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Geomechanical Principles of Hydraulic Fracturing Method in Unconventional Gas Reservoirs

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Abstract—Unconventional gas production from shale formation is not new to oil and gas experts worldwide. But our research work was built around hydraulic fracturing technique with focus on the Perkins Kern-Nordgren (PKN) 1972 hydraulic fracturing model(s). It is a very robust and flexible model that can be used on two major shale reservoirs (with the assumption of a fixed height and fracture fluid pressure). The essence was to compare detailed geo-mechanical parameters extracted from wire-line logs with Perkin-C model to select the right well as candidate for simulation. It aided in the prediction production of shale gas from tight shale formations. These also helped in reviewing safe and economical ways of obtaining clean energy sources. Based on similarities in well and formation properties our research team subjected IDJE-2 well (located in the Agbada shale Formation of Niger Delta, Nigeria) to various conditions, equations and assumptions proposed by the study model while also validating our results with the PENOBSCOT L-30 well, located in Canada (with existing profound results from stimulations). The PENOBSCOT L-30 well (Case 1) and IDJE-2 well (Case 2) were both subjected to same conditions, equations and assumptions as applicable to the study model to enable us compare and evaluate stimulation performances. But both cases tend to react differently. However the fluid behavior at constant injection time increases at about 99.64%. Whereas, the maximum width at wellbore shows that a constant increase of fracture width will yield an increase in propant permeability, tensile strength and Poisson's ratio for Case 1 & 2. Our research results show how rock properties can affect fracture geometry and expected production rates from stimulated shale reservoir formations.

Keywords— Perkins Kern-Nordgren PKN, Hydraulic fracturing, Niger Delta, Shale gas, Unconventional gas, geo-mechanical principles

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I. Introduction

Fracturing has been in existence since the 18th century but extracting unconventional gas is relatively new unlike coal-bed methane production that began in the 1980's; Shale gas extraction is even more recent and its technology is widely accepted and applied to improve gas recovery in unconventional reservoirs. Unconventional reservoir to be address here are wells with low permeability, low porosity and complicated geological setting in-situ stress field (as is observed in shale gas). This entire characteristic makes the process challenging. Massaras et al., (2012) stated that fracturing is of four categories namely:

i. Pneumatic Fracturing; uses gas, pressurized air and fluid

ii. Dynamic loading which uses cryogenic, thermal/mechanical and,

iii. Enhanced bacterial methano-genesis.

But for the purpose of this research, hydraulic fracturing method which falls under the pneumatic fracturing category will be considered.

Hydraulic fracturing is a very common and important simulation technique for enhancing unconventional gas reservoirs in the world today, Himanshu, (2011) states. It is basically a process of initiating and subsequently propagating a crack (or fracture) in the surface rock layer by means of a pressurized fluid. It is a process that produces fractures in rock formation which stimulate the flow of natural gas or oil and increasing the volume that can be recovered. Montgomery and Smith, (2010) stated that 2.5 million fracture treatments have been performed worldwide since Stanolind Oil introduced hydraulic fracturing method in 1949. According to them, it is believed that approximately 60% of all wells drilled today are fractured. Fracture stimulation not only increases the production rate, but it is credited with adding to the reserves. Montgomery and Smith, (2006) stated that 9 billion bbl. of oil and more than 700 Tscf of gas were added since 1949 to US reserves alone—which otherwise would have been uneconomical to develop, Hence accelerating production and net present value of reserves. Wells drilled vertically may now extend hundreds to thousands of feet below the land surface and may include horizontal or directional sections extending thousands of feet. Runar, (2010) stated that the Geo-mechanical assessment of the formation must be viewed and analyze in detail with necessary conversion done to determine the potential of fracturing and faulting caused by initiating the injection process. However, properties to be obtained from well logs such as Poisson's ratio, Young's modulus, stress, strain and shear modulus can be calculated using wireline logs i.e. sonic logs

This research seeks to review existing literature on hydraulic fracturing, its processes, geo-mechanical studies, methods of gathering information, and relevant recommendation.

