HYDRAULIC FRACTURING DESIGN: BEST PRACTICES FOR A FIELD DEVELOPMENT PLAN

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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.

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. 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. 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).

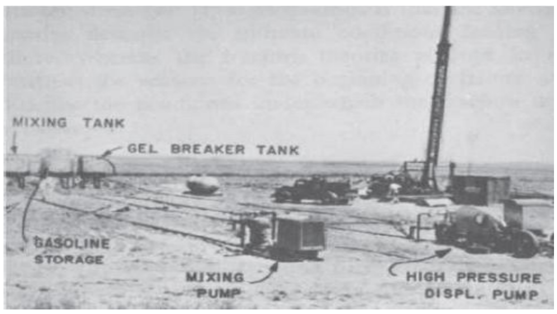

Figure 1.Klepper Well No.1, Hugoton gas field, Kansas.

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).

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.

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

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

- Increase the flow rate of oil and/or gas from low permeability reservoirs
- Increase the flow rate of oil and/or gas from wells that have been damaged
- Connect the natural fractures in a formation to the wellbore
- Decrease the pressure drop around the wellbore to minimize sand production and asphaltine and/or paraffin deposition
- Increase the area of drainage or the amount of formation in contact with the wellbore,
- Connect the full vertical extent of the formation to the wellbore

(United States Environmental Protection Agency, 2004)

2. PRETREATMENT FORMATION EVALUATION

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. (John L. Gidley, 1990). The most important aspect of a successful prefarcture formation evaluation is that a consistent picture of the formation should be developed by using all available techniques. For example, if permeability values obtained from core analysis and pressure transient analysis are not correlated it means that prefarcture formation evaluation might not be accurate.

3. HYDRAULIC FRACTURING TREATMENT DESIGN

Hydraulic fracturing treatments are designed based upon the knowledge obtained from pretreatment formation evaluation to maximize net present values (NPVs) of the fractured wells. 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.

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. 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 2. 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.

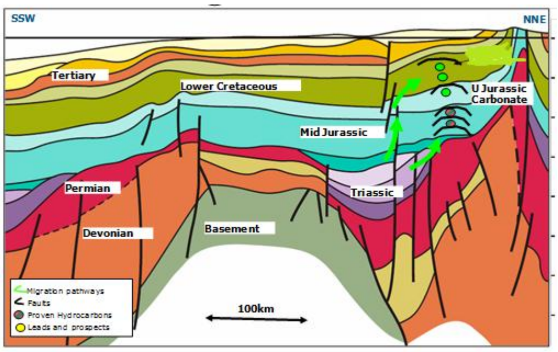

Figure 2. Structure of X field

The field is now in second development phase. There will be a total number of 198 wells drilled in this phase. There are 10 delineation wells which were drilled in 2012-2013, with complex data acquisition program to know the boundary of the reservoir. 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 should be noted that it is not expected that any of these three areas will be unproductive.

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. The bar chart in figure 3 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. But the long term cumulative production is higher for vertical wells for the whole field.

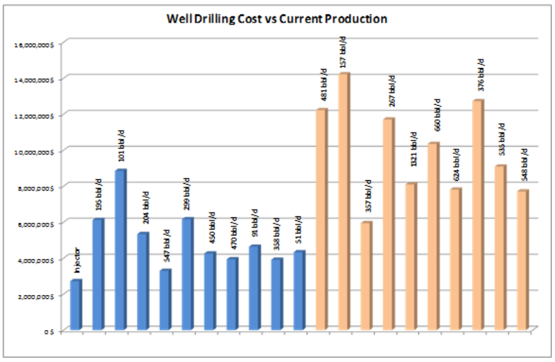

Figure 3. Drilling and production for horizontal as well as vertical wells

4.2. Production Data Analysis

<u>Well R</u>

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 as shown in figure 4, which implies that a good stimulation operation was performed on this well.

