Algerian Democratic Republic and Popular.

Ministy of Higher Education and Scientific Research

N° serie: ……. /2016

Kasdi Merbah University, Ouargla

Faculty of hydrocarbon, renewable energy, earth and universe science

Production department

Hydraulic Fracturing Analysis and Evaluation in Cambrian Reservoir Hassi Messaoud, Algeria Case of Study MD-505

MASTER OF SCIENCE

Major Subject: Petroleum Engineering

Submitted By:

Zakaria DAOUD

Abd esselam ALI SAHRAOUI

Supervisor:

Mohamed El-Ghali KHEBBAZ

Board of examiners:

Chairman: Fatiha CHELGHEM MAB - UKMO

Member: Fatma Zohra SOUICI MAA - UKMO

June 2016

Abstract:

Hydraulic fracturing is an important method used to overcome permeability restriction problems in oil and gas reservoirs, stimulating low permeability or damaged formations. Designing a hydraulic fracturing job requires an understanding of a pressure decline analysis. There are a various methods used for this analysis. In our work we used Nolte G-function because it is a good approach. In the case of the well MD 505, the flow rate was increased from 0.55 to 4.77 m^3/h. So the best analysis led to the success of fracturing operation.

Résumé:

La fracturation hydraulique est une méthode importante utilisée pour surmonter les problèmes de restriction de perméabilité, on stimulant les formations endommagé ou de perméabilité faible. La planification d'une fracturation hydraulique nécessite la compréhension de l'analyse de déclin de pression. Il existe plusieurs méthodes pour cette analyse. Dans notre travail on a utilisé la méthode de fonction G de Nolte car elle est une bonne approche. Dans le cas du puits MD 505, le débit est augmenté du 0,55 à 4,77 m^3/h. Alor, le succès de l'opération de fracturation est conduit par une meilleure analyse.

Dedication:

To Our Families and Friends

Acknowledgements:

We would like to express our deep and sincere gratitude to our advisor Mr. Mohamed El-Ghali KHEBBAZ for his support, his guidance, his passion and his demand for perfection.

And thanks also goes to all the engineers who help us accomplish this work: Mohamed Elhadi ATLILI, Hakim AKROUF, Abdelaziz MOULOUDENE, Adel ZINAT, Ahmed HIDOUD, Ali ALLALI, Messaoud SKIA, Youcef RIGHI, Farouk BOUZERDA, and Lounis SEHIB

We would also like to thank our families. They supported us throughout the course of completing our studies. Thanks go also to our friends and the staff of Kasdi Merbah University, for making our time at the university a great experience.

Nomenclature:

FVF	Formation Volumetric Factor.
F_{cd}	The Dimensionless Conductivity.
K_f	Permeability of The Fracture.
W_f	Width of The Fracture.
X_f	The Length of The Fracture.
$K_{e:}$	Permeability of The Formation.
$L_{xf:}$	Half Length of The Fracture.
K	The Formation Permeability.
H	The Net Height.
μ	The Fluid Viscosity.
R_e	The Drainage Radius.
R_w	The Wellbore Radius.
Hhp	Hydraulic Horsepower.
σ	In Situ-Stress.
ε	Strain.
E	Young's Modulus (psi).
ν	Poisson's Ratio.
G	Shear Modulus.
σV	The Vertical Stress.
σ'	The Effective Stress.
α	Biot's Constant.
σ_v	Overburden Stress (Psi).
ppa	Pound of Proppant Additive Per Gallon.
ε_{Tect}	Tectonic Strain.
BHLPP	Bottom Hole Last Pumping Pressure (psi).

BHISIP	Bottom Hole Instantaneous Shut In Pressure (psi).
SISIP	Surface Instantaneous Shut In Pressure (psi).
SLPP	Surface Last Pumping Pressure (psi).
Δp	The Pressure Differential (Or Drawdown).
$\Delta P_{pipe\ friction}$	Pipe Friction (psi).
ΔP_{nwb}	Near Well Bore Friction (psi).
ΔP_{Total}	Total Friction (psi).
P_{BH}	Bottom Hole Pressure (psi).
P_p	Pore Pressure (Psi).
η	Efficiency.
C_L	Leak Off Coefficient.
n’	Fluid Rheology Coefficient.
B_s	Reflect The Effect of Fluid Flow And Viscosity During The Closure.
E’	Deformation Modulus.
r_p	Ratio of Permeable Area To Total Frac Area
V_{Pad}	Volume of Gel (Gallon).
V_i	Volume Injected.
T_c	Closure Time (Min).
t_{inj}	Injection Time (Min).
Q	The Flow Rate (m^3/H).
Q_{Gas}	Gas Rate (m^3/H).
Q_{Oil}	Oil Rate (m^3/H).
GOR	Gas Oil Ratio.
UB	Upper Bound
LB	Lower Bound

Contents :

List of Figures:

CHAPTER I:

CHAPTER II:

CHAPTER III:

CHAPTER IV:

List of Tables:

Introduction:

The first start of production in the oil field is done through the natural energy of the reservoir. Over the years, the reservoir pressure drops due to accumulated production points which lead us to the assisted recovery. But the effectiveness of this method depends on the petro physical characteristics of the reservoir and the condition of the area surrounding the well. To restore or improve the productivity, a stimulation operation is needed.

Reservoir stimulation and artificial lift are the two main activities of the production engineer in the petroleum and related industries. The main purpose of stimulation is to enhance the property value by the faster delivery of the petroleum fluid and/or to increase ultimate economic recovery. Matrix stimulation and hydraulic fracturing are intended to remedy, or even improve, the natural connection of the wellbore with the reservoir, which could delay the need for artificial lift. Hydraulic fracturing has become a very common and widespread technique, due to technological advances that have allowed extracting the natural oil and gas. Hydraulic fracturing makes possible the production of oil and natural gas in areas where conventional technologies have proven ineffective. Recent studies estimate that up to 95% of natural gas wells drilled in the next decade will require hydraulic fracturing.

The success of such an operation depends heavily on selected parameters and decisions taken to avoid failure or any additional expense and have a good performance of the operation.

For these reasons, injectivity tests are performed before the actual treatment (hydraulic fracturing) to establish a good fracturing program, but the most important test is the mini frac test.

In 1979 NOLTE presented a comprehensive analysis of the pressure decline mechanism. It is therefore an analysis of the pressure decline in the phase between the instantaneous drop in pressure and the closing pressure.

Hydraulic fracturing study case (the well MD 505) is based on propagation models. Each model has its assumptions and its applicability, and the fracture propagates along a geometry which depends on the nature and properties of the rock.

So our goal is determining the explanation of hydraulic fracturing procedure in general way, and the prediction of fracture geometry using mini frac test DATA and evaluate the operation. We used the method of pressure decline developed by NOLTE in our work.

I.1. INTRODUCTION:

The Hassi Messaoud (HMD) structure lies approximately 800 km southeast of Algiers, Algeria. It is a flattened, broad, oval anticline trending north- northeast to south-southwest, parallel to the major fault zone.

It covers almost 2,000 Km² in the Oued Mya basin. The first well, MD1 was drilled in 1956 and more than 1,000 wells have been drilled over the last 40 years. The field has been subdivided into 25 zones based on observed inter well pressure communication, the reservoir is in the Cambrian subdivided into four lithozone Ri, Ra, R2, and R3.

I.2. THE GEOGRAPHICAL SITUATION:

Hassi Messaoud is located 800 km southeast of Algiers, between the meridians 5°30 6°00 and the parallels 31°00 and 32°00N (Figure I.1). It is 350km far from the Algero-Tunisian frontier and 80 km east of Ouargla. It is considered to be one of the largest oil deposits in the world and the more prospected of the Saharan platform.

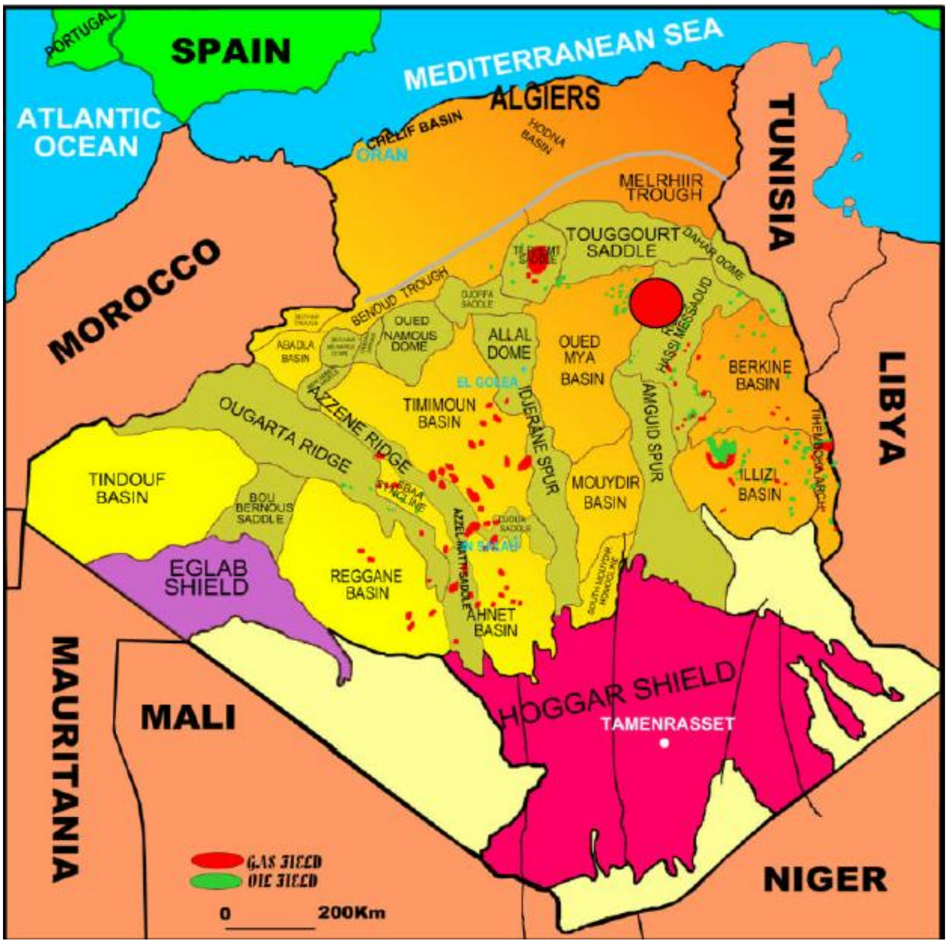


Figure I.1: Location of Hassi Messaoud Field, Algeria.

I.3. STRUCTURE AND STRATIGRAPHY:

The Saharan desert within the so-called Triassic Basin (Oued Mya Basin) is part of the North African stable craton. The basin has had a long history from Cambrian times onwards, and has a sedimentary column of about 5,000 m (Figure I.2). The **Cambrian** sediments are a thick series of fluvial and shallow marine sandstones, deposited on a peneplained surface composed, in the Hassi Messaoud area, of Early Cambrian granites. The Algerian Sahara was invaded by a relatively deep anoxic sea during the **Ordovician**, but this was followed by a regional regression and a period of coarse clastic, continental and glacial sedimentation.

During the **Late Silurian,** deep marine conditions once again occurred over a wide area in North Africa, but the **Caledonian orogeny** led to the creation of a number of gentle, regional uplifts. **Devonian** sandstones and shales were deposited extensively in fluvial and shallow marine environments over much of North Africa, including Algeria, and lie unconformable on tilted and eroded Lower Paleozoic sediments. They were followed by deltaic and marine sandstones and shales of **Carboniferous** age. It is not known for certain whether these Upper Paleozoic sediments were deposited over the Hassi Messaoud high because they have not been preserved there. They may have been deposited with a reduced thickness, but in any case would have been subsequently removed as a result of the tectonic upheavals related to the **Hercynian orogeny** of Late Carboniferous to Permian times. The grain of the Hercynian orogeny in the Hassi Messaoud area is oriented mostly NE-SW, as is typically seen in the trend of the Messaoud - El Agreb.

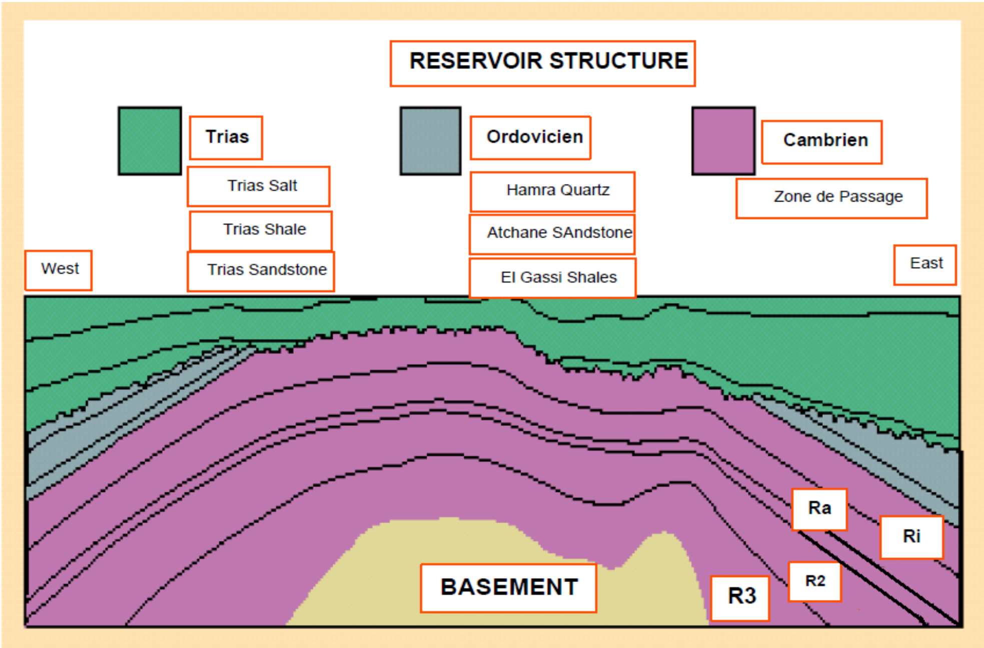


Figure I.2: Hassi Messaoud Reservoir Structure.

