

Modelling and Simulation Multi-stage Fracturing Propagation in Tight Reservoir through Horizontal Well

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Abstract: Horizontal wells can be stimulated by the creation of a number of hydraulic fractures along the wellbore. If the well is drilled in the direction of the minimum horizontal stress, a series of transverse hydraulic fractures will be induced. The limited communication between such transverse fractures and the wellbore creates a choking effect near the well and causes an apparent reduction in fracture conductivity. The lower Devonian F-D reservoir with highly heterogeneous and tight reservoir. The net to gross ratio is below 35%, the average porosity in the pay interval is around 8%, the average value permeability is around 0.1 mD. Packages of sandstone have rarely been observed greater than 5 m thick common at the base of the sequence. After drilling horizontal well W-H with success in the tight reservoir target and completed the well outcomes suggest that the deviated/horizontal wells with multi stage frac should be the tool for producing this tight reservoir. Well performance was simulated with semi-analytical models and by numerical simulation. The effect of fracture and reservoir properties of gas well productivity is discussed, and various development options for tight gas reservoirs are compared. To verify the efficiency of the frac job, a successful micro seismic acquisition was run confirming the field stress regime distribution and the creation of the induced fractures.

Key Words: Multi-stage Fracturing, Propagation, Tight Reservoir, Horizontal well.

1. Introduction

The use of horizontal wells for exploiting tight oil and gas reservoirs is now firmly established within the industry. Although most of the horizontal well drilling to date has centred on oil reservoirs, interest in applying it to gas reservoirs is increasing. Quite often the reserve category of these reservoirs is never converted from probable to proven. For this type of formation, there is common agreement in the petroleum community that the optimal way to produce, at the present state of art, is through hydraulic fracturing. Before drilling the well

W-H, made at least four attempts at hydraulic fracturing in vertical wells without obtaining significant production or having technical failure due to the abnormal high stress condition encountered. Success in a nonconventional tight formation is equally weighted between the operational ability to perform successful hydraulic fracturing jobs and whether the production results justify the expenditure. Considering the

complexity involved in the tight formation development, a multidisciplinary approach was applied to define the exploitation strategy.

In order to increment the probability of producing the “upside” volume, considering the tight nature of the reservoir, production by secondary permeability must be exploited.

The basic assumption for defining this strategy was to demonstrate and verify the presence of a secondary permeability system: natural fractures.

In today’s petroleum industry, both horizontal wells and fractured horizontal wells are popular and we start use micro seismic technology means micro seismic tools (geophones) in the observation wells in order to know more information on frac propagation and orientation.

2. F-D Tight Reservoir Formation

2.1) Geological Framework

The Siegenian F-D reservoir is the uppermost fining upward sequence deposited during the Lower Devonian age. It is delimited at the top by the Emsian shale’s and at the bottom by the F-D1 interval. The entire F formation is interpreted as a tidal sand body forming part of mixed sand and mud tidal flat setting with areas of fluvial/estuarine input. The currents in the formation that deposited are dominantly bidirectional with subordinate unidirectional current flows which indicate beds where fluvial processes are more dominant and rare areas where oscillatory/wave currents have locally reworked horizons.

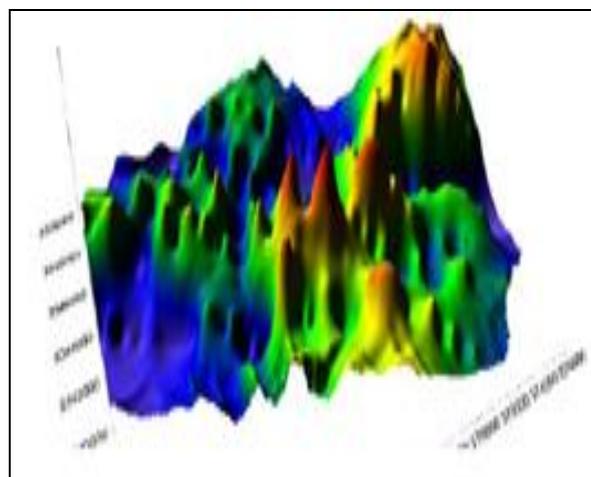


Fig1. F-D Tight reservoir formation [1]

2.2) Petro physical proprieties

The petro physical properties of F-D can be described as poor; porosity rarely exceeds 10 % and average permeability is 0.1 mD. Porous sandstones, with porosities in the range 18-25 %, have been encountered occasionally in F-D reservoir.

