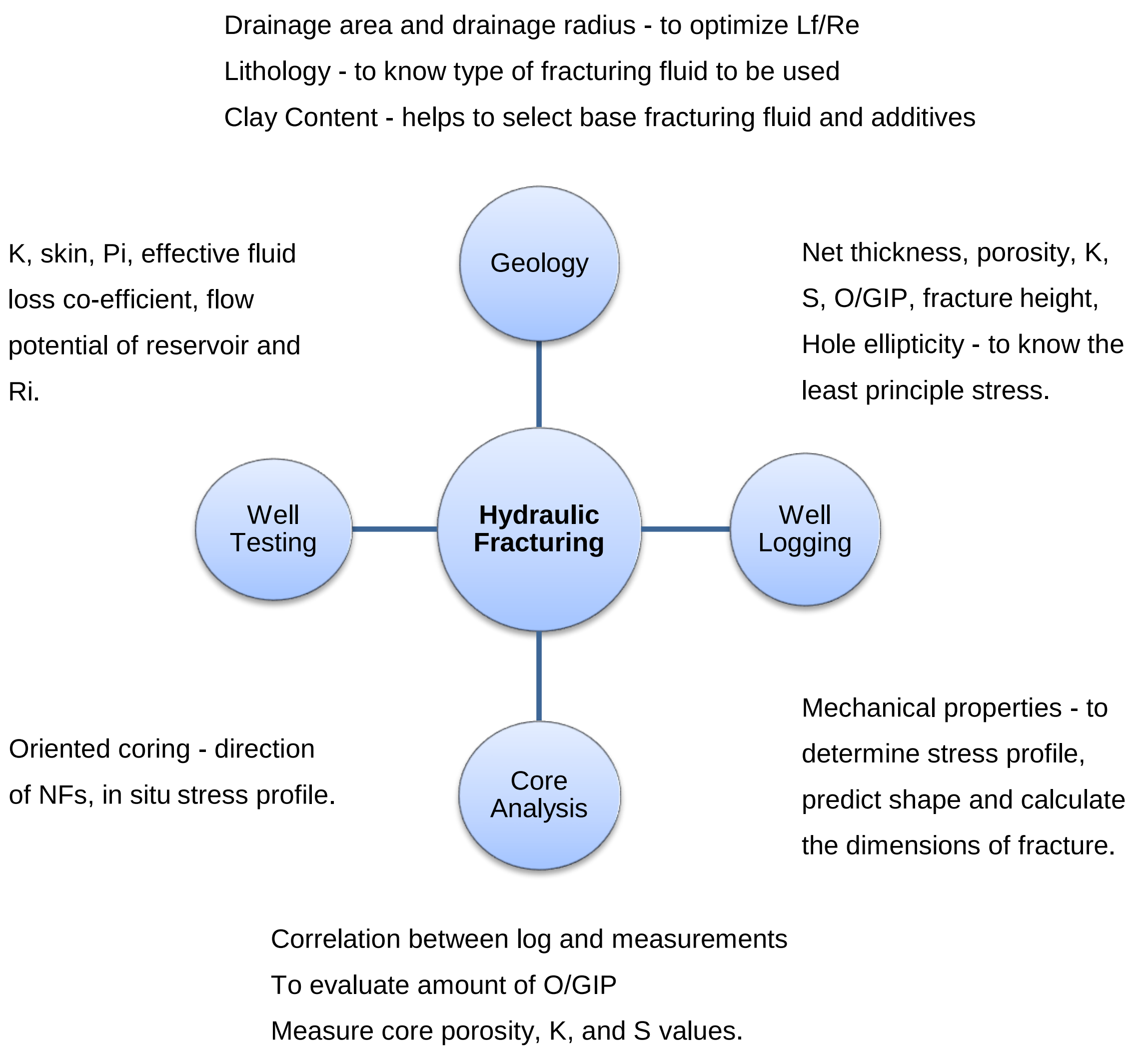



Figure 4.Major sources of data

### 2.2 Geologic Considerations

There are many aspects which should be considered during geologic evaluation of the candidate formation/reservoir. These aspects / parameters are:

1. Drainage area   2. Lithology   3. Clay Content   4. Fault patterns

#### 2.2.1. Drainage Area

The ratio of fracture length, $L_f$ , to drainage radius , $r_e$ , must be optimized to optimize the hydraulic fracturing treatment. In blanket reservoirs, it is possible to determine optimum fracture length and drainage radius by projecting flow rate vs. time as a function of fracture length and drainage radius. In lenticular reservoirs, drainage radius is a fixed parameter and not a function of fracture treatment size. The most probable value of drainage radius is obtained from the geologic studies of that area. After determining a probable value for drainage radius, the engineer can optimize propped fracture half-length by optimizing $\frac{L_f}{r_e}$ ratio. A diagrammatic cross section showing a general distribution of water and gas in conventional, tight lenticular and tight blanket sandstone reservoir intervals is depicted in Fig. 5.

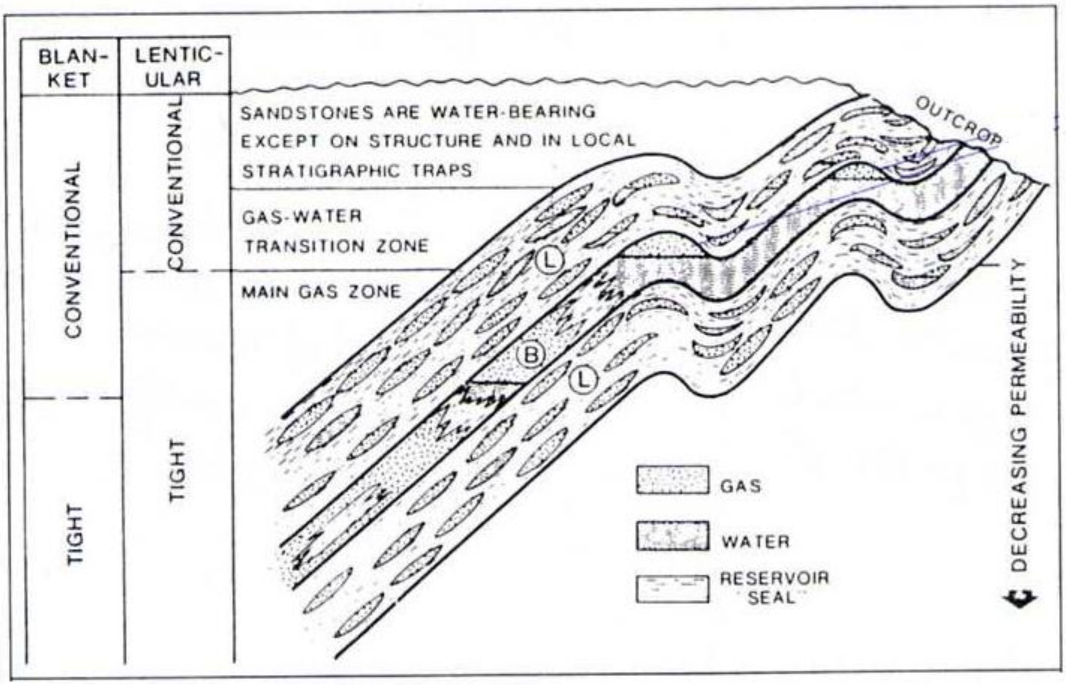



Figure 5.General distribution of water and gas in conventional, tight lenticular (L) and blanket (B) sandstone reservoir intervals (John L. Gidley, 1990).

Understanding the complexity of the geologic deposition patterns is important before designing a fracture treatment. Not only is it important to understand whether a formation is blanket or lenticular, gas bearing or water bearing, but it is also important to determine the probable size of the reservoir before designing the stimulation treatment. For designing the treatment in blanket reservoirs, the engineer must determine optimum values of fracture half-length and drainage radius. However, in lenticular reservoirs, the probable size and shape of the reservoir is estimated and then optimum fracture length is determined from the most probable reservoir size.

### 2.2.2. Lithology

This is another geologic characteristic which is important to know before designing a hydraulic fracturing treatment. For a sandstone reservoir, a water or oil based fracturing fluid will probably be selected. In shallow carbonate reservoirs, sometimes acid based fluid is feasible. The basic lithology of a reservoir is an important factor for the analysis of openhole geophysical logs as well. Other lithological characteristics can also be important depending upon certain geologic environment. For example, cementing material can be of crucial importance in situations where carbonate cement is holding together a fairly soft rock, acid should not be used to break down the perforations or to stimulate the reservoir.

### 2.2.3. Clay Content

It is important to know the type and distribution of material that fills the pores in a particular formation. It is well known that many low permeability reservoirs contain large amount of clay material in the pore space. Geologic studies that include core descriptions, use of scanning electron microscope (SEM's) and X-ray diffraction analysis can be very helpful to understand the type of clay and its distribution in a particular formation. Different types of clays affect and reduce the permeability of a sandstone reservoir as shown in the figure 6. A pore filling clay reduces the permeability to a higher extent than a pore lining clay. The type of minerals and their location in the rock matrix can be of vital importance to interpret well logs and reservoir behavior.

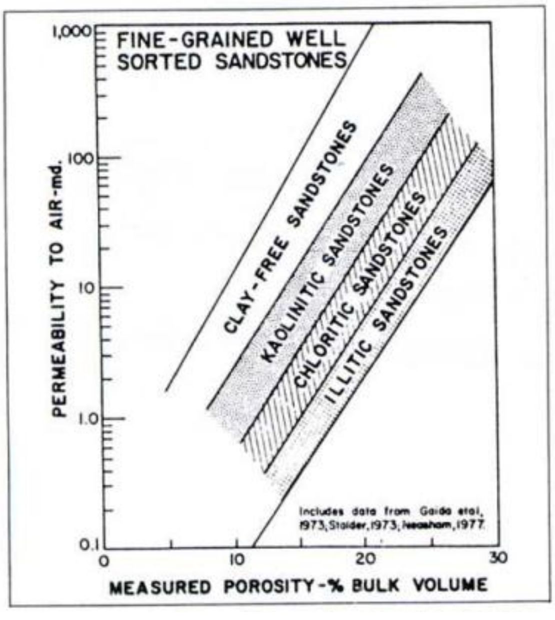



Figure 6.Porosity/permeability relationship of clay free and clay bearing sandstones (John L. Gidley, 1990).

#### 2.2.4. Fault patterns

The geologic study will be incomplete without the knowledge of regional and local stress patterns in an area. The knowledge of in-situ stresses is very important in designing the fracturing treatments. One way to investigate the stresses is to examine the regional and local fault systems. Hubbert and Wills explained that localized and regional stress patterns in an area are controlling factors in determining the orientation of hydraulic fractures and that the state of stress underground is not hydrostatic but depends on tectonic conditions. (Willis, 1957). They further concluded that hydraulically induced fractures are formed approximately perpendicular to the least principal stress. The study of fault system can give a great deal of information about the stress patterns in an area.

### 2.3. Logging Considerations

Well logging is a method to obtain geophysical logs of any particular formation using numerous sophisticated logging tools. An accurate analysis of these geophysical logs is a crucial part for better formation evaluation. A conventional log analysis usually provides the values of porosity, water saturation and net thickness of hydrocarbon zone. The values obtained from well logging and PVT properties obtained from laboratory measurements of the reservoir fluid, can be used to have a good estimation of oil and gas in place by the volumetric method as explained below.

$$OOIP = A * h * \varphi * (1 - S_w)/\beta \tag{2}$$

Small errors in porosity or saturation can cause a big difference in the estimation of reserves. Therefore an accurate well log analysis is very important. Most of the evaluation problems are not caused by logging measurement but by the inaccurate analysis of the analyst in determining the shale content, fluid content and borehole irregularities. Well logging helps us to obtain the values of following parameters.

#### 2.3.1 Shale Content Analysis

This analysis should be performed for better description of conventional as well as unconventional reservoirs. A good combination of logs consisting on gamma ray, spontaneous potential, induction, neutron, density and acoustic logs should be used for accurate formation evaluation. There are several methods to perform shaly sand analysis including, Archie, Waxman Smits and dual water model methods. Dual water model and Waxman Smits methods are probably the best methods to perform shaly sand analysis. For simplicity only Archie’s equation is presented below.

$$R_t = \frac{a * R_w}{\varphi^m S_w^n} \tag{3}$$

$$S_w^n = \frac{a * R_w}{\varphi^m R_t} \tag{4}$$

$$S_w^n = \frac{F * R_w}{R_t} \tag{5}$$

$$S_w^n = \frac{R_o}{R_t} \tag{6}$$

Where:

m = Cementation exponent; $S_w$ = Formation water saturation; $R_W$= Formation water resistivity; $R_t$= True formation resistivity; F = Formation Resistivity Factor = $F = a/\varphi\hat{}m$
n = Saturation exponent; a = Lithology or tortuosity factor

This equation is based upon the assumption that 100% of the current is transmitted through the fluids into the pore space from the resistivity logging tool. For clean and uniform size sands: a = 1 and m = 2. Wylie's equation is an important method to obtain porosity values. (M. R. J. Wyllie, 1956). Wylie's equation has been used to calculate porosity from compressional velocities obtained from acoustic logs.

$$V = (1-\varphi)V_{ma} + \varphi V_f \tag{7a}$$

Where:

$\phi$ = fractional porosity of the rock; $v$ = velocity of the formation (ft/sec); $v_f$ = velocity of interstitial fluids (ft/sec); $v_{ma}$ = velocity of the rock matrix (ft/sec)

Wylie's equation underestimates the porosity values lower by 25 %. Therefore, the Raymer-Hunt-Gardner's equation should be used for better approximation of porosity of tight low permeability reservoirs having lower porosity range.

$$V = (1-\varphi)^m V_{ma} + \varphi V_f \tag{7b}$$

#### 2.3.2 Mechanical Properties

The knowledge of mechanical properties of a producing formation as well as the surrounding formations is extremely important to predict the shape and to calculate the dimensions of hydraulic fractures. These mechanical properties include Young's modulus, shear modulus, Poisson's ratio, bulk modulus and compressibility. The following equations can be used to calculate the mechanical properties of a formation.

Young's modulus,

$$E = G(1 + v) \tag{8}$$

Shear modulus

$$G = 1.34 * \frac{10^{10}\rho_b}{\Delta t_s^2} \tag{9}$$

Poisson's ratio

$$v = \frac{0.5R_v^2 - 1}{R_v^2 - 1} \tag{10}$$

$$R_v = \frac{V_c}{V_s} = \frac{\Delta t_s}{\Delta t_c} \tag{11}$$

Where:

$V_c$= Compressional wave velocity & $V_s$= Shear wave velocity; $\Delta t_c$= Compressional wave travel time

$\Delta t_s$= Shear wave travel time.

Bulk modulus

$$K = 1.34 * 10^{10}\rho_b \left(\frac{1}{\Delta t_c{}^2} - \frac{4}{3\Delta t_s{}^2}\right) \tag{12}$$

Compressibility:

$$c_b = \frac{1}{K} \tag{13}$$

Where:

E= Young's modulus; G= shear modulus; $v$= Poisson's ratio; $R_v$= velocity ratio; $\rho_b$= bulk density

The best values of shear wave velocity and compressional wave velocity are obtained by recording a full wave form sonic signal from a downhole acoustic transmitter as shown in the figure 7.

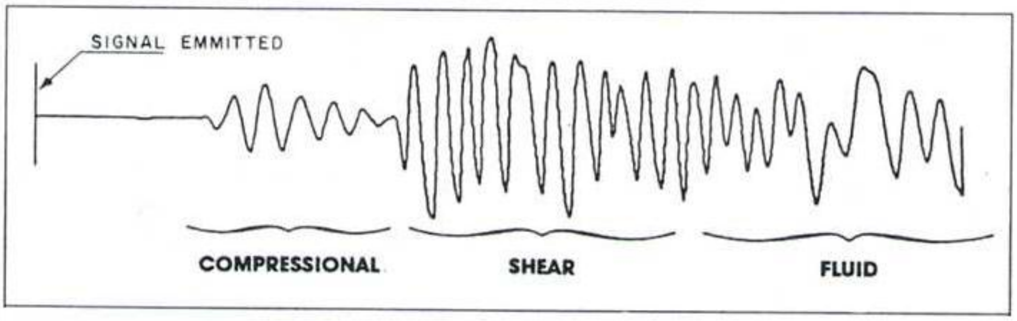



Figure 7. Typical sonic waveform in borehole (John L. Gidley, 1990).

The key to accurate determination of mechanical properties is an accurate measurement of shear wave travel time in the formation. It was first suggested by Pickett that the ratio of shear wave travel time and compressional wave travel time was a function of lithology. The relationship between compressional wave and shear wave travel time for a number of different lithologies and fluid saturations is illustrated in figure 8.

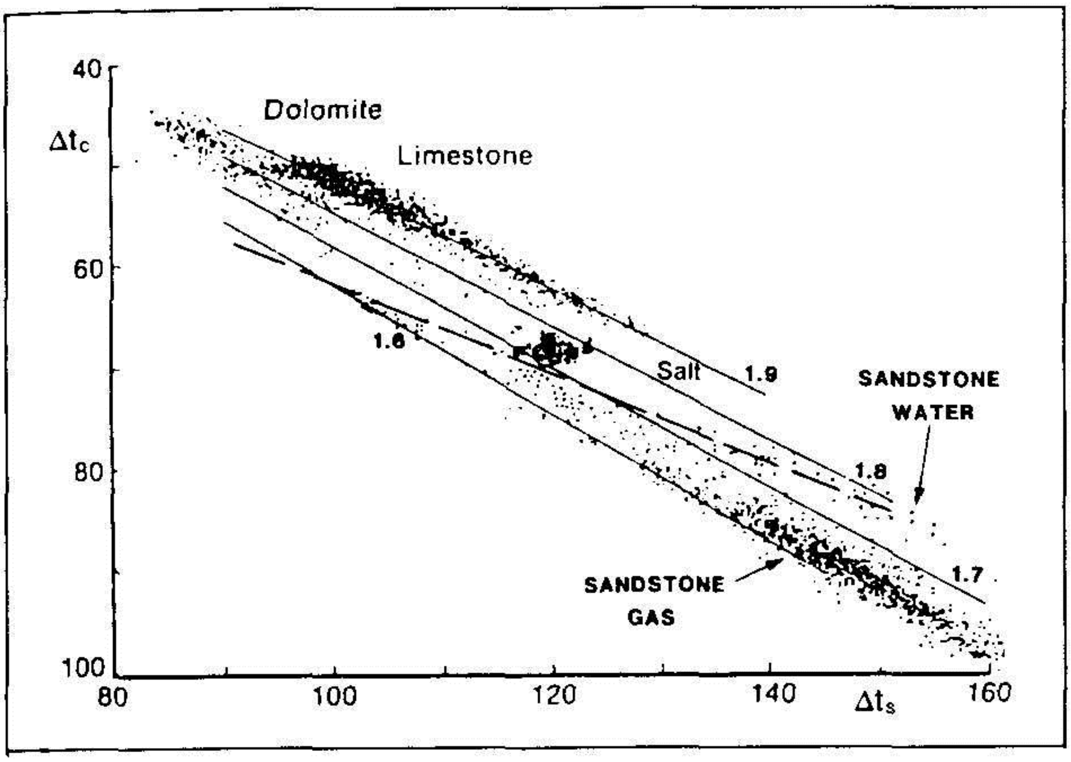



Figure 8. Well log examples, $\Delta t_c/\Delta t_s$ crossplots (John L. Gidley, 1990).

The velocity ratios from figure 8 are summarized in table 1.

Table 1. Velocity ratios from figure 8 (John L. Gidley, 1990)

| Lithology | $\Delta t_s/\Delta t_c$ |
|---|---|
| Sandstone/water | 1.78 |
| Sandstone/gas | 1.60 |
| Dolomite | 1.80 |
| Limestone | 1.90 |

It can be concluded from this relationship that, if one can determine the amount of dolomite, limestone, shale and probable fluid content then an estimation of shear wave travel time is possible from compressional wave travel time. Once velocity ratio is estimated then the values of Poisson's ratio and moduli can be calculated. A correlation between poisons ratio and shale index in shaly sand is presented in figure 9, which was developed by Anderson et al.

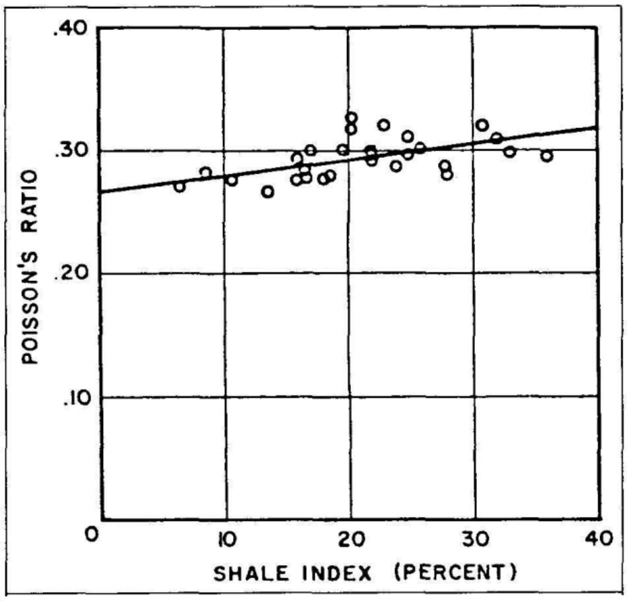



Figure 9.Correlation between poisons ratio and shale index (John L. Gidley, 1990).

The shale index was first defined by Alger et al. (R.P. Alger, 1959)

$$I_{shale} = \varphi_{sand} - {}^{\varphi_{Dolomite}}/_{\varphi_{sand}} \tag{14}$$

It must be noted that the calculation of mechanical properties on the basis of estimated values of lithology is acceptable only when the direct measurement of shear wave velocity is not available.

**2.3.3. Stress Profile**

One of the most important uses of mechanical properties data is to determine the stress profile in a formation containing multiple layers. The knowledge of in-situ stresses and stress profile is crucial in designing a fracture treatment which is confined within the productive interval. Effect of stress field on fracture propagation is presented in figure 10. Hubbert and Willis first presented the formulation to calculate the horizontal stresses in a reservoir by following method.

$$\sigma_x = \left({}^{v}/_{1-v}\right)(\sigma_z - p) + p + \sigma_E \tag{15}$$

Where:

$\sigma_x$= the total horizontal stress; $v$ = Poisson's ratio, $\sigma_z$= overburden stress; $p$ = reservoir fluid pressure or pore pressure; $\sigma_E$= externally generated stress

The above equation illustrates that the total horizontal stress can be calculated if Poisson's ratio, total overburden stress, pressure and externally generated stresses are known. (Willis, 1957).

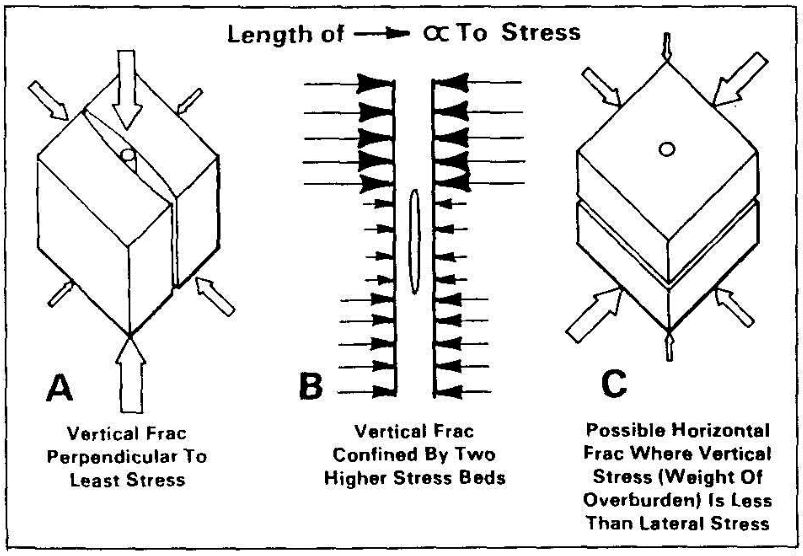



Figure 10. Effect of stress field on fracture propagation (John L. Gidley, 1990).

### 2.3.4. Temperature Log Base Profiles

Temperature logs are sometimes used to determine the injection profile before the fracture treatment. Temperature logs in combination with gamma ray logs can be used to determine where fluid enters or exits the casing. These logs can also provide information about flow channels behind the casings. Many engineers also try to determine the fracture height after stimulation treatment with gamma ray/temperature logs. However the measurements of fracture height from well logs can be misleading.