The productive formation of Hassi Messaoud is a series of Cambrian sandstones, with an average thickness of 300 m and 4 productive zones denominated R3, R2, Ra, Ri (from bottom to top). The Ra represents the best reservoir qualities. The Paleozoic of Hassi Messaoud has been eroded by the Hercynian unconformity which reaches the R2 in places. This erosion is increasingly important from the periphery to the center where the Ra is locally absent. Structurally, only the top of R2 allows us to correctly define the geometry of the Cambrian of Hassi Messaoud (Figure I.3). The Hassi Messaoud structure appears as a large SSW-NNE Oriented anticline, affected by the major faults SSW-NNE.

R3 lithozone

Non-producing zone with a very low permeability and a high clay content averaging 30 % (illite predominantly). The R3 section thickness increases from 275 m (902 ft) in well Md2 in the south central part of the field northward to 368 m (1207 ft) in well Omg57 north of the field.

R2 lithozone

It has a high clay content, averaging 20%, mainly illite with minor amount of kaolinite, occurring as interstitial clay and irregular thin inter beds of shale. R2 is a thick sequence of medium to coarse-grained sandstones. It has a good reservoir quality in the northern part of the field where water saturation is low. The R2 is considered the lower boundary for the net interval due to the proximity to the water oil contact (WOC). R2 is subdivided into two layers: The upper R2 (R2-r1), and the lower R2 (R2-r2). R2-r1 has in general better reservoir characteristics than the latter. Where it is not eroded, R2 zone is about 80 m (262 ft) thick.

Ra (anisometric zone)

The Ra zone has a maximum total thickness of 150 m (492 ft) in the western portion of the field, and it is considered as the primary reservoir. The Ra zone is fine-grained quartzite sandstone. Ra zone has been subdivided into five subzones highly laminated with silts and black shale, that are, from the upper to the lower: D4, D3, D2, ID, and D1. The predominant clay mineral in Ra is kaolinite. D5, D4, and D3 drains are eroded in the central northern portions of the field.

Ri (isometric zone)

Also referred to as D5, is a 50 m (164 ft) thick quartzitic sandstone unit. It is characterized as a uniformly thick, well sorted, medium grained sandstone with inter beds of shale and siltstone. D5 is not considered as a significant producing zone because of its poor reservoir characteristics. The predominant clay mineral in layer D5 is illite.

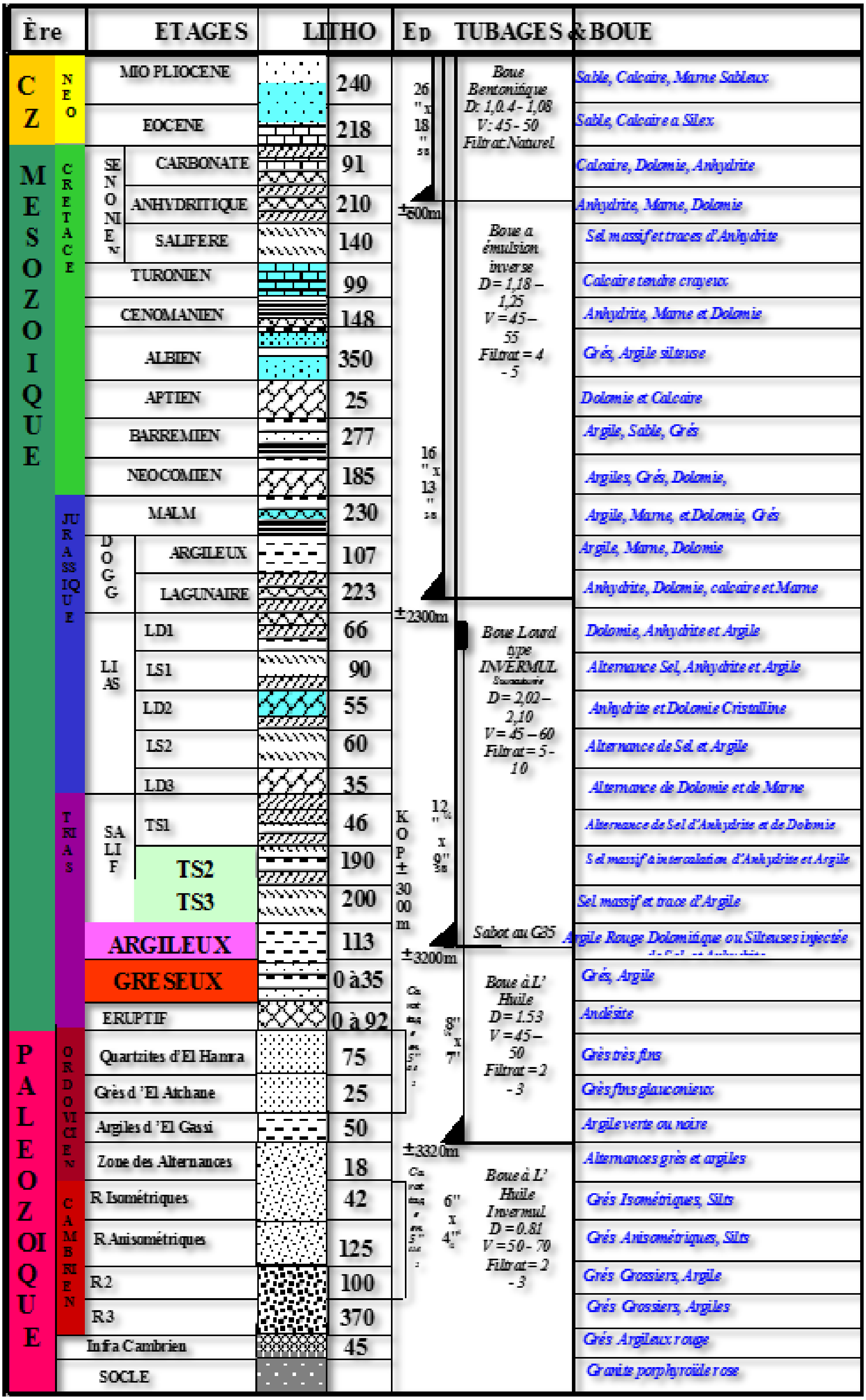


Figure I.3: Stratigraphic Section of Hassi Messaoud Field.

I.4. PETROPHYSICAL CHARACTERISTICS:

The base of the Cambrian reservoir is made of coarse to micro-conglomeratic sandstones inter bedded with highly fissured conglomerates. The grain size decreases from the bottom towards the top (60% to 75% in the R3, 90% to 95% in the Ri). The different parts of the Cambrian may be described as follows (Figure I.4):

- The R3 is composed of coarse sandstones and conglomerates, with a cement made of clay and dolomite. The clay is mainly Illite. The porosity varies from 5% to 10%. And permeability is in the range of below 10 md.
- The R2 is made of sandstones which are coarse but smaller sizes grain than do those in the R3. The cement is argillaceous (Kaolinite). The porosity varies from 10% to 13% and permeability is normally below 10 md.
- The Ra is characterized by the interstratification of sandstones and quartzites of variable grain size with shale beds. The cement is argillaceous (dickite). The Ra represents the best petro physical properties with porosity up to 15% and permeability of up to 1 Darcy where fissures exist.
- The Ri is made of fine rounded, isometric sandstone with considerable development of quartzite. The porosity varies from 5% to 10%. And permeability is in the range of below 10 md.

<table>
<tr><th colspan="3">TYPE OF CORRELATION</th><th>THICKNESS (m)</th><th>DRAINS</th></tr>
<tr><td rowspan="13">CAMBRIAN RESERVOIR</td><td colspan="2">Altern. Zone</td><td>19</td><td></td></tr>
<tr><td rowspan="7">R1</td><td>R iso</td><td>38</td><td>D_5</td></tr>
<tr><td rowspan="6">Ra</td><td>Variable</td><td>D_4</td></tr>
<tr><td>24</td><td>D_3</td></tr>
<tr><td>24</td><td>D_2</td></tr>
<tr><td>30</td><td>ID</td></tr>
<tr><td>27</td><td>D_1</td></tr>
<tr><td></td><td></td></tr>
<tr><td rowspan="5">R2</td><td rowspan="5">R_2-r_2 R_2-r_1</td><td>14</td><td rowspan="6">C</td></tr>
<tr><td>19</td></tr>
<tr><td>20</td></tr>
<tr><td>15</td></tr>
<tr><td>15</td></tr>
<tr><td colspan="2">R_3</td><td>300</td></tr>
</table>

Figure I.4: Cambrian Reservoir Lithozones.

The oil is under saturated and light. It contains no sulfur and have a density of 0.8 at surface. Its composition differs slightly from one zone to another.

- The oil viscosity at surface is 2 cp.
- The oil saturation is up to 85%.
- The reservoir temperature is 118 C.
- The oil FVF is 1.6 -1.7.
- The bubble point pressure is between 155 and 200 kg/cm2.
- The maximum porosity of all these reservoirs is approximately 15 %.
- The permeability varies from 0.5 to 1000 md in the fissured zones.

Salinity of connate water varies from one zone to another but is constant over large intervals.

II.1. HISTORY :

The first attempts at fracturing formations were not hydraulic in nature, they involved the use of high explosives to break the formation apart and provide “flow channels” from the reservoir to the wellbore. There are records indicating that this took place as early as 1890. Indeed, one of the predecessor companies of BJ Services, the Independent Torpedo Company, was founded in 1905. It used nitroglycerine to explosively stimulate formations in Ohio. This type of reservoir stimulation reached its ultimate conclusion with the experimental use of nuclear devices to fracture relatively shallow, low permeability formations in the late 1950’s and early 1960’s.

In the late 1930’s, acidizing had become an accepted well development technique. Several practitioners observed that above a certain “breakdown” pressure, injectivity would increase dramatically. It is probable that many of these early acid treatments were in fact acid fractures.

In 1940, Torrey recognized the pressure-induced fracturing of formations for what it was. His observations were based on squeeze cementing operations. He presented data to show that the pressures generated during these operations could part the rocks along bedding planes or other lines of “sedimentary weakness”. Similar observations were made for water injection wells by Yuster and Calhoun in 1945.

The first intentional hydraulic fracturing process for stimulation was performed in the Hugoton gas field in western Kansas, in 1947. The Klepper well was completed with 4 gas producing limestone intervals, one of which had been previously treated with acid. Four separate treatments were pumped, one for each zone, with a primitive packer being employed for isolation. The fluid used for the treatment was war-surplus napalm, surely an extremely hazardous operation. However, 3000 gals of fluid were pumped into each formation.

Although post treatment tests showed that the gas Injectivity of some zones had been increased relative to others, the overall deliverability from the well was not increased. It was therefore concluded that fracturing would not replace acidizing for limestone formations. However, by the mid-1960’s, propped hydraulic fracturing had replaced acidizing as the preferred stimulation method. Early treatments were pumped at 1 to 2 bpm with sand concentrations of 1 to 2 ppa.

Today, thousands of these treatments are pumped every year, ranging from small skin bypass fracturing at $20,000, to massive fracturing treatments that end up costing well over $1 million. Many fields only produce because of the hydraulic fracturing process. In spite of this, many industry practitioners remain ignorant of the processes involved and of what can be achieved.

II.2. INTRODUCTION :

The technique of hydraulic fracturing makes use of a liquid to fracture the reservoir rocks. A hydraulic fracture is formed by pumping the fracturing fluid into the wellbore at a rate sufficient to increase pressure down hole to exceed the strength of the rock. Hydraulic fracturing is used:

- when the natural permeability of the formation is low (<10 millidarcies)
- when the formation will not flow properly
- when the natural production level of the formation is below the economic potential to produce the well
- as a skin by pass technique in higher permeability and soft formations to reduce the pressure loss of the skin at the sand face

Hydraulic fracturing is associated with the following benefits:

- Improved productivity.
- Interconnected formation permeability.
- Improved ultimate recovery.
- Reduce production of formation sand in unconsolidated reservoirs.
- Aid in secondary recovery.
- Increased ease of injectivity.

Fracturing does not change the permeability of the formation, but creates a permeable path for the fluid to the wellbore. The primary purpose of hydraulic fracturing is to increase the effective wellbore radius by creating a fracture of a given length whose conductivity is greater than that of the formation. The dimensionless conductivity (F_{cd}) created by fracturing is described by the equation II.1:

$$F_{cd} = \frac{K_f W_f}{K_e X_f} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (II.1)$$

Where:

$K_{f:}$ permeability of the fracture.

$W_{f:}$ width of the fracture.

$K_{e:}$ permeability of the formation.

$X_{f:}$ half length of the fracture.

Figure II.1: Hydraulic Fracturing.

II.3. THE PROCESS:

Hydraulic fracturing occurs as a result of the phenomenon described by Darcy's law for radial flow:

$$Q = \frac{Kh}{\mu} \frac{\Delta P}{\ln \frac{r_e}{r_w}} \quad \text{(II. 2)}$$

Where Q is the flow rate, K the formation permeability, h the net height, ΔP the pressure differential (or drawdown), μ the fluid viscosity, r_e the drainage radius and r_w the wellbore radius. The equation II.2 describes the flow rate for a given reservoir-wellbore configuration, for an applied pressure differential. Re-arranging this equation gives a different emphasis:

$$\Delta P = \frac{Q\mu}{Kh} \ln \frac{r_e}{r_w} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (II.3)$$

This equation describes the pressure differential produced by a given flow rate. Remembering the Darcy's equation applies equally to injection and to production, the equation II.3 tells us the pressure differential needed to pump a fluid of viscosity μ into a given formation at a given rate Q.

As the flow rate increases, the differential pressure also increases. Pressure and stress are essentially the same thing, so that as the fluid flow generates a pressure differential, it also creates a stress in the formation. As flow rate (or viscosity) increases, so does the stress. If we are able to keep increasing the rate, eventually a point will be reached were the stress becomes greater than maximum stress that can be sustained by the formation and the rock physically splits apart. This is how we frac, by pumping a fluid into a formation at high rate and consequently high pressure. However, it is important to remember that it is **the pressure not the rate that creates fractures.**

Pressure and stress are stored energy, or more accurately stored energy per unit volume. Energy is what hydraulic fracturing is all about. In order to create and propagate a fracture to useful proportions, we have to transfer energy to the formation. Producing width and physically tearing the rock apart both require energy. Overcoming the often highly-viscous frac fluid's resistance to being pumped also takes energy. So the key to understanding the hydraulic fracturing process is to understand the sources of energy gain, such as the frac pumps and the well's hydrostatic head, and the sources of energy loss and use. The sum of these is always equal to zero.

