NuTech ENERGY ALLIANCE

Advanced Completion Evaluation

NuFIT™ Fracture Injection Vision

Evaluated For:

Example Company

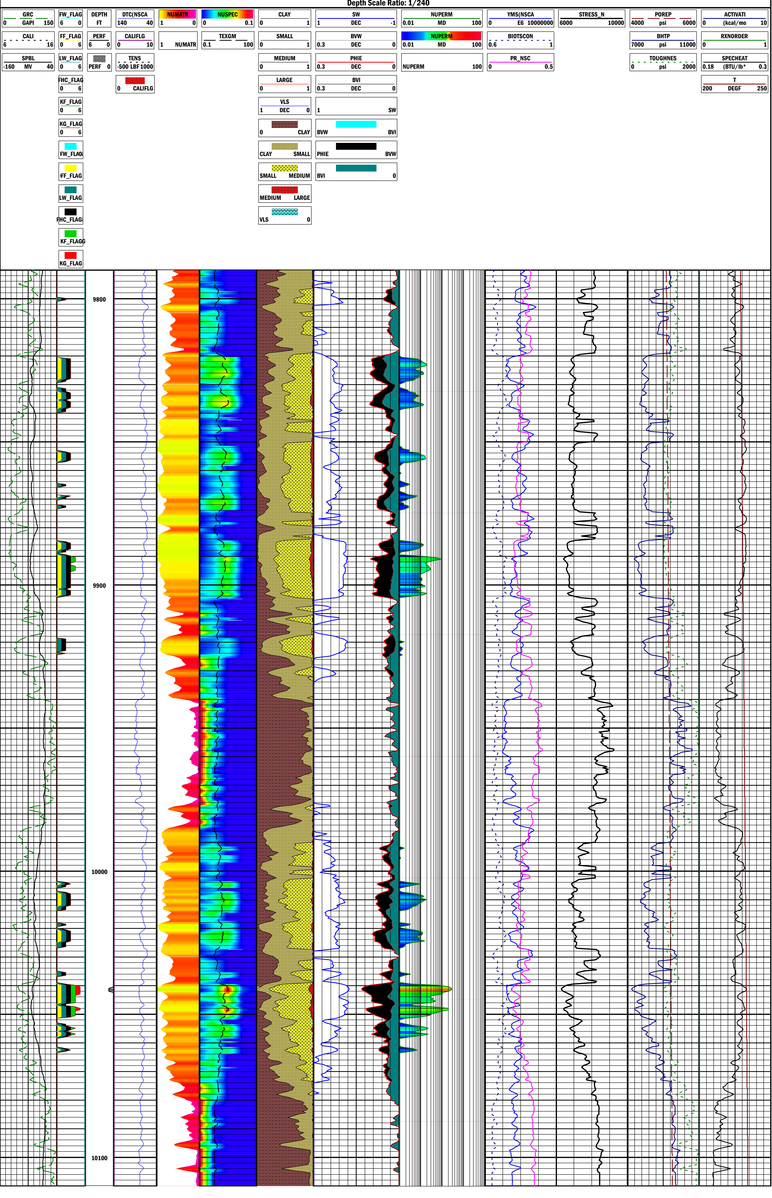
UPI:

Completed:

Company	
Well	COTTON VALLEY EXAMPLE
Field	
County	HARRISON
State	TEXAS
Country	USA
Location	
Section	
Township	
Range	
API Num	
Permanent Datum	
Elevation	
K.B.	
Log Measured From	
Above Perm Datum	
D.F.	
Drilling Meas From	
G.L.	

	Run 1	Run 2	Run 3
Date			
Depth - Driller	10160		
Depth - Logger	10174		
Btm Log Interval	10166		
Top Log Interval	1301		
Casing - Driller	9.625@1302		
Casing - Logger	1301		
Bitsize	8.75		
Type Fluid in Hole	DISPERSED		
Dens. / Visc.	10.05 / 36		
pH / Fluid Loss	9.8 / 10.6		
Source of Sample	CIRCULATION TANK		
Rm @ Meas. Temp	0.438 @ 102		
Rmf @ Meas. Temp	0.350 @ 102		
Rmc @ Meas. Temp	0.526 @ 102		
Source: Rmf / Rmc	CALC / CALC		
Rm @ BHT	0.157 @ 235		
Max. Rec. Temp.	235		

COTTON VALLEY EXAMPLE
13 Feb 2007 @ 15:31
DEPTH (FT)
Interval: 9790.00 to 10110.00
Depth Scale Ratio: 1/240



NOTES

NuFIT Product Description

NuFIT is a analysis oriented product in which NuTech will aid in the development of a specific injection test procedure and provide the analysis of this procedure in order to achieve direct measurements of the formation. These measurements include a calculation of closure and pore pressure along with the average formation permeability. NuFIT (NuTech Fracture Injection Test) may be used to aid in the calibration steps of the NuStim process prior to hydraulic fracturing.
Thank you for using NuTech.