### 2.3.5 Fracture Height

This is perhaps the most difficult parameter to measure during hydraulic fracturing design. Fracture height can be calculated if one can obtain complete description of all layers in the reservoirs by using a reliable three dimensional model. But for practical purposes, one can rely on the existing 2D models. However, to design a fracture treatment correctly with a 2D model, one must correctly estimate the created fracture height.

For most situations, one should consider only (1) thick, clean shales (2) thick, dense formations and (3) coal seams as potential barriers to fracture growth. The best method of estimating created fracture height from the log is to start at the perforated interval and search up and down until shale or dense streak is found that appears thick enough to be a barrier to fracture growth. It is observed that the size of fracture treatment, the viscosity of fracturing fluid, and the injection rate will influence the value of created fracture height. To design a fracture treatment with current technology, one must estimate fracture height from logs.

- In Fig. 11-a, the fracture is initiated near the top of the interval, and $h_f$ is not large enough to contact the entire zone, which is clearly an important reservoir concern.

- In Fig. 11-b, the fracture grew out of the zone and contacted mostly nonreservoir rock, diminishing $x_f$ relative to the treatment volume pumped.

  In Fig. 11-c, the fracture grew downward past the oil/water contact and if propped would possibly result in unacceptable water production.

In all these cases, fracture height growth is controlled by rock mechanics considerations such as in-situ stress, stress gradients, stress magnitude differences between geologic layers. (Michael J. Economides K. G., 2000).

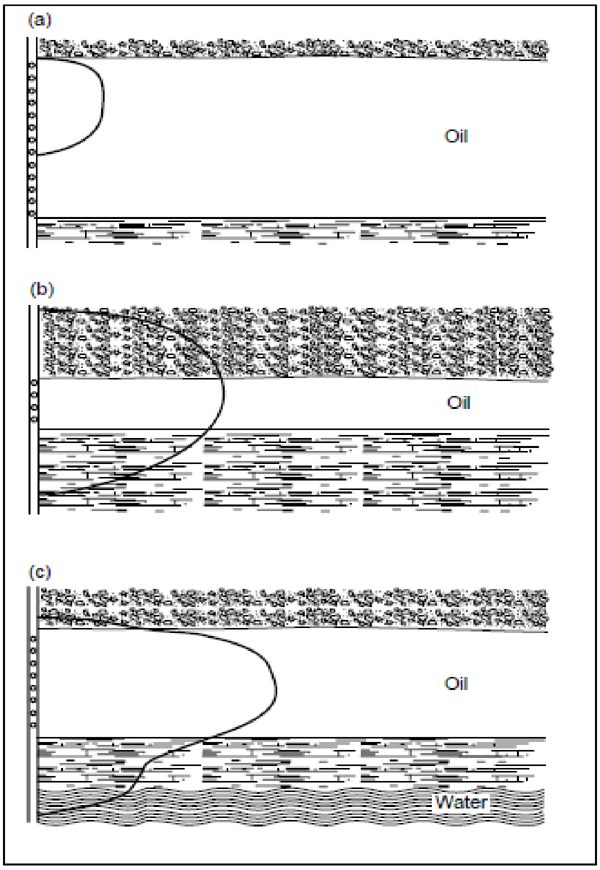



Figure 11. The importance of fracture height (Michael J. Economides K. G., 2000).

It was observed from the stimulation data analysis of X field reservoir that the fracture height was much higher than the reservoir thickness which means that the fracture propagated well outside of the reservoir zone. It would have been better if the information about reservoir thickness was obtained from well logging data and then used in designing the hydraulic fracturing operation with the aim of confining the fractures within the reservoir zone. The reservoir thickness can be calculated from the well log. In X field reservoir the thickness of the reservoir zone was around 30 meters and an example of a well log from X field is presented in the following figure 12.

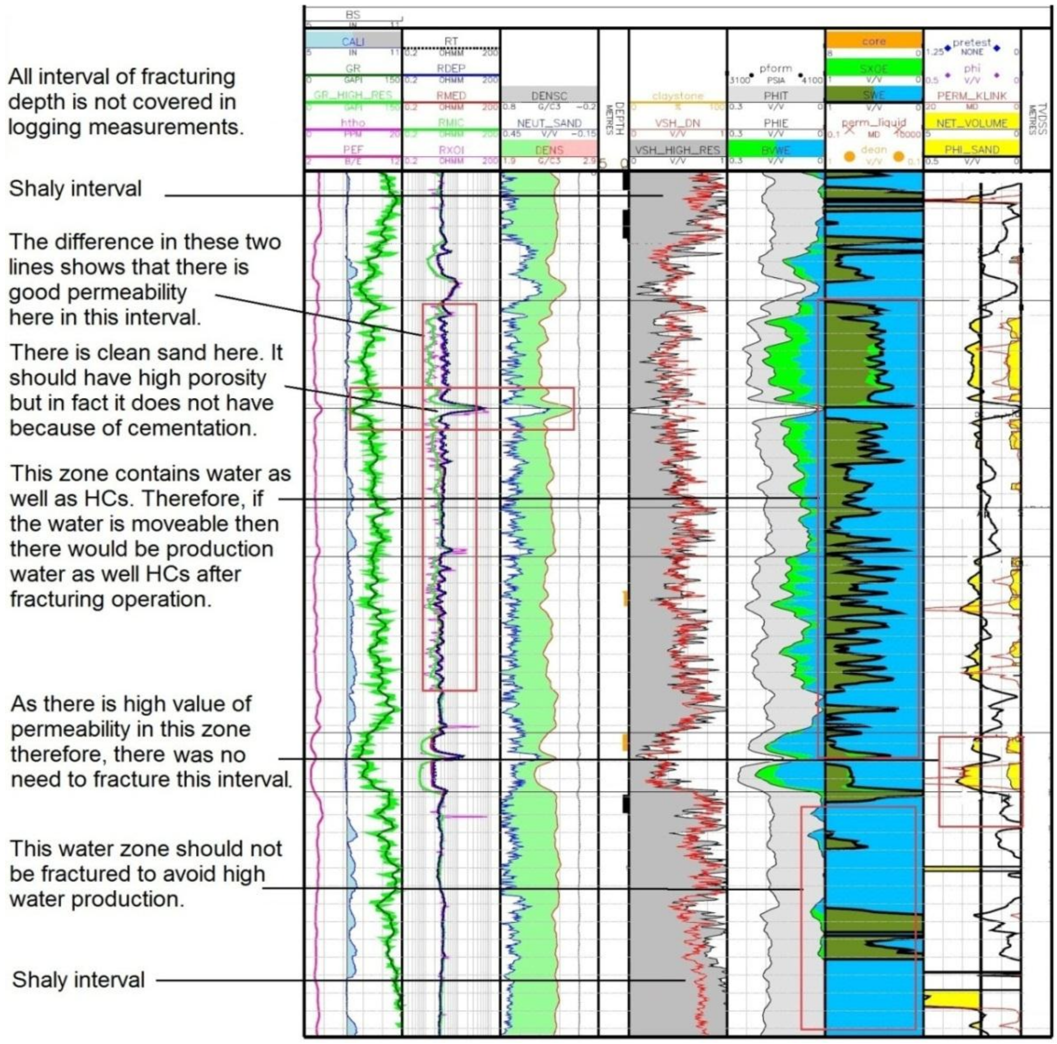



Figure 12. Well log analysis

### 2.4. Core Analysis

The description of layers surrounding the productive interval is important to design the hydraulic fracture treatment. Therefore, core should also be taken from the layers of shales, siltstones and mudstone both above and below the productive interval. In many cases, coring these potential barriers is more important than coring the productive interval. The main purpose of taking the cores are to evaluate the amount of oil and gas in place, to determine the effective permeability values and to obtain correlations between core and log readings.

Conventional core analysis is usually performed to calculate the values of porosity, permeability and water saturation at atmospheric conditions. The measurements are made at room temperature and moderate pressure after removing hydrocarbons and after drying the core sample in an oven. This type of analysis has been useful in conventional reservoirs; however, it is not useful for unconventional tight gas reservoirs. The values of permeability can decrease significantly for low permeability reservoirs when water saturation effects are included and core is tested under restored state conditions as demonstrated by Thomas and Ward. (R.D. Thomas, 1971).

Special core analysis can be used to determine the values of porosity, capillary pressure, relative permeabilities to oil, gas and water, saturation exponent and cementation factor under simulated reservoir conditions. Other parameters such as compressional and shear travel time, and formation density can also be measured in the laboratory. In addition to measuring the rock and fluid properties, it is also extremely important to run special tests to determine the possible interaction of fracturing fluid and proppants with the formation. It's because, fracturing fluid can play an important role in altering the formation characteristics such as wettability.

Oriented coring technique is useful in order to determine the direction of natural as well as hydraulically induced fractures and stress patterns. Special coring equipment is used to obtain an oriented core. Knowing the core orientation can be quite useful in planning the location of development wells in blanket reservoirs. It is illustrated in the fig.13 that when fracture orientation is known, the wells can be drilled to obtain adequate drainage area in the reservoir. But if the well spacing and location are not properly planned, the reservoir would not be drained sufficiently as can be seen in the figure. Optimum selection of infill well locations depends upon the orientation of propped fractures in low permeability reservoirs.

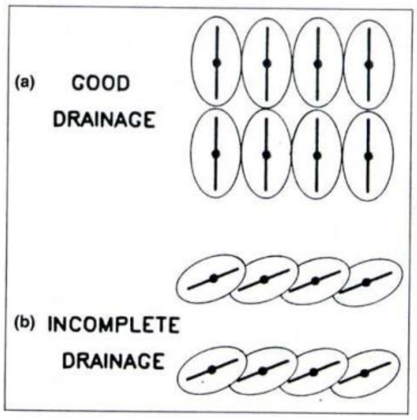



Figure 13.Optimum recovery (a), inefficient recovery (b) (John L. Gidley, 1990).

**2.5. Well Testing**

Once the decision has been made that hydrocarbons are present in commercial quantities in the reservoirs depending upon the analysis of geological, log and core data, a series of pre-fracture well test should be designed, executed and analyzed for further evaluation of the formation. The main purpose of well test is to estimate the dynamic reservoir permeability, skin factor and initial reservoir pressure along with some other properties such as in-situ stresses and effective fluid loss coefficient. Skin factor is a quantitative measure of the extent of damage of a formation. If the formation is damaged then the value of skin factor is positive but if the formation is stimulated then its value is negative. It is difficult to analyze post-fracture well tests, optimize fracture length and to design the optimum proppant for the fracture treatment if the correct value of in-situ permeability is not known from pre-fracture well test. The most important aspect of a successful pretreatment formation evaluation is that a consistent picture of the formation is developed by using all available techniques.

## CHAPTER.3 HYDRAULIC FRACTURING TREATMENT DESIGN

### 3.1. Introduction

Hydraulic fracturing treatments are designed based upon the knowledge obtained from pretreatment formation evaluation to maximize net present values (NPVs) of the fractured wells. Specifications of fracturing fluid and proppant, fluid volume, proppant weight requirements, fluid injection schedule, proppant mixing schedule and predicted injection pressure profile should be planned properly before going to the field operation.

A hydraulic fracturing design should follow the following procedure:

1. Selection of a fracturing fluid, 2. Selection of a proppant, 3. Determination of the maximum allowable treatment pressure. 4. Selection of a fracture propagation model, 5. Determination of treatment size (fracture length and proppant concentration), 6. Production forecast and NPV analysis

### 3.2 Selection of Fracturing Fluid

The major considerations for fluid selection are usually viscosity (for width, proppant transport or fluid-loss control) and cleanliness (after flowback) to produce maximum postfracture conductivity. Other considerations that may be of major concern for particular cases include

- compatibility with reservoir fluids and reservoir rock
- compatibility with reservoir pressure (e.g., foams to aid flowback in low-pressure reservoirs)
- surface pump pressure or pipe friction considerations
- cost
- compatibility with other materials (e.g., resin coated proppant)
- safety and environmental concerns

Fracturing fluid plays a vital role in hydraulic fracture treatment because it controls the efficiencies of carrying proppant and filling in the fracture pad. Fluid loss is a major fracture design variable characterized by a fluid-loss coefficient $C_L$ and a spurt-loss coefficient $S_p$. Spurt loss occurs only for wall-building fluids and only until the filter cake is established. Fluid loss into the formation is a more steady process than spurt loss. It occurs after the filter cake is developed. Excessive fluid loss prevents fracture propagation because of insufficient fluid volume accumulation in the fracture. Therefore, a fracturing fluid with the lowest possible value of fluid-loss (leak-off) coefficient $C_L$ should be selected. The second major variable is fluid viscosity. It affects transporting, suspending, and depositing the proppants, as well as their flowback after treatment. The viscosity should be controlled in a range suitable for the treatment. A fluid viscosity being too high can result in excessive injection pressure during the treatment. However, other considerations may also be of major concern for particular cases. They are compatibility with reservoir fluids and rock, compatibility with other materials (e.g., resin-coated proppant), compatibility with operating pressure and temperature, and safety and environmental concerns.

### 3.3 Selection of Proppant

Proppant must be selected on the basis of in situ stress conditions. Major concerns are compressive strength and the effect of stress on proppant permeability. For a vertical fracture, the compressive strength of the proppant should be greater than the effective horizontal stress. In general, bigger proppant yields better permeability, but proppant size must be checked against proppant admittance criteria through the perforations and inside the fracture. Figure 14 shows variation in proppant pack permeability under fracture closure stress. It can be observed that as the closure stress increases, the permeability decreases for different type of proppants.

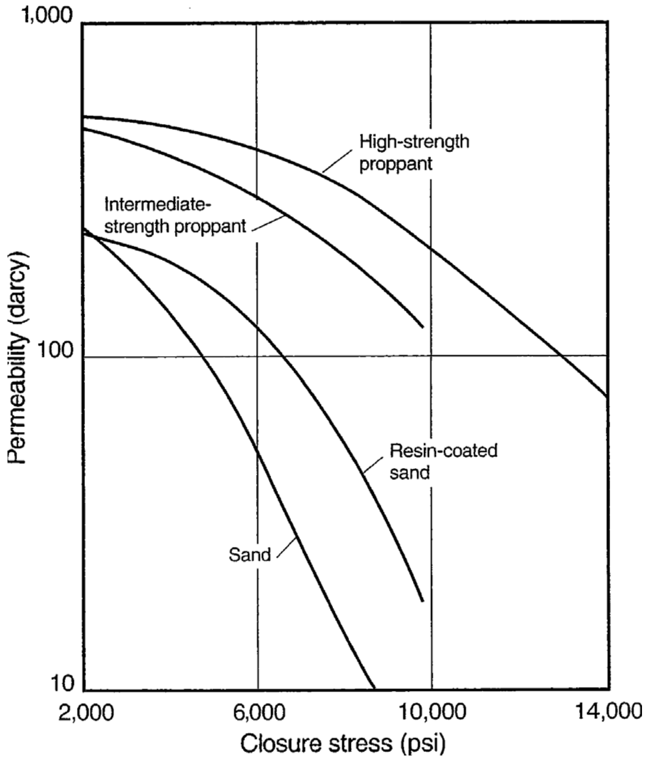



Figure 14.Effect of fracture closure stress on proppant pack permeability (Economides and Nolte, 2000)

### 3.4 Calculation of Maximum Treatment Pressure

The maximum treatment pressure is expected to occur when the formation is broken down. The bottom-hole pressure is equal to the formation breakdown pressure $P_{bd}$ and the expected surface pressure can be calculated by:

$$P_{si} = P_{bd} - \Delta P_h + \Delta P_f \tag{16}$$

Where:

$P_{si}$= surface injection pressure, psia;   $P_{bd}$= formation breakdown pressure, psia

$\Delta P_h$= hydrostatic pressure drop, psia;   $\Delta P_f$= frictional pressure drop, psia

The second and the third term in the right-hand side of Eq. (16) can be calculated using Eq. (17 & 18).

$$P_1 - P_2 = 0.433\gamma_0 LSin\theta + 1.15 * 10^{-5} * \frac{f_m \gamma_0 Q^2 L}{d^5} \tag{17}$$

Where:

$P_1$=inlet pressure, psi;   $P_2$=outlet pressure, psi;   $\gamma_0$=oil specific gravity

Q=oil flow rate, bbls/day;   d=pipe inner diameter, inch.

However, to avert the procedure of friction factor determination, the following approximation may be used for the frictional pressure drop calculation (Economides and Nolte, 2000):

$$\Delta P_f = \frac{518\rho^{0.79} q^{1.79} \mu^{0.207}}{1000 D^{4.79}} L \tag{18}$$

Where:

$\rho$ = density of fluid, g/cm$^3$;  $q$ = injection rate, bbl/min;  $\mu$ = fluid viscosity, cp

$D$ = tubing diameter, in.;  $L$ = tubing length, ft.

Equation (18) is relatively accurate for estimating frictional pressures for Newtonian fluids at low flow rates.

**3.5 Selection of Fracture Model**

The wide range of models and features available can make selecting a model an overwhelming task. It is always important to consider the availability and quality of input data in model selection. It is a famous quote about quality of data that “garbage-in garbage-out (GIGO)”. For most petroleum engineering problems, developing a complete and accurate data set is often the most time consuming and challenging part of solving the problem. For hydraulic fracture treatment design, the data required to run both the fracture design model and the reservoir simulation model can be divided into two groups. One group lists the data that can be controlled by the engineer. The second group reflects data that is measured or estimated, but cannot be controlled.

The primary data that can be controlled by the engineer includes the well completion details, treatment volume, pad volume, injection rate, fracture fluid viscosity, fracture fluid density, fluid loss additives, propping agent type and propping agent volume. The data that is measured or estimated by the design engineer includes formation depth, formation permeability, in-situ stresses in the pay zone, in-situ stresses in the surrounding layers, formation modulus, reservoir pressure, formation porosity, formation compressibility, and the thickness of the reservoir. (United States Environmental Protection Agency, 2004).

An appropriate fracture propagation model is selected for the formation characteristics and pressure behavior on the basis of in situ stresses and laboratory tests. Generally, the model should be selected to match the level of complexity required for the specific application, quality and quantity of data, allocated time to perform a design, and desired level of output. It is still a good practice use several models during the design phase. PKN (Perkins and Kern) model is a more appropriate approximation for fractures where the length is considerably longer than the height, and the KGD (Geertsma and de Klerk) model should be used for fractures where the fracture length is of the same order or shorter than the fracture height. The 3D models require more data, primarily in the form of profiles of stress and moduli. The data are obtained from log analysis, measurements on cores and interpretation of pressure from injection tests.  For instance, to simulate a short fracture to be created in thick sandstone, the KGD model may be beneficial. To simulate a long fracture to be created in sandstone tightly bonded by strong overlaying and underlying shales, the PKN model is more appropriate. To simulate frac-packing in thick sandstone, the radial fracture model may be adequate.

### 3.5.1. Fracture Geometry

The three basic types of geometries 2D (PKN, KGD, radial), 3D (planner 3D, lumped 3D, discrete P3D) and multilayer fracture (MLF) models in a multilayer setting (PKN fractures, P3D fractures) are presented in the following figures from 15 to 17.

For the 2D PKN model, the fracture height estimated by the engineer remains constant for the simulation. The fracture length grows from a line source of perforations, and all layers have the same penetration. The simulation can be approximated by the average modulus of all the layers, with the reduced width from a higher stress layer between the sands accounted for by a multiplying correction (Nolte, 1982).

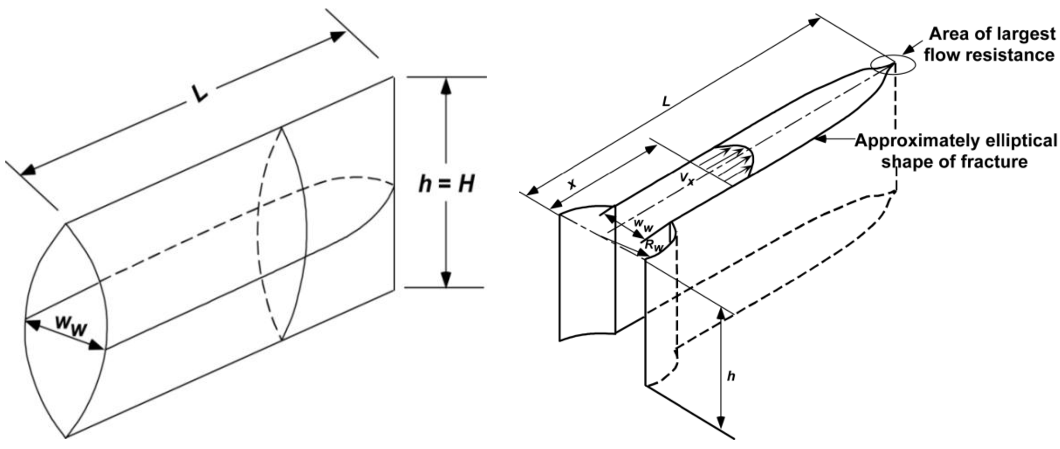



Figure 15.PKN geometry of 2D fracture (left); KGD geometry of a 2D fracture (right) (Economides and Nolte, 2000)

For the P3D model, the fracture initiates in the zone with the lower in-situ stress. The height growth is determined by the stress of bounding layers and other mechanical properties. Growth into the other sand layer depends on the stress and thickness of inter bedded shale layer and the distance between the two; it is independent of the wellbore and perforations in the layer. With a relatively low stress contrast, the two fractures join rapidly and behave as a single fracture. The height growth beyond the three layers depends on the stress and modulus profile of the adjoining layers. The simulated penetration is generally greater in the lower stress zone. The P3D model is a common geometry model for fracture design and is represented in figure 16.

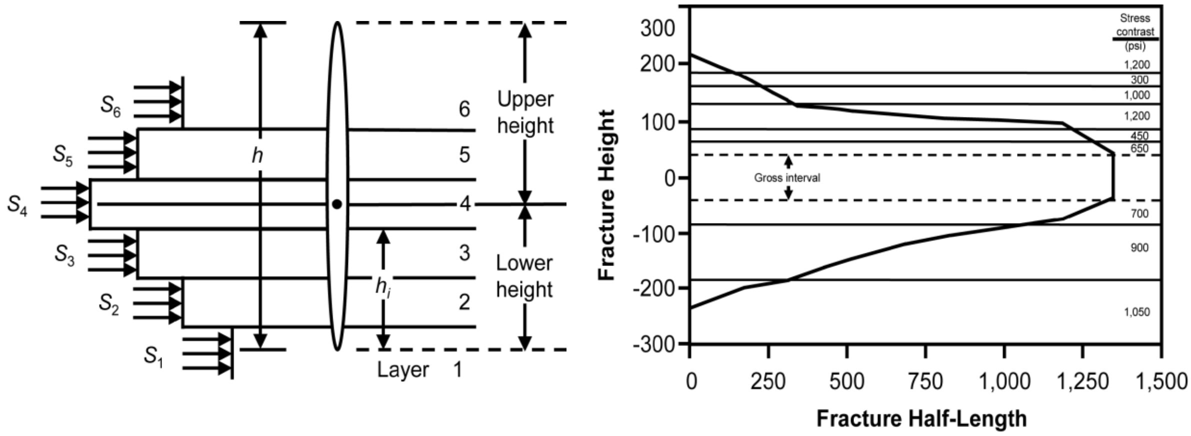



Figure 16. Width and height from a P3D model (L) Length and height distribution from a P3D model (R) (Economides and Nolte, 2000).

The MLF model allows simulating simultaneous fractures. The fractures (PKN) in the layers are initiated when the wellbore pressure is above the layer's stress. This model is the most applicable when separate fractures initiate and they do not aggregate, which is the expected case. After the MLF model is used to define the relative injection rates for the zones, the P3D model can be employed for a more detailed consideration of each zone. The fractures can have different lengths and each fracture's geometry depends on its height, net pressure, modulus and efficiency. This model can also address the application of limited entry and determination of the stages required for adequate stimulation of a number of layers. 2D, P3D and MLF models are shown in figure 17 below.