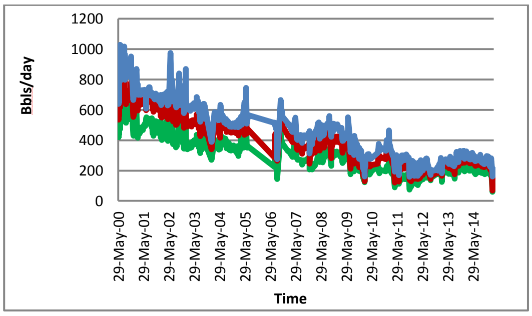

Figure 4. Flow rate of oil (green), water (blue) and gas(red) with time

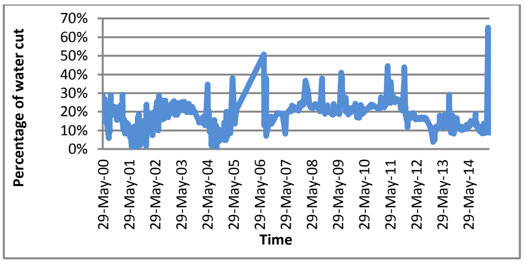

Figure 5. Water cut vs time

The water cut is between 10-40% which is fine for this type of reservoir.

Well# 9

A significant production of water along with oil and water cut can be seen in the following figure 6 & 7. Initially there is high water cut and the production of oil starts increasing from February 11.

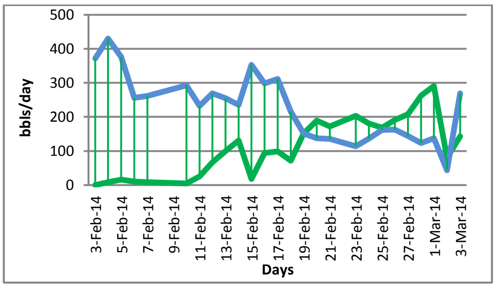

Figure 6. Oil and water rate vs. time

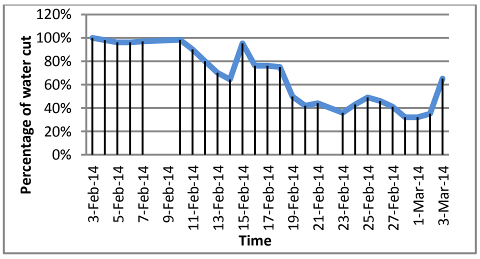

Figure 7. Water cut with time

There is almost 100% production of water in the beginning which corresponds to the flow back production of fracturing fluid and water which was used during the hydraulic fracturing treatment.

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 as shown in figure 8 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.

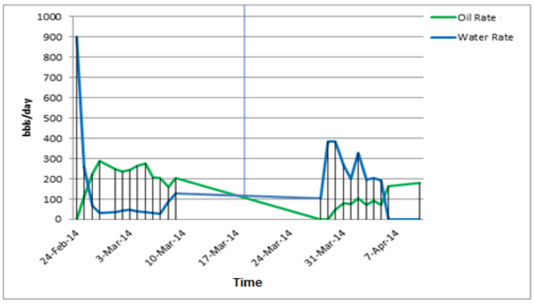

Figure 8. Oil and water rate Vs. time

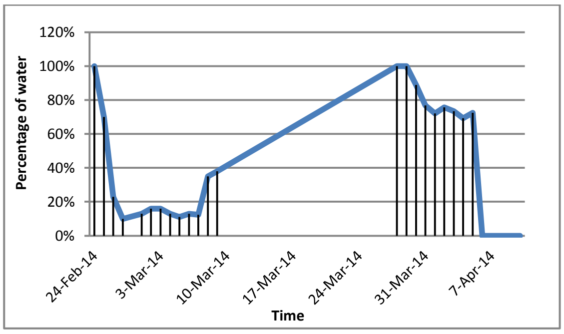

Figure 9. Water cut Vs. time

The water cut was significantly lower after first hydraulic fracturing treatment. But when the well was fractured again, the 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 as represented in figure 10. 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.

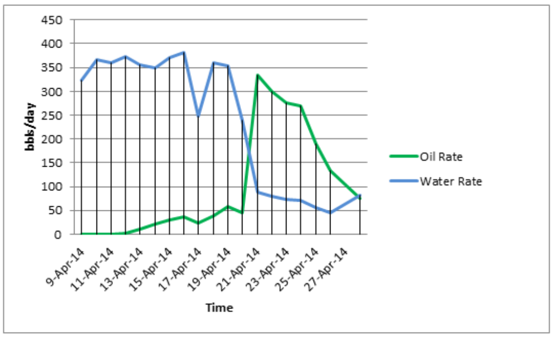

Figure 10. Oil and water rate Vs. time

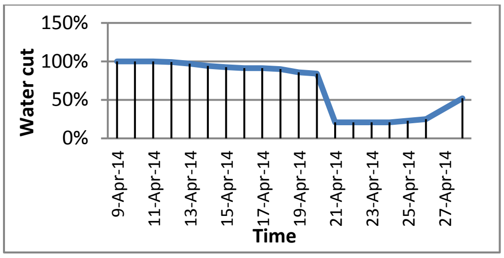

Figure 11. Water cut Vs. time

The water cut is around 20% for this well.