The low porosities and permeabilities encountered over most of the F-D have been attributed to diagenesis and to quartz overgrowth and the presence of illite in particular. The good quality reservoir intervals found in the F-D1 reservoir below, and rarely in F-D, contain grain-coating chlorite, which prevents the precipitation of quartz cement, thus preserving porosity and permeability. Small quantities of chlorite are present also in F-D, but a recent petro graphic study has shown that it is later-stage, post-dating quartz precipitation, too late to protect the porosity and permeability [1].

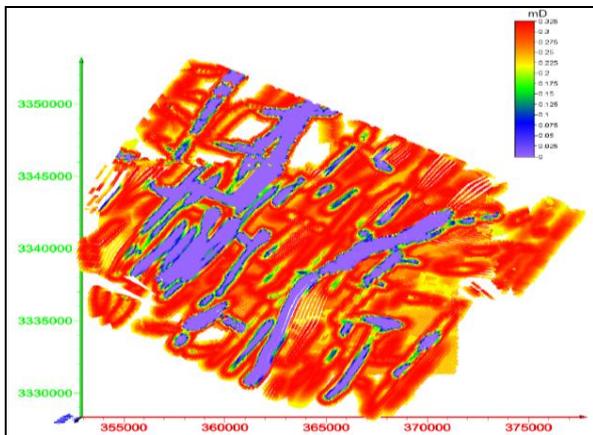


Fig2. Average permeability expected

A significant decrease in permeability is present along the major faults. Increased permeability around shorter fault and particularly the NW-SE ones.

3. Modeling Multi-stage Fracturing in Horizontal Well

Modeling multi-stage fracturing in tight reservoir through horizontal well, based on two wells W-H and W-V, The main target of W-H well test in the F-D Formation is to evaluate the productivity improvement caused by a multi fracturing job in a horizontal well drilled in a tight reservoir with observation well W-V by microseismic tools . In order to accurately orient the tools it is recommended to get a geophone – source angle between 15 and 30 degrees. This corresponds to a radius comprised between 1180 and 2540 meters. To get the best results it is better to surround the well head with 5 different points.

Verify the feasibility of fracturing the lower Devonian (F-D) formation, to know the direction of propagation waves frac received by geophone after processing. Correct the design frac with new direction of propagation wave's frac and will be revised drain direction of new Wells to be drilled.

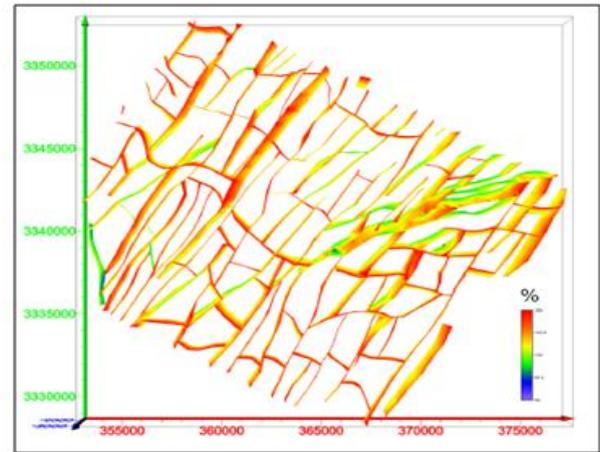


Fig3. Natural fracture probability in F-D

The probability of natural fracture development values range between 0% and 200%, referred to the probability of fracturing in the rock with average rheology.