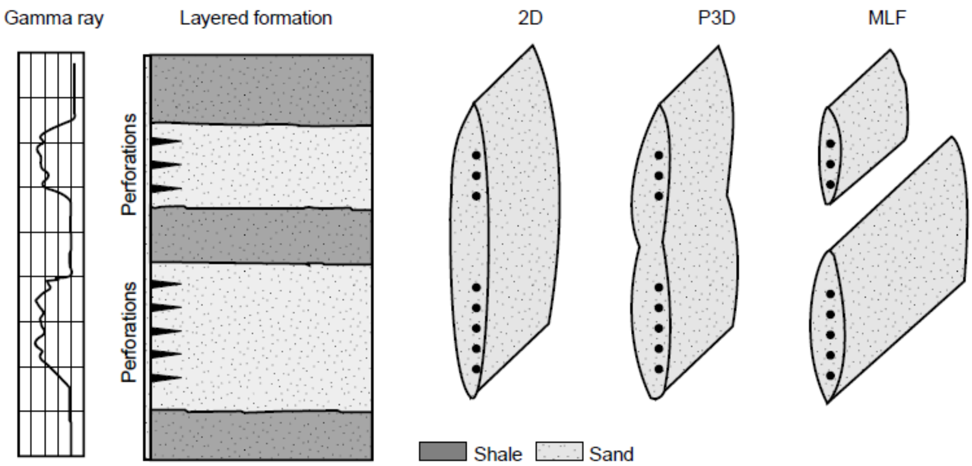



Figure 17.Fracture geometry of 2D, P3D and MLF models (Economides and Nolte, 2000).

### 3.6 Selection of Treatment Size

The optimum design for a conventional fracture treatment is one in which the pad volume has leaked off into the formation and the proppant has reached the tip at the end of pumping, leaving the fracture filled with the proppant-laden slurry to provide a fairly uniform propped width and sufficient conductivity to minimize the pressure drop during production. (Economides and Nolte, 2000)

Treatment size is primarily defined by the fracture length. Fluid and proppant volumes are controlled by fracture length, injection rate, and leak-off properties. A general statement can be made that the greater the propped fracture length and greater the proppant volume, the greater the production rate of the fractured well. Limiting effects are imposed by technical and economic factors such as available pumping rate and costs of fluid and proppant. Within these constraints, the optimum scale of treatment should be ideally determined based on the maximum NPV. This section demonstrates how to design treatment size using the KGD fracture model for simplicity. Calculation procedure is summarized as follows:

1. Assume a fracture half-length $X_f$ and injection rate $q_i$ and calculate the average fracture width w using a selected fracture model.

2. Based on material balance, solve injection fluid volume $V_{inj}$ from the following equation:

$$V_{inj} = q_i t_i \tag{19}$$

$$V_{frac} = A_f \overline{W} \tag{20}$$

$$V_{Leakoff} = 2K_L C_L A_f r_p \sqrt{t_i} \tag{21}$$

And

$$K_L = \frac{1}{2}\left[\left[\frac{8}{3}\eta + \pi(1-\eta)\right]\right] \tag{22}$$

$$r_p = \frac{h}{h_f} \tag{23}$$

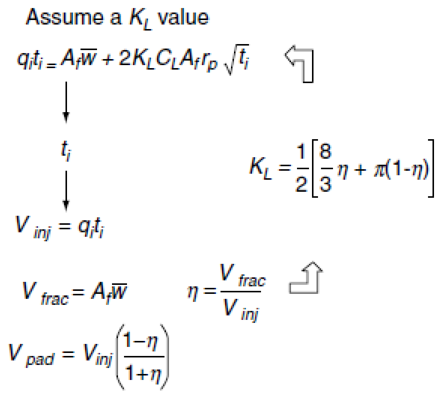
$$A_f = 2x_f h_f \tag{24}$$

$$\eta = \frac{V_{frac}}{V_{inj}} \tag{25}$$

$$V_{pad} = V_{inj}\frac{1-\eta}{1+\eta} \tag{26}$$

Since:

$K_L$ depends upon fluid efficiency $\eta$ which is not known in the beginning, so, numerical iteration procedure is required. This procedure is explained below.




Where:

$V_{inj}$= injection fluid volume; $\eta$= fluid efficiency; $\overline{W}$= average fracture width; $A_f$= fracture area

$r_p = \frac{h}{h_f}$= payzone thickness/ fracture height; $C_L$ = fluid loss coefficient in ft/ (min) $^{1/2}$

$K_L$ = fluid loss multiplier;

3) Generate proppant concentration schedule using:

$$C_p(t) = C_f\left(\frac{t - t_{pad}}{t_{inj} + t_{pad}}\right)^{\varepsilon} \tag{27}$$

Where $C_f$ is the final proppant concentration in ppg. The proppant concentration in pounds per gallon of added fluid is expressed as;

$$\acute{C}_p = \frac{C_p}{1 - {C_p}/{\rho_p}} \tag{28}$$

And

$$\varepsilon = \frac{1 - \eta}{1 + \eta} \tag{29}$$

4. Predict propped fracture width using

$$w = \frac{C_p}{(1 - \phi_p)\rho_p} \tag{30}$$

Where:

$C_p$= proppant concentration in ppg; $M_p$= proppant weight in lbs.; $\phi_p$= proppant porosity

$t$= injection time of calculating slurry concentration (min); $t_{pad}$= time to pump the pad volume

$$C_p = \frac{M_p}{2x_f h_f} \tag{31}$$

$$M_p = \bar{c_p}\left(V_{inj} - V_{pad}\right) \tag{32}$$

$$\bar{c_p} = \frac{C_f}{1 + \eta} \tag{33}$$

### 3.7 Production forecast and NPV Analyses

The hydraulic fracturing design is finalized on the basis of production forecast and NPV analyses. The information of the selected fracture half-length $X_f$ and the calculated fracture width w, together with formation permeability (k) and fracture permeability ($k_f$) can be used to predict the dimensionless fracture conductivity FCD with Eq. (39). The equivalent skin factor $S_f$ can be estimated based on Fig. 19. Then the productivity index of the fractured well can be calculated using Eq. (40). Comparison of the production forecast for the fractured well and the predicted production decline for the unstimulated well allows for calculations of the annual incremental cumulative production for year “n” for an oil well:

$$\Delta N_{p,n} = N_{p,n}^{f} - N_{p,n}^{nf} \tag{34}$$

Where:

$\Delta N_{p,n}$ = Predicted annual incremental cumulative production for year n

$N_{p,n}^{f}$ = Forecasted annual cumulative production of fractured well for year n

$N_{p,n}^{nf}$ = Predicted annual cumulative production for non-fractured well for year n

The annual incremental revenue above the one that the unstimulated well would deliver is expressed as;

$$\Delta R_n = (\$)\Delta N_{p,n} \tag{35}$$

Where $ stands for oil price.

The present value of the future revenue is then can be calculated by the equation (36)

$$NPV_R = \sum_{n=1}^{m} \frac{\Delta R_n}{(1 + i))^n} \tag{36}$$

Where *m* is the remaining life of well in years and $i$ is the discount rate. The NPV of hydraulic fracturing project is:

$$NPV = NPV_R - cost \tag{37}$$

The cost should include the expenses of fracturing fluid, proppant, pumping and fixed cost of the treatment job. To predict the pumping cost, required hydraulic horse power needs to be calculated by

$$HHP = \frac{q_i p_{si}}{40.8} \tag{38}$$

### 3.8. Productivity of Fractured Wells

Hydraulically created fractures gather fluids from reservoir matrix and provide channels for the fluid to flow into wellbores. Apparently, the productivity of fractured wells depends on two steps: (1) receiving fluids from formation and (2) transporting the received fluid to the wellbore. Usually one of the steps is a limiting step that controls the well-production rate. The efficiency of the first step depends on fracture dimension (length and height), and the efficiency of the second step depends on fracture permeability. The relative importance of each of the steps can be analyzed using the concept of fracture conductivity defined as (R.G. Agarwal, 1979) & (Cinco-ley, 1981).

$$F_{CD} = \frac{k_f w}{k x_f} \tag{39}$$

Where:

$F_{CD}$= dimensionless fracture conductivity; $k_f$ = fracture permeability, md

$w$ = fracture width, ft; $x_f$ = fracture half-length, ft. $k$ = formation permeability

The effect of stimulation on production rate is illustrated in the following figure 18.

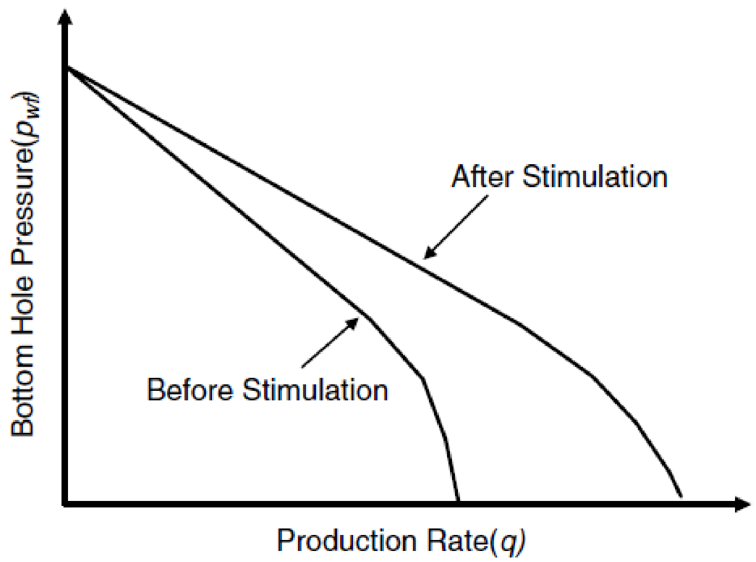



Figure 18. Comparison of oil well inflow performance relationship (IPR) curves before and after stimulation (Economides and Nolte, 2000).

In the situations in which the fracture dimension is much less than the drainage area of the well, the long-term productivity of the fractured well can be estimated assuming pseudo-radial flow in the reservoir. Then the inflow equation can be written as:

$$q = \frac{kh(p_e - p_{wf})}{141.2\ \beta\mu(ln\frac{r_e}{r_w} + S_f)} \tag{40}$$

Where:

$S_f$ = equivalent skin factor. Fold of increase (FOI) in well productivity can be expressed as:

$$\frac{J}{J_o} = \frac{ln\frac{r_e}{r_w}}{ln\frac{r_e}{r_w} + S_f} \tag{41}$$

Where;

$J$ = productivity of fractured well, stb/day-psi;

$J_o$= productivity of nonfractured well, stb/day-psi

$r_e$ = radius of drainage area, ft

The equivalent skin factor $S_f$ can be determined based on fracture conductivity and figure 20 as given below.

It is seen from figure 19 that the parameter $(ln\frac{x_f}{r_w} + S_f)$ approaches a constant value in the range of FCD > 100, i.e.

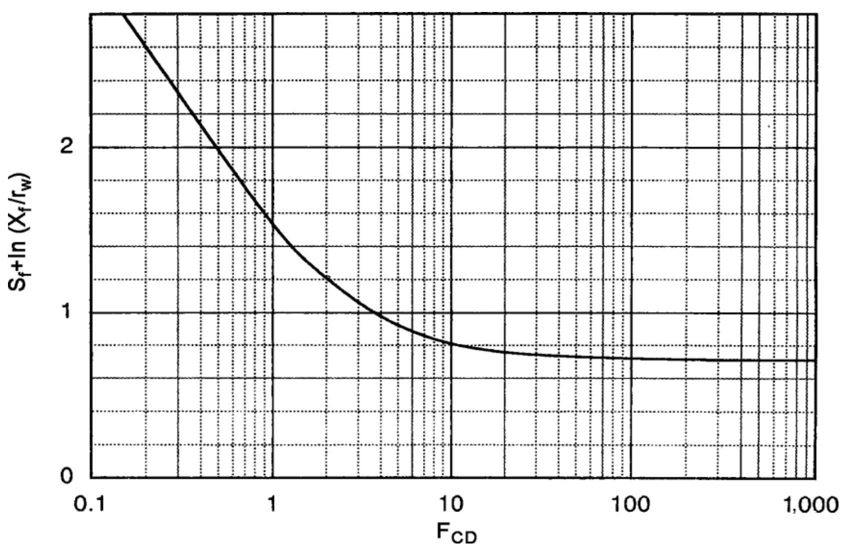



Figure 19. Relationship between fracture conductivity and equivalent skin factor (Cinco-Ley and Samaniego, 1981).

$$S_f \approx 0.7 - \ln(\frac{x_f}{r_w}) \tag{42}$$

Above equation reveals that the equivalent skin factor of fractured wells depends only on fracture length for high-conductivity fractures, not fracture permeability and width. This is the situation in which the first step is the limiting step. On the other hand, Fig. 19 indicates that the parameter $(ln\frac{x_f}{r_w} + S_f)$ declines linearly with log (FCD) in the range of FCD < 1, i.e.

$$S_f \approx 1.52 + 2.31\log(r_w) - 1.545\log\left(\frac{k_f w}{r_w}\right) - 0.765\ \log(x_f) \tag{43}$$

Comparing the coefficients of the last two terms in this relation indicates that the equivalent skin factor of fractured well is more sensitive to the fracture permeability and width than to fracture length for low-conductivity fractures. This is the situation in which the second step is the limiting step. The previous analyses reveal that low-permeability reservoirs, leading to high-conductivity fractures, would benefit greatly from fracture length, whereas high-permeability reservoirs, naturally leading to low-conductivity fractures, require good fracture permeability and width. Valko et al. (1997) converted the data in figure 19 into the following correlation:

$$S_f + \left(ln\frac{x_f}{r_w}\right) = \frac{1.65 - 0.328u + 0.116u^2}{1 + 0.180u + 0.064u^2 + 0.05u^3} \tag{44}$$

Where;

$$u = \ln(F_{CD}) \tag{45}$$

$r_w$= wellbore radius in ft.    $w$= fracture width in inches;

## CHAPTER 4. INTRODUCTION OF X FIELD, PRODUCTION AND STIMULATION DATA ANALYSIS, PROBLEMS AND THEIR PROPOSED SOLUTIONS

### 4.1. Introduction to X Field

The X field structure is a low relief anticline with an areal extent of about 100 km2. Exploration started in the 60's, and the first commercial oil was drilled in the main reservoir in June 1969. The main reservoir is Lower Cretaceous age with other volumetric upsides. Hydrocarbon migration was along NW-SE faults from the underlying Jurassic and Triassic source rocks. This migration and structure can be observed in figure 20. The green arrows are showing the migration of hydrocarbons. The main reservoir rocks are Lower Cretaceous sandstone, Lower Cretaceous carbonate and Middle Jurassic sandstone. This particular reservoir consists of thin, very fine-grained, argillaceous sandstone beds interbedded with shaly heteroliths and intervals of calcite cemented sandstones which can be observed on the right side of figure 20.

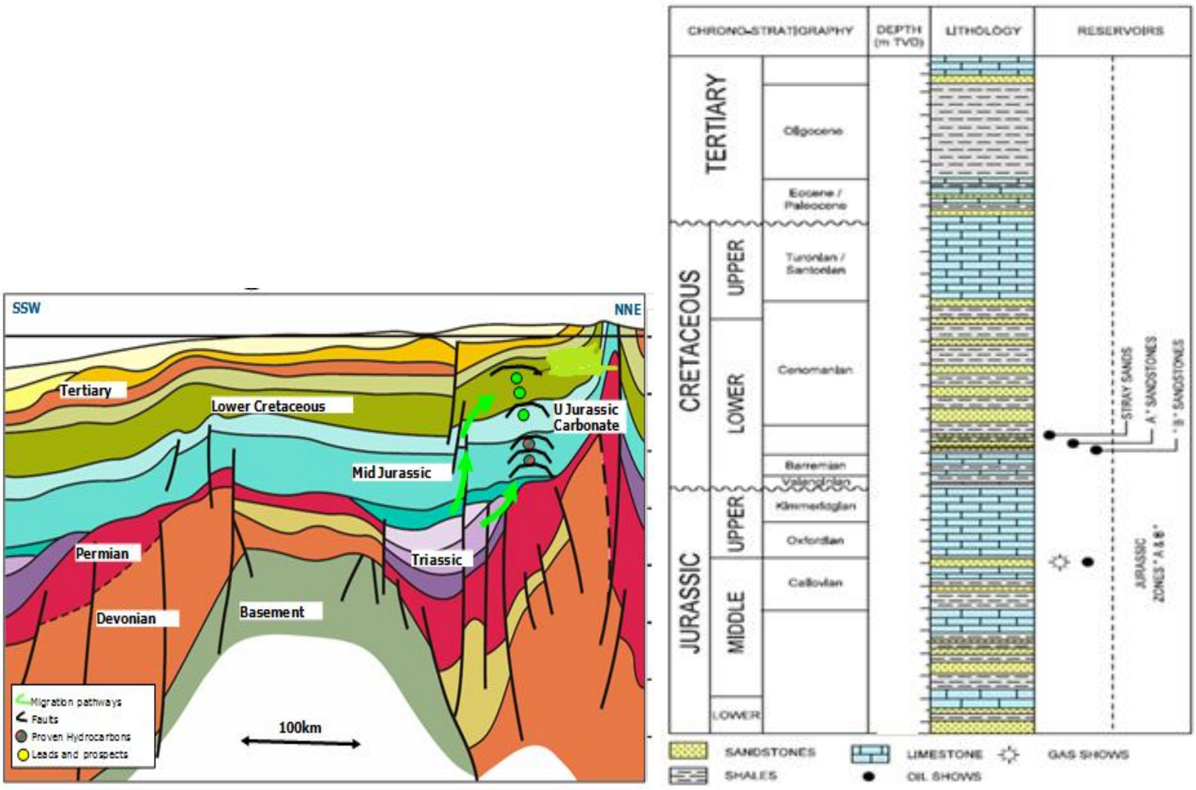



Figure 20. Structure of X field

The boundary of reservoir is shown in figure 21. There is a fault which is dividing the above anticline structure in two parts. One half of this anticline structure contains hydrocarbons while the other half does not. The shallowest part of this anticline structure is depicted in red and deepest part is represented in purple in the following map. There are several faults which can also be seen.

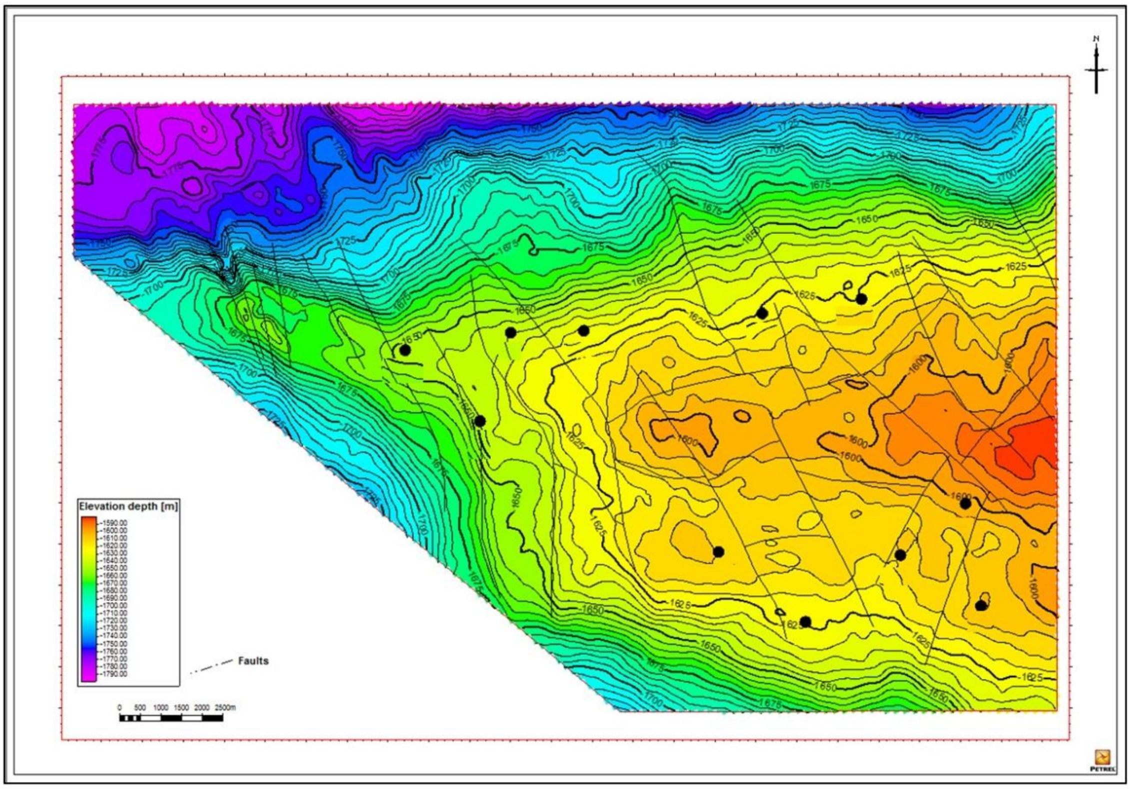



Figure 21. Structural map of the reservoir

The water level is inclined with free water level at different depth for each well as shown in the following figure 22. The water level is changing from 1640 to around 1687 meters.

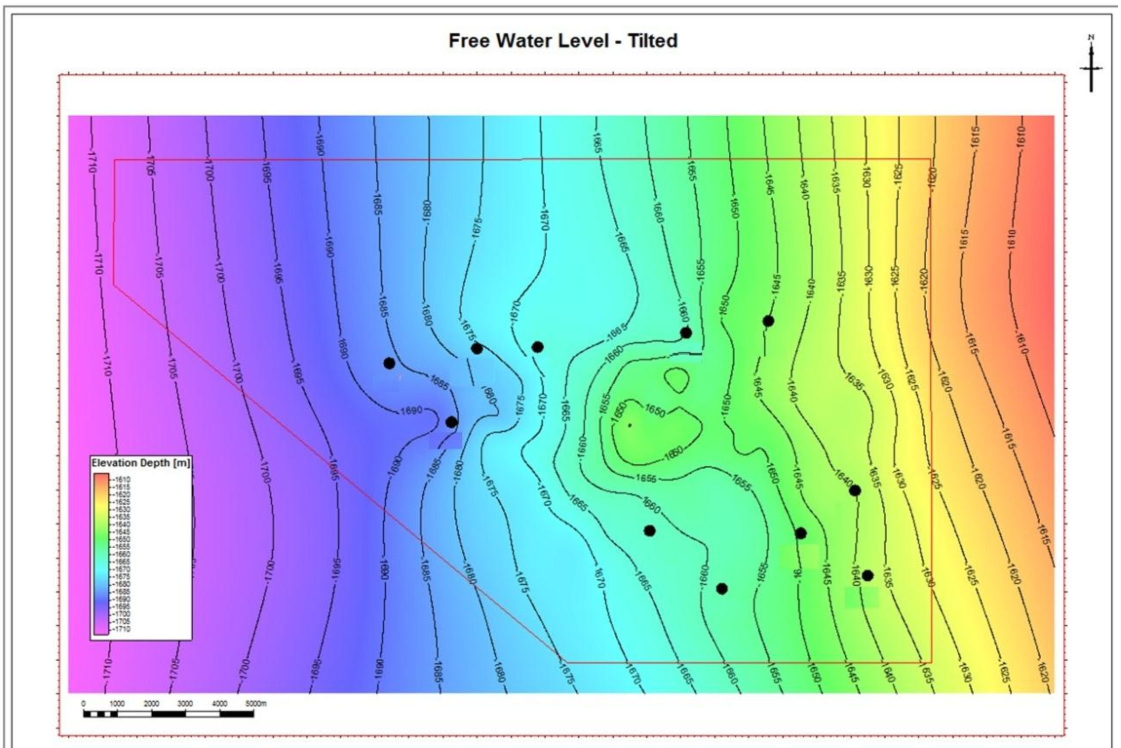



Figure 22. Varying free water level for different wells

### 4.1.1. Field development plan and location of delineation wells

The X field is now in its second phase of development. It is planned to develop the field with 198 vertical wells. The field development plan focuses on:

| | |
|---|---|
| 1. Development area of the X field | 2. Optimized well design |
| 3. Production profiles for oil, gas and water | 4. Water injection profiles |
| 5. Surface facilities and infrastructure | 6. Expenditures (CAPEX and OPEX) |
| 7. Gas utilization including NGL injection | 8. Kazakh content strategy |
| 9. Environmental impact | 10. Safety |

All the wells can be seen in the following figure 23. The wells will be drilled in 5 spot patterns (83 water injectors and 115 producers) with an 800 m producer-producer spacing.