As pressure is energy, a great deal can be learned about a formation by studying the pressures produced by a treatment. The product of the pressure and the flow rate gives us the rate at which energy is being used, i.e. work. This is usually expressed as hydraulic horsepower. The analysis of the behavior of fracturing pressures is probably the most complex aspect of the process that most Frac Engineer will become involved in.

Once a fracture has been created, proppant is placed inside it. If the treatment has been designed effectively and pumped without any problems, then this proppant should form a highly conductive path from the reservoir to the wellbore. This is what makes the well produce more.

II.3.1 The Basic Process :

As fluid is pumped into a permeable formation, a differential pressure is generated that is proportional to the permeability of the formation K_f. As the rate increases, this pressure differential between the wellbore pressure and the original reservoir pressure, also increases. Eventually, as the rate is increased, this pressure differential will exceed the stress needed to break the rock apart and a fracture is formed. At this point, if the pumps are shut down or the pressure is bleed off, the fracture will close again. Eventually, depending on how hard the rock is and the magnitude of the force acting to close the fracture, it will be as if the rock had never been fractured. By itself, this would not necessarily produce any increase in production.

However, if we pump some propping agent, or proppant, into the fracture and then release the pressure, the fracture will stay propped open, providing the proppant is stronger than the forces trying to close the fracture. If this proppant also has a permeability, then under the right circumstances a path of increased permeability has been created from the reservoir to the wellbore. If the treatment has been designed correctly, this will produce an increase in production.

Generally, the process requires that a highly viscous fluid is pumped into the well at high rate and pressure, although this is not always the case. High rate and high pressure mean horsepower, and this is why the process generally involves large trucks or skids with huge diesel engines and massive pumps. A typical frac pump will be rated at 700 to 2700 hydraulic horsepower (HHP) to put this in perspective, the average car engine has a maximum power output of 80 to 100 HP. In order to create the fracture, a fluid stage known as the pad is generally pumped first. This is then followed by several stages of proppant-laden fluid, which actually caries the proppant into the fracture. Finally, the whole treatment is displaced to the perforations. These stages are pumped consecutively, without any pauses. Once the displacement has finished, the pumps are shut down and the fracture is allowed to close on the proppant. The Frac Engineer can vary the pad size, the proppant stage size, and the number of proppant stages, the proppant concentration in the stages, the overall pump rate and the fluid type in order to produce the required fracture characteristics.

II.3.2 Fracturing Equipment :

Fracture treatments require multiple pieces of sophisticated equipment specifically designed for hydraulic fracturing. In many cases, multiple pieces of the same kind of equipment, such as pumps, are necessary. The type, size, and number of pieces of equipment needed are dependent on the size of the fracture treatment, type of treatment, as well as the additives, proppants, and fluids that are used. Table II.1 presents a listing of typical equipment used during a fracturing job, and the purpose of the identified equipment.

Table II.1: Hydraulic Fracturing Equipment.

Equipment Item	Purpose	Number on site	Description (size, capacity)
Fracturing Head	A well head connection that allows fracture equipment to attach to the well	1	
Fracturing pumps	Heavy duty pumps that take the fluid from the blender and pressurize it via a positive displacement pump	2+	Number on site depends on the pumping pressure and rates required for stimulation ; for horizontal well shale gas fracturing there are usually multiple pumps on site
Blender pumps	Takes fluid from the fracturing tanks and sand from the hopper and combines these with chemical additives before transferring the mixture to the fracturing pumps	1+	A backup blender is sometimes on location
Transfer pimps	A trailer-mounter pump and manifold system that transfers fluid from one series of Fracturing Tanks to another, or from ponds to the manifold	1+	Typically used prior to the start of the fracturing job ; once the job is started the fracturing pumps perform water transfers

Sand Storage Units	Large Tanks that hold the proppant and feed the proppant to the blender via a large conveyor belt	3+	150 to 200 tones
Fracturing Tank-supply	Water containment tanks that store the required volume of water to be used in fracture stimulations	3+	~80 m^3/tank (Varies)
Fracturing Tanks-Receiving	Water containment tanks that store produced water from hydraulic fracture stimulations	3+	~80 m^3/tank (Varies)
Gel Slurry Tanker Truck	Transports gel slurry to the job site ; the equipment has 2 compartments to allow for the gel to be agitated between the compartments to prevent separation or break down	1	15 m^3
Chemical Storage Trucks	Flatbed trucks used to transport chemicals to the job site, may contain a pump to transfer chemical additives from the on-board storage tanks to the required equipment (i.e. blender)	1+	
Technical Monitoring Van	The work area for Engineers, Supervisors, pump Operators, Company Representatives, and Regulatory Personnel	1	
Acid Transport Trucks	Used to transport acids to job sites ; a truck has separate compartments for the transport of multiple acids or additives	1+	19 m^3/truck
Manifold Trailer	Large manifold system that acts as a transfer station for all fluids ; mixed fluids from blender pumps move through the manifold on the way to the pump trucks	1	

Once onsite, the equipment is "rigged up." The "rig-up" process involves making all of the iron connections necessary between the fracturing head on the well, the fracturing manifold trailer, the fracturing pumps, and the additive equipment which feed fluids and additives into the pumps. Figure II.2 is a picture of a fracturing wellhead set up used during the hydraulic fracturing. As mentioned earlier, these connections undergo a series of assessments and pre-tests to ensure that they are capable of handling the pressure of the fracturing job and that the connections have been properly made and sealed.

Figure II.2: Hydraulic Fracturing Equipment Onsite.

II.3.3 Hydraulic Fracturing Fluids :

Water and sand are the most common constituents of most fracturing fluids, several parameters affect the volume of fracture fluid required for a successful stimulation:

- Propping agent amount and type
- Rock type/stimulation objective
- Designed fracture conductivity
- Rock closure stress/fracture width
- Fluid leak off characteristics
- Proppant transport
- Formation permeability
- Injection rate
- Reservoir thickness.

The main components of a fracturing fluid, besides the base carrier fluid (typically water), are the following additive. Common additive purposes and examples of chemicals used for these purposes are presented in Table II.2.

Table II.2: Fracturing Fluid Additives, Main Compounds and Common Uses.

Additive Type	Main Compound	Use in Hydraulic Fracturing Fluids	Common Use of Main Compound
Acid	Hydraulic Acid Or Muriatic Acid	Acids are used to clean cement from casing perforations and drilling mud clogging natural formation porosity, if any, prior to fracturing fluid injection (dilute acids concentrations are typically about 15% acid)	Swimming pool chemical and cleaner
Biocide	Glutaraldehyde	Fracture fluids typically contain gels that are organic and provide a medium for bacterial growth. Bacteria can break down the gelling agent reducing its viscosity an ability to carry proppant. Biocides are added to the mixing tanks with the gelling agents to kill these bacteria.	Cold sterilant in health care industry
Breaker	Sodium Chloride	Breakers are chemicals that are typically introduced toward the later sequences of a fracturing job to "break down" the viscosity of the gelling agent to better release the proppant from the fluid enhance the recovery or "flow back" of the fracturing fluid.	Food Preservative
Corrosion Inhibitor	N, N-Dimethyl Form amide	Corrosion inhibitors are used in fracture fluids that contain acids; they inhibit the corrosion of steel tubing, well casings, tools, and tanks.	Crystallization medium in Pharmaceuticals
Cross linker	Borate Salts	There are two basic types of gels used in fracturing fluids: linear and cross-linked. Cross-linked gels have the advantage of higher viscosities that do not break down quickly.	Non-CCA wood preservatives and fungicides

Friction Reducer	Petroleum Distillate Or Mineral Oil	Friction reducers minimize friction, allowing fracture fluids to be injected at optimum rates and pressures.	Cosmetics, nail and skin products
Gel	Guar Gum Or Hydroxyethyl cellulose	Gels are used in fracturing fluids to increase fluid viscosity, allowing them to carry more proppant than straight water solutions. In general, gelling agents are biodegradable.	Food-grade product used to increase viscosity and elasticity of ice cream, sauces and salad dressings.
Iron Control	Citric Acid	Iron controls are sequestering agents that prevent precipitation of metal oxides.	Used to remove lime deposits. Lemon Juice is ~ 7% Citric Acid
Kcl	Potassium Chloride	Kcl is added to water to create a brine carrier fluid.	Table salt substitute
Oxygen Scavenger	Ammonium Bisulfate	Oxygen present in fracturing fluids through dissolution of air causes the premature degradation of the fracturing fluid; oxygen scavengers are commonly used to bind the oxygen.	Used in cosmetics
Proppant	Silica , Quartz Sand	Proppants consist of granular material, such as sand, mixed with the fracture fluid. They are used to hold open the hydraulic fractures, allowing the gas or oil to flow to the production well.	Play box sand, concrete or mortar sand.
Scale Inhibitor	Ethylene Glycol	Scale inhibitors are added to fracturing fluid to prevent precipitation of scale (calcium carbonate precipitate).	Automotive antifreeze and de-icing agent
Surfactant	Naphthalene	Surfactants are used to reduce interfacial tension and promote more efficient clean-up or flow-back of injected fluids.	Household fumigant (found in mothballs)

III.1. INTRODUCTION :

Rock mechanics is the study of the mechanical properties of a rock, especially those properties which are of significance to Engineers. It includes the determination and effects of physical properties such as bending strength, crushing strength, shear strength, moduli of elasticity, porosity, permeability and density, and their interrelationships.

III.2. MECHANICAL ROCK PROPERTIES :

- ✓ In situ-Stress (σ)
- ✓ Strain (ε)
- ✓ Young's Modulus (E)
- ✓ Poisson's Ratio (ν)
- ✓ Shear Modulus (G)

The mathematical solutions of almost all rock mechanics problems are expressed in terms of stresses and strains.

III.2.1. In-situ stress :

a. Definition:

Rocks at great depth are subject to high stresses. The stress in each direction is normally different as they come from different sources. In a stress system the principle stresses are 90 degrees apart, or mutually perpendicular.

Generally if we consider that the vertical stress (σ_V) will be a principal stress. We can complete the stress state with 2 horizontal stresses that are 90 degrees apart (and both 90 degrees from vertical).

Thus the in-situ stresses can be represented as shown below (Figure III.1):

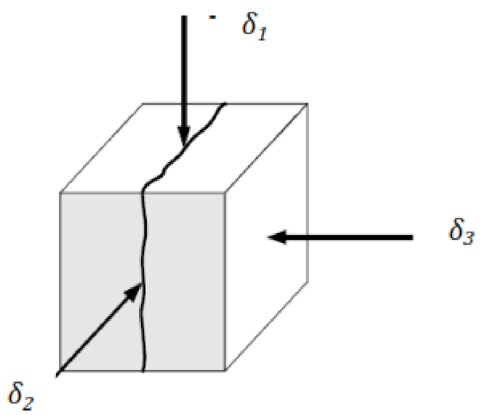


Figure III.1: The In-situ Stresses.

b. Effective stress:

Each in-situ stress is then reduced by the amount of the pore pressure. The pore pressure (Pp) in the rock acts in all directions and so has the effect of reducing the grain to grain stresses. Pore fluids in the reservoir rock play an important role because they support a portion of the total applied stress. Hence, only a portion of the total stress, namely the effective stress component, is carried by the rock matrix.

In 1923, Terzaghi first introduced the effective stress concept for one-dimensional consolidation and proposed the following relationship:

$$\sigma' = \sigma - \alpha\, P_P \quad \text{(III. 1)}$$

Where:

σ': is the effective stress governing the failure of the material.

σ: is the total applied stress.

P_p: is the pore pressure.

α: is Biot's constant.

This one-dimensional approach was later generalized by Biot, who proposed a consistent theory to account for the coupled diffusion/deformation processes. Terzaghi's law was slightly modified in rock mechanics by applying a correction factor to the pore pressure term.

c. Horizontal Stress (σ_h) :

To determine the horizontal stresses, we need to include the Poisson ratio. The amount of effective Horizontal Stress is defined as:

$$\sigma'_h = \left(\frac{\nu}{1-\nu}\right) * \sigma'_v \quad \text{(III. 2)}$$

The absolute horizontal Stress is affected also by:

- Pore pressure
- Tectonic component

$$\sigma_h = \sigma'_h + \alpha p_p + \varepsilon_{tec} E \quad \text{(III. 3)}$$

$$\sigma_{h\min} = \left(\frac{\nu}{1-\nu}\right)\left(\sigma_v - \alpha\, p_r\right) + \alpha\, p_r + (\varepsilon_{Tect} * E) \quad \text{(III. 4)}$$

Where:

(ν) =*Poisson Ratio*

(σ_{ϖ}) = *Overburden Stress (Psi)*

(a) = *Biot's Constant*

(P_p) = *Pore Pressure (Psi)*

(ε_{Tect}) = *Tectonic Strain*

(E) = *Young Modulus (Psi)*

The value of the minimum horizontal stress can be determined in different way:

$$\sigma_h = ISIP \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots \ldots (III.5)$$

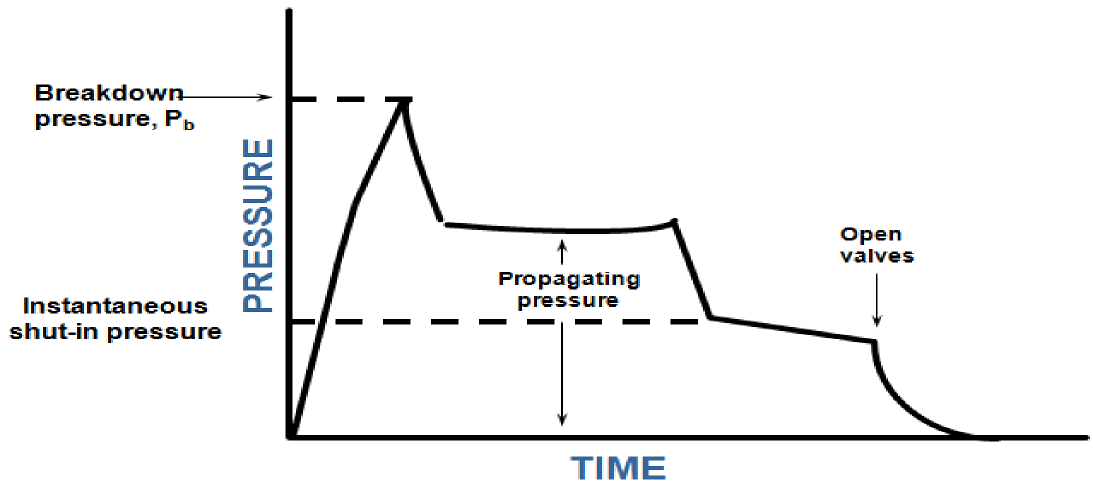


Figure III.2: The Instantaneous Shut-In Pressure Plot.