Nigeria is deeply affected by insufficient power to feed her populace, which has brought slow pace of development in all sectors of its economy. However, the inclusion of unconventional gas to the already existing energy resources cannot be overemphasized as it will go a long way in giving her citizenry energy independence, economic definition and stability. The world's energy demand will increase by 30-40% in the next 20 years making hydraulic fracturing technology vital throughout the world and Nigeria is not exempted.

Oil Producer Trade Section (OPTS) 2016, states that Nigeria is in the position to generate 40,000Mw of power daily for 68 years from the Country's indigenous gas reserve estimated 181Tcf in-turn making her gas supper-power- the largest in Africa and ninth largest in the world but it has only 4000kw in full operation which is not up one-tenth of the abundance of its resources.

It has been observed that since inception, Nigeria has always turned a blind eye on her abundant unconventional gas reservoirs which is unfair. Presently, the United States of America, Canada, China and Argentina are beneficiaries of the shale boom which has transformed their economy enormously. However, as a matter of importance and national urgency, gas from shale formation should be considered as a bailout as it will affect Nigerian economy positively, businesses, increase jobs creation and give access to clean and ready gas supply thereby reducing carbon emission by half that of oil making her a net gas exporter. Hence, hydraulic fracturing method in unconventional gas reservoir with the use of geo-mechanical principles is used to develop shale gas deposit. Hydraulic fracturing design models are used as prediction tools for optimizing hydraulic fracturing.

A. Shale Reservoir Charactertics

Shale is a sedimentary rock which consists of very fine grained rock of silt and clay particles (basically lithified mud). Sixty percent of the earth's sedimentary crust consists of shale; hence it forms primarily the source rock for conventional hydrocarbon deposit around the world. Despite having reasonable porosity, it has extremely low permeabilities (Nanodarcies to microdarcies). Organic shale are different from other mudstones and clay-stones because they are laminated, finely layered and fissile mostly characterized by higher level of total organic carbon (TOC) of range 2%- 10% Reservoir, pictorially represented below. Few shale deposits from the abundance are actually okay for development as hydrocarbon resources play. Hence the target for shale gas exploration is characterized by:

i. High level of Organic matter 2.2wt % ,
ii. Low level of oxygen,
iii. Density ~2500kg/m^3,
iv. Porosity up to 30%,
v. Permeability in nano-darcies to micro-darcies,
vi. Bulk Modulus ~10G Pa,
vii. Young's Modulus 0.2 - 0.4,
viii. Shear modulus ~1.6G_{Pa}, 5 -100 M_{Pa},
ix. Shear strength 3 - 30 M_{Pa},
x. P-waves velocity 1400 - 3000m/s ,
xi. S-waves ~ 2600m/s

As a result of the rock properties, production increases from the onset of hydraulic fracturing, which enables permeable pathway for gas fluid by aiding natural fracture. For emphasis, hydraulic fracturing is the use of the exact formulation of fluid and materials to create or restore small fracture in a formation in order to stimulate production from new and existing gas wells. For proper extraction of natural gas the process stages are:

i. The acid stage; this consist of the mixture of dilute acid such as hydrochloric acid or muriatic acid and water to clear cement debris on the path of the wellbore thereby opening conduit for frack-fluid to dissolve carbonate minerals near the wellbore.

ii. A pad stage; consists slick water solution without a propant. This facilitates flow and replacement of propant materials around the wellbore.

iii. A prop sequence stage; this is done with the intention to keep open or 'prop' the fracture created. The mixture of several hundred-thousand gallons of water combines with propant material (fine mesh sand or ceramics) to use sequentially.

iv. Finally, the flush stage; this entails the use of fresh water to flush excess propant from the wellbore.