NuFIT Analyst's Remarks

Pseudo-Radial flow was not observed in this well. This flow regime is critical to determine the permeability from the after closure analysis. The before closure analysis can also be used for a permeability estimate when in normal leak-off. This data set shows evidence of fracture extension and "height recession" in the before closure regime. This type of leak-off will effect and negate the perm calculation from the before closure portion of the data as the fracture area is changing during the shut-in period and the rate of leak-off is changing as a system of secondary porosity is closing.

Therefore there are two options left for estimating the permeability of the system, to match the rate of leak-off during the before closure period or to do a permeability estimate from the after closure data by extrapoating the the data to a maximum possible permeability. Trying to match the before closure leak-off rate will give a faulty view of the perm because the leak-off area is changing because of the fracture extension. An estimate of permeability from the after closure analysis was obtained, however this value should be regarded as a maximum value of permeability and the actual value is likely much lower.

The analysis shows a g-time closure of 8.8 which indicates a zone of marginal permeability.

PROJ. ID: COTTON VALLEY NuFIT EXAMPLE

Stage 1 NuFIT Analysis:

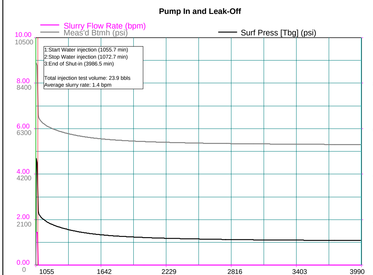
WELL #1
(10,041 - 10,042 FT) COTTON VALLEY TAYLOR
HARRISON COUNTY, TX

Well Bore Schematic

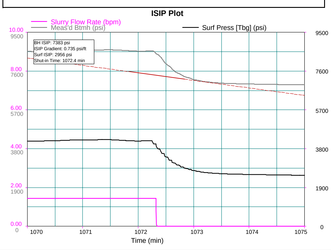
Reservoir Information	
Porosity (%)	7.3
Gross Height (ft):	63.5
Net Height (ft):	23
Young's Modulus (e6 psi):	4.1
Poisson's Ratio:	0.25
Perforations (ft):	10,041 - 10,042

Test Information	
Pressure Transducer Location:	Surface
Average Pump Rate (bpm):	1.4
Total Volume Pumped (bbls):	23.9
Total Time Pumping (min):	17.1
Hydrostatic Pressure (psi):	4427
Surface ISIP (psi):	2956
BHTP (psi):	7383
Fracture Gradient (psi/ft):	0.735
Wellbore Fluid:	2% KCl
Pumped Fluid:	2% KCl

Job Data

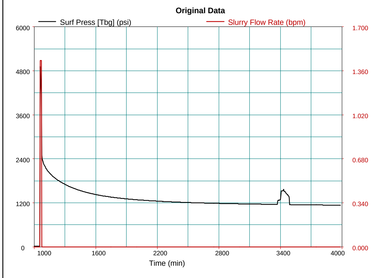


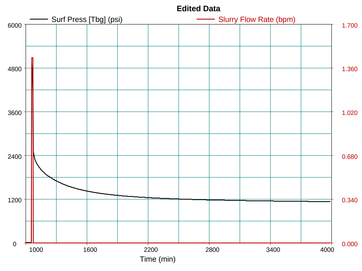
The job display plot shows the actual injection test performed on the reservoir and the pressure decline after the test. From this plot we can determine the ISIP (2956 psi), average pump rate (1.4 bpm), volume pumped (23.9 bbl) and the amount of time to pump the treatment (17.1 minutes). These data points and the subsequent pressure decline are used in the calculations to determine the reservoir properties.