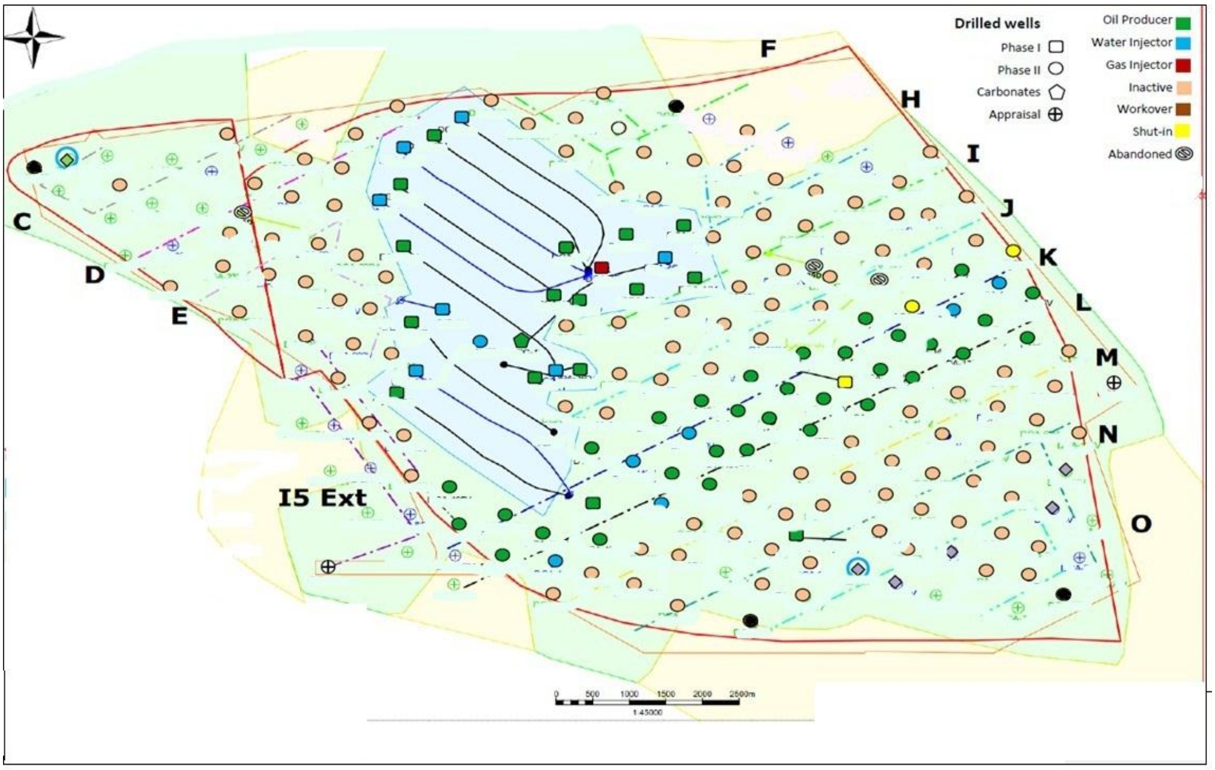



Figure 23. Map showing the location of wells in 2nd phase of development

There are 10 delineation wells which were drilled to know the boundary of the reservoir. These delineation wells were drilled in 2012-2013, with complex data acquisition program. The data obtained from these wells will effectively de-risk the development of areas with uncertain reservoir quality and hydrocarbon volumes. These areas are located in the southeastern, western and northern part of the X field where modern well data are sparse or absent. If any of the delineation wells should give disappointing well-test or logging results, the planned development will be adjusted accordingly by either moving planned wells to a new location or by cancelling the drilling of wells in a certain area entirely. It is not expected that any of these three areas will be unproductive.

#### 4.1.2. Horizontal and vertical well scenarios

It has been planned after the cost benefit analysis that all wells will be vertical and will be hydraulically stimulated with one large fracture to increase well performance. Both vertical and horizontal well scenarios have been presented in the figures 24-29 given below. Several colored lines are displaying the performance of different wells in both development scenarios.

The comparison of following two production scenarios of horizontal and vertical wells in figure 24 & 25 clearly shows that the horizontal wells produce at higher rate than vertical wells.

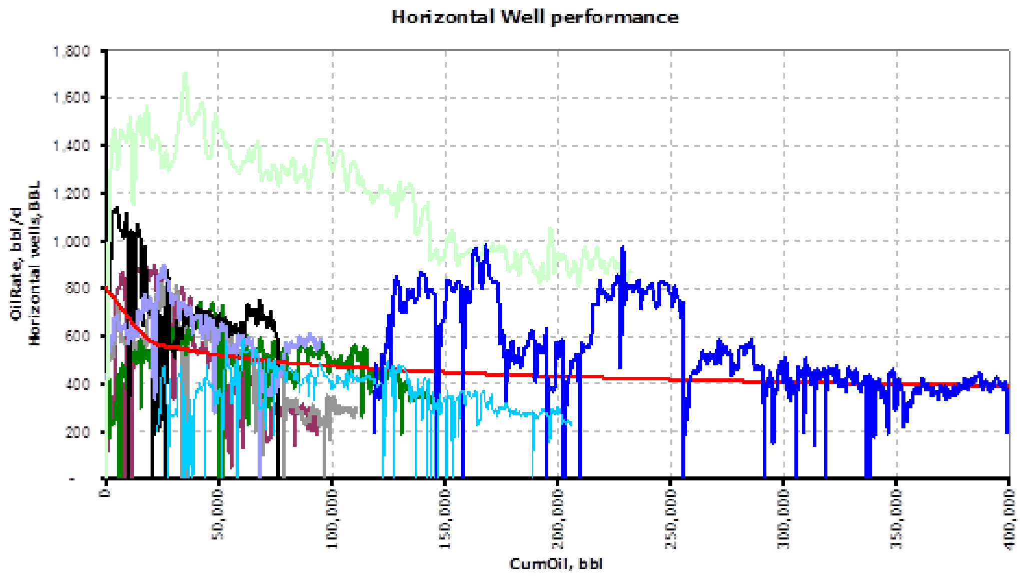



Figure 24. Horizontal well performance

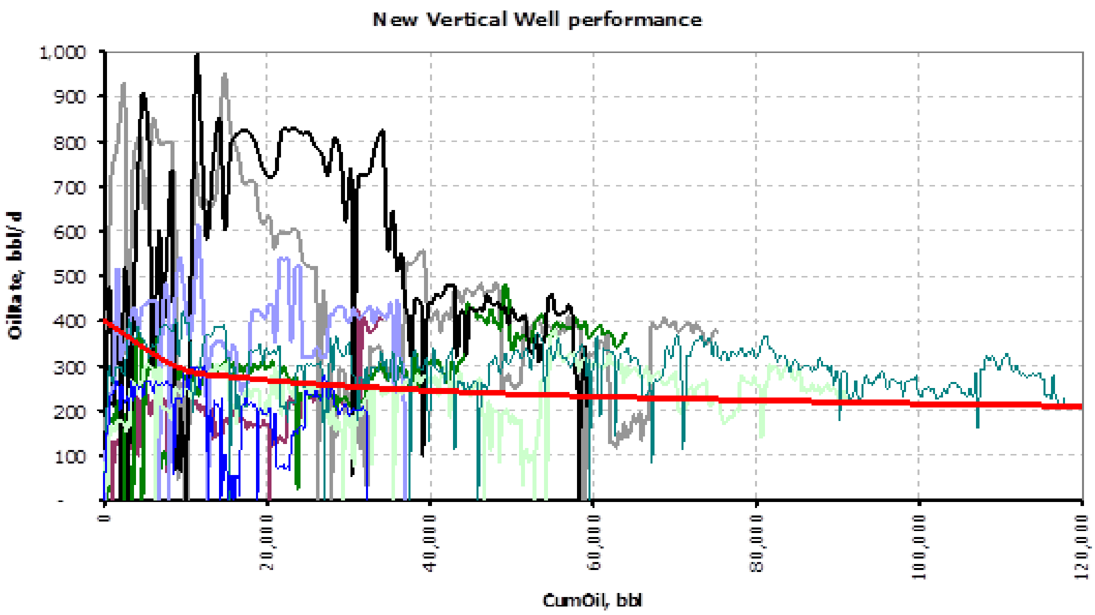



Figure 25. Vertical well performance

Total field production of X field both for vertical wells field development and horizontal wells field development is shown in following two graphs in figure 26 and 27. It can be noticed that the cumulative production of field is around 60,000,000 bbls for vertical well scenario in year 2024 but it is around 40,000,000 bbls in case of horizontal wells scenario. There is a significant difference of 20,000,000 bbls in both cases. Therefore, it can be stated that vertical wells produce more in long term as compare to horizontal wells.

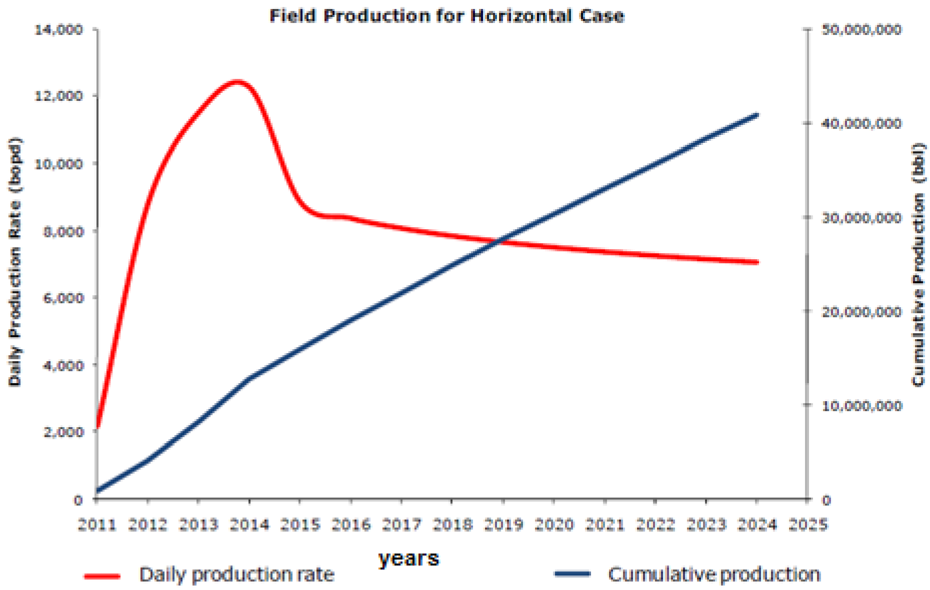



Figure 26. Total field production profile for horizontal wells scenario

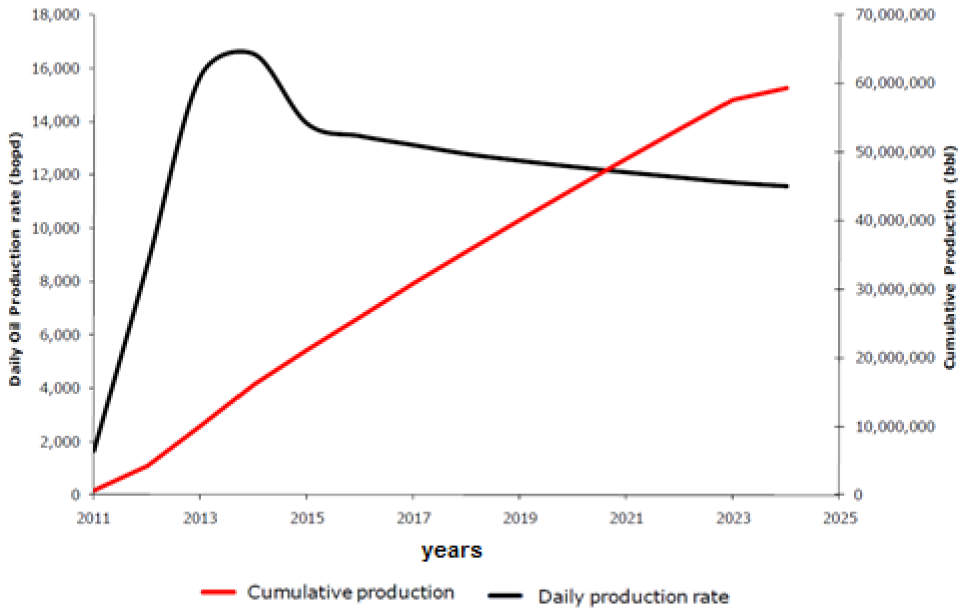



Figure 27. . Total field production in vertical wells scenario

The bar chart below in figure 28 is representing the well drilling cost and current production for vertical wells in blue and horizontal wells in light brown. It can be seen that drilling cost as well as production is much higher for horizontal wells as compare to those of vertical wells with the exception one well.

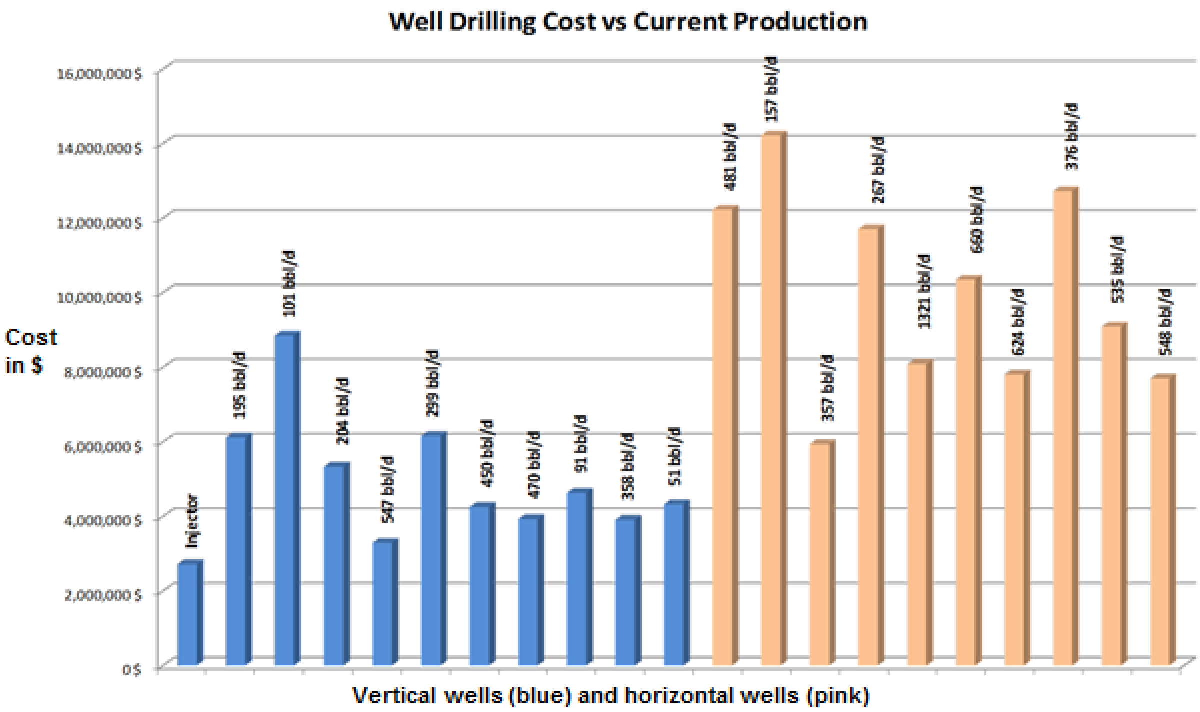



Figure 28. Drilling and production for horizontal as well as vertical wells

The cost for horizontal wells is much higher as discussed above. In the beginning, the daily production rate for horizontal wells is more than double as compare to that of vertical wells but this production rate declines to the same level as of vertical wells just after 700 days, as presented in the following figure 29. Therefore, after the cost benefit analysis, it was observed that the incremental production was not paying for the extra investment in drilling the horizontal wells and hence it was decided to drill vertical wells.

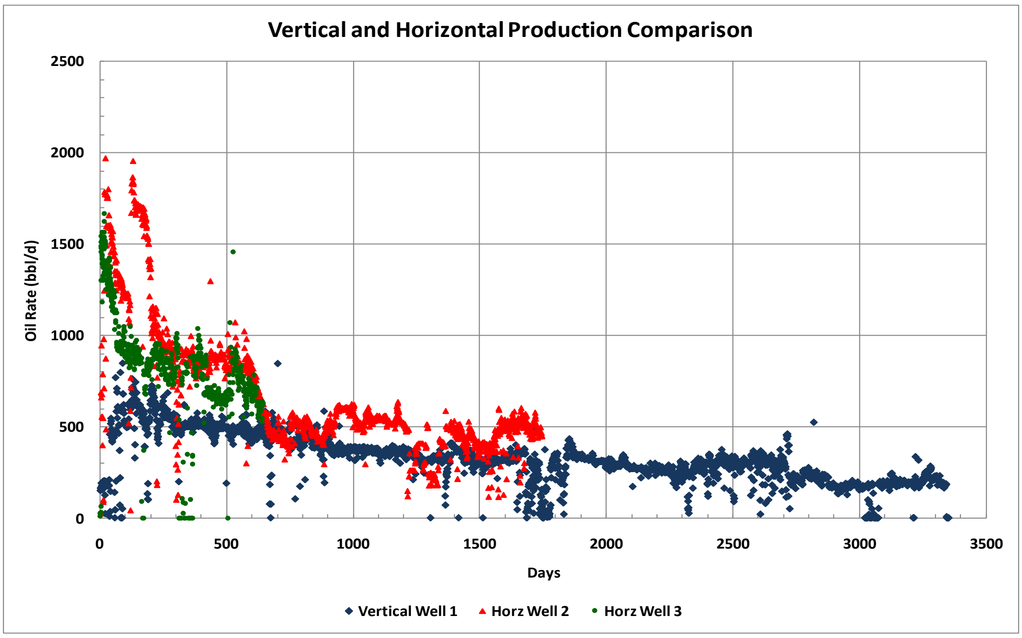



Figure 29. Horizontal and vertical wells production comparison

### 4.2. Production Data Analysis

Production data from several delineation wells is analyzed in this section.

**Well R**

This well serves as a reference well to compare the results in terms of production from different wells. The production form this well is smooth and good which shows that a good stimulation operation was performed on this well. The production profilers are shown in figure 30.

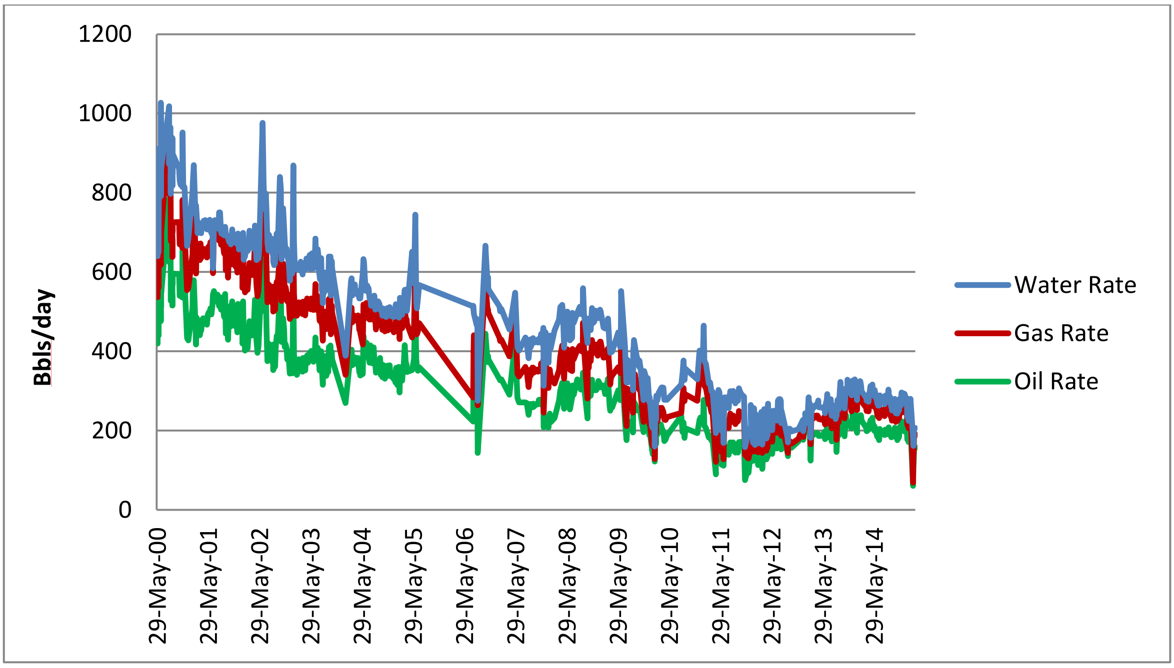



Figure 30. Flow rate of oil, water and gas with time

The water cut is between 10-40% as can been in figure 31, which is fine for this type of reservoir.

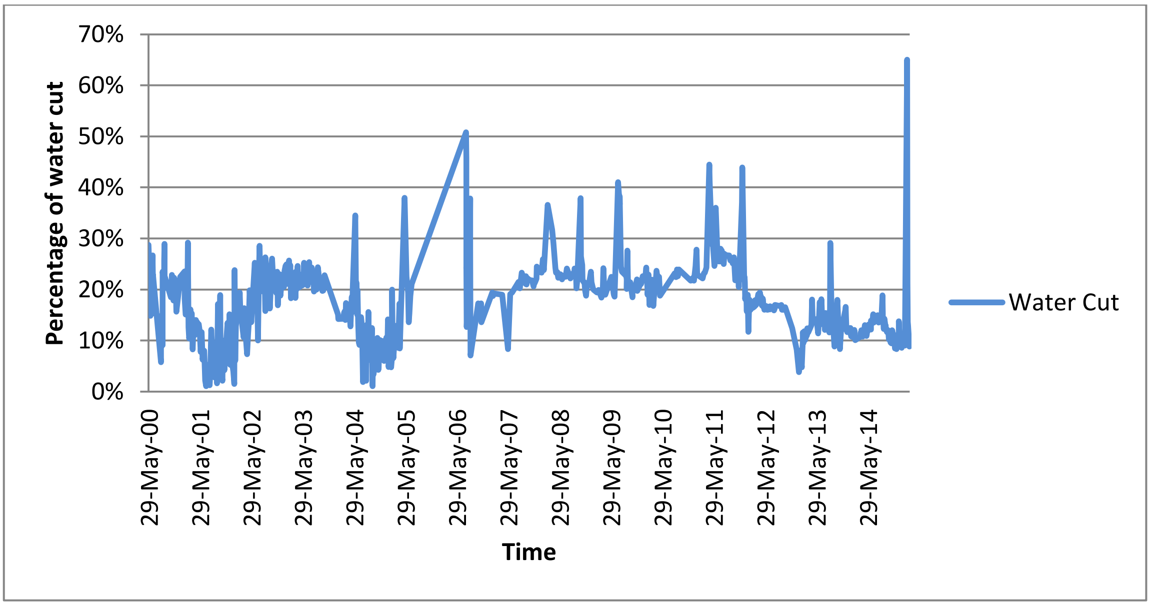



Figure 31. Water cut vs. time

**Well# 9**

A significant production of water along with oil can be observed in the following figure 32. Initially there is high water cut and the production of oil starts increasing from February 11.

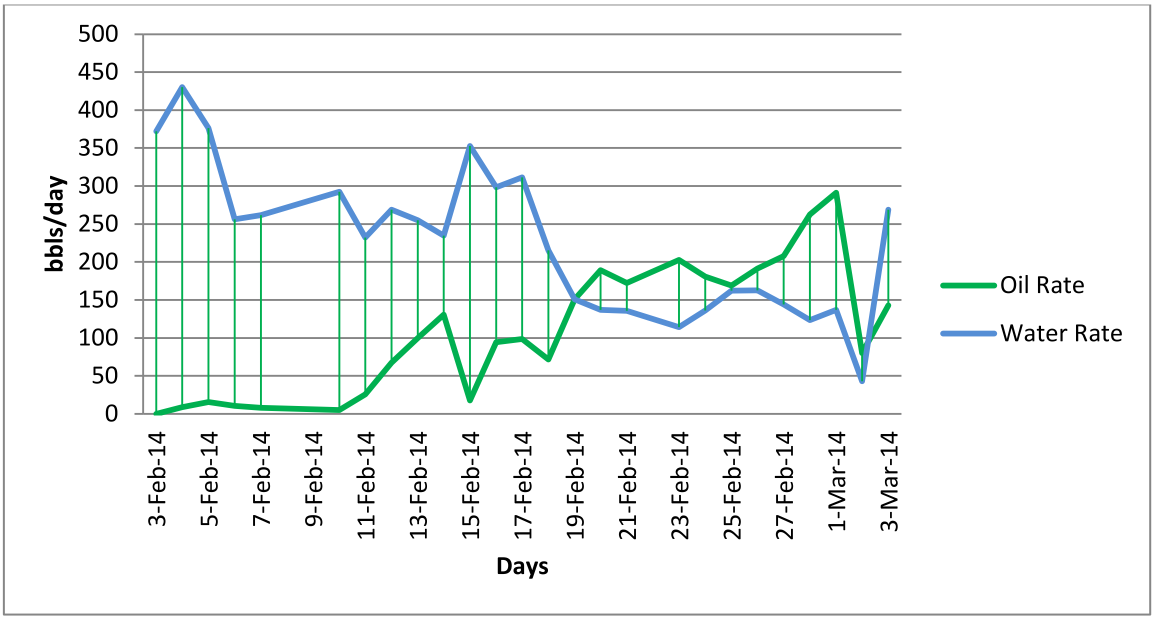



Figure 32. Oil and water rate vs. time

There is almost 100% production of water in the beginning as shown in figure 33, which corresponds to the flow back production of fracturing fluid used during the hydraulic fracturing treatment.