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 as shown in figure 12.

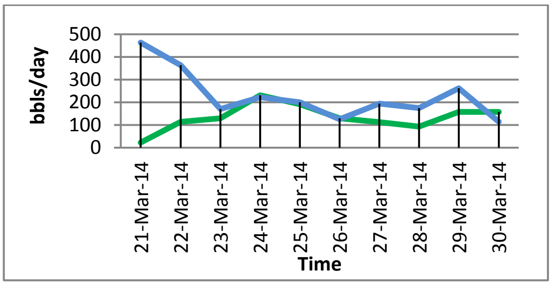

Figure 12. Oil and water rate Vs. time

The water cut remains between 40-60% (figure 13) except in the initial period which is because of the production of flow back water after the fracturing operation.

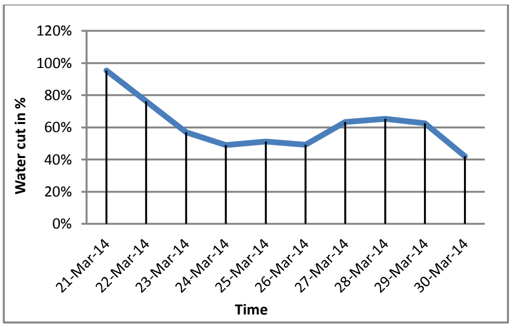

Figure 13. Water cut Vs. time

Well# 3

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. This can be seen in figure 14.

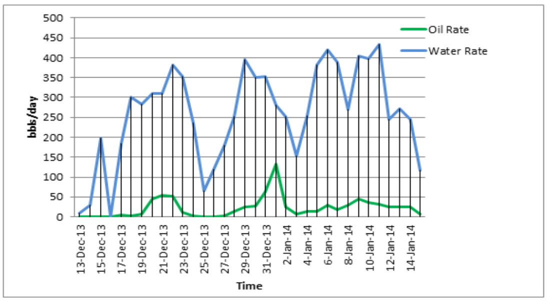

Figure 14. Oil and water rate Vs. time

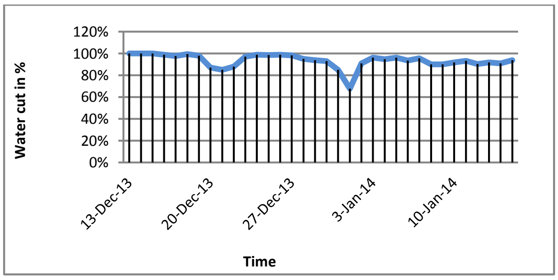

Figure 15. Water cut Vs. time

The 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 as can be observed in figure 16.

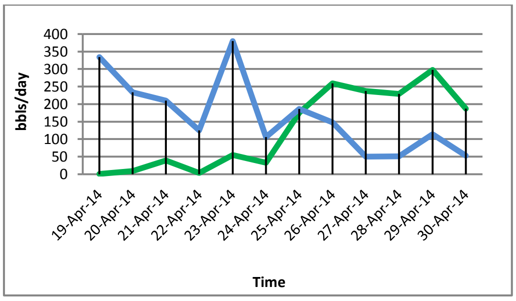

Figure 16. Oil and water rate Vs. time

The water cut is around 20% (Figure 17)

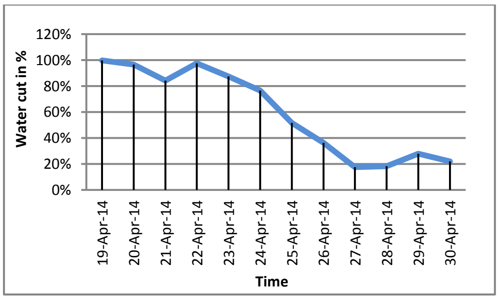

Figure 17. Water cut Vs. time

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.