III.2.2. Strain (ε) :

a. *Definition of Strain :*

When a force, or stress, is applied to a rock, it changes shape or size. The deformation of the rock is called strain, and the magnitude of the induced strain is proportional to the applied stress.

Strain is a dimensionless parameter which can be positive or negative depending on the agreed upon sign convention. Typically in fracture mechanics compression is considered to be positive strain and elongation is negative, but this is not always true.

b. *Strain is of two types:*

- ✓ Axial Strain
- ✓ Radial Strain

Axial strain: Whenever there is a change in length axially due to an axial stress – an axial strain is created.

Radial strain: Due to an axial stress, change in the dimensions in the other two directions cause Radial Strain.

Like stresses, strains in a body may have different values and directions at different points

c. *Strain Formula:*

For an axially loaded cylindrical sample, the change in sample length divided by the original sample length is defined as the induced strain.

$$strain = \frac{Change\ in\ Length}{Original\ Length} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (III.6)$$

$$\varepsilon = \frac{L2 - L1}{L1} = \frac{\Delta L}{L} \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots \quad (III.7)$$

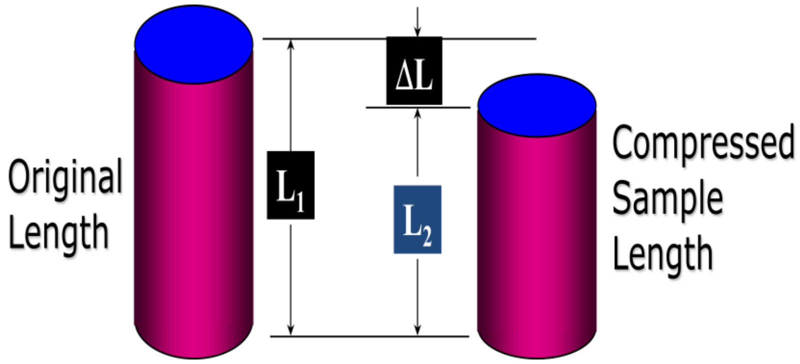


Figure III.3: The Strain of the Rock.

III.2.3. Young's Modulus (E) :

a. *Definition :*

Defined as stress divided by strain, has the same units as pressure or stress. Young's Modulus, which is denoted by a capital E. Note that if the material tested is perfectly linear and elastic, one value of E will define the stress-strain behavior of the material under all loading conditions.

This relationship exists between stress and strain. A higher applied load (or stress) usually causes a larger strain. For a perfectly linear, elastic medium the relationship between stress and strain follows a single straight line.

b. *Young's modulus Formula:*

$$E = \frac{\sigma_x}{\varepsilon_x} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.8)$$

Where:

$$\sigma_x = \frac{F}{\pi * (\frac{D}{2})^2} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.9)$$

$$\varepsilon_x = \frac{L_i - L_f}{L_i} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.10)$$

$$E = 2(1 + v)G \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.11)$$

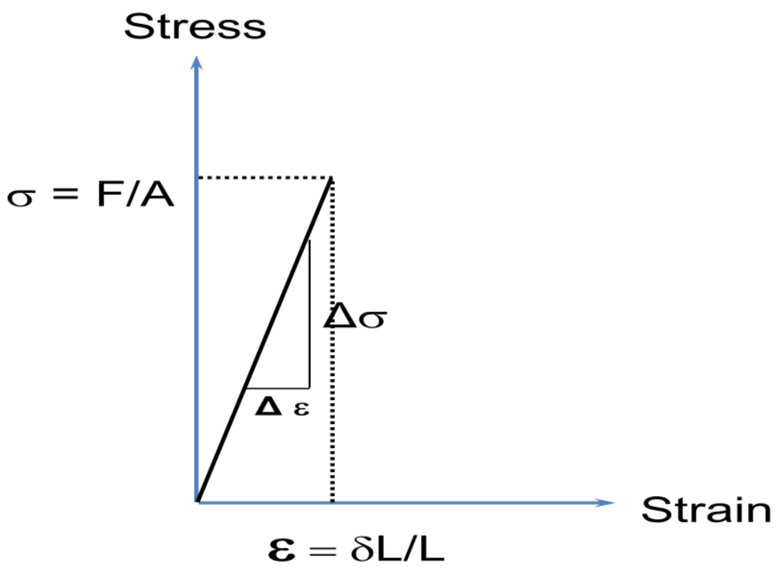


Figure III.4: Young Modulus Representation.

c. *Importance Of Young's Modulus :*

The Young's Modulus is an important parameter to calculate the fracture pressure, width profile and the differences in the young`s modulus of adjacent layers can have effect on fracture height.

For the same pressure, formations with low Young's Modulus will have wider fractures than formation with higher Young's Modulus.

III.2.4. Poisson's Ratio (ν) :

a. Definition :

Poisson's Ratio is defined as the ratio of lateral to axial strain under conditions of axial loading. If a load is applied along a given axis a strain results which is proportional to the Young's Modulus (E) (Figure III.5).

b. Poisson's ratio :

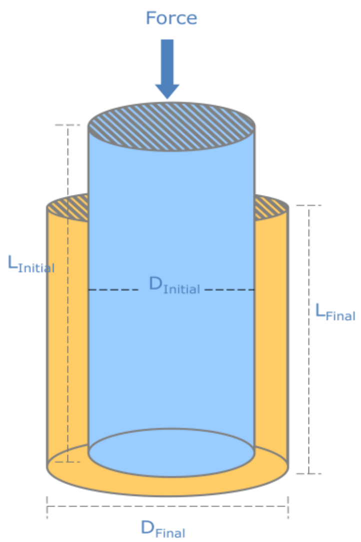


Figure III.5: Poisson's Ratio Representation.

$$\nu = \frac{\varepsilon\ lateral}{\varepsilon\ Axial} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (III.12)$$

$$\varepsilon\ Axial = \frac{\delta L}{L} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (III.13)$$

$$\varepsilon\ lateral = \frac{\delta r}{r} \quad \ldots\ldots\ldots\ldots\ldots\ldots \quad (III.14)$$

The numerical value of Poisson's Ratio lies between 0.0 and 0.5.

- ✓ A value of zero means that no lateral strain results when a sample is loaded.
- ✓ A value of 0.5 means that the sample expands laterally as much as it is compacted axially.

A soft, incompressible rubber has a Poisson's Ratio of about 0.5 while rock samples generally range from 0.15 to 0.35.

Therefore a material with a low value for Poisson's ratio will have a wider fracture since not as much axial force is trying to close the fracture. The reverse is true for materials with high Poisson's ratios.

III.2.5. Shear Modulus (G) :

The shear modulus is similar to the Young's modulus, except that it refers to the material being in shear, rather than in compression or tension. It defines how much energy is required to elastically deform a material in shear:

With reference to (Figure III.6) the shear stress τ, is given by:

$$\tau[psi] = \frac{F}{A} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.15)$$

Where **A** is the area of the block of material parallel to the line of action of the force **F**, (this is the plane along which the shear stress acts) and is equal to a × b.

The shear strain γ, is defined as follows:

$$\gamma = \frac{\Delta x}{l} = tan\,\theta \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (III.16)$$

Therefore, the shear modulus G, is equal to the shear stress divided by the shear strain:

$$G = \frac{shear\ stress}{shear\ strain} = \frac{\frac{F}{A}}{\frac{\Delta X}{L}} = \frac{\tau}{\tan\theta} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (\mathrm{III}.17)$$

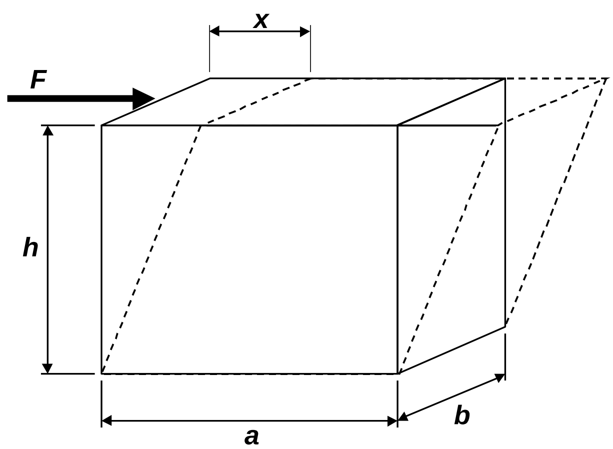


Figure III.6: The Shear Modulus Made by the Force F.

III.3. FRACTURE GEOMETRY:

The efficiency of fracturing operation is based on three following dimensions:

III.3.1. The length X_L:

This is the distance between the well and the end of the fracture, so it can be the length or half-length depending on the fracture if it is one or two symmetrical wings (Figure III.7).

III.3.2. The width W:

This is the distance between the two vertical sections of the fracture (Figure III.7).

III.3.3. The height H:

This is the distance measured vertically between the two points associated with a zero thickness (Figure III.7).

All this concerns the vertical fracture, in terms of the horizontal fracture we have the height which replaces the thickness and otherwise.

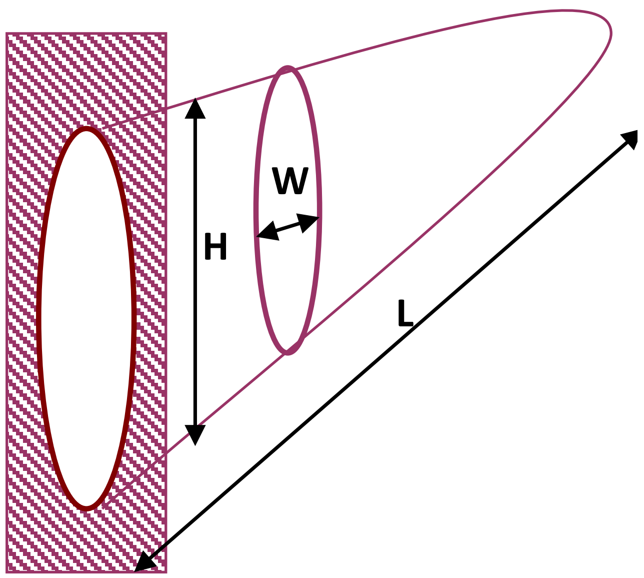


Figure III.7: Geometry Parameters of the Fracture Wing.

III.4. FRACTURE MECHANICS :

Fracture mechanics for concrete can be a useful tool for the designer because of the insight it provides on size effects, that is how the size of a structural element will affect the ultimate load capacity. Fracture mechanics also provides powerful criteria for the prediction of crack propagation.

There are various models used to approximately define the development and propagation of fracture geometry, which can be broadly classified into 2D and 3D categories. 2D models include, the Perkins-Kern-Nordgren (PKN) fracture model, and the Khristianovic-Geertsma-de. Klerk (KGD) fracture model, and the radial model. 3D models include fully 3D models and pseudo-three-dimensional (P-3D) models. The P-3D model is used in the oil industry due to its simplification of height growth at the wellbore and along the fracture length in multi-layered formations.

III.4.1. PKN:

Perkins and Kern (Perkins and Kern 1961) developed equations to compute fracture length and width with a fixed height. Later Nordgren (Nordgren 1972) improved this model by adding fluid loss to the solution, hence, this model is commonly called PKN model. The PKN model assumes that fracture toughness could be neglected, because the energy required for fracture to propagate was significantly less than that required for fluid to flow along fracture length, and the plane strain behavior in the vertical direction, and the fracture has a constant height, and propagates along the horizontal direction (Figure III.8).

From the aspect of solid mechanics, when the fracture height, hf, is fixed and is much smaller than its length, the problem is reduced to two-dimensions by using the plane strain assumption. For the PKN model, plane strain is considered in the vertical direction, and the rock response in each vertical section along the x-direction is assumed independent on its neighboring vertical planes. Plain strain implies that the elastic deformations (strains) to open or close, or shear the fracture are fully concentrated in the vertical planes sections perpendicular to the direction of fracture propagation. This is true if the fracture length is much larger than the height.

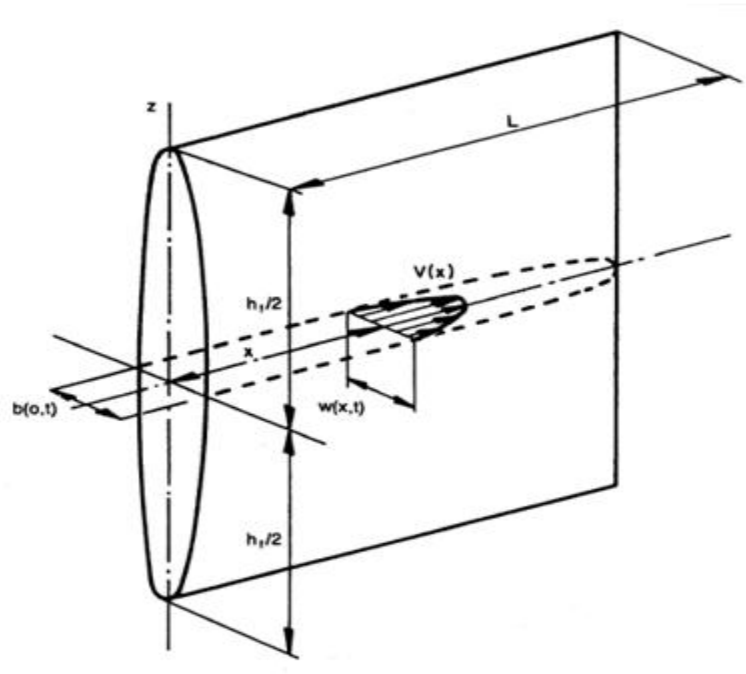


Figure III.8: PKN Fracture Schematic Diagram.