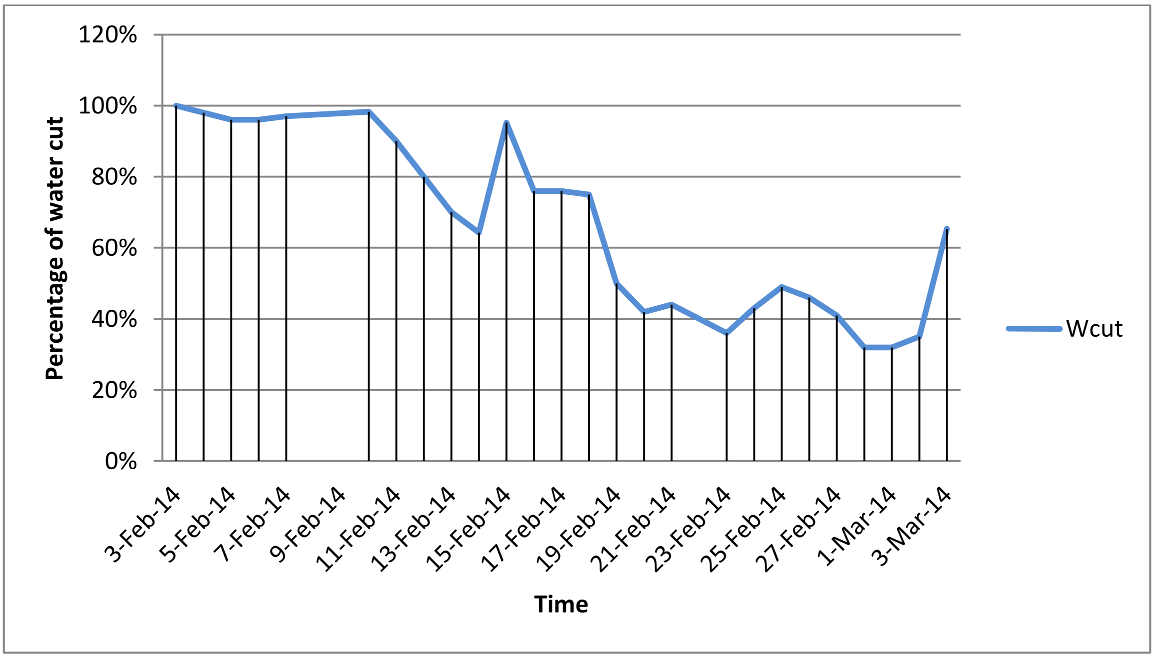



Figure 33. Water cut with time

**Well# 0**

The production from this well is interesting. Only this well was tested after the first fracturing operation. The well was re-fractured and tested again. When the well was initially fractured, it gave good result in terms of production but after re-fracturing the result was disappointing because the re-fracturing operation which was too aggressive and the fracture was not confined within the reservoir zone i.e. the fracture extended outside the reservoir zone. These results are shown in figure 34.

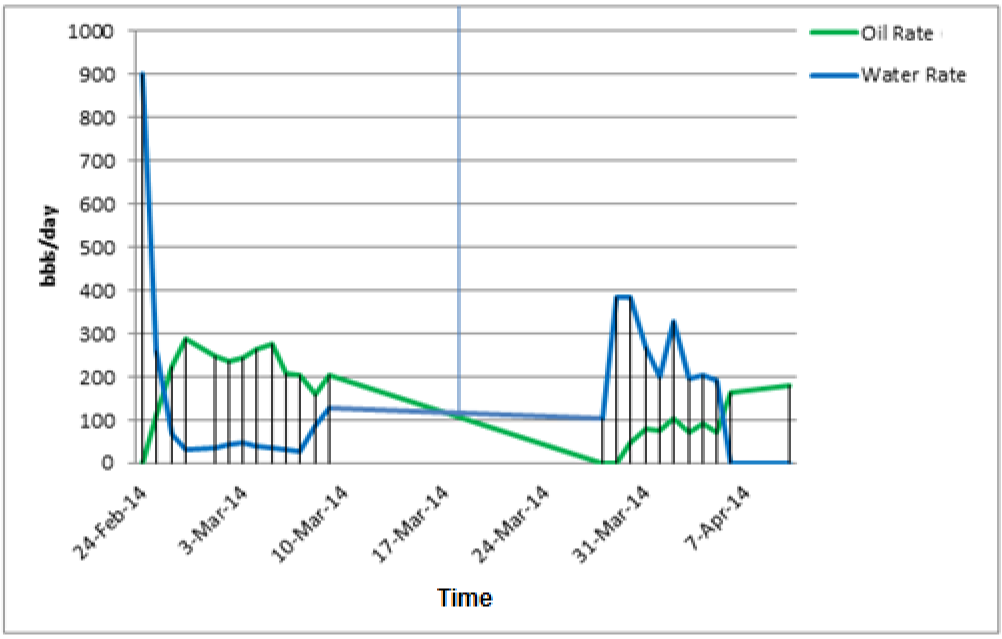



Figure 34. Oil and water rate vs. time

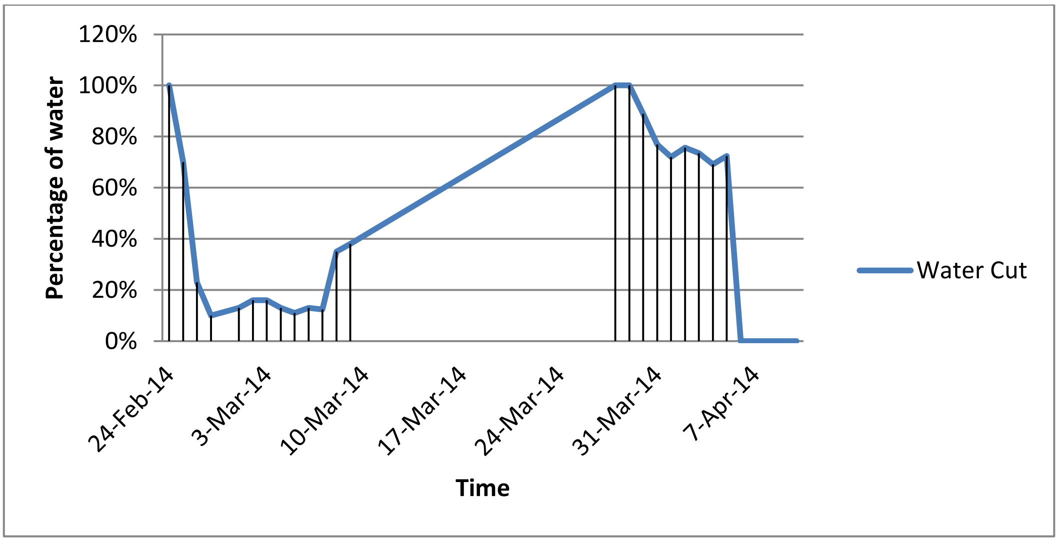



Figure 35. Water cut vs. time

It is illustrated in figure 35 that water cut was significantly lower after first hydraulic fracturing treatment. But when well was fractured again, water cut increased significantly from less the 20% to almost 70 % which is because of the extension of fractures both above and below the reservoir zone.

**Well# 1**

Initially there is high production of water which corresponds to the production of flow back water after the fracturing operation. After four days the production of oil starts increasing and goes up to maximum of around 330 bbls/day and then starts declining. Blue line is for water and green one for oil flow rate as presented in the following figure 36.

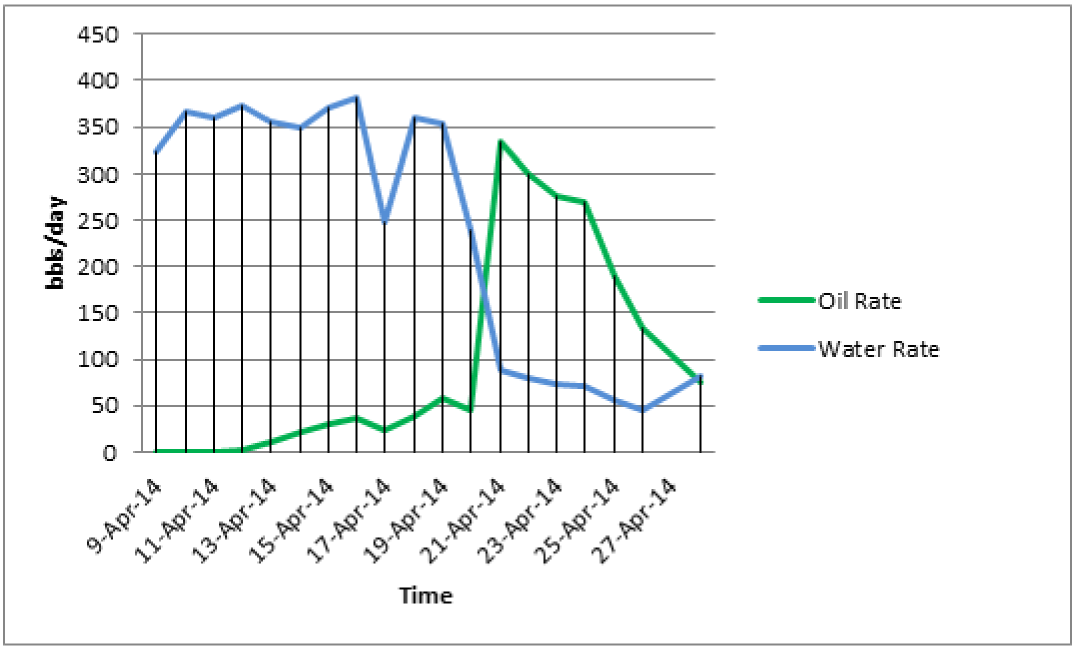



Figure 36. Oil and water rate vs. time

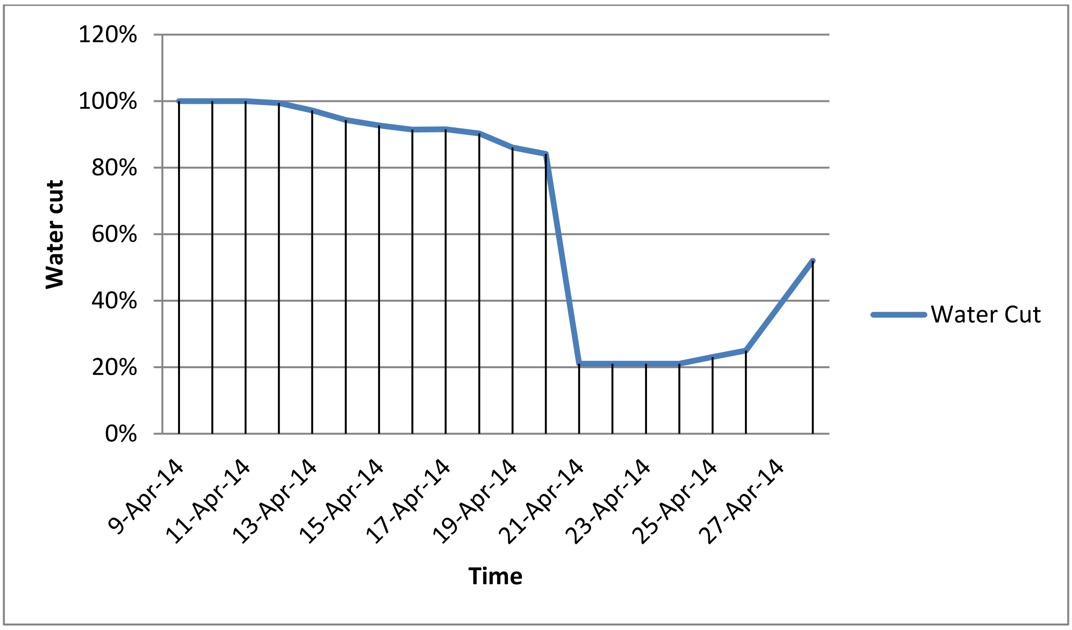



Figure 37. Water cut vs. time

The water cut is around 20% for this well as shown in figure 37.

**Well# 2**

There is high water production in the beginning and then starts decreasing gradually at faster rate. The oil rate increases till around 220 barrels/day. The production oil and water is rather fluctuating for this well. These results are shown in figure 38.

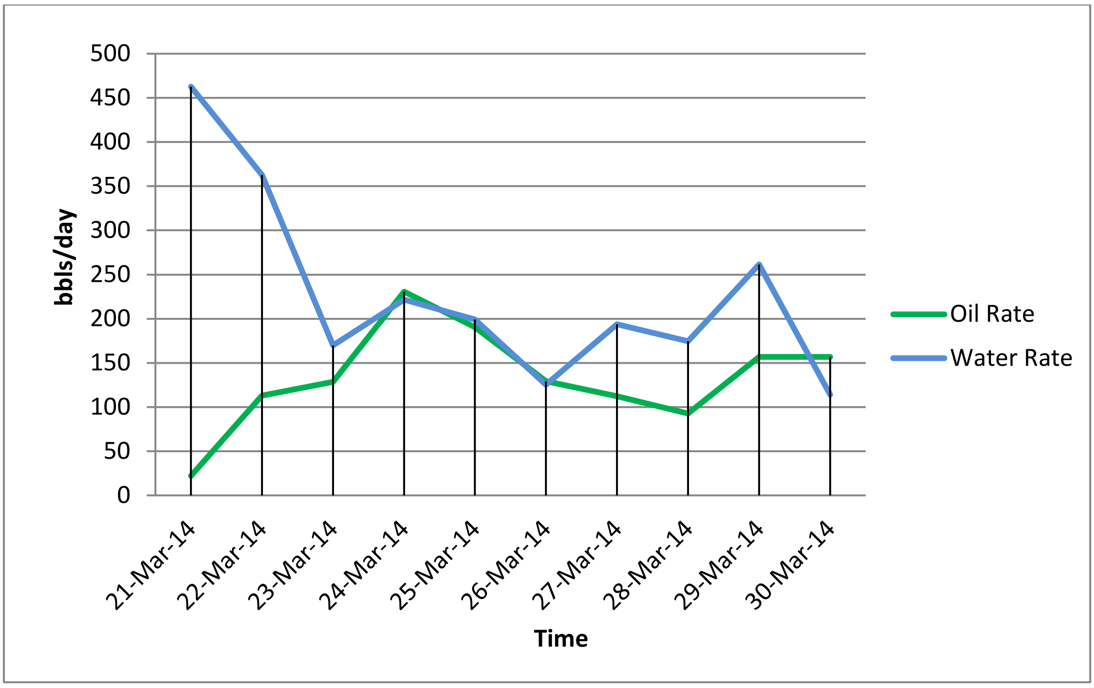



Figure 38. Oil and water rate vs. time

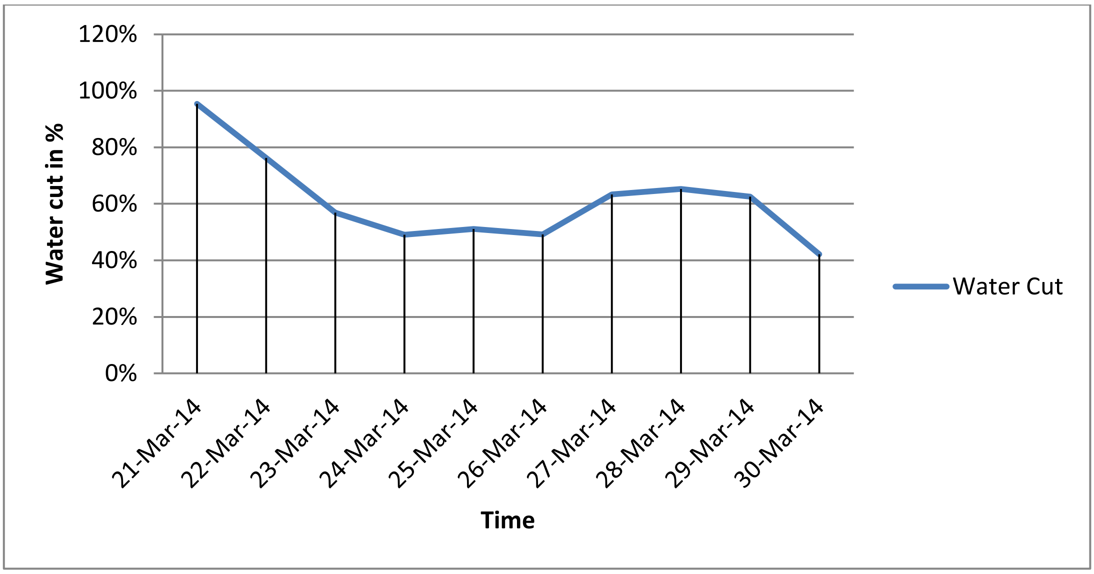



Figure 39. Water cut vs. time

It can be observed in figure 39 that the water cut remains between 40-60% except in the initial period which is because of the production of flow back water after the fracturing operation.

**Well# 3**

It is shown in figure 40 that the production of water from this well is very high. There is almost no production of oil as can be seen in the following chart. It can be concluded from the production profile of this well that it is located on the flanks of the reservoirs.

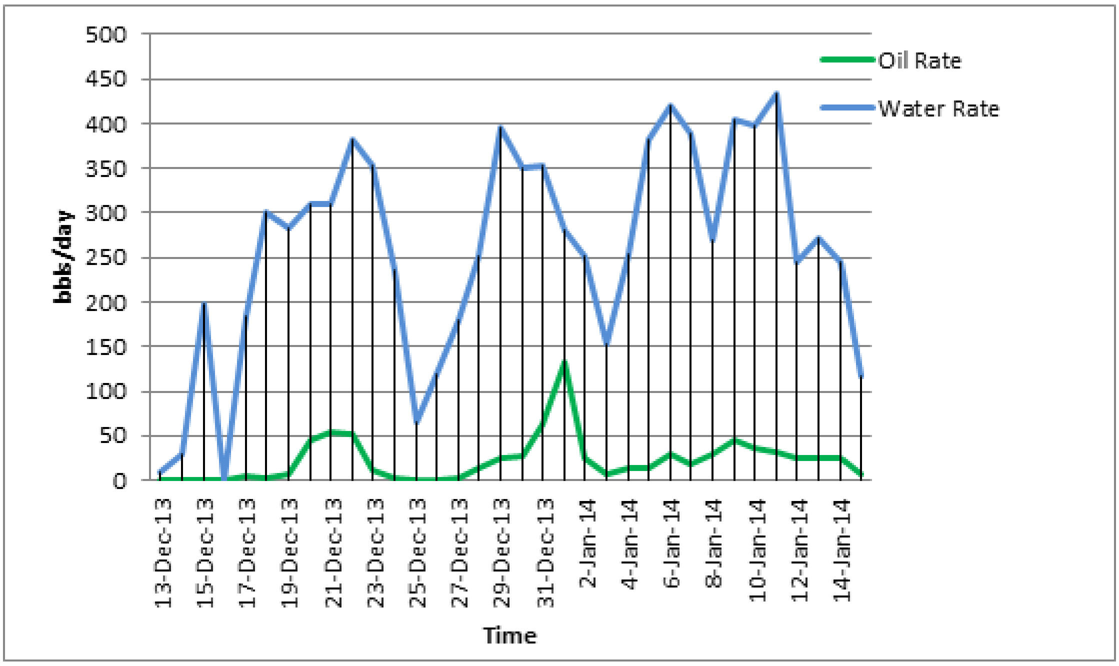



Figure 40. Oil and water rate vs. time

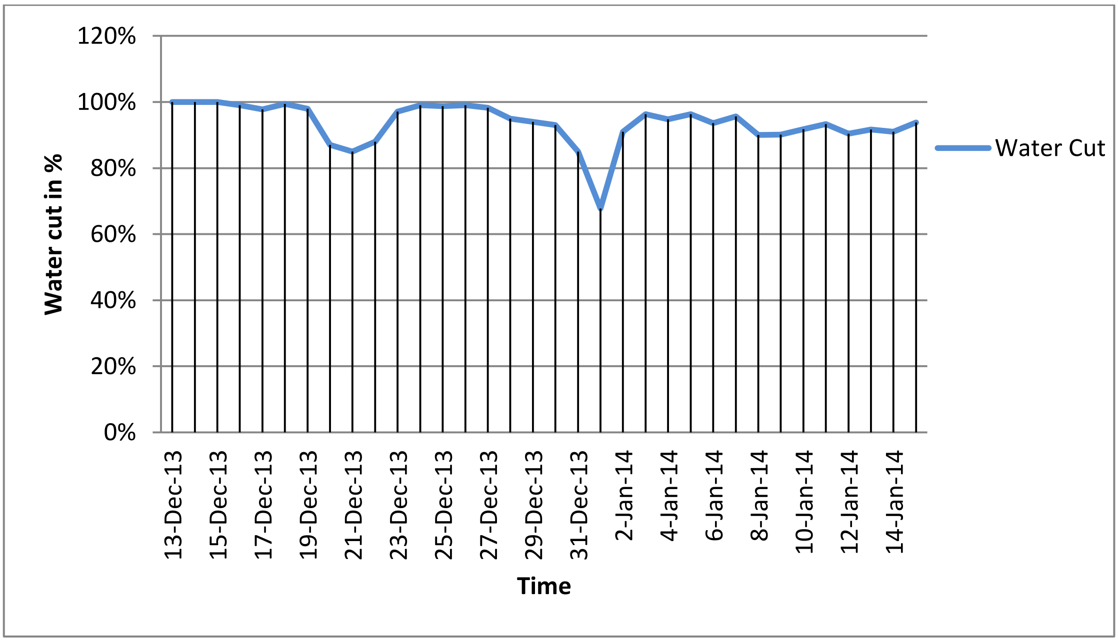



Figure 41. Water cut vs. time

It is represented in figure 41 that water cut is almost 100% for this well during the whole production period.

**Well# 7**

Initially there is high production of water which in fact is the production of flow back water after the fracturing operation. The oil production reaches up to 300 barrels/day and then starts decreasing. These results are shown in figure 42 below.