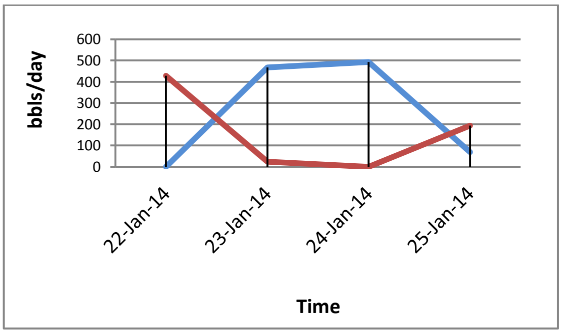

Figure 18. Oil and water rate Vs. time

4.3. Stimulation Data Analysis

It can be clearly observed in bar chart in figure 19 that there was good correlation between matched and designed fracture profiles. It is important to state here that the same behavior was observed for other wells too.

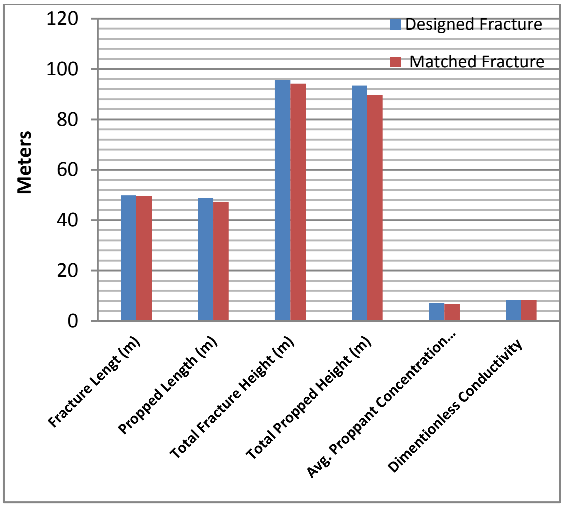

Figure 19. Comparison between different parameters of matched and designed fracture profile

It is shown in figure 20a that the comparison of fracture to and bottom of initial fracturing operation and re-fracturing operation. 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.

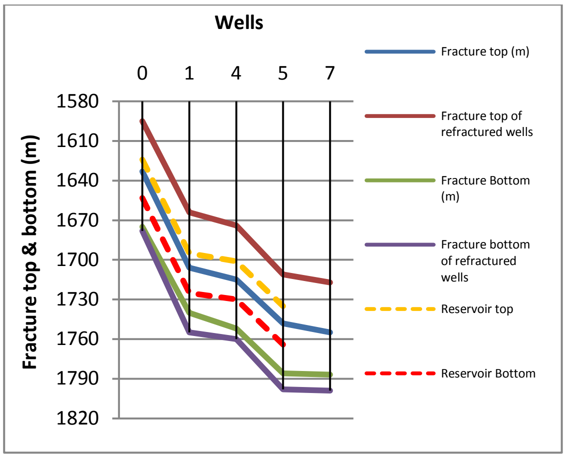

Figure 20a. Comparison of fracture top and bottom before and after re-stimulation for given wells

The following figure 20b 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.

It can be seen in figure 21 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.

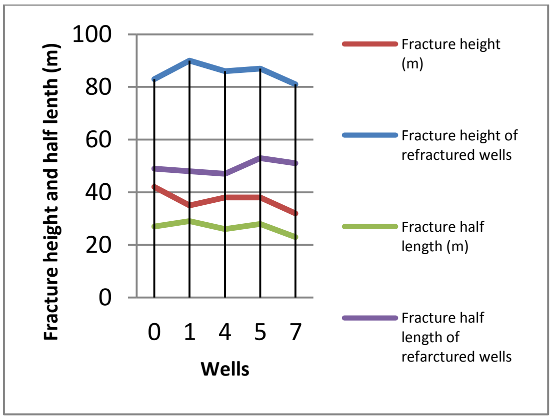

Figure 20b. Comparison of fracture height and half-length for given wells

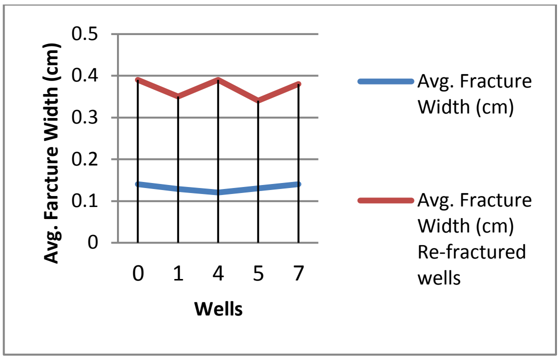

Figure 21. Comparison of average fracture width before and after re-stimulation for given wells

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 as shown in figure 22. In my opinion this stress for re-fractured wells should be lower than that of initially fractured wells. But Mother Nature is very heterogeneous and we cannot be 100% sure about our predictions.