From the aspect of fluid mechanics, fluid flow problem in PKN model is considered in one dimension in an elliptical channel. The fluid pressure, f p, is assumed to be constant in each vertical cross section perpendicular to the direction of propagation.

III.4.2. KGD :

KGD model was developed by Khristianovitch and Zheltov (1955) and Geertsma and de Klerk (1969). It considers fracture mechanics effects on the fracture tip, and simplifies the solution by assuming that the flow rate in the fracture is constant and the pressure is also constant along the majority of the fracture length, except for a small region close to the tips. In this model, plane strain is assumed to be in horizontal direction i.e., all horizontal cross sections act independently. This holds true only if fracture height is much greater than fracture length. Also, since it assumes that the fracture width does not change along the fracture face all section are identical. The model also assumes that fluid flow and fracture propagation are in one dimension (Figure III.9).

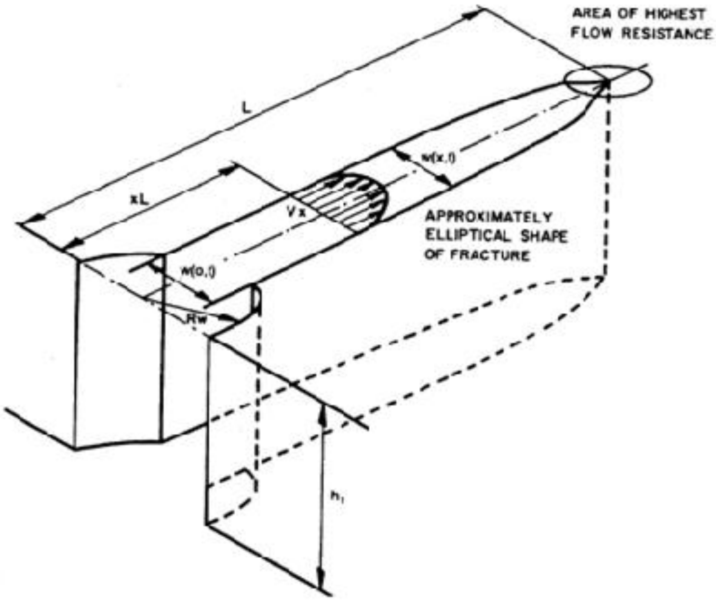


Figure III.9: KGD Fracture Schematic Diagram.

In summary, KGD model has six assumptions:

1) The fracture has an elliptical cross section in the horizontal plane.

2) Each horizontal plane deforms independently.

3) Fracture height, hf, is constant.

4) Fluid pressure in the propagation direction is determined by flow resistance in a narrow rectangular, vertical slit of variable width.

5) Fluid does not flow through the entire fracture length.

6) Cross sections in the vertical plane are rectangular (fracture width is constant along its height).

III.4.3. Radial Model (or Penny-Shaped) :

In this model, the fracture is assumed to propagate within a given plane and the geometry of the fracture is symmetrical with respect to the point at which fluids are injected (Figure III.10). A study of penny-shaped fracture in a dry rock mass was carried out by Abé et Al. (Abé et Al. 1976). In their study, they assumed a uniform distribution of fluid pressure and constant fluid injection rate.

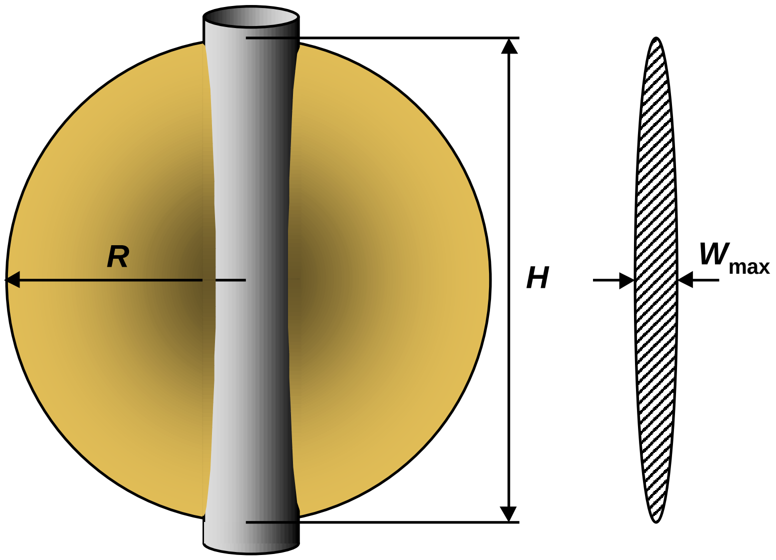


Figure III.10: Geometry of a Penny-Shaped or Radial Model.

III.4.4. Comparison between 2D models:

The following table (Table III.1) gives comparison of the three types of 2D hydraulic fracture models.

Table III.1: Comparison Between Traditional 2D Hydraulic Fracture Models.

Model	Assumptions	Shape	Application
PKN	Fixed Height, Plain Strain in vertical direction	Elliptical Cross Section	Length >> Height
KGD	Fixed Height, Plain Strain in horizontal direction	Rectangle Cross Section	Length << Height
Radial	Propagate in a given plane, Symmetrical to the wellbore	Circular Cross Section	Radial

III.4.5. Three-dimensional and Pseudo Three-dimensional Models

The 2D fracture models discussed in the previous sections have been reasonably successful in practical simulation with a simplified calculation. However, they have limitations in that it is required to specify fracture height and/or assume radial fracture geometry to perform them. To solve that problem, pseudo-3D models are formulated by removing the assumption of constant and uniform height (Morales 1989; Settari and Cleary 1986). Instead, the height in pseudo-3D models is a function of position along the fracture and simulation time. Different from 2D models, a vertical fluid flow component is added in pseudo-3D models, and fracture lengths must be much greater than fracture heights. The even more complex fully 3D models are introduced to handle fractures of arbitrary shape and orientation by removing the assumptions in Pseudo-3D model.

IV.1. WELL PARAMETERS & RESERVOIR CHARACTERISTICS :

IV.1.1. Well information:

Well name	: **MD505**
Zone	: **14**
Drilling date	: **23/05/1999**
Well type	: **Oil producer**
Perforated Interval	: **28 (m)**
TVD	: **3491.8 (m)**

IV.1.2. Reservoir characteristic:

Reservoir	: **Cambrian**
Temperature	: **118 °C**
Permeability	: **0.5 (m.Darcy)**
Porosity	: **8-9**
Skin	: **4.63**
Reservoir pressure	: **4364 (Psi)**
Stress Gradient	: **0.77 (Psi/ft)**
Young’s modulus	: **$7.5*10^6$ (Psi)**
Poisson’s ration	: **0.20**

IV.1.3. Last Measured parameters:

Bottom hole dynamic pressure	: **1002.3 (Psi)**
Well head pressure	: **284 (Psi)**
Productivity Index	: **0.01**
GOR	: **1629**
Production rate	: **0.55**
WOR	: **0.036**

IV.1.4. Well sketch :

The wellbore diagram is shown in the Appendix (Appendix IV.I).

IV.2. THE PROGRESS OF INJECTIVITY TEST:

Step rate tests are usually performed before a hydraulic fracture treatment, as part of the fracture design process. Together with the mini frac they are used to adjust the fracture model to the actual pressure response of the formation.

There are two types of step rate test, the step up test and the step down test. The first One is used to determine fracture extension pressure, while the other is used to determine near wellbore friction. Both tests can be extremely useful when designing the principal treatment.

The test itself consists of pumping fluid into the formation at various rates. These rates start off slowly and gradually increase. The first step is usually the lowest rate that the pumps can manage. It is important to get as many stages at low rate as possible. At each stage, first achieve the rate, then wait for the pressure to stabilize and finally record the exact pressure and rate. Then move on to the next stage.

In the well MD505, the job started by pumping the treated water using low rate to establish some pressure and rate, then increase the rate to 15.5 bpm and wait the pressure to be stabilize, then switch the next pad using 15% HCL acid to clean the tubing, wellbore and perforation to minimize the friction, in this step using low rate to well manage treating the damage, after displace the acid by the treated water. The rate was raised to get to breakdown pressure. All the information collected are represented in the table below:

Table IV.1: The Injectivity Test Progress.

Step	Fluid Name	Volume (bbl)	Rate (bpm)	Well Head pressure (psi)	Bottom hole pressure (psi)	Annulus 1 pressure (psi)	Annulus 2 pressure (psi)
Injectivity	Treated water	84	15.5	3500	7400	1200	600
Acid	15% HCL	95	5	2200	7068	1300	70
Flush and break down	Treated water	294	10	2700	6700	1300	650
			15	2800	7100		
			20	3800	8300		
			25	4300	8550		
			30	7300	8900		

The following figure represent the different pressure recorded during Injectivity test and breakdown:

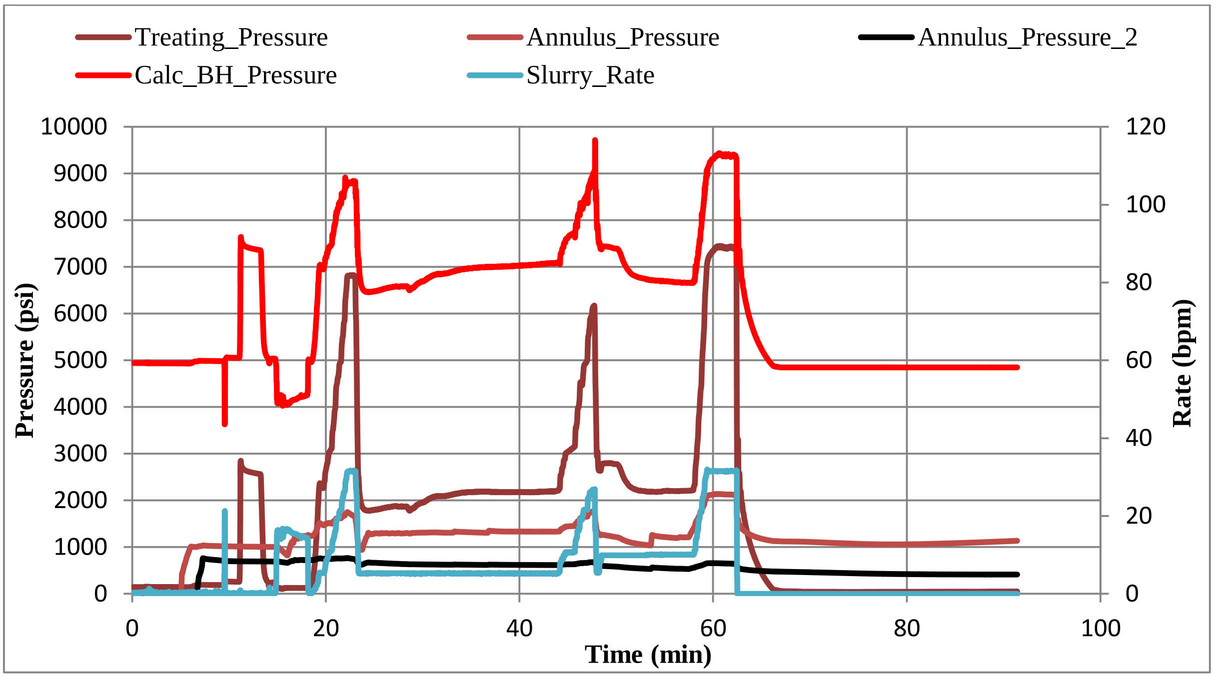


Figure IV.1: The Injectivity Test.

IV.3. THE PROGRESS OF MINI FRAC:

The Mini fracturing operation of the well MD505 was realized to obtain the result to establish the principal design treatment.

The purpose of the Mini Frac is to provide the best possible information about the formation, prior to pumping the principal treatment.

The Mini Frac is designed to be as close as possible to the principal treatment, without pumping any proppant. The Mini Frac should be pumped using the anticipated treatment fluid, at the anticipated rate. It should also be of sufficient volume.

The Mini Frac started by mixing the gel and check the quality of gel QA/QC (quality assurance/ quality control), then testing the gel 35# (V= 1000 gal, Temp = 72°F, viscosity = 28 cp, PH 11 « with buffer », cross linking time = 18 sec) then opening the well head and start pumping it gradually to reach 30 bpm, after pass to the pad stage and pump a cross-linked gel35#. In the end flush it with a linear gel 35#. The information collected are represented is the following table (Table IV.2):

Table IV.2: The Mini Frac Progress.