B. Stages in Shale Gas Extration

Shale gas extraction consists of three consecutive stages listed below:

a. Exploration: This is the initial process of the project phase where appraisal wells are drilled (2-3 wells) and fractured to determine the presence of tight gas in the reservoir. Also, to determine the economic viability of the reservoir.
b. Production: The production stage involves the commercial production of gas. Shale with commercial reserve of gas well typically is greater than hundred meters thick and laterally over a space of over hundred square kilometer down subsurface. They are characterized by shallow dip meaning they

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are almost horizontal. Hence horizontal drilling and hydraulic fracturing are likely to increase production.

c. Abandonment: This happened to every other well. A shale gas well is abandoned once it reaches the end of its producing life- when extraction is no more economic. Section of the well above subsurface is hewed after they are filled with cement to prevent gas from contaminating the water table.

C. Brief History and Locations (S) of Shale Gas Deposits in Nigeria

Nigeria has no commercial productions of unconventional gas. Nevertheless there is a pointer to the fact of the presence of unconventional gas resources such as the tight sands gas, coal-beds methane (CBM) and shale gas within Nigeria. These resources are located mostly on the inland basins of Benue trough and Maiduguri (i.e. Borno) basin, the study area spans from northeastern to the southeastern parts of Nigeria. The lower Benue (i.e. Anambra basin), the middle Benue and the upper Benue (i.e. Yola sub-basins and Gongola) made up the Benue trough. Facts also have it that Nigeria is not left out in terms of shale deposits. Shale formation are abundantly located in Nigeria most especially the North-east and south-south. Hence there are potentials for shale gas in the Niger Delta basins most especially the Imo shale group with 312m thickness which exists in the Paleocene basin/age and Cross-river basins- south western regions of Nigeria and Benin (Dahomey) basins in the south-south respectively. States such as Benue, Borno, Adamawa, Anambra, and Enugu significantly stands out. also examples of such Basins such as the Agwu shale formation, Eze-Aku Shale, Nsukka formation 233m, Mamu formation, Nkporo shale 1829m, Ajali sandstones 450m, Enugu shale and Afowo shale formation of Dahomey Basins. Ekwueme et al (1995)

Also, the Odukpani formation consists of black calcareous shale which has been assigned. Eze-Aku formation consist black calcareous shale, shelly with boundary thickness towards Aba in Abia state to Owerri. Agwu formation also consist bluish-grey shale a cenomanian age based on the amount of fauna Ehinola et al. (2008)

II. INTRODUCING THE RESEARCH MODEL (S)

A. Perkin-Kern-Nordgren (PKN) 1972 Model

We compared and analyzed geo-mechanical parameters from the Niger Delta shale gas reservoir(s) using Perkin-Kern-Nordgren (PKN) 1972 model for possible hydraulic fracturing and validating our result findings using foreign reservoir data(s). We also looked at the applicability of hydraulic fracturing technology history as applied in foreign unconventional reservoir rocks in contrast to Niger Delta. Our research team also extracted foreign reservoir geo-mechanical parameters using Techlog software(s). Defining shale formation geo-mechanical properties and parameters required indirect presentation of hydraulic fracturing from well-log data(s) like sonic, gamma ray, density/porosity log while using conversion equations' methods to calculate the:

a. Poisson's ratio

b. Young modulus and

c. To determine where to fracture the shale formation for maximum flow to the well bore.

1) Perkins-C Model/Method

Perkins and kern (1961) Nordgren (1972) incorporated the carter equation II in the original PKN model which states the engineering procedure for material balance at constant injection rate with fluid leak off. In as much as it is a method, it is more preferred in the oil industry because of its vertical plain strain assumption which is more physically acceptable for proposed height contained fractures where the fracture length becomes considerably greater than the fracture height. Moreover, it predicts fracture length closer than all other 3D models and is widely applicable to unconventional formations.

Fracture in this method requires a constant height H, elliptic vertical cross-section with maximum width Wm at the center, propagated in horizontal x direction given the injection rate (Q0), fluid properties, mechanical properties of the rock formation, in-situ stress σ0, virgin pore pressure P0, leak-off coefficient, well fracture width and history as well as pressure history in borehole (fracture inlet), fracture direction/ azimuth.