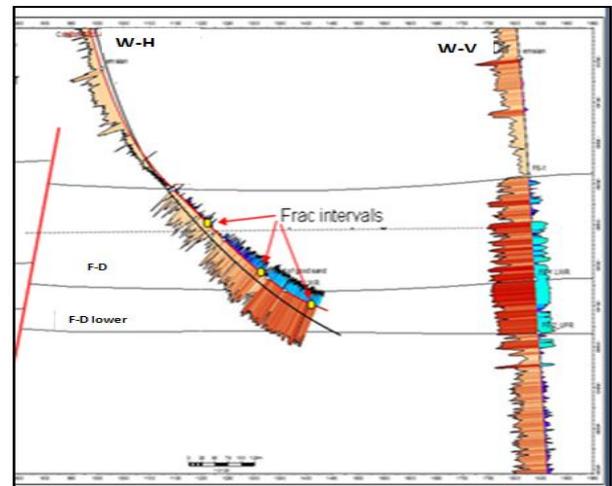


Fig4. Cross-section showing GR (clean intervals in red) and porosity (blue) and frac intervals

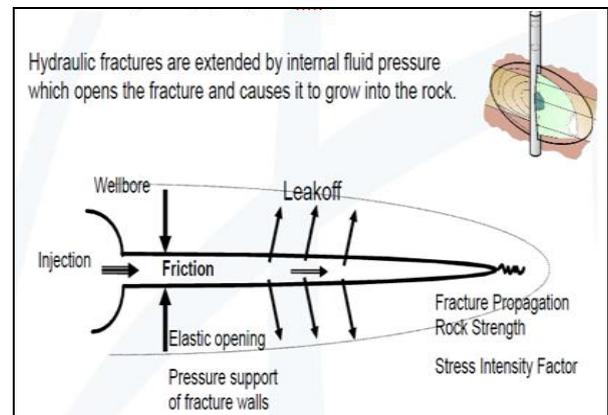


Fig5. Fracture design

To create orthogonal fractures to achieve greater contact with reservoir (higher production), possible risk of screen out due to fracture tortuosity.

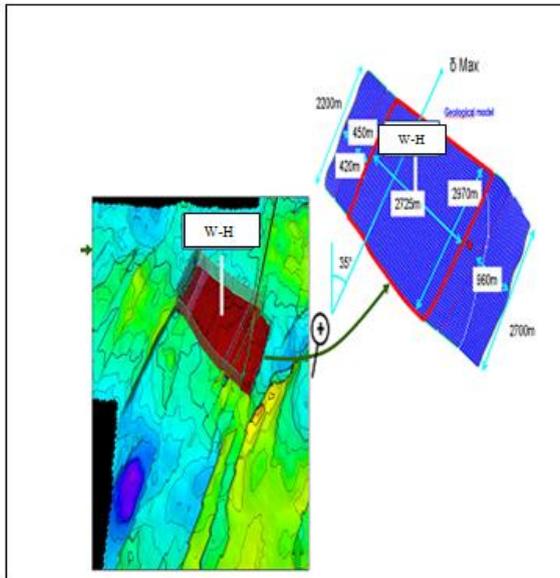


Fig.6. W-H sector model

4. Multi Stage Fracturing Results

Based on past experience of frac we performed fracturing study for F-D tight reservoir especially on W-H well. The study was performed by building a geo-mechanical model to determine rock properties and in-situ stress. The tri-axial, uni-axial and scratch tests were conducted to determine rock strength, young modulus and Poisson ratio. The stress profile also built contains pore pressure, overburden stress, minimum and maximum horizontal stresses and horizontal stress direction.

The analysis from previous frac campaign data has been performed and used as one of data reference / calibration.

The result of study is to perform multi-stage hydraulic fracturing in lateral/sub-horizontal drain of W-H. The frac job has been designed to perform 3 stages of hydraulic fracturing across 270 m of F-D sub-horizontal drain. The use of abrasive jetting technology instead of explosive perforating and followed by spotting acid was suggested to optimize the net pressure required to perform frac.