Stage	Fluid name	Volume (gal)	Rate (bpm)	Well head pressure (psi)	Bottom hole pressure (psi)	Annulus 1 pressure (psi)	Annulus 2 pressure (psi)	Total friction (psi)
Pre-pad	linear gel 35#	1000	30	3600	7700	1500	700	-
Pad	cross-linked gel 35#	3000	30	5500	8960	1500	700	1395
		2000	30	5450	9039	1450	600	1290
		5000	30	5438	9082	1500	650	1260
		5000	30	5462	9141	1500	700	1226
		5000	30	5475	9165	1600	700	1220
Flush	linear gel 35#	6000	30	4700	9300	1500	550	-

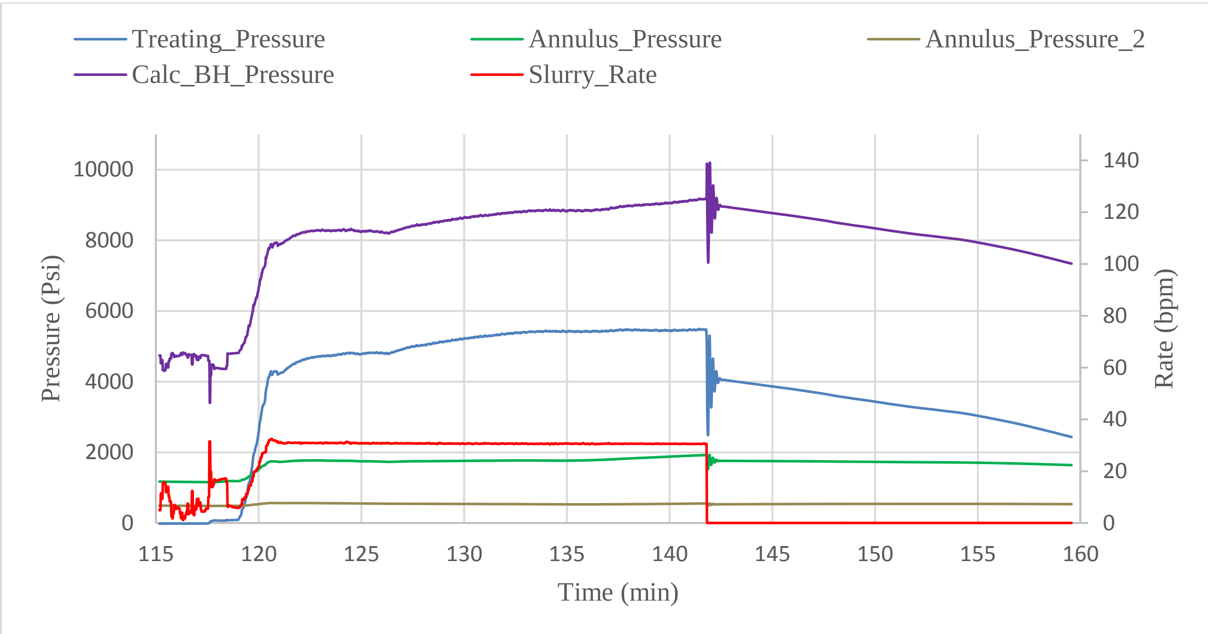


Figure IV.2: Mini Frac Data.

IV.4. PRESSURE DECLINE ANALYSIS:

The pressure decline Data was analyzed to determine closure pressure and time, fluid efficiency, leak-off coefficient and fracture geometry and other fracturing parameters which will talk about in the this chapter.

IV.4.1. Estimate the treating pressures:

The ISIP represent the intersection between the extrapolation of pressure decline and the end of pumping Q= 0. And the LPP is the last pumping pressure recorded.

a. *Determination of bottom hole ISIP & LPP:*

From the diagram we find that the ISIP is about 9000 psi, and the LPP is about 9179 psi.

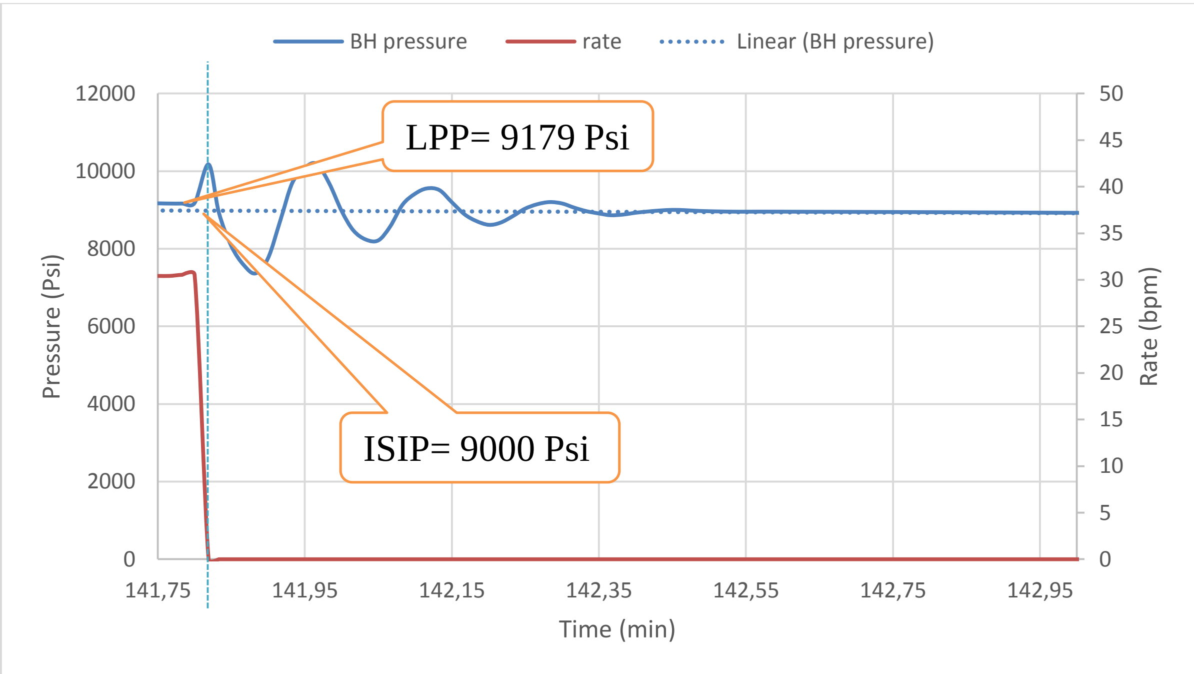


Figure IV.3: Bottom Hole Pressure Decline Curve.

b. *Determination of surface ISIP & LPP:*

From the diagram we find that the ISIP is 4100 psi, and the LPP is about 5477 psi.

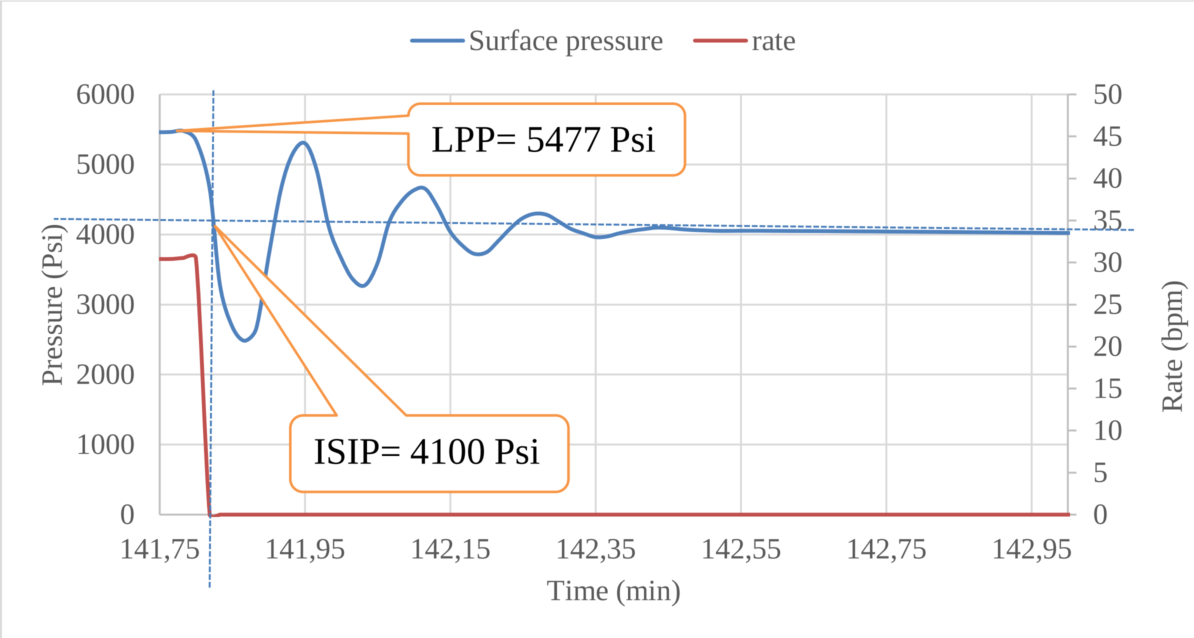


Figure IV.4: Surface Pressure Decline Curve.

IV.4.2. Determination of Friction:

We have two major friction which are, pipe friction and near wellbore friction and they are calculated as it's shown below:

$$\Delta p_{nwb} = BHLLP - BHISIP = 9179 - 9000 = 179\ Psi \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(\text{IV}.1)$$

$$\Delta p_{Total} = SLLP - SISIP = 5477 - 4100 = 1377 Psi \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(\text{IV}.2)$$

$$\Delta p_{pipe\ friction} = \Delta p_{Total} - \Delta p_{nwb} = 1377 - 179 = 1198\ Psi \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots(\text{IV}.3)$$

IV.4.3. Determination of closure pressure:

The closure pressure can be determined with many methods, in our case we are going to use Nolte G-function method

a. <u>Nolte G-function method:</u>

The Closure pressure is calculated based on the G-function method using these formula:

$$G(\Delta t_D) = \frac{16}{3\pi}\left[(1+\Delta t_D)^{3/2} - (\Delta t_D)^{3/2} - 1\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [UB] \ldots\ldots (\text{IV}.4)$$

$$G(\Delta t_D) = \frac{4}{\pi}\left[(1+\Delta t_D)\sin^{-1}(1+\Delta t_D)^{-1/2} + (\Delta t_D)^{1/2} - \frac{\pi}{2}\right] \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots [LB] \ldots\ldots (\text{IV}.5)$$

Where:

$$\Delta t_D = \frac{Shutin\ Time}{\text{Pumping time}} = \frac{\Delta t}{t_p} \ldots \ldots (IV.6)$$

After the shut-in, we draw the plot $P_{BH} = F\left(G(\Delta t_D)\right)$ and $G\frac{dp}{dg} = F\left(G(\Delta t_D)\right)$, (Figure IV.5):

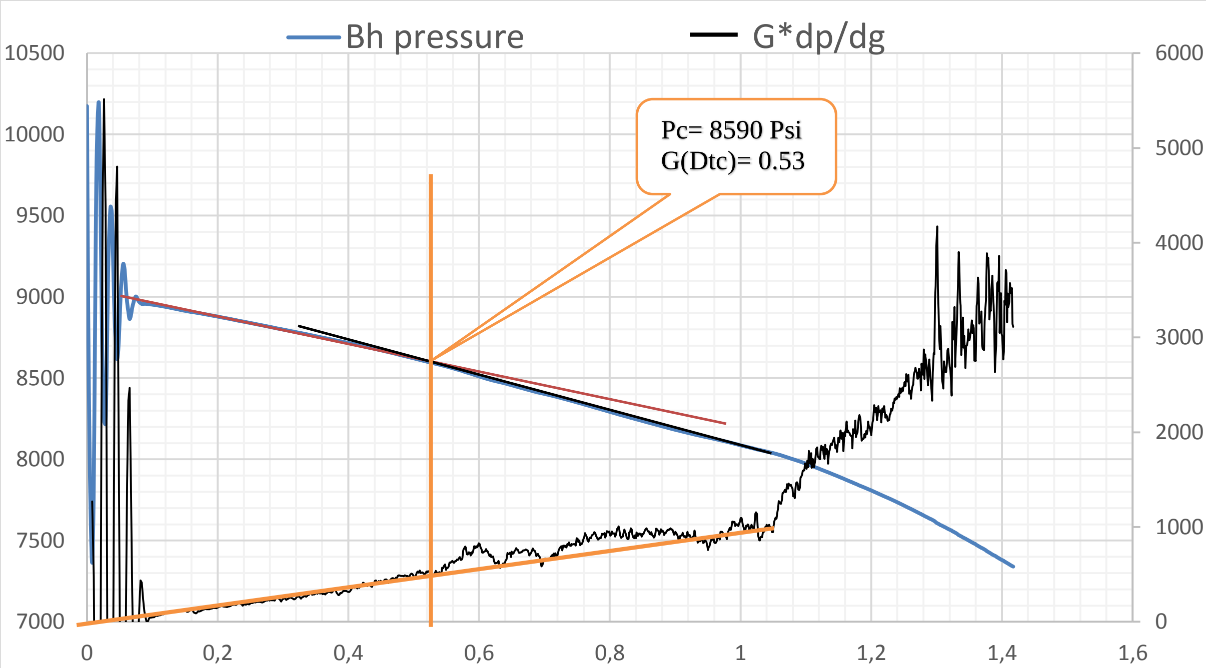


Figure IV.5: Nolte G-Function Plot.

The Nolte G Time function indicates that the bottom hole closure pressure is 8590 psi, corresponding to a fracture closure pressure gradient of 0.76 psi/ft. The Closure Time is 20.828 min.

b. Net pressure:

$$P_{net} = ISIP - P_c = 9000 - 8590 = 410\ Psi \ldots \ldots (IV.7)$$

c. Fracture gradient:

$$G_f = \frac{P_{ISIP}}{H} \ldots \ldots (IV.8)$$

$$G_f = \frac{9000}{11218.8} = 0.80\ psi/ft$$

d. Efficiency:

For constant leak-off (constant permeability and fracture area) efficiency can be estimated from the value of the G-function at closure.

$$\eta = \frac{Fracture\ volume}{Total\ injected\ volume} = \frac{\text{G}\ (\Delta t_c)}{2 + \text{G}\ (\Delta t_c)} \ldots \ldots (IV.9)$$

$$\eta = \frac{0.53}{2 + 0.53} = 0.2095$$

$$\eta = 20.95\%$$

IV.4.4. Propagation model:

From the plot (Figure IV.6) we can see that the fracture is propagation with the model PKN.