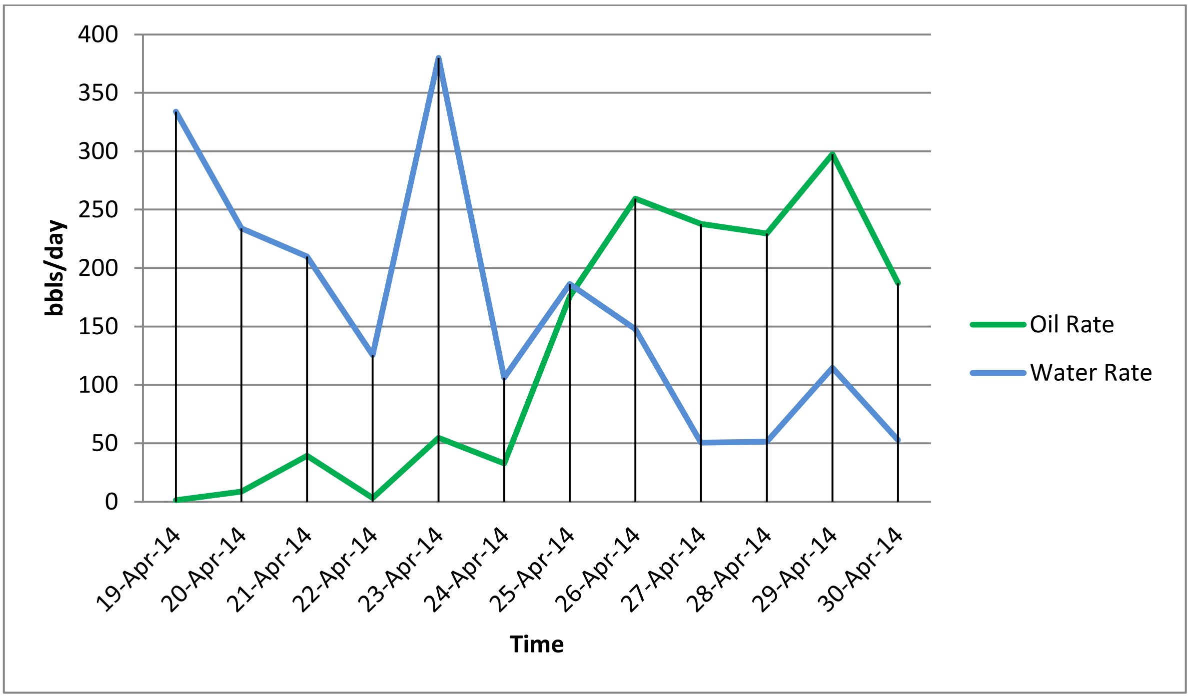



Figure 42. Oil and water rate vs. time

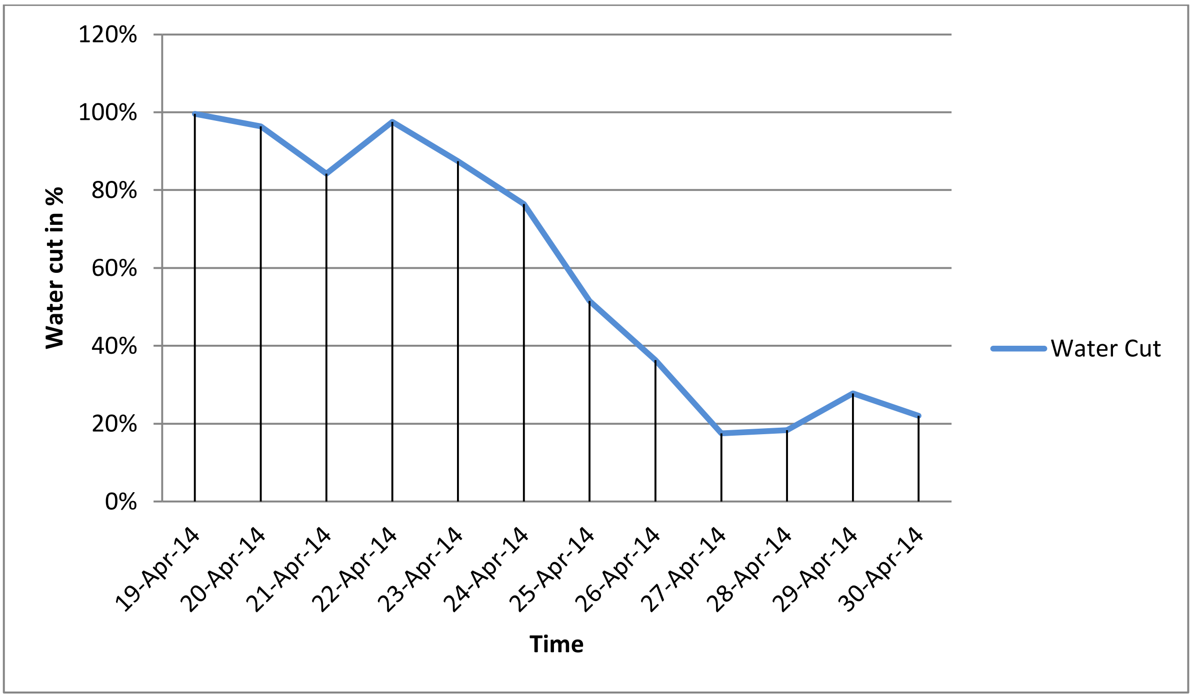



Figure 43. Water cut vs. time

It is depicted in figure 43 that the water cut is around 20%.

**Well# 8**

There is only four days production data available for this well because it started producing significant amount of gas. Therefore, the well was shut-in after this short period of production. These results are shown in figure 44 below.

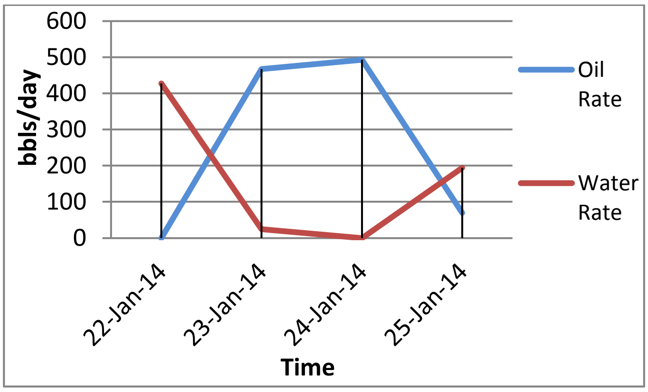



Figure 44. Oil and water rate vs. time

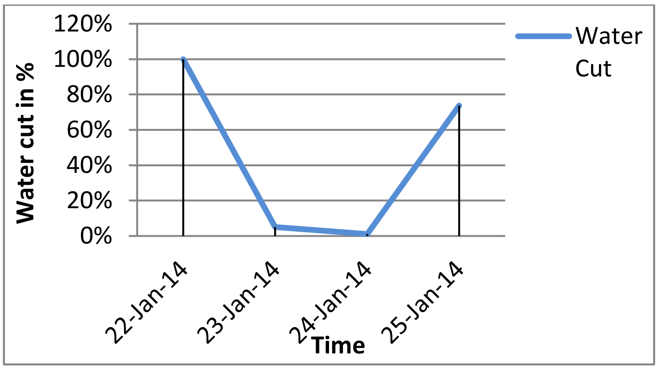



Figure 45. Water cut vs. time

From production data analysis it has been observed that overall there is high water production from all delineation wells except a few wells such as well no.7.

### 4.3. Stimulation Data Analysis

The following tables summarize the different parameters of fracturing operation. These parameters include for example, maximum pressure of the job, fracture closure pressure, pad volume and formation breakdown pressure, perforation interval, average treating pressure and rate, perforation friction and propped fracture height and half-length etc. These parameters show how fracturing operation was carried out in general. How much proppant was used, what were the fracture height and half length, what was pad volume and fluid efficiency etc.? All of these questions can be answered from the stimulation data. There are two names for a few wells such as 1 & 1*, 4 & 4*. The second name which is represented with asterisk sign shows that the well was re-stimulated.

Table 2. Stimulation treatment parameters for all delineation wells

| Well No | Perforation interval m | Initial wellhead pressure psi | Fracture closure pressure psi | Fracture closure gradient psi/ft | Fluid efficiency % | Total proppant placed kg | Propant left kg |
|---|---|---|---|---|---|---|---|
| 0 | 1642-1645 | 34 | 3108 | 0.575 | 65.48 | 5670 | 330 |
| 0* | 1642-1645 | 28 | 2976 | 0.639 | 65.89 | 49592 | 408 |
| 1 | 1713-1717 | 60 | 3042 | 0.61 | 60.63 | 5228 | 272 |
| 1* | 1713-1717 | 15 | 3083 | 0.545 | 55.6 | 49600 | 400 |
| 2 | 1647.7-1657.7 | 41 | 3285 | 0.6 | 16.79 | 49592 | 408 |
| 3 | 1712.6-1722.6 | 400 | 3181 | 0.56 | 80 | 49510 | 490 |
| 4 | 1720-1724.5 | 54 | 3265 | 0.577 | 68.63 | 5638 | 362 |
| 4* | 1720-1724.5 | 113 | 3165 | 0.56 | 65.05 | 49600 | 400 |
| 5 | 1755-1761 | 39 | 3135 | 0.56 | 61.46 | 5800 | 200 |
| 5* | 1755-1761 | 27 | 3239 | 0.58 | 59.57 | 49320 | 680 |
| 6 | 1734-1744 | 20 | 3086 | 0.539 | 60.4 | 49592 | 408 |
| 7 | 1762-1766.5 | 175 | 3216 | 0.555 | 60.12 | 5728 | 272 |
| 7* | 1762-1766.5 | 20 | 3186 | 0.548 | 59.7 | 9592 | 408 |
| 8 | 1741.9-1751.9 | 103 | 3221 | 0.57 | 65 | 49592 | 408 |
| 9 | 1669-1679 | 34 | 2979 | 0.54 | 58.67 | 49600 | 400 |

One point can be observed in the following table that there is great difference between maximum pressure of the job and formation breakdown pressure. Maximum pressure of the job is double or more than double for most of the wells. In fact the pressure of the job should be higher but there should not be so much difference between these two pressures.

Table 3. Stimulation treatment and formation parameters for all delineation wells

| Well No | Maximu-m pressure of the job psi | Initial wellhead pressure psi | Formation breakdow n pressure psi | Rate at formation breakdown pressure bpm | NWB friction. psi | Perforation friction psi | Net pressure increase psi |
|---|---|---|---|---|---|---|---|
| 0 | 5800 | 34 | 2813 | 14.5 | 111.65 | 168.2 | 108.75 |
| 0* | 4500 | 28 | 2674 | 15.36 | 44.95 | 23.2 | 122 |
| 1 | 5285 | 60 | 2100 | 15.82 | 163.85 | 31.9 | 45 |
| 1* | 4500 | 15 | 3187 | 14.27 | 20.3 | 84.1 | 111 |
| 2 | 4500 | 41 | 3586 | 11 | 56.55 | 20.3 | 99.6 |
| 3 | 4400 | 400 | 3050 | 12 | 16 | 320 | 105 |
| 4 | 5345 | 54 | 2494 | 15.68 | 18 | 66 | 57 |
| 4* | 4500 | 113 | 2474 | 10.91 | 14.5 | 50.75 | 148 |
| 5 | 5220 | 39 | 2587 | 15.3 | 136 | 42 | 77 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 5* | 4500 | 27 | 2745 | 15.32 | 63.8 | 40.6 | 155 |
| 6 | 4500 | 20 | 3788 | 14.9 | 25 | 9 | 195.5 |
| 7 | 5548 | 175 | 2494 | 7.2 | 47.85 | 78.3 | 88.2 |
| 7* | 4500 | 20 | 3026 | Not given | 70 | 30 | 157 |
| 8 | 4500 | 103 | 2557 | 10.9 | 20.3 | 40.6 | 123 |
| 9 | 4500 | 34 | 2861 | 9.9 | 33.35 | 40.6 | 155 |

| Well No. | Pad volume % | No. of open perforations. | Initial ISIP psi | Final ISIP psi | Fracture half length m | Propped fracture height m | Av. treating rate bpm | Treating pressure psi |
|---|---|---|---|---|---|---|---|---|
| 0 | 20.86 | 13 | 1034 | 987 | 27 | 42 | 14.49 | 1774.8 |
| 0* | 14.29 | 36 | 1038 | 1080 | 49 | 83 | 13.9 | 2099 |
| 1 | 24.53 | 30 | 900 | 815 | 29 | 35 | 14.6 | 1692 |
| 1* | 24.7 | 19 | 961 | 912 | 48 | 90 | 14.6 | 2065 |
| 2 | 20.38 | 37 | 1166 | 1161 | 50 | 96 | 14.8 | 2458 |
| 3 | 17.9 | 12 | 1083 | 1077 | 53 | 51 | 15.1 | 2226 |
| 4 | 18.62 | 72 | 1031 | 986 | 26 | 38 | 14.8 | 1730 |
| 4* | 21 | 22 | 1079 | 1094 | 47 | 86 | 14 | 2202 |
| 5 | 23.86 | 25 | 901 | 875 | 28 | 38 | 14.9 | 1760 |
| 5* | 21.34 | 27 | 1042 | 1053 | 53 | 87 | 14.2 | 2255 |
| 6 | 25 | 26 | 904 | 969 | 50 | 85 | 14.8 | 1968 |
| 7 | 24.9 | 19 | 883 | 789 | 23 | 32 | 14.8 | 2295 |
| 7* | 21.27 | 31 | 1032 | 1031 | 51 | 81 | 14.9 | 2428 |
| 8 | 17.25 | 26 | 1046 | 1161 | 54 | 87 | 13.5 | 2028 |
| 9 | 22.09 | 26 | 840 | 932 | 47 | 90 | 14 | 1948 |

### 4.3.1. Explanation of stimulation data

The above stimulation job parameters are explained in this section.  When fracturing fluid is injected into the formation at high rate and pressure, the stress in the formation is increased. If the fluid is injected continuously, eventually a point is reached where the stress becomes greater than the maximum stress that can be sustained by the formation and the formation splits apart as a result of the high pressure. The pressure at this moment is termed as the formation breakdown pressure. Fracture closure pressure is the pressure exerted by the formation on the proppant. The volume of fracturing fluid which is injected in the pad stage which is the first stage of injection of fracturing fluid is called pad volume. That ratio, $\eta = V_{frac}/V_{inj}$, is called fluid efficiency. Greater the volume of fracturing fluid in the fracture, greater will be the efficiency of the fluid. NWB (near wellbore) friction is the friction around the wellbore because of damage incurred by the drilling fluid. Net pressure $P_{net}$, is the difference between the pressure of fracturing fluid inside the fracture and the closure pressure i.e. $P_{net} = P_f - P_c$.

### 4.3.2. Comparison of designed and matched fracture

Fracture profiles of designed and matched fracture for well 9 are presented in figure 46 & 47. Designed profile is the one which was obtained as an output from the software. Several parameters are provided as in input to the software as a result of which this fracture profile was generated. The input parameters include but not limited to slurry rate, proppant concentration, stress regimes, permeability etc. After modeling this profile, another profile is also generated from the real time data obtained from the fracturing operation. Both of these profiles have been compared in this section. It can be clearly observed from fracture profiles (figure 46 & 47) and bar chart (figure 48) that there was good correlation between matched and designed fracture profiles. It is important to mention here that the same behavior was observed for other wells too. Finally it can be stated that, the fracturing operation was carried out as it was designed.

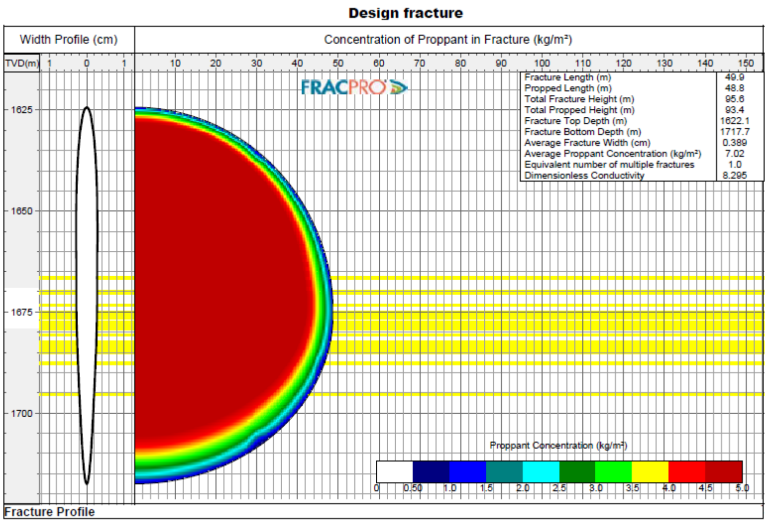



Figure 46. Profile of designed fracture on FracPro

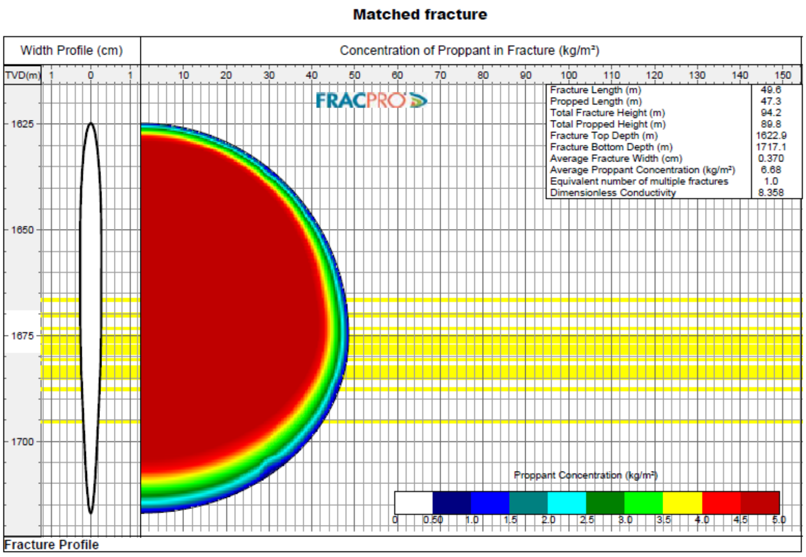



Figure 47. Profile of matched fracture on FracPro

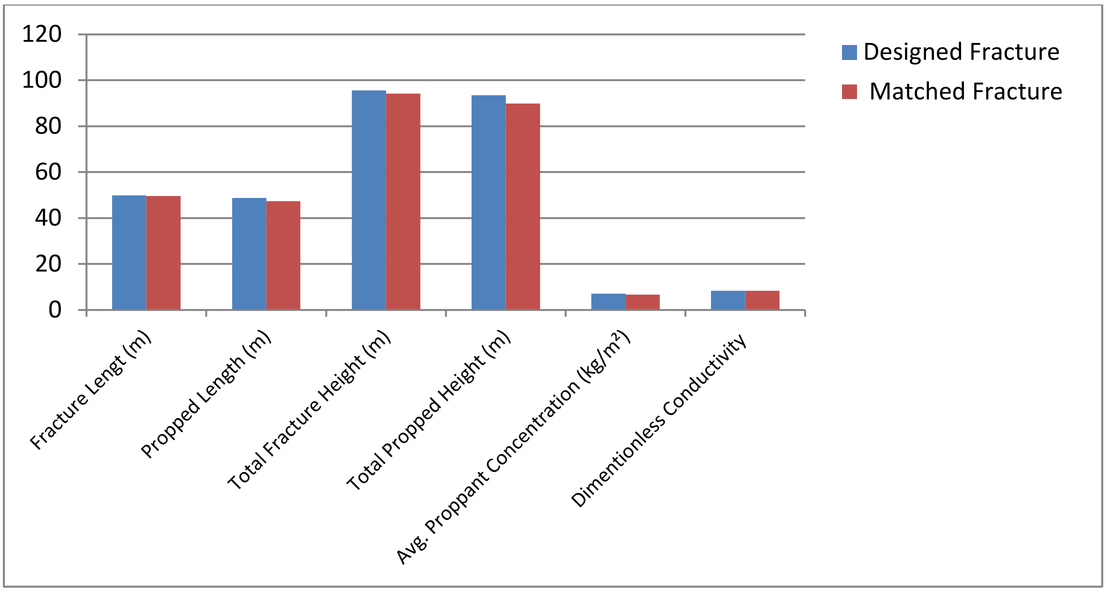



Figure 48. Comparison between different parameters of matched and designed fracture profile

### 4.3.3. Comparison of different fracture parameters before and after re-stimulation

The comparisons of fracture top and bottom of initial fracturing operation and re-fracturing operation are shown in figure 49 below. The fracture top was at the depth of 1633m and bottom was at 1675m for well number 0 and after re-fracturing the fracture top and bottom moved to 1595m and 1678m respectively. Similarly the fracture top and bottom changed after the re-fracturing operation for other wells.

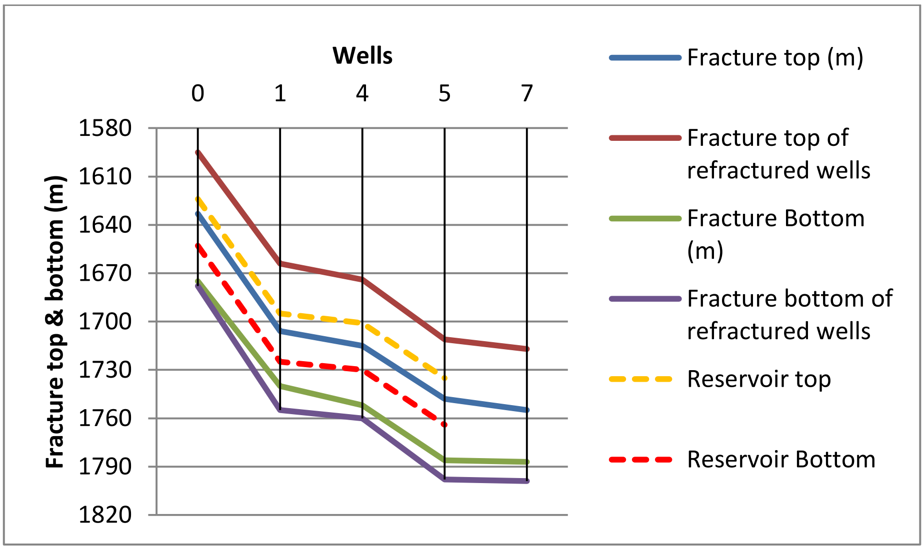



Figure 49. Comparison of fracture top and bottom before and after re-stimulation for given wells

The following figure 50 shows the comparison of fracture height and fracture half-length of initial fracturing operation and re-fracturing operation. The fracture height is around 40m for the initial treatment and then increases up to 85m after re-fracturing. Similarly fracturing half-length increases from 30m to 50m after re-fracturing. Therefore, it can be concluded that the second fracturing treatment was too aggressive that it propagated the fractures outside of the reservoir top and bottom.

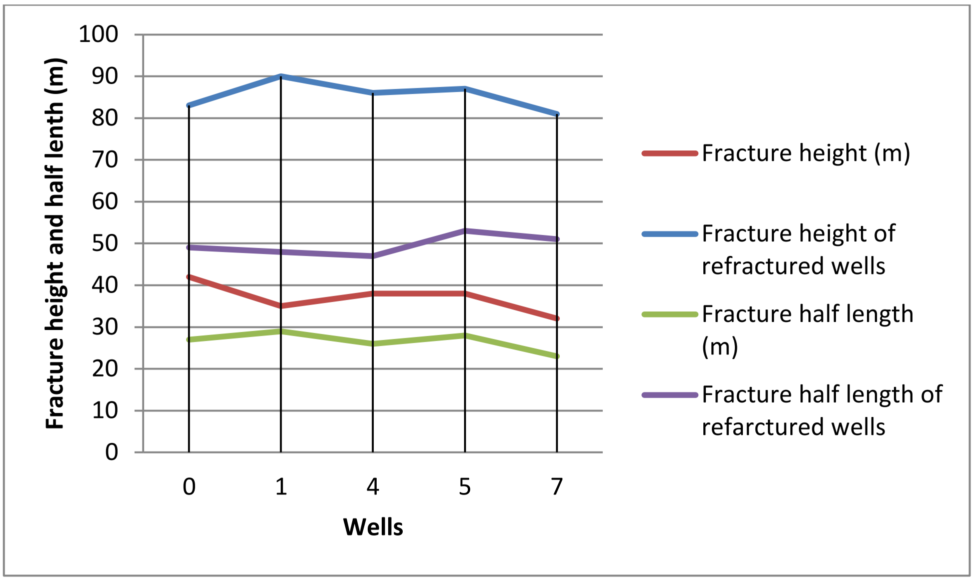



Figure 50. Comparison of fracture height and half-length for given wells

It is depicted in figure 51 that there is a significant increase in average fracture width after re-fracturing the well. The average fracture width was around 0.14 cm after fracturing but after re-fracturing it increased to 0.36.

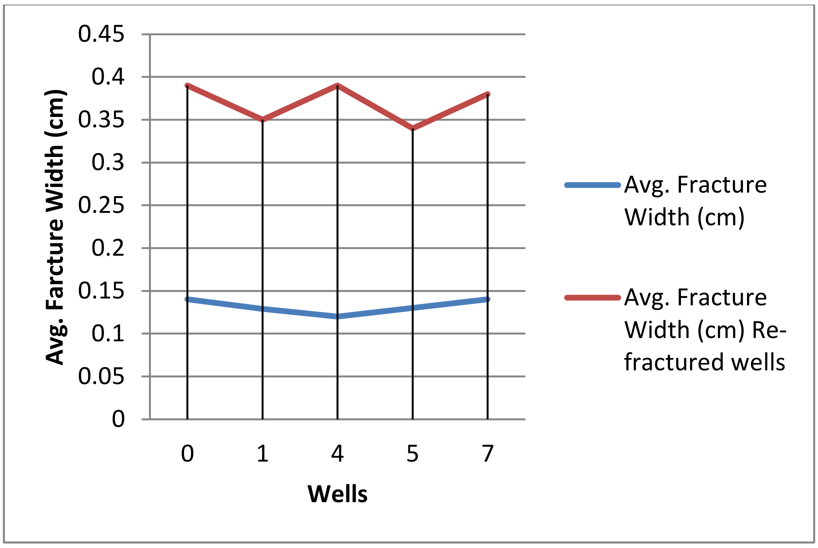



Figure 51. Comparison of average fracture width before and after re-stimulation for given wells

The behavior of bottom hole fracture closure stress is not uniform for both fracturing treatment. The bottom hole fracture closure stress decreases from 217 to 210 bar and increases from 206 to 216 bar for well number 0 and 1 respectively. In my opinion this stress for re-fractured wells should be lower than that of initially fractured wells. But there can be much heterogeneity and we cannot be 100% sure about our predictions. These results are shown in figure 52.