2) General PKN Assumptions

In order to simplify the complex problem the following assumptions were made by the PKN models:

1. The fracture fluid pressure is constant in vertical cross section perpendicular to the direction of propagation.
2. Fracture height $h_f$is fixed and independent of fracture length
3. Each plane obtained an elliptical shape with maximum width in the center.
4. Resistance to deformation prevails in vertical plane.

$$w(x,t) = \frac{(1-v)h_f\,(P-\sigma h)}{G} \quad (1)$$

5. Flow-rate is a function of growth rate of the fracture width.

$$\frac{\delta q}{dx} = -\frac{\pi h_f}{4}\frac{\partial w}{\partial_t} \quad (2)$$

6. Vertical cross-section has an elliptical form
7. Isotropic, homogenous, linear elastic rock mass
8. Fracture is in pain strain in the vertical.

B. Well Candidacy Selection Criteria

Hydraulic fracturing is a serious and costly business. Hence, the failure or success of a hydraulic fracture treatment depends on the quality of the well(s) selected. Therefore, choosing an excellent well candidate for stimulation is important. However, to select the best candidate for stimulation, the design engineer must consider the following variables:

i. Formation permeability: Permeability is either a low–permeability zone or already highly damaged (high skin factor).
ii. The in-situ stress distribution within the formation
iii. The reservoir depth: Zones to be fractured are usually thick pay zone with large areal extent.
iv. Skin factor: this refers to whether the reservoir has been stimulated or is damaged (Note: If it is positive, reservoir is damaged, indicating a good candidate for stimulation)
v. The reservoir fluid viscosity.
vi. The condition of the wellbore: Well must possess substantial volume of gas in place (GIP) and the need to increase productivity index should arise.

C. Data –Set (S) Development

A complete and accurate dataset set is needed by a petroleum engineer for fracture treatment design. Compiling set could be time consuming but rewarding. Fracture design model are often categorized as either 'controlled' or 'Not controlled' by engineer. Those controlled are the well completion details, treatment volume, injection rate, fracture fluid viscosity, fracture fluid density, propant agent type and volume, in-situ stress. (Note that all three are primary data) while formation permeability (which is most important), formation modulus, reservoir pressure, reservoir thickness, formation porosity, formation depth, formation compressibility are measured or estimated. In all these, it is important to state in-situ stress profile, permeability of formation to be stimulated above and below target zones which will affect fracture height growth. Meanwhile, data to be design are obtained from various source including the production data, completion records, open-hole log, drilling record and publications. A proper flow chart is given below to illustrate the whole process using these model(s).

D. Hydraulic Fracturing Principle (S)/ Equations

Firstly, from the starting point at injection time't', the injection rate entering one wing of the fracture is equal to the sum of the different leak-off rate with the growth rate of the fracture volume. Mathematically, injection rate is given by equation 3.4 below:

$$\frac{q_i}{2} = 2\int_0^t \frac{c_l}{\sqrt{t-\tau}}\left(\frac{\partial_A}{\partial_t}\right)\partial_\tau + \left(w + 2s_p\right)\frac{\partial_A}{\partial_t} + A\frac{\partial_w}{\partial_t} \qquad (3)$$

Where,
q_i = total rate of injection
C_L= Overall Leak-Off Coefficient
τ= opening time at filtration start
S_P= Spurt Loss
Note:
1. Neglecting width increase during fracture growth
2. Assuming constant injection rate.