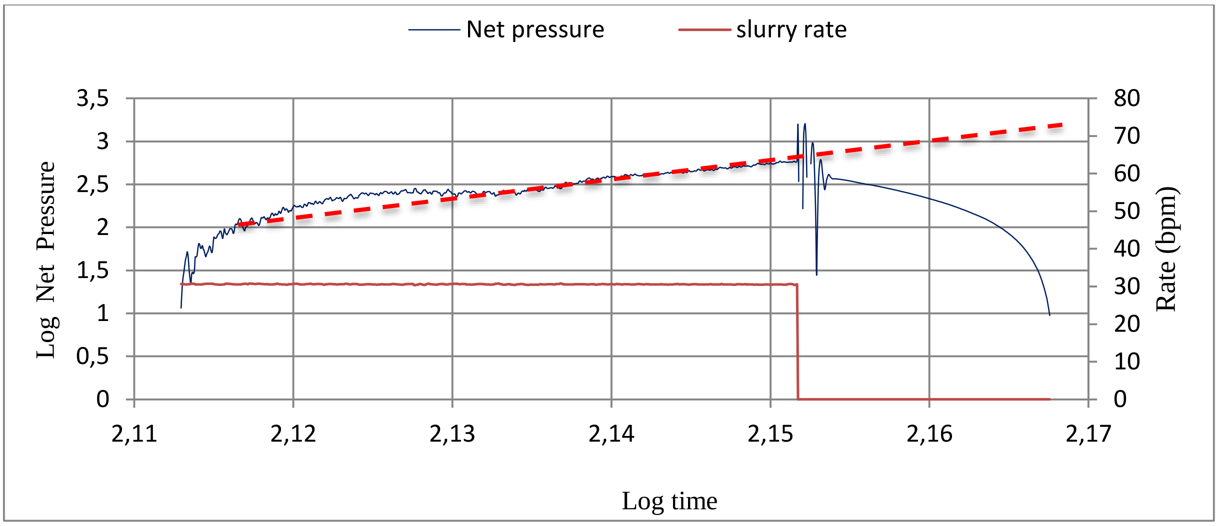


Figure IV.6: Log Net Pressure vs. Log Time Plot.

IV.4.5. Determination of fracture height:

A temperature survey was performed following the mini frac. It shows that the cooling start from 3403m to unknown limit (Appendix IV.2). So we used a fracturing simulator to obtain the fracture height. The inputs are the closure stress in the fracture interval (horizontal minimum stress “Appendix IV.3”) and bounding layers were assigned typical value of stress based on the relative clay content of the lithology. The simulator shows that the fracture stops at the top of D2 (3447m).

$$h_f = 3447 - 3403 = 44\ m$$

IV.4.6. Leak-off Estimation:

The type of fracturing fluids used in different fracturing jobs may vary greatly in components, which alters their mechanical properties. The rate of fluid leak-off into a formation is considered independent of the pressure on fracture/reservoir face and only is a function of time since the beginning of pumping and the fracture arrival time at a location.

$$C_L = \frac{m\,\beta_s}{r_p\sqrt{t_{inj}}E'}h_f \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.10)$$

$$\beta_s = \frac{2n' + 2}{2n' + 3 + a} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.11)$$

$$\beta_s = \frac{2 * 0.4 + 2}{2 * 0.4 + 3 + 1} = 0.5833$$

$$E^{'} = \frac{\mathrm{E}}{(1 - v^2)} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.12)$$

$$E^{'} = \frac{7.5 * 10^6}{(1 - 0.2^2)} = 7.8125 * 10^6$$

$$r_p = \frac{h_p}{h_f} \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.13)$$

$$r_p = \frac{21}{44} = 0.4773$$

$$m = \frac{8720 - 8590}{0.36 - 0.53} = \ 764.7$$

$$t_{inj} = 15.468\,min$$

Now we can calculate the leak-off:

$$C_L = \frac{764.7 * 0.5833}{0.4773 * \sqrt{15.468} * 7.8125 * 10^6}144.35$$

$$C_L = 0.004$$

IV.4.7. Determination of Pad Volume:

$$V_{pad} = \frac{(1 - \eta)}{(1 + \eta)}V_i \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.14)$$

$$V_i = \ Q_i * t_p \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots (IV.15)$$

$$V_i = 30.7 * 15.468 = 2666.4\,ft^3$$

$$V_{pad} = \frac{(1 - 0.2095)}{(1 + 0.2095)}2666.4 = 1742.7\,ft^3$$

IV.4.8. Determination of fracture geometry parameters:

a. The length:

$$X_f = \frac{(1-\eta)V_i}{(4C_l h_f r_p \sqrt{t_p})^{4/3}} \dots \text{(IV. 16)}$$

$$X_f = \frac{(1-0.2095)2666.4}{(4*0.004*144.35*0.4773*\sqrt{15.468})^{4/3}}$$

$$X_f = 364.62\ ft$$

The length for one wing is: 111.14 m.

b. The width:

$$V_f = \eta * V_i \dots \text{(IV. 17)}$$

$$V_f = 0.21 * 2666.4 = 559.94\ ft^3$$

$$W = \frac{V_f}{A_f} = \frac{V_f}{2x_f h_f} \dots \text{(IV. 18)}$$

$$W = \frac{559.94}{2*364.62*144.35}$$

$$W = 0.0053\ \ ft$$

IV.4.9. Determination of the conductivity:

The selection of proppant is controled by a wanted conductivity for a wanted flow rate, It is based on the in-situ stress & perforation diameters. For that we calculate the fracture conductivity:

$$F_{cd} = \frac{K_f W}{K_e X_f} \dots \text{(IV. 19)}$$

But before that we have to determine proppant permeability from the plot (Annex IV.1). We find the proppant permeability using the fracture closure pressure and the type of proppant (Pc = 8590 psi, intermediate strength proppant) it gives us a permeability of: K_F = 200 Darcy

So the conductivity will be: $F_{cd} = \frac{200*0.0053}{0.5*10^{-3}*364.62} = \ 5.8$

IV.5. COMPARISON OF THE OBTAINED RESULT WITH THE SOFTWARE'S:

The folowing table (Table IV.3) will compare the calculated result with those of the software

Table IV.3: Comparison of the Obtained Result with the Software.

Parameter	Symbol (Unit)	Calculated value	Software Value
Cross-linked gel	PAD (gal)	13036.3	18932
Bottom hole ISIP	BHISIP (psi)	9000	8996
Surface ISIP	SISIP (psi)	4100	4090
Last Pumping Pressure - Surface	SLPP (psi)	5477	5465
Last Pumping Pressure - BH	BHLPP (psi)	9179	9173
Closure Time	T_c (min)	20.832	19.607
Closure pressure	P_c (psi)	8590	8560
Fracture Closure Gradient	G_f (psi/ft)	0.76	0.78
Net pressure	P_{Net} (psi)	410	435.87
Total Friction	ΔP_T (psi)	1377	1375
Efficiency	η (%)	20.95	20
Leak-off coefficient	C_L (ft/$\sqrt{min}$)	0.004	0.002
Length	X_f (m)	111.14	135
Height	h_f (m)	44	44.7
Width	W_f (in)	0.0636	0.04

IV.6. EVALUATION OF FRACTURING OPERATION:

Once the fracturing operation is done, post frac cleaning with coiled tubing will be performed using water and Azote, to get the best clean-up of the well. Then a kick off operation will be done to get a flow from the reservoir. We can notice a gain in the flow rate (from 0.55 m^3/h to 4.77m^3/h) from the well test Data (Table IV.4).

So we can say that the fracturing operation was done with success, and gave a good results.

Table IV.4:Gauging Before and After Fracturing.

	1st Gauging Before main frac	1st Gauging After main frac	2end Gauging After main frac	3rd Gauging After main frac
Gauging Date	12-10-2015	30-11-2015	04-12-2015	29-12-2015
Q_{oil} **(m^3/h)**	0.55	2.01	4.77	4.93
Q_{Gas} **(m^3/h)**	900.03	2408.68	4952.21	2856.87
GOR	1629	1200	1038	579
Well Head Pressure (Kg/cm^2)	20.1	91	54.5	11

The following figure (Figure IV.7) shows the flow rate before and after fracturing operation.

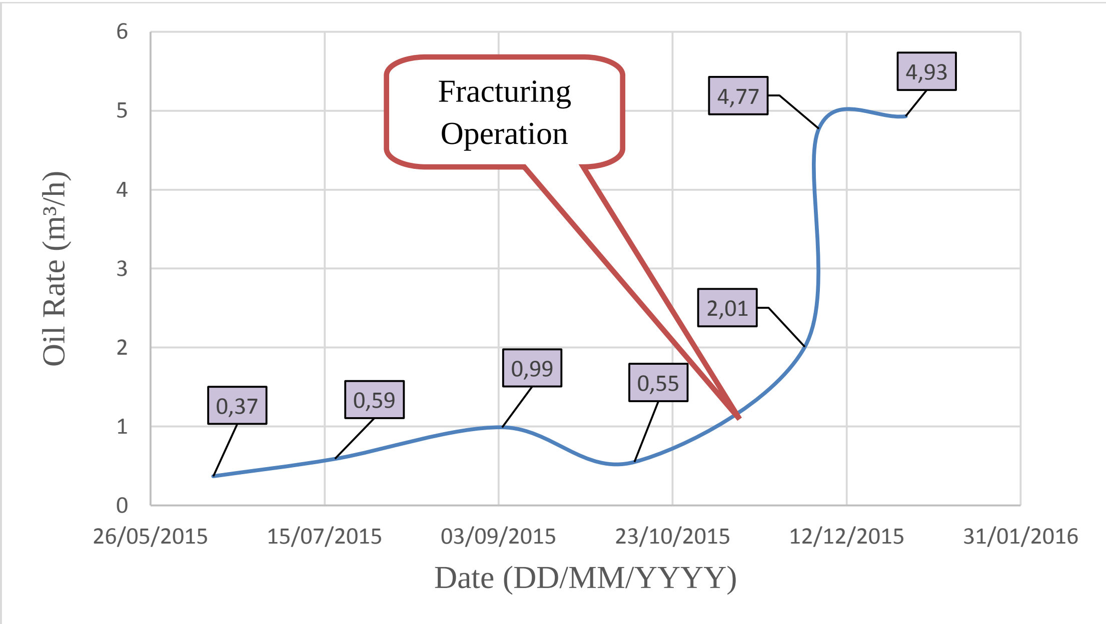


Figure IV.7: Evolution of the Well Flow Rate.

Conclusion:

This study has allowed us to show the importance and efficiency using hydraulic fracturing technique in the exploitation of reservoirs with poor physical characteristics, including permeability of the rock. This technique increase the well productivity, which gives a considerable economic gain.

In our study, we analyze the results of hydraulic fracturing done in the well MD 505 Hassi Messaoud. We can conclude:

The important gain in the flow rate and conductivity shows the necessity of using this technique of stimulation in this type of reservoir.

The results of the different stages of the calculations are similar to those obtained by the simulator, but it is certain that the design established simulator remains the most accurate, since the establishment of the design based on models proposed, and still have a margin error, and that the computer tool tries to minimize it.

Moreover, the method of NOLTE, based on material balances and analysis of pressure decline after shut-in, appears as a good approach because it is a synthesis of the work already carried out previously. In other words, to master the software (simulators) that process hydraulic fracturing, it is important to understand and master the method of NOLTE manually.

Finally, it is important to give time for the establishment of a hydraulic fracturing design, to consider all possible variants, and in the same time minimizing the percentage of failure, knowing that globally the success rate is not high. Moreover, this work is not for a single engineer, but of a multidisciplinary team (reservoir, geology, production ...).

Recommendations

According to this study and for good treatment by hydraulic fracturing, it is recommended to:

- ✓ Cleanout treatment with coiled tubing is recommended before fracturing, to remove paraffin and debris from the well.
- ✓ An injectivity test with treated water is required to verify the injectivity between the perforations and the formation. If the injection is limited, a spearhead acid with 15% HCL-acid is recommended
- ✓ Analyze the fracturing fluids and check its compatibility with the formation fluids.
- ✓ Use the Thermometry test in order to control the increase in fracture height and adapt the technique radioactive tracers to follow the path of fractures.
- ✓ Perform a test after frac, using well testing (Build Up) to better evaluate the results of fracturing (IP, Kh, skin ...).
- ✓ Treatment analysis with calculated bottom hole pressure might be erroneous due to the difficulties associated with calculating accurate friction pressures. A method of monitoring real time bottom hole pressure would improve the quality of the treatments and associated analysis.

References:

[1] Fadila, B. Reservoir Characterization And Reservoir Modeling In The Northwestern Part Of Hassi Messaoud Field Algeria, PhD Thesis, At The Department Of Earth Sciences, University Of Hamburg (Hamburg, Germany), 2004.

[2] Luca, G. An overview of hydraulic fracturing and other formation stimulation technologies for shale gas production , JAC technical reports, Joint Research Centre, Westerduinweg 3, 1755 LE, Petten, (The Netherlands), 2013.

[3] Koceir, Tiab, Influence of Stress and Lithology on Hydraulic Fracturing in Hassi Messaoud Reservoir, Algeria, U. of Oklahoma (SPE 62608), 2000.

[4] Nolte, K. G. Determination of fracture parameters from fracturing pressure decline, Nevada, USA (SPE 8341), 1979.

[5] Barree, R. D, Barree, V. L, & Craig, D. P. Holistic fracture diagnostics: consistent interpretation of pre-frac injection tests using multiple analysis methods, SPE Production and Operations, 2009.

[6] Economides, M. J, & Nolte, K. J. Reservoir Stimulation, 3rd Edition, Wiley, 2000.