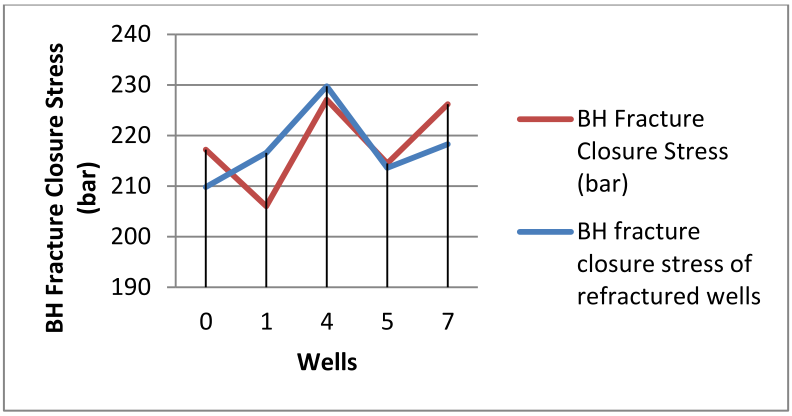
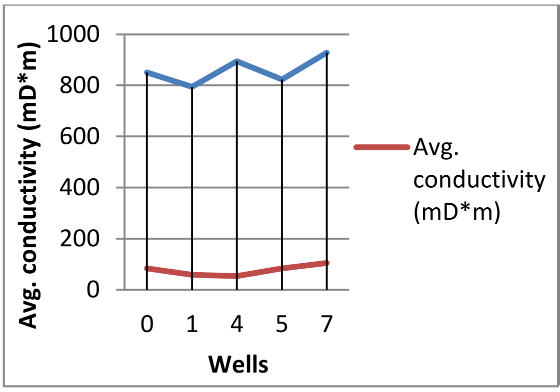



Figure 52. Comparison of fracture closure stress before and after re-stimulation for given wells

There is an enormous increase in the average conductivity for all the wells after the re-fracturing. For example the avg. conductivity increased from 83 to 850 mD*m for well number 0 and from 105 to 928 for well number 7. These results are shown in the following figure 53. The average proppant concentration also increased significantly after re-fracturing. For instance, the average proppant concentration increased from almost 3 kg/m$^3$ to 7 kg/m$^3$ fro well number 0. These results are shown in the following figure 54.



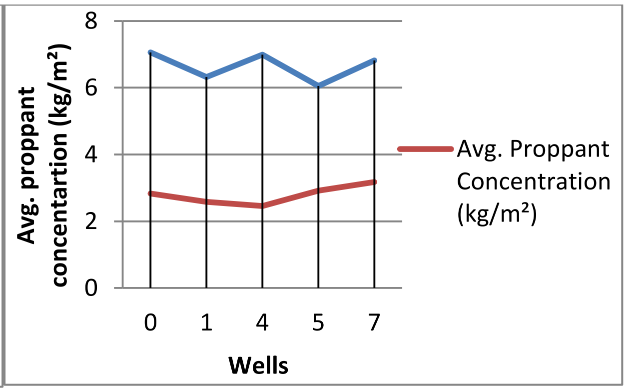




Figure 53. Comparison of average fracture conductivity before and after re-stimulation for given wells (L) & Figure 54. Comparison of average proppant concentration before and after re-stimulation for given wells (R)

After the stimulation data analysis it was observed that the re-fracturing operation was too aggressive and as a result of it the fractures propagated outside of the reservoir zone.

### 4.4. Problems and Their Solutions

#### 4.4.1. Effect of Shut in Time on Production

A well may undergo long duration of shut in depending upon particular field constraints after the hydraulic fracturing treatment. The practices of shutting in the well after the hydraulic fracturing treatment have been reported in oil and gas industry. In unconventional reservoirs, field experiences indicate that such shut-in periods may improve well productivity significantly while reducing water production. Some work has been done on this issue and some papers have been presented in last couple of years. There are several processes which can take place after shutting in the well for long time.

1. Drainage/Imbibition; 2. Wettability alteration 3. Change in proppant and rock conductivity

4. Polymer damage; 5. Other types of damage caused by the interaction of fracturing fluid containing different types of additives.

These processes depend upon the properties of reservoir rock and period of shutting in the well. According to (A. Bertoncello, 2014) water is displaced by two different processes. First, water is forced into the oil-wet pore network by pressure differential during hydraulic fracturing. Second, once in the oil-wet pore network, the water naturally imbibes into the water-wet pores network by capillary action. Early cleanup minimizes the amount of water invading the oil-wet pores. Shutting-in the well facilitates imbibition of the trapped water from the oil-wet pores to the water-wet pores. Wettability of pore network is shown in the following figure 55.In left figure bigger pores are oil wet and smaller pores are water wet but in the figure on the left, for X field reservoir, bigger as well as smaller pores are water wet.

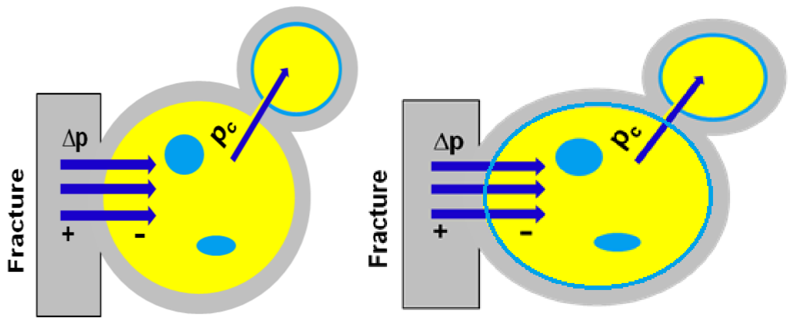



Figure 55. Oil wet bigger pores and water wet smaller pores (left), X field reservoir with neutral to water wet pore network (right) (A. Bertoncello, 2014).

The complete process is explained in following figure 56 for an oil wet rock system.

Step 1: Water invades the oil-wet pores during hydraulic fracturing treatment.

Step 2: The invasion creates an area of high water saturation and low gas permeability near the fracture.

Step 3: The water block around the fracture limits gas flow. Increase in net confining stress (NCS) during drawdown further decreases formation permeability and slows down the imbibition of water from oil-wet to water-wet pores.

Step 4: Cleaning up the well early minimizes invasion. Resting the well after cleanup speeds-up the imbibition process because viscous forces do not counteract capillary forces and because the pressure buildup decreases NCS, which, in turn, enhances the formation permeability.

Step 5: After well shut-in, most of the water has imbibed from the oil-wet to the water-wet pores. Gas can then freely flow through the large interconnected oil-wet pores, improving the well's deliverability.

In a water wet system, water occupies the small pores and coats most of the large pores with a thin film. (Djebbar Tiab, 2014). Therefore, for this shale reservoir the larger pores are water wet and it aided the production of oil. The oil flowed easily through the bigger water coated pore network. What actually happens inside the reservoir strongly depends upon many factors such as wettability alteration, change in fracture and proppant permeability and formation characteristics etc. In relation to X field, as the pores are neutrally to water wet, therefore in my opinion, the same phenomenon could happen in X field too. It is just a rough prediction. But, it is highly recommended to perform core analysis in the laboratory at same conditions as prevailing in this reservoir such as temperature, pressure, fracturing fluid composition, shut in time etc. to know the exact phenomenon which can take place in this specific reservoir during the shut in period.

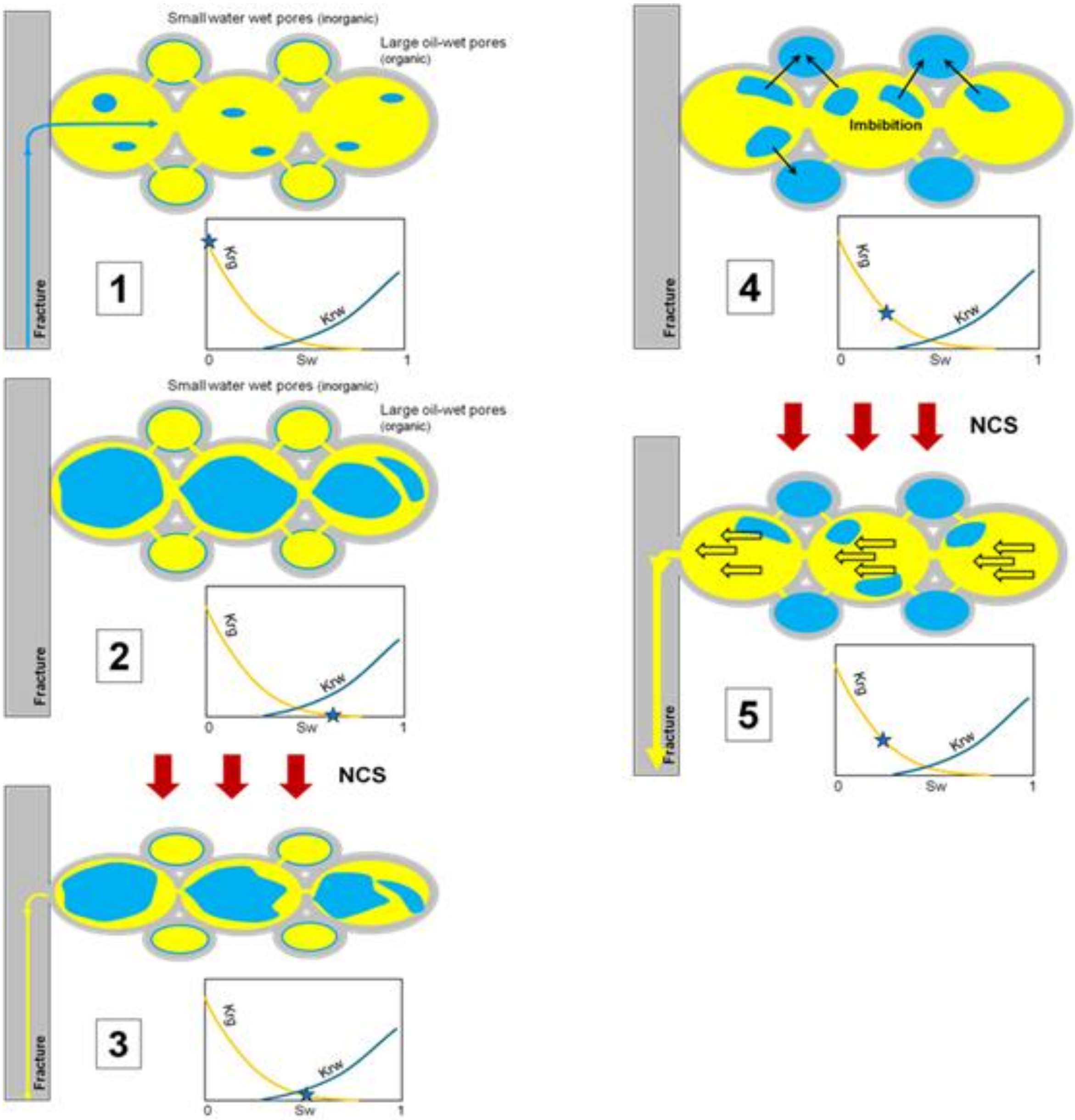



Figure 56. Process of imbibition after shutting in the well (A. Bertoncello, 2014).

#### 4.4.2. Mud Losses

Mud loss is a term which is used for uncontrolled invasion of mud into the formation. There are several potential reasons for mud losses such as high permeability channels, natural fractures, drilling induced fractures or hydraulically created fractures etc. In case of X field, the reason for mud losses was the presence of faults and natural fractures. These faults and fractures can be seen in figure 21.

#### 4.4.3. Fines Production

This particular reservoir in X field consists of thin, very fine-grained, argillaceous sandstone beds interbedded with shaly heteroliths and intervals of calcite cemented sandstones. The X field reservoir has varying thicknesses from 11 to 15 m. These low permeablility sandstone units are laminated with claystone and siltstone, making the mineralogical composition a mixture of quartz, feldspars, small quantities of calcareous material and varying amounts (15- 50%) of clayminerals. Because of unconsolidated nature of the formation there is a problem of fines production. There are a couple of methods which can applied to avoid the fines prodction, which are listed below:

1. Use of sand screen

2. Limited entry perforating

3. Proper alignment and orientation of perforations

3. Perforating only the intervals which are consolidated. These consolidated intervals can be located with the help of sonic logging.

## CHAPTER 5. FRACTURING FLUID AND WATER MANAGEMENT

### 5.1. Introduction

Nowadays, our society, especially in Europe, is extremely concerned about using huge amount of water and chemicals during the hydraulic fracturing operation and its impact on environment and human health. Agriculture, manufacturing and municipal water supply are also some other major sectors where huge amount of water is used. An estimate of water usage in different areas in USA in 2010 is presented in figure 60 in the appendix. A careful management of flow back fracturing fluid and waste water is necessary to avoid any potential problems associated with environment or human health. The recycling of produced water and fracturing flowback for reuse in hydraulic fracturing is growing gradually to develop the unconventional resource plays. The factors driving the conservation of water are the limitations in sources of fresh water in areas with a high rate of development, the attractive economics of recycling compared with truck transportation costs, minimization of road traffic to reduce environmental impacts, and water disposal costs. Normal sources of fresh water for hydraulic fracturing include glacial and bedrock aquifer systems, surface waters, and municipal supplies. (Boschee, 2012)

Water management is extremely important to successfully carry out the hydraulic fracturing operation in unconventional reservoirs. The industry has vast experience of hydraulic fracturing in conventional and unconventional reservoirs. Nearly 2.5 million conventional HF operations have been carried out in the world. The major difference between fracturing operations in conventional and unconventional reservoirs is the quantity of water used and produced after the fracturing treatment. The much higher volumes of fluid required for unconventional HF make it different from conventional HF. Whereas a conventional HF may require about 2,000 bbls of water per well, an unconventional HF may require between 50,000 and 120,000 bbls of water per well. Fluid volume, flowback variability and load recovery are the unique features of fracturing fluid management in unconventional reservoirs. (Walsh, Water Management for Hydraulic Fracturing in Unconventional Resources—Part 1, 2013). For instance, the volume of water used in a Bakken play fracture ranges from approximately 0.5 million to 3 million gallons (10,000 bbls to 60,000 bbls), depending on the number of stages in the fracture. (Boschee, 2012). (Halldorson, 2013) Identified five factors that dominate water management for HF which are:

1) Disposal 2) Fresh water 3) Regulatory and community concerns 4) Recycling and reuse 5) Transport

Consensual decisions should be made to develop a cost-effective water management strategy that minimizes environmental impact and is also acceptable to local communities. Walsh along with his colleague devised a water management strategy (Walsh 2013; Walsh and Crisp 2013) that focuses on the following five key drivers:

• Hydrology of the field (or region)—defines availability of fresh water

• Regulatory requirements—define disposal options

• Fracture fluid quality—defines the required quality of water

• Flowback fluid characteristics—define the treatment requirements

• Stage of field development—defines the availability of technology

**5.2. Composition of Fracturing Fluid**

(Michael J. Economides T. M., 2007) and (King, 2010) reported that the main fluid additives are friction reducer, biocide, oxygen scavenger, scale inhibitor, wetting agent, breaking agent, and proppant. The fluids and their concentrations are selected on the basis of the petrophysics of the formation (Rickman et al.2008). The usual composition of fracturing fluid is shown in figure 57 (Ground Water Protection Council, 2009). The mineralogy (clay, quartz, or carbonate content), brittleness, permeability, and the closure stress are factors that help to determine the optimum fluid type. The selection of the fluid type(s) and concentration(s) vary depending on the properties of the hydrocarbon bearing formations. (Walsh, Water Management for Hydraulic Fracturing in Unconventional Resources Part 2 - Properties and Characteristics of Flowback Fluids, 2013). From a water treating perspective, the following are the critical components of HF flowback fluids in unconventional resources:

• Dispersed light oil • Dissolved polymer • Organic solids (mostly dispersed/suspended polymer)

• Inorganic solids (sand, clay, precipitated mineral, and proppant) • Surfactant (wetting agent)

• Dissolved salt

The fracturing fluid composition of two real fields, one from Poland and other one from USA are presented as an example in the appendix in figure 62 and 62.

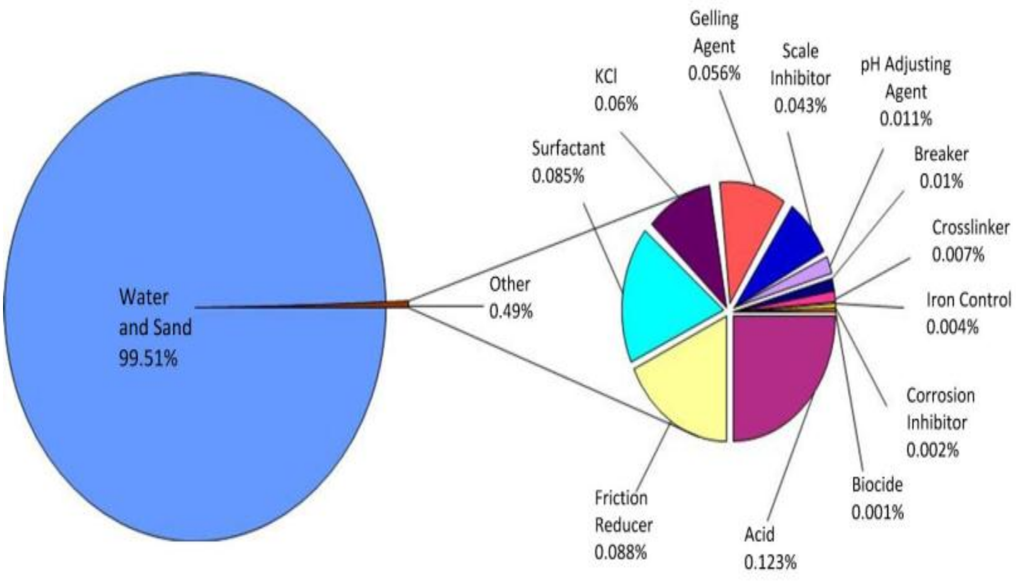



Figure 57. Normal proportion of water and additives in fracturing fluid

### 5.3. Water Treatment Technologies

There is a need in the oil and gas industry to find a single, flexible, and multipurpose water treatment technology that is capable of handling most flowback fluid types. This would simplify the selection, purchase, deployment, and operation of equipment in the field. However, such a technology has not yet been identified, although there are some technologies that come close to meeting the need. Nearly all produced water is managed in the following ways: (Veil, 2015)

- Injection to a hydrocarbon-bearing formation to help produce more hydrocarbon
- Injection to a non-hydrocarbon-bearing formation for disposal
- Discharge to surface water bodies
- Evaporation
- Paying a commercial disposal service to take the water and manage it
- Reuse for oil and gas operations (drilling fluids, frac fluids)
- Reuse for other purposes.

The water cycle is presented in following figure 58.

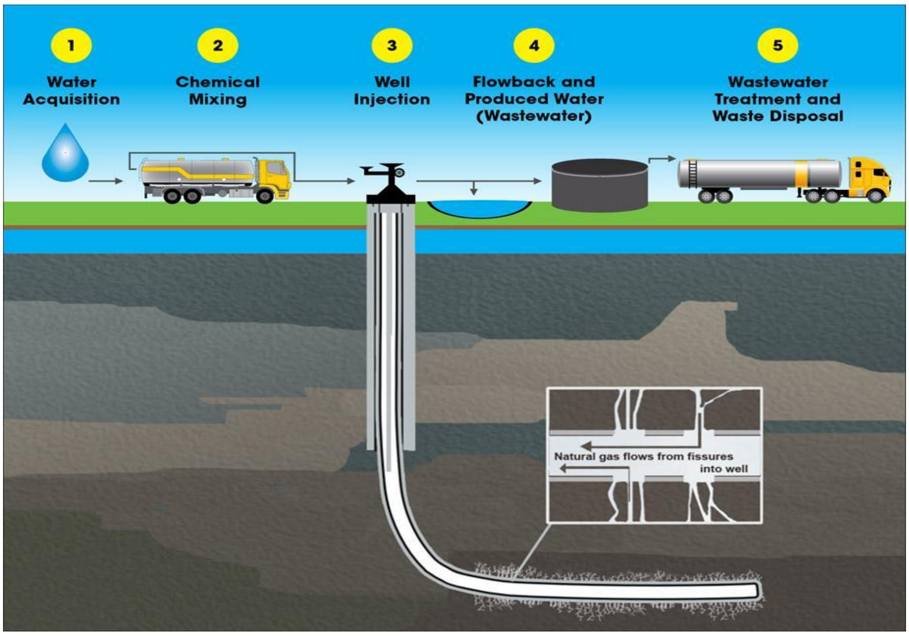



Figure 58. Water cycle; Source: http://www2.epa.gov/hfstudy/hydraulic-fracturing-water-cycle#1

Water treatment for HF includes desalination of aquifer water, biological and corrosion control, control of mineral precipitation, treatments to break the polymer gel, and a number of other technologies for recycling the HF flowback fluid. Regardless of the technology that occurs downstream, it is almost always advantageous to apply coarse filtration as an initial treatment step. Mineral and organic suspended solids are removed after coarse filtration. These solids are composed of quartz, carbonate, and clay particles, and broken and unbroken polymer.

Two important technologies for the removal of suspended solids are coagulation/flocculation and electrocoagulation. These technologies are being applied successfully now and their use is likely to grow in future. The technologies themselves are only a part of the job. Equally important are the logistics, services, on-site support, reliability, and troubleshooting capabilities of the service companies. (Walsh, Water Management for Hydraulic Fracturing in Unconventional Resources—Part 3, Water Treatment Technologies: Coagulation/Flocculation and Electrocoagulation, 2013).

Following tables summarize the different treatment technologies. (A. Hussain, 2014) & (Pei Xu, 2011)

Table 4.Fundamental treatment technologies

| **Fundamental treatment technologies (Pretreatment)** | | |
|---|---|---|
| Basic Separation | Adsorption | Advanced Separation |
| 1. Settling | 2. Activated Carbon | 3. Chemical Oxidation |
| 4. Electrocoagulation | 5. Zeolite | 6. Microfiltration |
| 7. Flotation | 8. Ion exchange | 9. Ultrafiltration |
| 10. Hydrocyclone | | |

Table 5.Desalination treatment technologies

| **Desalination treatment technologies (Membrane separations)** | | |
|---|---|---|
| High pressure membrane | Electrically driven processes | Novel membrane processes |
| 11. Reverse osmosis | 12. Electrodialysis | 13. Membrane distillation |
| 14. Nanofiltration | 15. Electro ionization | 16. Forward osmosis |
| 17. VESP | 18. CDI | |

Table 6.Other treatment technologies

| **Other treatment technologies** | | |
|---|---|---|
| Thermal technologies | Zero liquid discharge technologies | Integrated systems |
| 19. Vapor compression | 20. Evaporation | 21. Two stage reverse osmosis hybrids |
| 22. Multi-effect distillation | 23. Crystallizer | 24. Mechanical vapor compression |
| 25. Multistage flash | 26. Wind aided intensified evaporation | |

Water quality, the characteristics of the flowback fluids and volume are important in the selection of water treating technology and equipment. The flowback fluid characteristics vary significantly from field to field. Perry and Bosch (2013) reported a standard deviation in total dissolved solids (TDS) of 50,000 mg/L in a dataset of more than 500 samples taken from the Bakken development. Such a large standard deviation is not unique. For the Wolfcamp development, the dataset contained nearly 200 samples, and the standard deviation was close to 50,000 mg/L. The standard deviation for gas wells in the Marcellus play was 77,000 mg/L in a dataset of close to 1,000 samples. Another important variable is load recovery which stands for the fraction of HF fluid produced on flow back. Selection of water treatment equipment on the basis of significant differences from one field to another, or from one fluid type to another, while taking into account large variations is a challenging task.(Walsh, Water Management for Hydraulic Fracturing in Unconventional Resources Part 2 - Properties and Characteristics of Flowback Fluids, 2013).

Fluid volume affects key aspects of development, such as water sourcing and water disposal. Water management is required at an early stage of field development because of large volume of fluid. This is a significant departure from traditional oil and gas field development, in which water production typically occurs after startup and water treatment facilities are typically added late in field life. Water management for unconventional hydrocarbons however requires that decisions to be made at an early stage in the development of a field to minimize overall water management costs. When these decisions are not made early, or when they are not implemented in a timely manner, the number of water management options may be scarce and the cost of water management can escalate exponentially. Different stages of development are discussed in detail below. (Walsh, Water Management for Hydraulic Fracturing – Part 4, 2013).