Fracture surface area A at a given time't' is also given by equation (4) below:

$$A(t) = \frac{(w+2S_p)}{4C_l}\frac{q_i}{2}\left[\exp(\beta^2)\,erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \qquad (4)$$

Where:
shape factor, $\beta = \frac{2C_l\sqrt{\pi t}}{w+2S_p}$

Further recommended because of the inaccuracy of rock properties, fracture width at wellbore Wf for no leak-off is improved to (5) below as:

$$W_{f=}9.15\wedge\left(\frac{1}{2n+2}\right)3.98^{\frac{n}{2n+2}}\left[\frac{1+2.14n}{n}\right]K\left(\frac{1}{2n+2}\right)\left(\left(\frac{q_1}{2}\right)^n\frac{hf^{1-n}\,xf}{E!}\right)\wedge^{\frac{1}{2n+2}} \qquad (5)$$

Where:
n = power law component (dimensionless)
k = consistency index (pas-sec^n)

Using shape factor (π/5) for PKN model, the average width (ϖ) along fracture length is given by Wf= π/5.

Using carter Equation II with the average fracture width, fracture half-length/ fracture height can therefore be given as:

$$x_f = \frac{(\varpi+2S_p)}{4C_l{}^2\pi h_f}\frac{q_i}{2}\left[exp(\beta^2)erfc(\beta) + \frac{2\beta}{\sqrt{\pi}} - 1\right] \qquad (6)$$

The above equation 3.7 serves as the solution to fracture propagation problem knowing values (xf) and (q1). The fracture length or injection time can easily be determined using the numerical root finding method.

Net fracture pressure (Pnet) is calculated:

$$P_{net} = \frac{E'}{2h_f}W_{w,0} \qquad (7)$$

Hence, the fracture treatment pressure Ptreat at wellbore equals the addition of in-situ stress and net fracture pressure.

At the Wellbore, Ptreat = $\sigma + P_{net}$

Nolte et al, (2000) presented an approximate optimum pad volume and propant schedule which is important to hydraulic fracturing treatment design. He stated that the material balance equation during fracture growth at any time is:

$$v_{i=}v_{f+}v_l \qquad (8)$$

$$v_i = q_i \times t_i \qquad (9)$$

Where:
V_f = fracture volume
V_l = fluid volume leaked.
Economides and Nolte (2000) projected (v_f) as:

$$v_f = \frac{\pi}{2}\gamma h_f x_f w_f \qquad (10)$$

Final propped width after the closure of fracture is given as:

$$w_p = \frac{W_{pr}}{2x_f h_f (1-\emptyset_p)\rho_p} \quad (11)$$

Where:
W_{Pr} = Weight of propant
Q_p= Propant porosity
ρ_p = proppant density
$2x_f h_{f\,=}$ fracture area.

III. RESEARCHED CASES

A. Case 1: PENOBSCOT L-30, Located in Canada

Assumptions / Data(s)
Well fracture properties:
Injection rate @ 46 bpm / 0.12189m^3/s
Leak-off coefficient @ 6×10^{-5} m/s
Injection time @ 1000 sec
Young's modulus (E) @ 0.3
Poisons ratio @ 0.40
Fluid viscosity (μ) @ $5.6\times10^{-7\text{mPa}}$ or 5.6×10^{-4}cp
Fracture height (h_f) @ 10_{ft} / 15.24m
Spurt loss @ 0.65 gal /sq-ft
Fracture length (X_f) @ 50 ft.
Fracture half-length (L_f) @ 25ft
Porosity (ϕ) 15% - 25%
Permeability (k) @ 25mD
Maximum fracture width @ the wellbore in terms of power law is given as:

$$W_{f=}9.15\wedge\left(\frac{1}{2n+2}\right)3.98^{\frac{n}{2n+2}}\left[\frac{1+2.14n}{n}\right]K\left(\frac{1}{2n+2}\right)\left(\left(\frac{q_1}{2}\right)^n\frac{hf^{1-n}\,xf}{E!}\right)\wedge^{\frac{1}{2n+2}} \quad (12)$$

Where:
$$, E! = \frac{\mathrm{E}}{1-\mathrm{v}^2}$$

$$n = 0.1756(1000\mu)^{-0.1233} \quad (13)$$

For the fluid behavior as given by Peter P. Valko (2005):

$$k = 47.880(500\mu - 0.0159) \quad (14)$$

Based on our assumptions stated above for Case 1, we have that:

Power law Rheology, n' = 0.2,

k' = 12.6lbft/ft2.Sn and E! = 0.3

Substituting these variables into (5), the maximum fracture width gave 94.5m which when converted to inches gave 59.12in respectively.

$$\hat{W}e = 0.628\mathrm{W}_{w,0} \quad (15)$$

with a shape factor (β) = 7.04×10-5.