In the end of frac job, the coiled tubing was run to mill out plugs and tested the well by commingling the three fracs followed by pressure buildup. The fracture treatment was performed consisted of an abrasive jetting, an injectivity test followed by 15% acid spearhead, mini frac and main fracture treatment for each stage except no mini frac was performed on the 2nd frac stage. The injection tests and mini frac were analyzed on location to finalized main treatment program.

4.1) 1st Stage Frac

Interval frac 1m, the injection tests suggested a reduction of 500 psi surface treating pressure after acid pumped and identified possible natural fissure/fractures appearance due to fast leak off from step rate down test

analysis. The mini frac resulted with instantaneous shut-in pressure (ISIP) of 11324 psi, corresponding to a fracture gradient of 0.82 psi/ft. The main fracture treatment was performed as per design by pumping a total of 135,340 lbs of proppant placed in formation to a maximum concentration of 6 lbm/gal. (62,180 lbs of Sinterball 30-50 and 68,506 lbs of Sinterball 20-40). A total of 135, 72- lbs of proppant was pumped from surface.

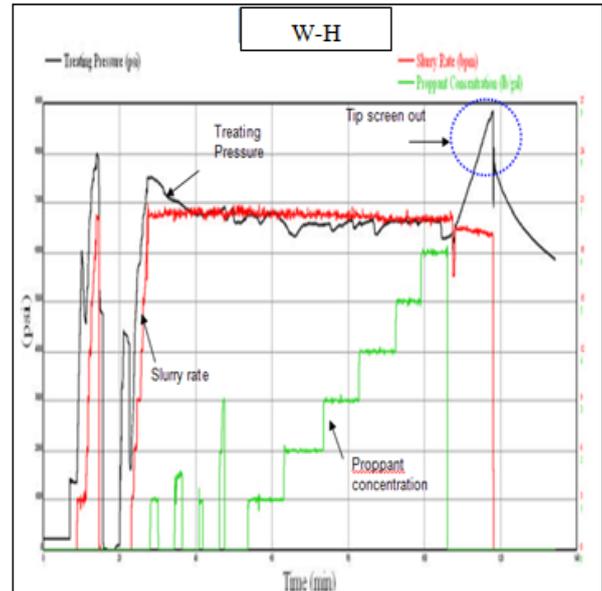


Fig.7. Treatment Data Plot Main Frac – 1st Frac Stage

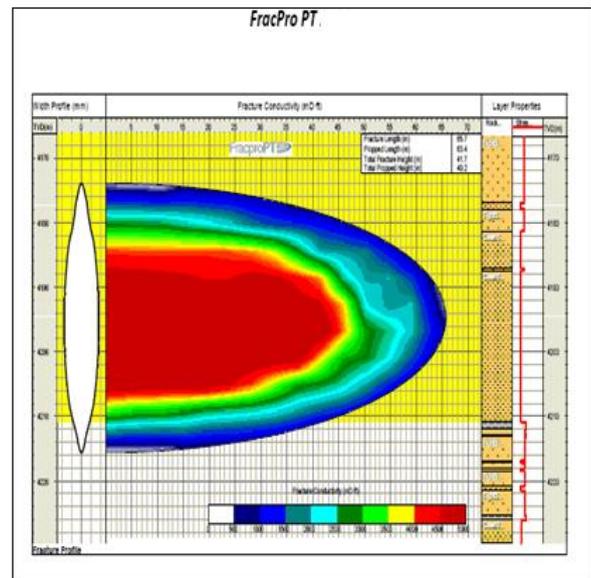


Fig.8. 1st Stage Frac Profile [2]