1) Stage 1: Remote and isolated well development –mobile water treating systems

2) Stage 2: Well clusters with some in-field drilling and completions – modular water treating systems

3) Stage 3: Extensive in-field development with infrastructure to transport water to and from a centralized treatment facility –centralized water treatment plants

#### 5.3.1. Mobile stage of development

In the early stage of development of an unconventional field, a number of individual wells are drilled and completed. The initial wells in a region are typically drilled in remote and isolated areas. If water recycle is carried out, the water treating equipment must be mobile. Such equipment is compact and placed on a flatbed truck.

The economics of this kind of water treatment are significantly different from industrial water treatment economics. Capital cost is typically a small fraction of the total cost. Most of the cost of water treatment is due to staff time related to transportation to site, setup of the equipment, operation of the equipment, and demobilization and return transportation. If the equipment is complex then additional time is required to mobilize and setup the equipment, and additional operators will be required that will increase the expenses. If the capacity is low, then additional time is required to process the water volumes. As a general observation, the water treatment rate must be around 5 to 7 barrels of water per minute. Lower capacity will just simply take too long and the cost of personnel on site will be too high. These factors are the main cost drivers. Thus, appropriate equipment in this stage of development is compact, simple, and relatively of high capacity. Very few technologies meet these criteria.

### 5.3.2. Modular stage of development

As field development progresses, the leases are secured and the drilling campaign becomes more organized and structured. Clusters of wells are drilled and completed. It is then possible for several adjacent wells to be developed in sequence or simultaneously, facilitating the use of a modular water treating system. In this case, a daisy chain or hub-and-spoke type of water piping arrangement can be constructed to feed the water treatment and to convey treated water to the wells that require it. Lay-flat hose, storage tanks, pond liners are all important components of the water management facility. The equipment would be transported on a few flatbed trucks. A few weeks would be required to prepare the site and setup the equipment. When a few or several wells are involved, the construction cost of a modular treating system is justified.

### 5.3.3. Centralized stage of development

Many wells are drilled at closer distance in later stages of field life. The construction of a water conveyance network together with a centralized water treatment facility becomes justified at this stage. This is the current trend in the Marcellus Shale. It has also been successfully implemented in the Pinedale Anticline in southwestern Wyoming (Boschee 2012). The capital cost of the water transport system and of the water treatment facility are the main cost drivers. In this case, the capital costs contribute significantly to the overall cost. Due to plant automation and the ability to achieve relatively stable steady state operation, the number of operators is minimized, compared to the previous stages of field development. In the centralized application of desalination, MVC is not the only thermal desalination that could be applied. If low grade steam is available then multi-stage flash distillation (MSF) or multiple-effect distillation could be used for reduction of energy use. (Walsh, Water Management for Hydraulic Fracturing – Part 4, 2013). Moreover, it is important to know the exact composition of flowback and fracturing fluid to select the appropriate treatment technology for careful and responsible management of waste water and fracturing fluid.

# CHAPTER 6. CONCLUSIONS, RECOMMENDATIONS AND FUTURE WORK

The following conclusions have been deduced from the study.

1. Pretreatment formation evaluation using different sources of data such as geology, mud logging, well logging, core analysis and other available sources is extremely important for a successful hydraulic fracturing design and operation. In relation to the X field, it was observed that well logs were not analyzed to design the HF treatment and that the fractures were propagated above and below the reservoir zone into the water layer which was the reason for enormous amount of water production almost from all of the delineation wells.

2. Stimulation data analysis showed that the fracture treatments were carried out in accordance with the design. There was a good match between designed and matched fracture profiles.

3. Well number 0 was tested after initial stimulation operation and good results were obtained in terms of production. The reason could be that the fractures were confined within the reservoir zone but after re-stimulation, there was high water production and the reason for it can be the propagation of fractures outside of the reservoir zone. From production data analysis of this well, it can be stated that maybe there was no need of performing a re-stimulation operation on this well.

4. Overall, high amount of water production can be associated with an inappropriate fracturing treatment design. The design did not follow the indications from well logging data and as a result of which the fracturing treatment was overdesigned in terms of fracture height, width, proppant concentration etc.

5. It was observed that mud losses were associated with the faults, natural and drilling induced fractures.

6. The study which was presented in the thesis regarding effect of shut in time on production, indicated that sufficient shut in time enhanced the shale gas production by overcoming the problem of water blockage after the fracturing treatment. Once the well was shut in for sufficiently long time, water imbibed into the smaller pores by leaving behind a good passage for gas to flow easily in the bigger pores. In relation to X field, as the pores are neutrally to water wet, the same phenomenon could happen in X field too i.e. production could be enhanced after sufficient shut in period. It is just a vague prediction without any experimental basis. But what actually happens inside the reservoir strongly depends upon many factors such as wettability alteration, change in fracture and proppant permeability and formation characteristics , interaction of fracturing fluid with the formation, polymer damage etc.

7. Moreover, it is recommended to use well logging, core analysis, geologic data and other data if available such as well tests, temperature logs, tracers, NMR logs and surface tilt meters to properly design the HF operation for the other wells to be drilled in future.

8. As the field is in second phase of development where significant number of wells i.e. 183 wells will be drilled, so, it is recommended to establish a centralized stage of development facility for fracturing fluid and waste water treatment and management.

9. Finally, to deal with the problem of fines production, it is recommended to use any of the suggested methods such as sand screen, selection of appropriate perforation interval based upon sonic logging measurements or use of limited entry perforating.

### 6.1. Future Work

When the well is shut in for long time after fracturing operation, several processes can take place such as imbibition/drainage, wettability alteration, polymer damage, proppant pack and formation permeability change etc. As none of these processes have been observed in the laboratory particularly for X field, therefore, to clearly understand the effect of shut in time on production, it is recommended to perform core analysis and analyze the effect of fracturing fluid on wettability alteration, proppants characteristics, formation damage etc.

It is also recommended to measure the effect on proppant pack conductivity during shut in period by any laboratory experiment such as given below. (D. M. Bilden, 1995)

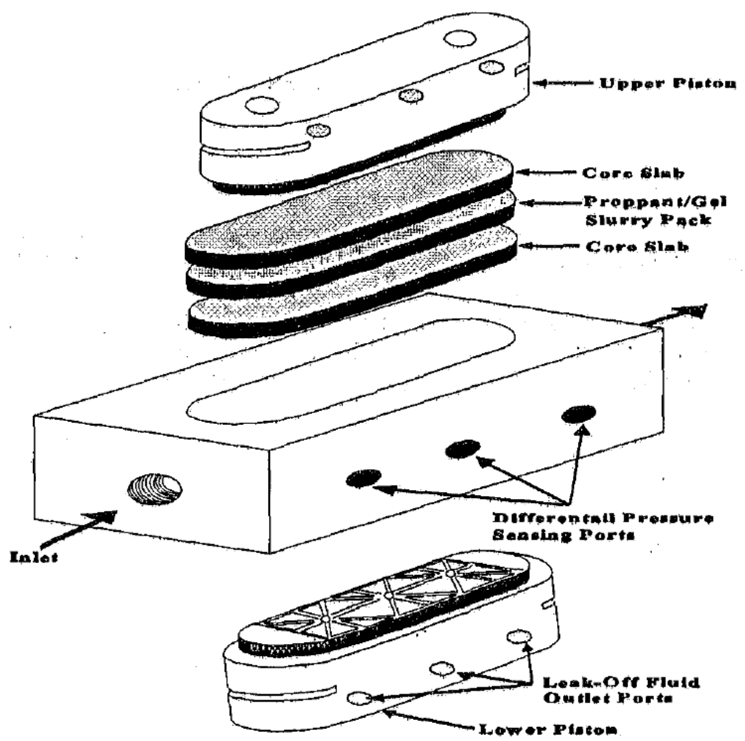



Figure 59. Schematic of modified API conductivity test cell

## NOMENCLATURE

| | | |
|---|---|---|
| $A_f$ | = | fracture area, $ft^2$ |
| a | = | Archie cementation constant |
| $C_L$ | = | fluid loss coefficient in ft/ $(min)^{1/2}$ |
| $C_p$ | = | proppant concentration in ppg |
| D | = | pipe inner diameter, inch. |
| E | = | Young's modulus |
| $F_{CD}$ | = | dimensionless fracture conductivity |
| G | = | shear modulus |
| H | = | Thickness of reservoir, ft |
| F | = | Formation Resistivity Factor = $F = a/\varphi$^$m$ |
| $J$ | = | productivity of fractured well, stb/day-psi; |
| $J_o$ | = | productivity of nonfractured well, stb/day-psi |
| $K_L$ | = | fluid loss multiplier; |
| k | = | permeability, md |
| $k_f$ | = | fracture permeability, md |
| $L$ | = | tubing length, ft |
| $M_p$ | = | proppant weight in lbs |
| m | = | Archie cementation exponent |
| n | = | Archie saturation exponent |
| $\Delta N_{p,n}$ | = | predicted annual incremental cumulative production for year n |
| $N_{p,n}^{f}$ | = | forecasted annual cumulative production of fractured well for year n |
| $N_{p,n}^{nf}$ | = | predicted annual cumulative production for non-fractured well for year n |
| $p$ | = | reservoir fluid pressure or pore pressure, psi |
| $P_{si}$ | = | surface injection pressure, psia |
| $P_{bd}$ | = | formation breakdown pressure, psia |
| $\Delta P_h$ | = | hydrostatic pressure drop, psia |
| $\Delta P_f$ | = | frictional pressure drop, psia |
| $P_1$ | = | inlet pressure, psi |
| $P_2$ | = | outlet pressure, psi |
| Q | = | oil flow rate, bbls/day; |
| $q$ | = | injection rate, bbls/min; |
| Qv | = | cation-exchange capacity of total PV, meq/ml |
| Ri | = | radius of investigation, ft |
| $R_0$ | = | rock resistivity with 100% PV water saturation, ohm•m |
| $R_{sh}$ | = | shale resistivity, ohm•m |
| $R_v$ | = | velocity ratio |
| $R_t$ | = | true resistivity of uninvaded, deep formation, ohm•m |
| $R_W$ | = | formation water resistivity ohm•m |

| | | |
|---|---|---|
| $r_w$ | = | wellbore radius in ft. |
| $r_e$ | = | radius of drainage area, ft |
| $r_p = \frac{h}{h_f}$ | = | payzone thickness/ fracture height, ft. |
| $S_g$ | = | gas saturation, %PV |
| $S_f$ | = | equivalent skin factor |
| $S_o$ | = | oil saturation, %PV |
| $S_w$ | = | water saturation, %PV |
| $S_{wc}$ | = | connate water saturation, %PV |
| $t$ | = | injection time of calculating slurry concentration (min) |
| $t_{pad}$ | = | time to pump the pad volume, min |
| $V_{cl}$ | = | clay content, %BV |
| Vsh | = | shale content, %BV |
| $V_{inj}$ | = | injection fluid volume, gallons |
| $v$ | = | velocity of the formation (ft/sec); |
| $v_f$ | = | velocity of interstitial fluids (ft/sec); |
| $v_{ma}$ | = | velocity of the rock matrix (ft/sec) |
| $\bar{W}$ | = | average fracture width, ft |
| $w$ | = | fracture width in inches. |
| $x_f$ | = | fracture half-length, ft. |
| $\beta$ | = | formation volume factor , res. bbl/stb |
| $\rho_b$ | = | formation bulk density, g/cm3 |
| $\rho_f$ | = | fluid density, g/cm3 |
| $\rho_{ma}$ | = | matrix or grain density, g/cm3 |
| $\rho_w$ | = | water density, g/cm3 |
| $\phi$ | = | porosity, %BV |
| $\phi$e | = | effective porosity, %BV |
| $\phi_{sand}$ | = | sand porosity, %BV |
| $\phi_{sh}$ | = | shale porosity, %BV |
| $\phi_t$ | = | total porosity, %BV |
| $\phi_{Dolomite}$ | = | porosity of dolomite |
| $\phi_p$ | = | proppant porosity |
| $\sigma_x$ | = | the total horizontal stress, psi |
| $\sigma_z$ | = | overburden stress, psi |
| $\sigma_E$ | = | externally generated stress, psi |
| $v$ | = | Poisson's ratio |
| $\gamma_0$ | = | oil specific gravity |
| $\mu$ | = | fluid viscosity, cp |
| $\eta$ | = | fluid efficiency |

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## APPENDIX


Figure 60.Total water withdrawals by category in USA in 2010 (Molly A. Maupin, 2014).

Source: Estimated Use of Water in the United States in 2010 USGS Circular1405 (http://pubs.usgs.gov/circ/1405/)

NGS FACTS

Natural Gas from Shale

hydraulic fracturing Fluid and Additive Component Transparency Service

### WELL LOCATION

| | |
|---|---|
| Country | Poland |
| Area | Lublewo |

### WELL DESCRIPTION

| | |
|---|---|
| Government approval references | |
| Operator of well | Lane Energy Poland |
| Name of well | Lublewo LEP-1ST1H |
| Well registration number | |
| Fracturing completion date | 28 July 2014 |
| Well depth (TVD meters) | 2,825 |
| Top perf depth (TVDm) | 2,825.1 |
| Top perf depth (MDm) | 2,964.2 |
| Bottom perf depth (TVDm) | 2,829.0 |
| Bottom perf depth (MDm) | 4,433.5 |

### HYDRAULIC FRACTURING FLUID DATA

| | |
|---|---|
| Water volume[1] ($m^3$) | 16,826.9 |
| Max mass % of total hydraulic fracturing fluid | 81.988% |
| Proppant (kilograms) | 3,457,739 |
| Max mass % of total hydraulic fracturing fluid | 16.971% |
| max (mass%) water + proppant= | 98.96% |

### HYDRAULIC FRACTURING FLUID PRODUCTS

| | |
|---|---|
| Product Trade Names in Fracturing Fluid (if applicable) | AIC191, BAN171D, BCN103, BIN191, BSN102, CFC102, CSC171, FRA101, GGN171, HCL015, ICA101, PHA172, PHA271, SFN191, XBA171, XBN201 |
| Product Purpose in Well | Acid corrosion inhibitor, acidizing, biocide, breaker catalyst, clay fix, clay substitute, delayed borate crosslinker, dry breaker, fluid viscosifier, friction reducer, high pH buffer, instant borate crosslinker iron control, liquid breaker, low pH buffer, surfactant |
| Supplier(s) | Brenntag. NALCO. CESI. UOS. ChemPur |

### HYDRAULIC FRACTURING FLUID CONSTITUENTS

| Chemical substance in fracturing fluid[2] | Chemical Abstract Service Number (CAS Number)[3] | Maximum Chemical substance Mass % in Hyd Fracturing Fluid[4] | Comments |
|---|---|---|---|
| *Water* | – | *93.0404%* | |
| *Calcined bauxite (Proppant)* | *66402-68-4* | *5.7540%* | |
| *Hydroclonic Acid* | *7647-01-0* | *0.3995%* | |
| *Aliphatic acid salt* | *Proprietary* | *0.1133%* | |
| *Aliphatic acids* | *Proprietary* | *0.0043%* | |
| *Aliphatic alcohols, ethoxylated #1* | *Proprietary* | *0.0043%* | |
| *Boric acid* | *10043-35-3* | *0.0576%* | |
| *Carbohydrate polymer derivative* | *Proprietary* | *0.2741%* | |
| *5-chloro-2-methyl-2H-isithiazol-3-one and 2-methyl-2H-isothiazol-3-one (3:1)* | *55965-84-9* | *0.0008%* | |

| Chemical substance in fracturing fluid[2] | Chemical Abstract Service Number (CAS Number)[3] | Maximum Chemical substance Mass % in Hyd Fracturing Fluid[4] | Co |
|---|---|---|---|
| *Cholinium Chloride* | *Proprietary* | *0.0713%* | |
| *Diammoniumperoxodisulfat* | *7727-54-0* | *0.0080%* | |
| *(Ethylendioxy) dimethanol* | *3586-55-8* | *0.0493%* | |
| *Ethyleneglycol* | *107-21-1* | *0.0041%* | |
| *Magnesium Nitrate* | *10377-60-3* | *0.0082%* | |
| *Methanol* | *67-56-1* | *0.0057%* | |
| *Polyethylene glycol monohexyl ether* | *31726-34-8* | *0.0123%* | |
| *Prop-2-yn-1-ol* | *107-19-7* | *0.0014%* | |
| *Sodiumhydroxid* | *1310-73-2* | *0.1740%* | |
| *Tetranatriumethylendiamintetraacetat* | *64-02-8* | *0.0172%* | |

Figure 61.Composition of fracturing fluid for Lublewo LEP well in Poland

Source link: http://www.ngsfacts.org/findawell/list/

API No.: 42-493-32572

State: Texas

Operator Name: Marathon

County: Wilson

Well Name: Kennedy #1H

Longitude: -98.2657583

True Vertical Depth: 7069

Latitude: 28.9977083

Measured Depth: 11144

Long Lat Projection: NAD27

Date: 06/14/2011

Production Type: Oil

| File Name: | Carrier Data File.xls | Proppant Data File.xls | Additive Data File.xls |
|---|---|---|---|
| Last Modified: | 1/15/2011 2:48 PM | 1/27/2011 10:58 AM | 5/17/2011 3:42 PM |

Proposal No.: 1001143206B

Invoice No.: 1001794742, 1001794744, 1001794745, 1001794749, 1001795830, 1001795888, 1001795902, 1001795910, 1001796762, 1001796764, 1001796765

| Product | Use | Product Volume (Gallons) | Product % Volume (% of Total Volume) | Product Density (lb/gal) | Product Weight (lb) | Product % Weight (% of Total Product Weights) | Ingredient | Ingredient CAS No. | Ingredient % (% of Product) (Conservative*) | Ingredient Weight (lb) (Conservative*) | Ingredient % Weight (%) (Conservative*) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Water | Carrier | 1,908,984 | 92.50% | 8.33 | 15,901,837 | 86.20% | | | | | |
| | | | | | | | Water | 7732-18-5 | 100% | 15,901,837 | 86.17% |
| Frac Sand (All Meshes) [CWT] | Proppant | 52,505 | 2.54% | 22.1 | 1,160,360 | 6.29% | | | | | |
| | | | | | | | Crystalline Silica (Quartz) | 14808-60-7 | 100% | 1,160,360 | 6.29% |
| Tempered HS | Proppant | 33,305 | 1.61% | 21.68 | 722,060 | 3.91% | | | | | |
| | | | | | | | Silicon Dioxide (Silica Sand) | 14808-60-7 | 97% | 700,398 | 3.80% |
| | | | | | | | Phenol Formaldehyde Resin | 9003-35-4 | 5% | 36,103 | 0.20% |
| | | | | | | | Hexamethylenetetramine | 1009-7-0 | 0% | 72 | 0.00% |
| Hydrochloric Acid, 10.1-15% | Acidizing | 56,186 | 2.72% | 9.67 | 543,319 | 2.95% | | | | | |
| | | | | | | | Hydrochloric Acid | 7647-01-0 | 15% | 81,498 | 0.44% |
| | | | | | | | Water | 7732-18-5 | 85% | 461,821 | 2.50% |
| Enzyme G-I | Breaker | 95 | 0.00% | 8.34 | 792 | 0.00% | | | | | |
| | | | | | | | Hemicellulase Enzyme Concentrate | 9025-56-3 | 3% | 24 | 0.00% |
| | | | | | | | Water | 7732-18-5 | 97% | 769 | 0.00% |
| GBW-23L | Breaker | 860 | 0.04% | 7.84 | 6,742 | 0.04% | | | | | |
| | | | | | | | White Mineral Oil | 8042-47-5 | 91% | 6,136 | 0.03% |
| | | | | | | | Magnesium Hydroxide | 1309-42-8 | 5% | 337 | 0.00% |
| | | | | | | | Magnesium Peroxide | 14452-57-4 | 3% | 202 | 0.00% |
| | | | | | | | Magnesium Oxide | 1309-48-4 | 2% | 135 | 0.00% |
| GW-4LDF | Gellant | 5,712 | 0.28% | 9.59 | 54,778 | 0.30% | | | | | |
| | | | | | | | Petroleum Distillates Blend | CBI | 70% | 38,345 | 0.21% |
| | | | | | | | Guar Gum | 9000-30-0 | 40% | 21,911 | 0.12% |
| FRW-14 | Friction Reducer | 1,295 | 0.06% | 8.84 | 11,448 | 0.06% | | | | | |
| | | | | | | | Hydrotreated Light | 64742-47-8 | 40% | 4,579 | 0.02% |
| | | | | | | | Distillate | | | | |
| | | | | | | | Ethoxylated Alcohol | 68439-50-9 | 5% | 572 | 0.00% |
| CI-27 | Corrosion Inhibitor | 220 | 0.01% | 7.51 | 1,652 | 0.01% | | | | | |
| | | | | | | | Methanol | 67-56-1 | 60% | 991 | 0.01% |
| | | | | | | | Thiourea Polymer | 68527-49-1 | 30% | 496 | 0.00% |
| | | | | | | | Tall Oil Acid | 61790-12-3 | 30% | 496 | 0.00% |
| | | | | | | | Ethoxylated Alcohols^ C14-15 | 68951-67-7 | 30% | 496 | 0.00% |
| | | | | | | | Propargyl Alcohol | 107-19-7 | 10% | 165 | 0.00% |
| | | | | | | | Alkenes^ C>10 Alpha- | 64743-02-8 | 5% | 83 | 0.00% |
| Ferrotrol 280L | Iron Control | 275 | 0.01% | 9.51 | 2,615 | 0.01% | | | | | |
| | | | | | | | Thioglycol | 60-24-2 | 100% | 2,615 | 0.01% |
| | | | | | | | Cupric Chloride Dihydrate | 10125-13-0 | 100% | 2,615 | 0.01% |
| Scalesorb 3 | Scale Inhibitor | 97 | 0.00% | 19.68 | 1,900 | 0.01% | | | | | |
| | | | | | | | Calcined Diatomaceous Earth | 91053-39-3 | 100% | 1,900 | 0.01% |
| | | | | | | | Amino Tri (Methylene Phosphonic Acid) | 6419-19-8 | 30% | 570 | 0.00% |
| | | | | | | | Phosphonic Acid | 13598-36-2 | 1% | 19 | 0.00% |
| | | | | | | | Crystalline Silica Quartz | 14808-60-7 | 1% | 19 | 0.00% |
| XLW-30AG | Crosslinker | 710 | 0.03% | 8.76 | 6,220 | 0.03% | | | | | |
| | | | | | | | Hydrotreated Light Distillate | 64742-47-8 | 70% | 4,354 | 0.02% |
| Alpha 114 | Biocide | 577 | 0.03% | 8.55 | 4,933 | 0.03% | | | | | |
| | | | | | | | Gluteraldehyde | 111-30-8 | 15% | 740 | 0.00% |
| | | | | | | | N-Alkyl Dimethyl Benzyl Ammonium Chloride | 139-08-2 | 5% | 247 | 0.00% |
| XLW-32 | Crosslinker | 135 | 0.01% | 7.38 | 996 | 0.01% | | | | | |
| | | | | | | | Boric Oxide | 1303-86-2 | 90% | 897 | 0.00% |
| | | | | | | | Methanol | 67-56-1 | 20% | 199 | 0.00% |
| BF-9L | Buffer | 708 | 0.03% | 12.38 | 8,765 | 0.05% | | | | | |
| | | | | | | | Potassium Hydroxide | 1310-58-3 | 15% | 1,315 | 0.01% |
| ClayCare | Clay Control | 2,100 | 0.10% | 9.17 | 19,257 | 0.10% | | | | | |
| | | | | | | | Choline Chloride | 67-48-1 | 75% | 14,443 | 0.08% |
| | | | | | | | Water | 7732-18-5 | 30% | 5,777 | 0.03% |
| TOTALS | | 2,063,764 | 100% | | 18,447,675 | 100% | | | | 18,453,534 | 100.00% |

Data entered by USER via PROGRAM

Data calculated by EXCEL

Data transferred from "MSDS" by PROGRAM

Conservative* = Total Ingredient Percentages may exceed 100% and Total Ingredient Weights may exceed Product Weight

Figure 62.Composition of fracturing fluid for well Kennedy #1H in Wilson country Texas, USA

Source link: http://www.fracfocusdata.org/DisclosureSearch/SearchResults.aspx