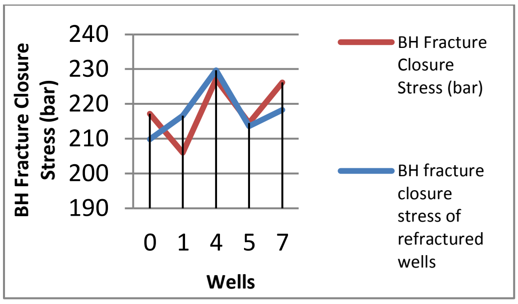

Figure 22. Comparison of fracture closure stress before and after re-stimulation for given wells

There is an enormous increase in the average conductivity for all 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. (Figure 23**)**

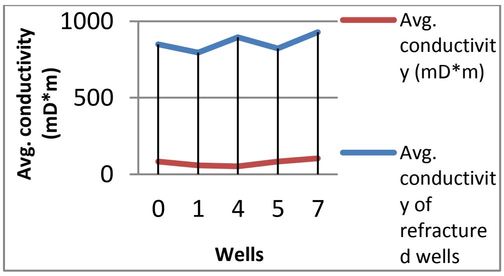

Figure 24. Comparison of average fracture conductivity before and after re-stimulation for given wells

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 as depicted in figure 24.

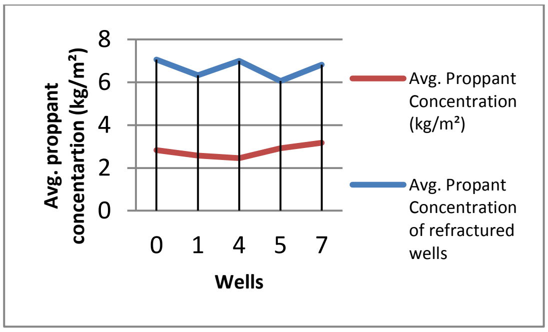

Figure 25. Comparison of average proppant concentration before and after re-stimulation for given wells

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. The wettability of pores is illustrated in figure 25.

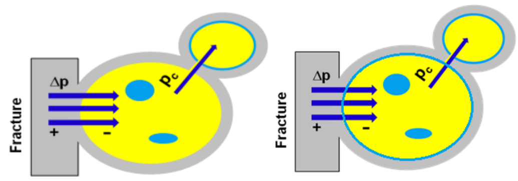

Figure 26. Oil wet bigger pores and water wet smaller pores (left),X field reservoir has neutrally to water wet pore network (right)

The complete process is explained in above representation for an oil wet rock system.

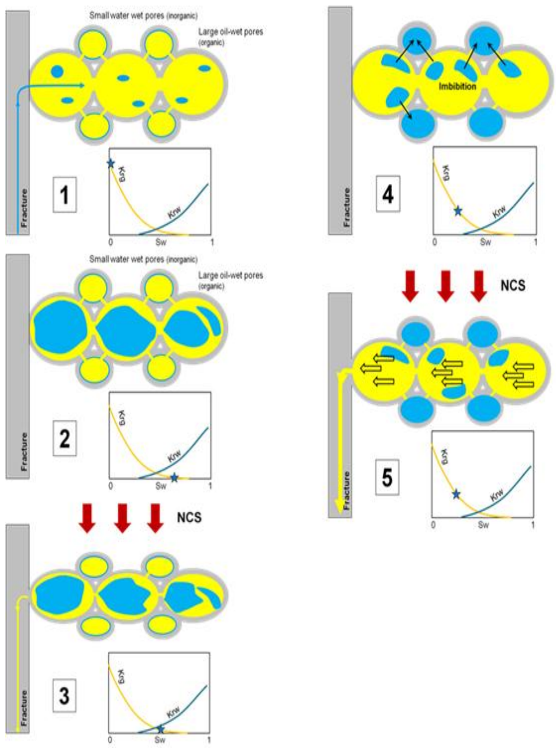

Figure 27. Process of imbibition after shutting in the well

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

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.