4.2) 2nd Stage Frac

Interval frac 1m and 100m between the first and second stage, The injection tests suggested a reduction of 950 psi surface treating pressure after acid pumped and identified possible natural fissure/fractures appearance due to higher fluid leak off than expected. The main frac was re-designed with smaller 35-50 mesh ahead of the 20-40 mesh to decrease the risk of early screen out. The main fracture treatment was performed with near

wellbore proppant screen out took place during the 4 lbm/gal (20-40 mesh) proppant stage at perforations. A total of 46,214 lbs of proppant placed in formation to a maximum concentration of 4 lbm/gal (40,046 lbs of Sinterball 30-50 and 6,168 lbs of Sinterball 20-40 mesh). A total of 85,846 lbs proppant was pumped from surface.

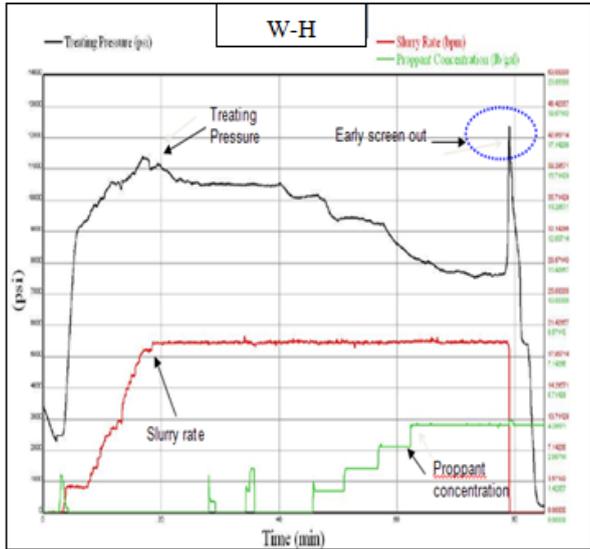


Fig9. Treatment Data Plot Main Frac – 2nd Frac Stage

main fracture treatment was performed with near wellbore screen out took place during 3 lbm/gal (30-50 mesh) as the pressure increased rapidly when the 3 lbm/gal sand arrive at perforation. A total of 27,799 lbs of 30-50 proppant placed in formation to a maximum concentration of 3 lbm/gal. A total of 67,772 lbs of proppant was pumped from surface.