More so, the fracture Area 'A' when calculated from (4) at a given time't' using the complimentary error function table $erfl\ 0.06 - 1.31$ A(t) , gives a fracture area of 5777m2.

The net fracture pressure P(net) from (7) also gave a value of 1.6947psi/ft

1) PROPANT SCHEDULING:

Applying Material balance equation:
$v_i = v_f + v_l$
Nolte exponent, $\varepsilon = \frac{1-\eta_e}{1+\eta_e}$ = 0.53.
$v_{pad} = \varepsilon v_i = 64.6m^3$
$t_{pad} = \varepsilon \times t_e$= 530 sec
Fluid efficiency; $\eta_e = \frac{v_{ef}}{v_1}$ = 0.2798 or 28%
The dimensionless fracture gradient (Cf_D) is given by Cinco-Ley (1978) as:

$$cf_D = 31.4159kL_f \quad (16)$$

From Case 1 data above, if the formation permeability is 25md and the optimum fracture half-length is 25ft, then the optimum fracture conductivity would be 1964 md-ft. the dimensionless fracture gradient, CfD, at minimum 10 is considered to prevent any clean-up issues hence slick-water is most appropriate to be used as a propant for hydraulic fracturing this zone. 2.5g/cm3was assumed as the density of HPG as well as the weight of propant as 3.0mmlb.

The injected slurry volume is represented by (17) below and it yielded about 121.89m3 or 32,199.89 gallons after substituting known values.

$$V_1 = q_1 \times t_e \quad (17)$$

Volume at the end of pumping gives 9.00988m^3 after substituting known values into (18) below:

$$V_{fe} = x_f \times h_f \times \hat{\mathrm{W}}_e \quad (18)$$

Final propped width 'Wp' after closure of fracture as stated in (9) gives approx. 1411.8m

B. Case 2: IDJE-2, AGBADA Formation, Nigeria

Assumption(s) / Real Data values:
Fracture properties/assumptions for IDJE-2 well, Agbada shale Formation are:
Injection rate @ 46 bpm
Leak-off coefficient @ 6×10^{-5} m/s
Injection time @ 1000 sec
Young's modulus (E) @ 2.3×10^{10}
Poisons ratio @ 0.33-044
Fluid viscosity (μ) @ 0.15cp

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Fracture height (h_f) @ 10ft
Spurt loss @ 0.65 gal / sq-ft
Fracture length (X_f) @ 50ft.
Fracture half-length (L_f) @ 25ft
Porosity (ϕ) @ 30%
Permeability (k) @ 40mD
Maximum fracture width at wellbore in terms of power law is given as:

$$W_{f=}9.15\wedge\left(\frac{1}{2n+2}\right)3.98^{\frac{n}{2n+2}}\left[\frac{1+2.14n}{n}\right]K\left(\frac{1}{2n+2}\right)\left(\left(\frac{q_1}{2}\right)^n\frac{hf^{1-n}\ xf}{E!}\right)\wedge^{\frac{1}{2n+2}}$$

Where:

$$, E! = \frac{E}{1-v^2}$$

$$n = 0.1756(1\mu)^{-0.1233}$$

$k = 47.880(500\mu - 0.0159)$ Peter P. Valko. (2005)

Substituting the values from Case 2 assumptions above gives:
Power law Rheology, $n' = 0.1$, and $k' = 3590 lbft/ft^2 \cdot S^n$ and $E! = 5.84\times 10^9$

Therefore, substituting the variables into (5) for the maximum fracture width gives 94.5m which when converted to inches gives 59.12in.

$$\hat{W}e = 0.628W_{w,0}$$

Also, with a shape factor (β) of 3.08×10^{-3}

More so, the fracture Area 'A' when calculated from (4) at a given time't' using the complimentary error function table $erfl$ 0.06 − 1.31 A(t) , gives a fracture area of 5777m^2.