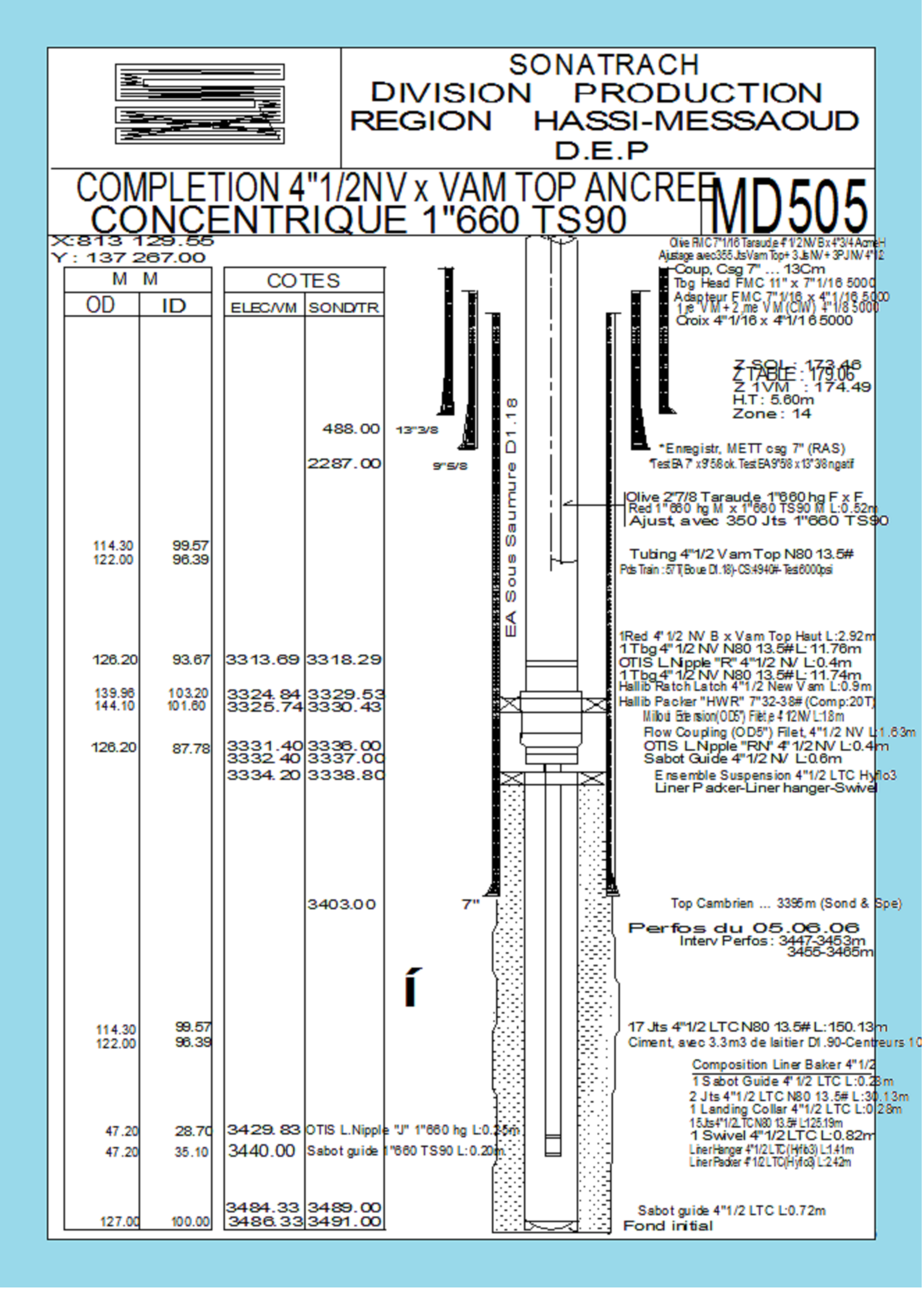
[7] Jing, X. A PKN Hydraulic Fracture Model Study And Formation Permeability Determination, PhD Thesis, Texas A&M University In Partial Fulfillment Of The Requirements For The Degree Of Master Of Science (China University Of Petroleum), 2011.

[8] Meyer & Associates, Inc. Meyer Fracturing Simulators, User's Guide, United States of America. (Ninth Edition1), 2011.

[9] ALL Consulting, LLC. The Modern Practices of Hydraulic Fracturing: A Focus on Canadian Resources, Tulsa, Oklahoma, 2012.

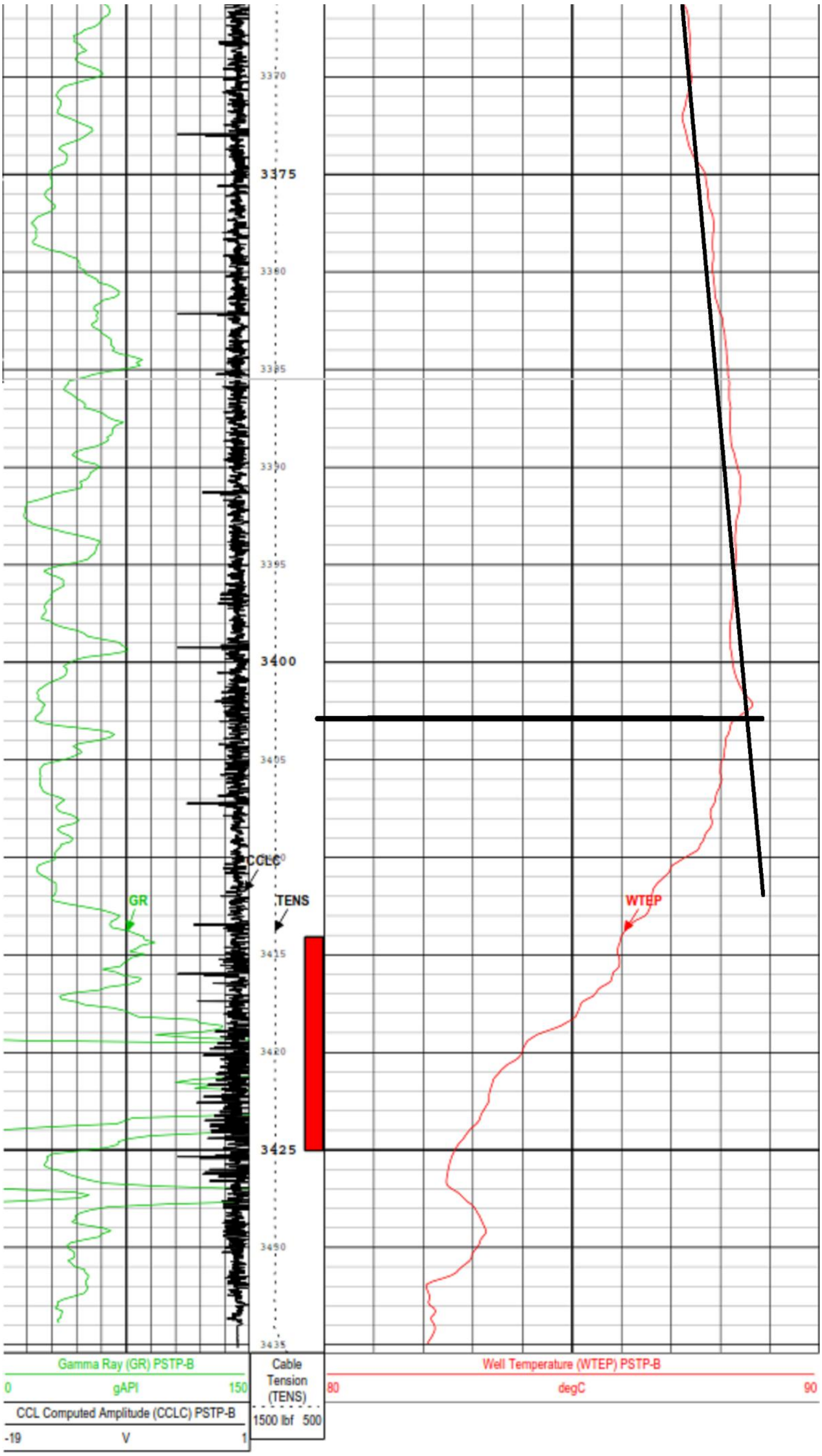
[10] MAHMOUD.M, OULD VEDHILI .M, EVALUATION D'UNE FRACTURATION HYDRAULIQUE Puits OKN-612 A HBK, Master Thesis, Université M'HAMED BOUGARA BOUMERDES Faculté des Hydrocarbures et de la Chimie, Département : Gisement. (Algeria), 2010.

Appendix:



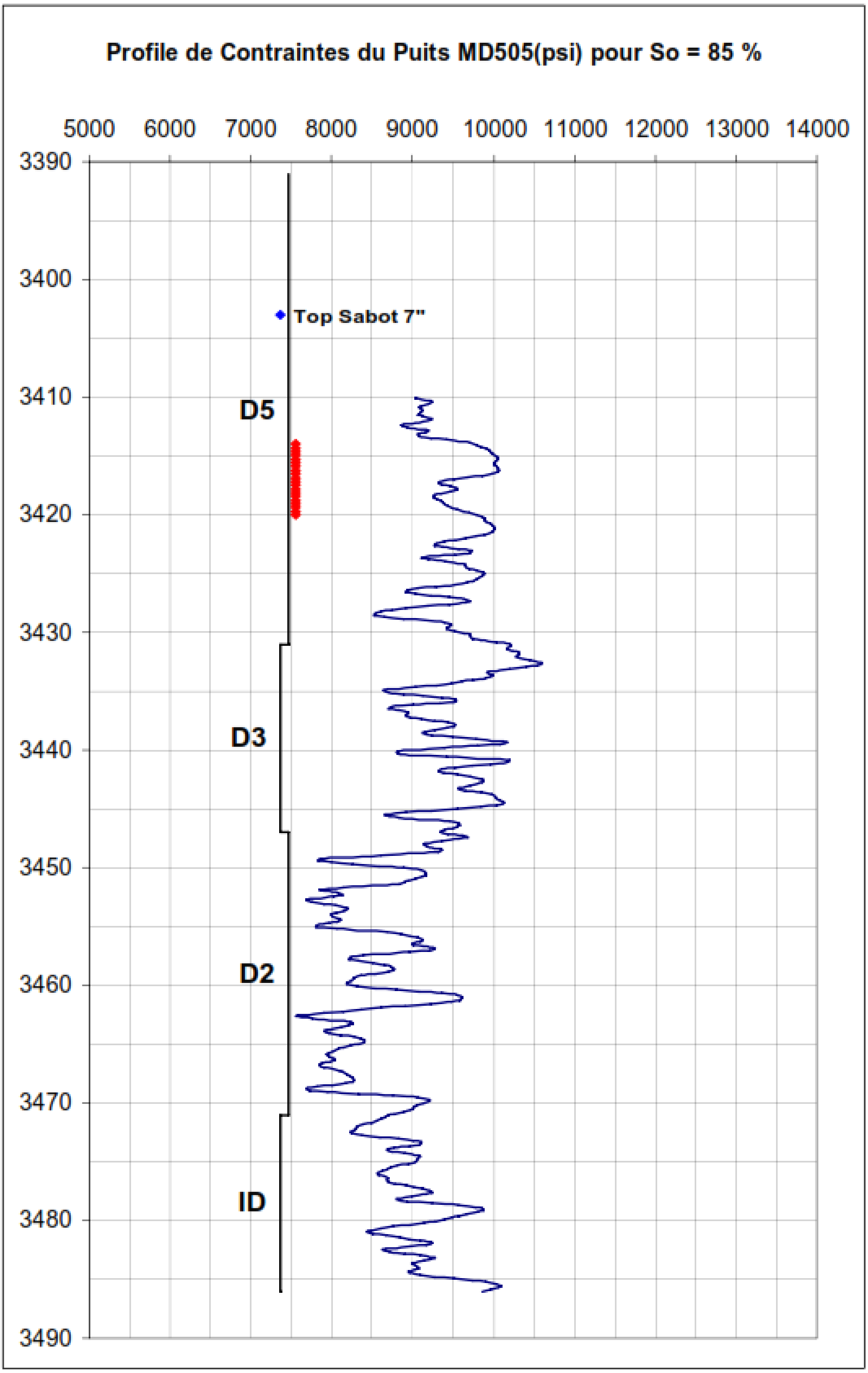
Appendix IV.1: Well Sketch.

Appendix:



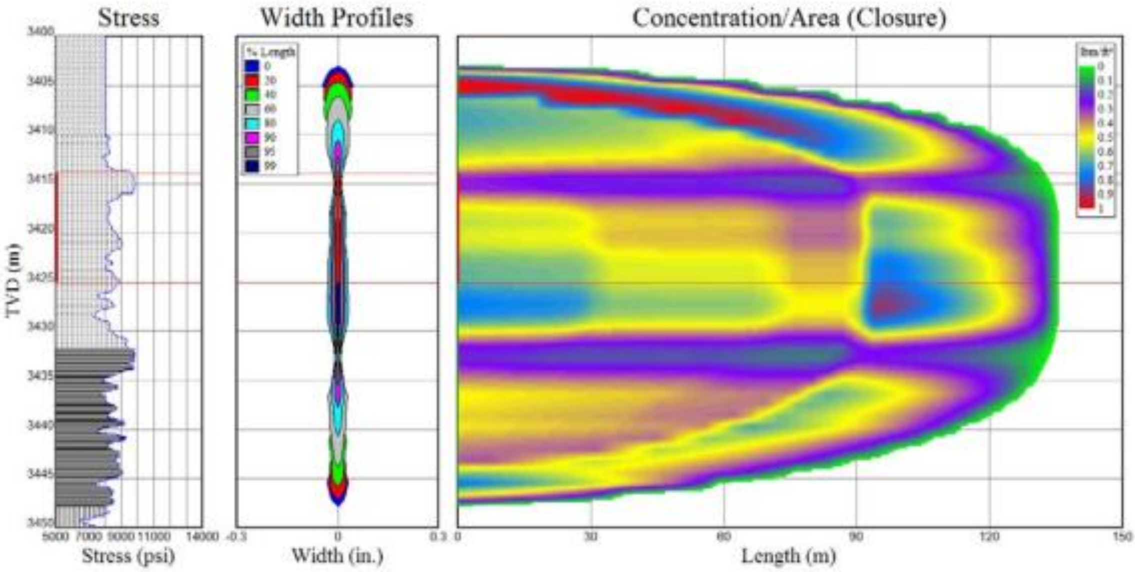
Appendix IV.2: Temperature log MD505.

Appendix:



Appendix IV.3: Stress Profile MD505.

Appendix:



Appendix IV.4: Fracture Concentration Profile.

VITA

Name:	Abd esselam ALI SAHRAOUI	Zakaria DAOUD
Permanent Address:	Bellâa, Bir Elarech, Setif, Algeria.	738 Hai Zitoune, Ain Temouchent, Algeria.
Email Address:	islamali481992@gmail.com	daoudzaki@gmail.com
Phone Number:	+ (213) 664 18 40 49	+ (213) 797 86 73 72

Education:

Kasdi Merbah University, Ouargla.
Master of Science in Petroleum Engineering.
June 2016

Kasdi Merbah University, Ouargla.
Bachelor of Science in Production of Hydrocarbon.
June 2014