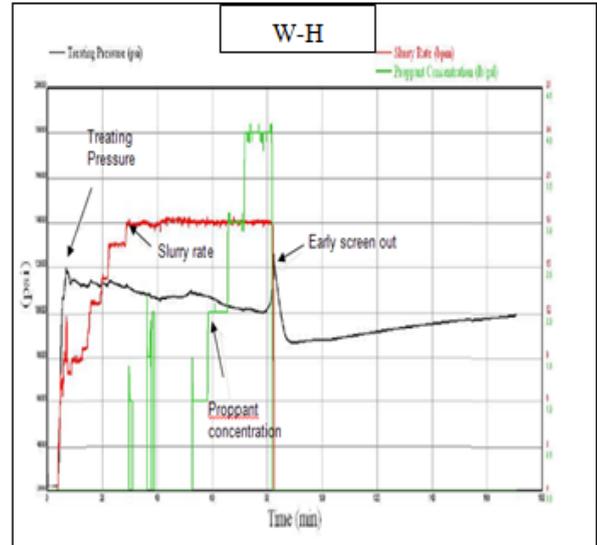


Fig11. Treatment Data Plot Main Frac – 3rd Frac Stage

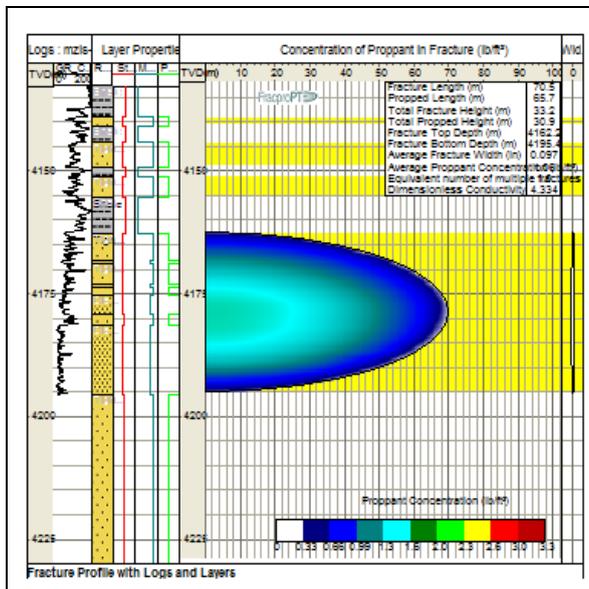


Fig10. 2nd Stage Frac Profile[2]

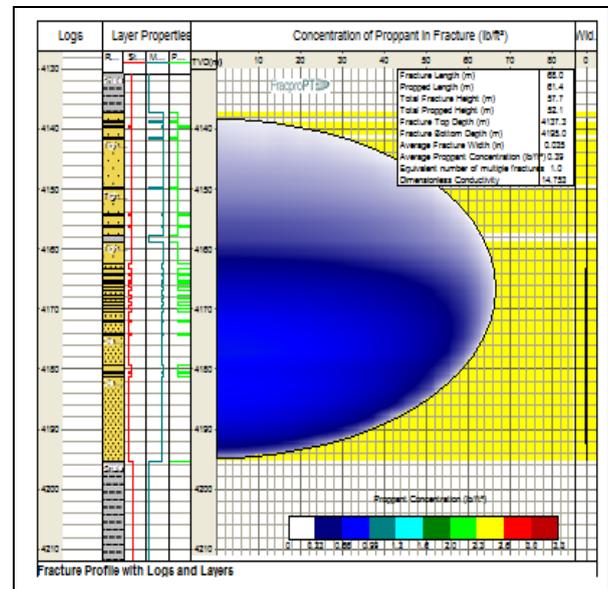


Fig12. 3rd Stage Frac Profile[2]

4.3) 3rd Stage Frac

Interval frac 1m and 100m between the second and third stage, the injection tests could not see clearly a reduction of surface treating pressure after acid pumped due to pressure fluctuation. The mini frac resulted with instantaneous shut-in pressure (ISIP) of 14.741 psi, corresponding to a fracture gradient of 1.04 psi/ft. The main frac was re-designed based on analysis of the mini frac and the previous 2 pumped stages by changing the sand from 20-40 mesh into 30-50 mesh and lowered the expected concentration from 8 ppa to 7 ppa with possible 20-40 mesh stage at 6 ppa. The

Below is the matched treatment data using FracPro PT for the three frac stages:

	1st Stage	2nd Stage	3rd Stage
Propped Length (m)	67	66	61
Total Propped Height (m)	42	31	52
Upper Frac Height TVD (m)	4174	4162	4140
Lower frac Height (TVD) (m)	4216	4193	4192
Avg. Propped Width in Pay (mm)	6.32	3	1.7
Avg. Proppant Conc in Pay (lbm/ft)	2.8	1.1	0.4
Avg. Frac Conductivity (md-ft)	3292	674	184
Dim. Frac Conductivity	89.1	4.3	14
Ref. Formation permeability (md)	0.172	0.7	0.07
Damage Factor Applied	0.5	0.3	0.3

Table 1. Frac Simulation Results – FracPro PT

5. Micro seismic Acquisitions and Results

The micro seismic acquisitions were performed to analyze the fractures direction and propagation during the frac jobs performed in the well W-H, using as observer the closest well W-V:

No micro seismic events were detected during the mini frac of the 1st stage performed. During the main frac of 1st stage performed 62 events were located perpendicularly to the well. The interpretation of micro seismic events confirms the expected fracture direction and propagation (along the maximum stress direction) and is in line with fracturing simulation results (~ 60 m frac half length)[3].