Based upon special core analysis, the wettability of the X field reservoir is neutral to slightly water wet. 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 reservoir the larger pores will be water wet and it will aid the production of oil. The oil will flow easily through the bigger water coated pore network. 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 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. 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 reservoir during the shut in period.

4.4.2. Mud Losses

Mud loss is a term which 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 for well # , the reason for mud losses was the presence of hydraulically created fractures which were propagated far from the location of fracturing treatment.

4.4.3. Fins Production

The X field reservoirs have thicknesses varying from 11 to 15 m. These low permeable 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 fins production. There are a couple of methods which can applied to avoid the fins prodction, such as use of sand screen, limied entry perforating and perforating only the intervals which are consolidated. These consolidated intervals can be located with the help of sonic logging.

5. FRACTURING FLUID AND WATER MANAGEMENT

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. 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 tanker truck transportation costs, minimization of road traffic to reduce environmental impacts, and water disposal costs. Traditional sources of fresh water for hydraulic fracturing include glacial and bedrock aquifer systems, surface waters, and municipal supplies. (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 and regulations 4) Recycling and reuse 5) Transport

(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.

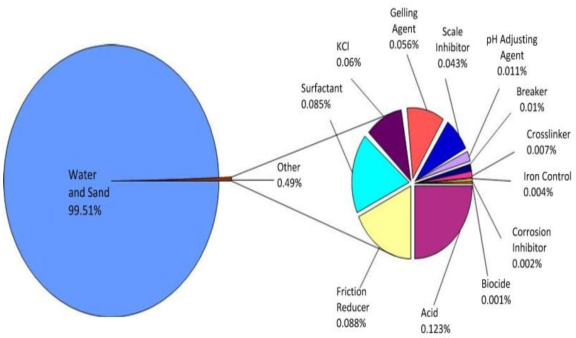

Figure 28. Normal proportion of water and additives in fracturing fluid

5.1. 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

Water quality, the characteristics of the flowback fluids and volume are important in the selection of water treating 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.

Water management for unconventional hydrocarbons 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 given below. (Walsh, Water Management for Hydraulic Fracturing – Part 4, 2013).

1) Stage 1: Remote and isolated well development –mobile stage of development

2) Stage 2: Well clusters with some in-field drilling and completions – modular stage of development

3) Stage 3: Extensive in-field development with infrastructure to transport water to and from a centralized treatment facility –centralized stage of development. (Walsh, Water Management for Hydraulic Fracturing – Part 4, 2013).

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 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 layers which was the reason of enormous amount of water production 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 design and matched fractures.

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 is the propagation of fractures outside of the reservoir zone. From production data analysis of this well, it can be stated that there was no need of re-stimulation operation.

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 natural and hydraulically created 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 oil and 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. 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 etc. In relation to X field, as the pores are neutrally to water wet, the same phenomenon could happen in X field too. 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 reservoir during the shut in period.

7. Moreover, it is recommended to use well logging, core analysis, geologic data and other data if available such as well tests and surface tilt meters to properly design the HF operation for the 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 for fracturing fluid and waste water treatment.

9. Finally, to deal with the problem of fins 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 special and conventional core analysis and analyze the effect of fracturing fluid on wettability alteration, formation damage etc.

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

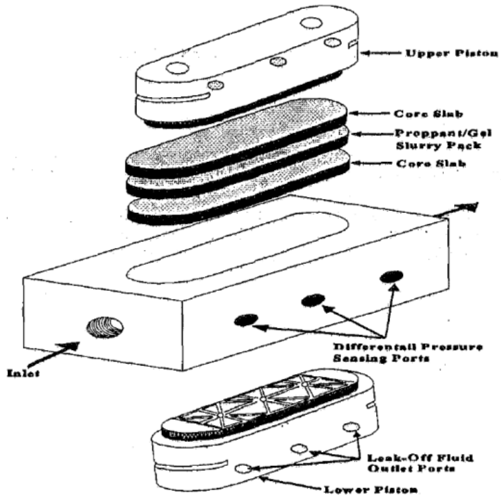

Figure 29. Schematic of modified API conductivity test cell

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