The net fracture pressure P(net) from (7) gave a value of 2.56psi/ft

1) PROPANT SCHEDULING:

Material balance equation as stated by Nolte (1986)

$$v_i = v_f + v_l$$

Nolte exponent $(\varepsilon) = \frac{1-\eta_e}{1+\eta_e} = 0.90$

$$v_{pad} = \varepsilon v_i = 109.8_m^3$$

$$t_{pad} = \varepsilon \times t_e = 900 \text{ sec}$$

Fluid efficiency;

$$\eta_e = \frac{v_{ef}}{v_1} = 0.261$$ which is equivalent to 26%

The required dimensionless fracture conductivity (Cf_D) by Cinco-Ley (1978) is:

$$cf_D = 31.4159kL_f$$

From data above, if the formation permeability is 25md and the optimum fracture half-length is 25ft, then the optimum fracture conductivity would be 1964 md-ft. The dimensionless fracture gradient, CfD, at minimum 10 is considered to prevent any clean-up issues hence slick-water is most appropriate to be used as a propant for hydraulic fracturing this zone. 2.5g / cm3 were assumed as the density of HPG as well as the weight of propant as 3.0mmlb.

The injected slurry volume from equation below gives 121.89.m3

$$V_1 = q_1 \times t_e$$

Volume at the end of pumping gives 8.41m^3

$$V_{fe} = x_f \times h_f \times \hat{W}_e$$

Final propped width 'Wp' after closure of fracture as stated in (9) gives 1411.8m

Having view hydraulic fracturing technology in its entirety in unconventional reservoir rock and tentatively analyzed the geo-mechanical properties using the pern-kern-Nordgren model of different location of interest, I found out the following as answers to my research questions. These are illustrated in figures below.

Also, with basic assumption taken, the model reacted slightly differently in both cases. For the fluid behavior at constant injection time, a noticeable increase of 99.64% in consistency index represents an apparent or effective viscosity as a function of shear rate which describes the behavior of a real non-Newtonian fluid in any flow condition.

IV. RESULTS, DISCUSSIONS AND INTERPRETATAIONS

TABLE 1.1 CALCULATED RESULTS IN SUMMARY FOR CASE 1& 2 APPLYING PKN-PKN-MODEL

PARAMETER(S)	PENOBSCOT L-30 (WELL1) CASE 1 (CANAD	IDJE - 2 (WELL 2) CASE 2 (AGBADA, NIGE
Fluid Efficiency (%)	28	26
Fracture Area (m2)	5777	5777
Nolte Exponent	0.53	0.90
Shape Factor	7.04 X 10-5	3.08 X 10-3
Power Law Rheology (n)	0.2	0.1
Max.Fracture Width,Wmax (m)	94.5	94.5
Net Fracture Pressure (psi/ft)	1.6947	2.5600
Optimum Fracture Conductivity (md-ft)	1964	1964

Injected Slurry Vol.(m3)	121.89	121.89
Final Propped Width (m)	1411.8	1411.8
Final Pumped Vol.(m3)	9.009	8.410