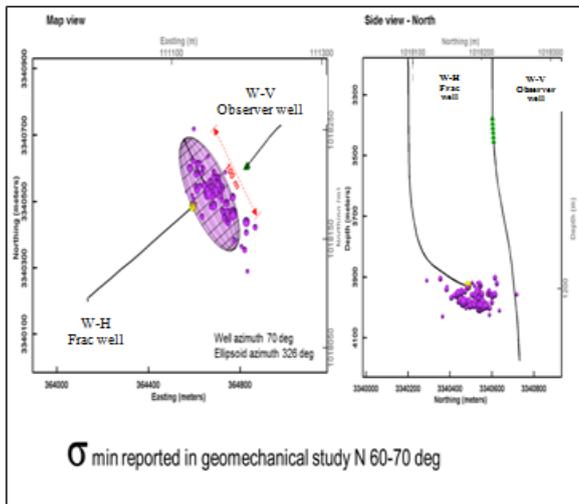


Fig13. Micro seismic interpretation of 1st stage Main Frac- job

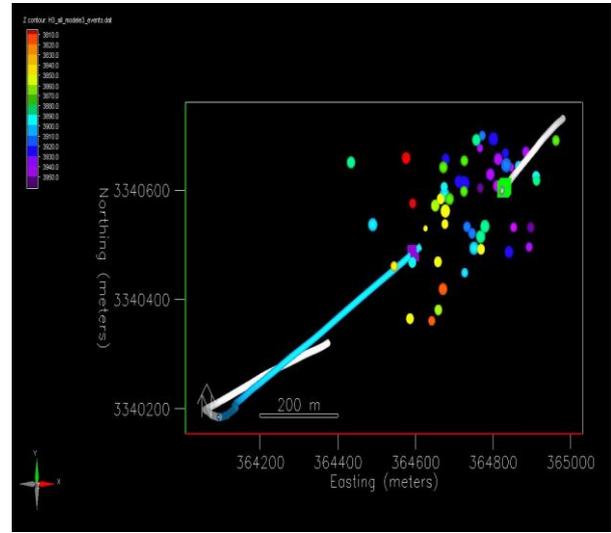


Fig14. 1st Stage – Main Frac – Plan view (X,Y)

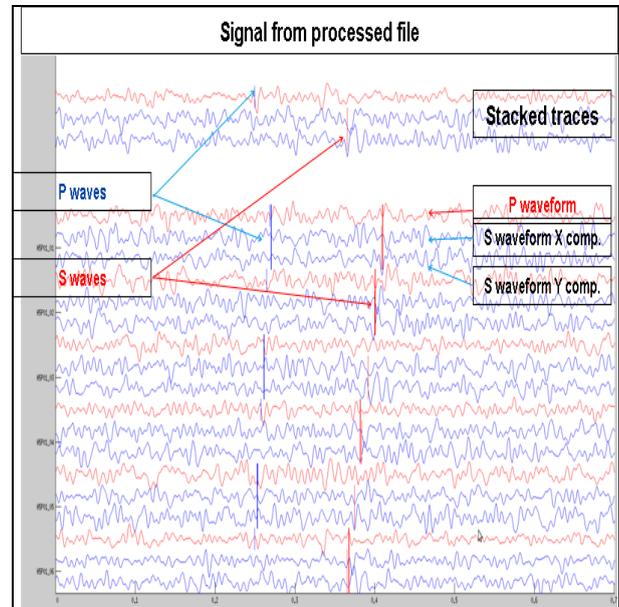


Fig15.1st Stage example: strongest event during Main Frac

There was poor micro seismic events detection during the 2nd main frac stage performed.

5 string shot were run in W-H and the events were recorded by micro seismic geophone placed in the observer well W-V for the velocity calibration to improve the interpretation of previous wave detection.