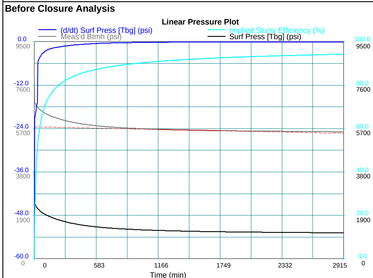
Data Quality

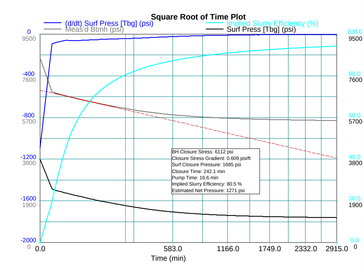
Pressure data was provided in two files for this analysis. Since both files contain the exact same values it is assumed that the data from only one gauge was provided. The gauge appears to function normally during most of the test interval. Two discrepancies were noted in the data, one at 1250 minutes and the other at 3400 minutes. The first one is very small and easily edited from the data, the second one is much larger but using average data across this interval still seems to provide a valid analysis. No digital data was provided on the pumping rate or volume. A curve describing assumed volume and rate of 1,000 gallons at 1.4 bpm was generated. If these values are close to the actual there should be little impact on the overall analysis without this digital information.

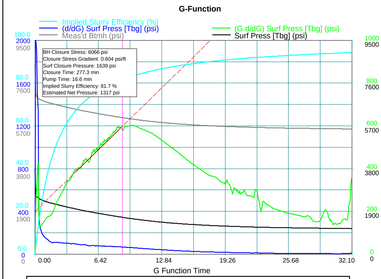


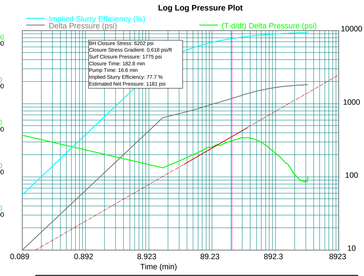


Before Closure Analysis









The g function plot is a diagnostic plot that allows for determination of the type of leak-off in the induced fracture and the point at which closure occurs. This plot uses the g-function, which is a function of the derivative of pressure and time, and plots this against g-time, which is a dimensionless time unit based on the amount of time used to pump the injection test. These equations provide for a unique relationship that provides a method of determining the type of leak-off based on the shape of the g-function curve.

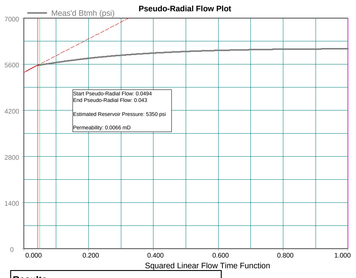
Primary Leak-off Mechanism **Frac Extension**

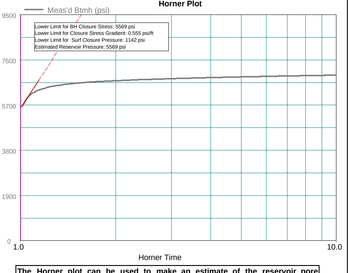
The log-log plot of pressure provides another diagnostic method to observe fracture closure. On this plot three different flow regimes are identified by slopes of 1, 0.5 and 0.25. These slopes represent three separate flow regimes: well bore storage, bi-linear flow, and fracture linear flow. On this plot closure should occur between the 0.5 and 0.25 slope points. Often this plot can have unusual characteristics due to a non-ideal leak-off regime. Therefore this plot is normally used only as a secondary indicator since it can not determine the type of leak-off and the indicated closure point can be mis-leading in a non-ideal leak-off case.

To determine the type of leakoff a straight line is drawn through the early time data and normally this line will intersect the origin. In this case a straight line drawn through the early time data will not pass through the origin. Instead the data will fit very well on a straight line, but the intercept will be above the origin which indicates fracture extension. Here the pressure in the fracture is not being relieved by pressure decline in to the reservoir, but instead it is being relieved by creating additional fracture length. This is an indication of low reservoir permeability.

Before Closure Analysis Results	
Primary Leak-off Mechanism:	Frac Extension
Secondary Leak-off Mechanism:	Height Recession
Closure Time (min):	277.26
G-Time Closure:	8.8
BH Closure Pressure (psi):	6066
Closure Gradient (psi/ft):	0.604
Fissure Opening Pressure (psi):	N/A
Fluid Efficiency (%):	81.7
KANE Pad (%):	3.3
Nolte Pad (%):	8.3
Shell Pad (%):	10.1

After Closure Analysis





Results:	
Reservoir Pore Pressure (psi):	5350
Reservoir Permeability Ft (md-ft)	0.080
Net Height (ft)	12
Reservoir Permeability (md)	0.0066

The Horner plot can be used to make an estimate of the reservoir pore pressure. Once the pressure decline has entered a period of pseudo radial flow a straight line can be drawn through that data. The intercept of that line on the Y-axis provides an estimate of the reservoir pressure. If the data set is limited and the well has not entered pseudo radial flow the plot can still provide an estimated maximum possible reservoir pressure.

Note: Pseudo-Radial flow was not observed during the shut-in period on this zone. This flow regime is critical to determine the permeability from the after closure analysis.