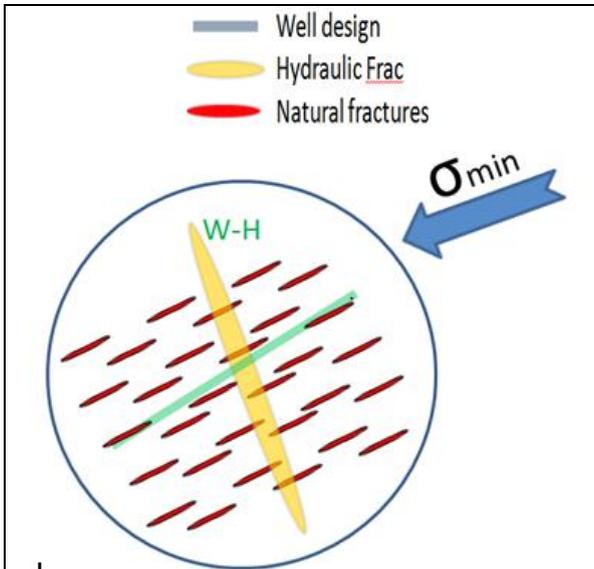


Fig16. Direction of minimum stress [4,5]

W-H: N58° ,Frac Azim: N244° , σ_{min} : N70°
 Hydraulic fracture: N160°

In this case we observed low natural fractures contribution and significant add value from HF

6. Well Testing Post Hydraulic Fracturing

The coiled tubing job has been performed to mill out plugs that have been installed during three frac stages followed by clean-up flow to clean out proppant from wellbore until measured BSW less than 5%. Three memory down hole gauges were installed to record bottom hole pressure behavior during production testing and build-up. The well was tested with two different choke sizes for 5 hours each followed by 12 days of BU with 6420 psi as SBHP. The short period of flow test is due to amount of authorized gas to be flared (higher gas rate than expected). Below is the summary of production testing :

	BHDD	Oil Rate	Gas Rate
	Psi	bbl/d	MMScf/d
DD 1	200	785	3.34
DD 2	400	1660	7.48

Table2. Post Hydraulic Fracturing Production Testing

It is expected that most of the production was coming from the 1st frac stage that successfully placed all proppant into the formation as per design, while the other two stages had early / premature screen out. This is the first time that the tight F-D reservoir was produced to surface with commercial rates.

The pressure build-up analysis was not reliable due to a very short production test period and because the measured SBHP after 12 days of build-up was still increasing without reaching stabilization; therefore, no clear radial flow was seen in pressure derivatives.

The static pressure measured 2 months later (6550 psi @ gauge depth) highlighted that the initial reservoir pressure was completely recovered, so that the problem could be the recharge of natural/induced fractures due to the very low matrix permeability of this tight reservoir far away from the wellbore [6].

7. Conclusion

One of the techniques which can help to optimize reservoir performance is the hydraulic fracturing of multiple zones along the horizontal drain.

Surface based micro seismic monitoring provides an important and complementary technique to down hole micro earth quake monitoring techniques. Given the S/N at the surface and the array design, events at magnitude levels similar to those seen down hole can be mapped.

The frequency content of these events at the surface results in reduced resolution compared to the down hole results. While the detection threshold and location accuracy are not as impressive near the observation well, the fact that the larger surface array is able to detect and locate micro seismic activity over a larger area allows greater access to the complexities of hydraulic fracture growth and interaction with the natural fracture system at distances that have not been investigated in the past.

The development of a tight reservoir like F-D could be considered for many aspects a sort of “leap in the dark”.

Poor petro physical properties, high stress condition, strong presence of diagenesis, bad seismic resolution could remarkably increase the risk of failure on the future exploitation of this reservoir.

Previous well tests and frac jobs have unfortunately confirmed how much challenging is to quantify and clarify these uncertainties.

After reaching gradually during these years a proper knowledge of the different aspects that characterize this reservoir, finally the first good results started to come (W-H successful frac job and well test, confirmation of natural fractures).

For the future development of F-D, by continuing to apply the appropriate technologies and dedicated studies on this reservoir it will be more than likely to reach a “safe landing”.

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