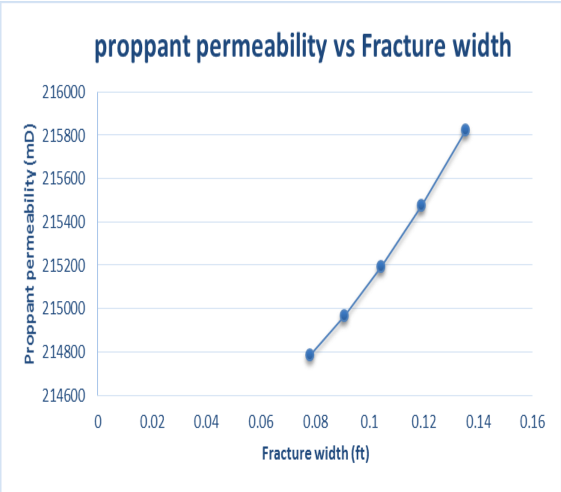

Figure 1. A graph showing the relationship between the power component and the average well fractured width (inch)

A. Results Discussions/Interpretations (S):

Fig.1 above shows at a glance the responds of Well 1 and Well 2 properties by the PKN hydraulic fracturing model used. Well 1 showed a higher average well width and Well 2 shows average well width of 0.0552inch. This is considerably low when taking into account the above assumptions which states that before PKN model must be used, its fracture height must be at least twice of the fracture length.

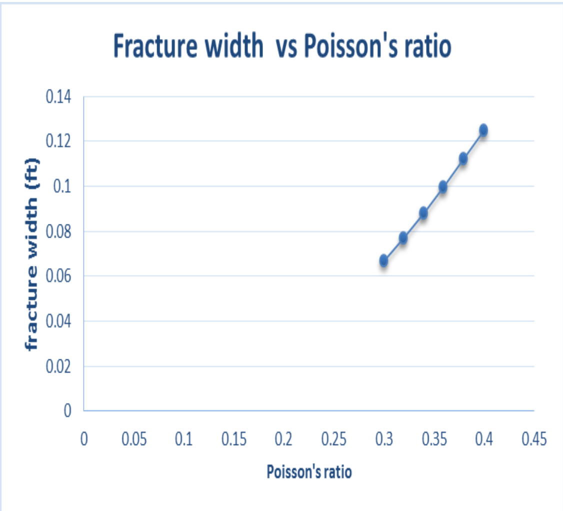

Figure 2. A graph showing the relationship between the fracture width and the Poisson's ratio

B. Result Discussions/Interpretations

Rock properties such as permeability, tensile strength and pore pressure affects fracture geometry. Of these, young's modulus, Poisson's ratio stands out as that factor which control other rock properties, since they affect fracture geometry directly. However, the study of the relationship between the fracture parameters such as Fracture width, height, and half-length was considered closely, also operational parameters such as injection rate was also studied to show their effect on fracture geometry. Young's modulus expresses resistance of material to deform. Therefore, Young's modulus value increases as the expected fracture width decrease. However, the reduction per unit change of Young's modulus is not significant (0.088inches). Shale formation generally has relatively low Young's modulus, meaning that fracture width will be greater than expected width from conventional formation.

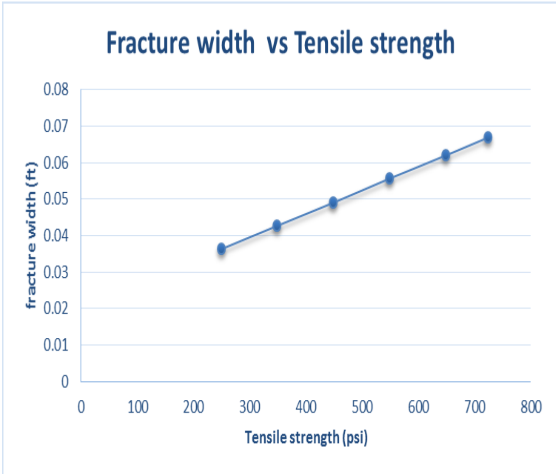

Figure 3. A graph showing the relationship between the fracture width and the Tensile strength

C. Result Discussions/Interpretations

Hydraulic fracture increases as width increases which directly increases Poisson's ratio. Also, from analysis has stated that rock with high strength will have less Poisson's ratio since they deform less when compressive force acts on them. To this premise, it is stated that Poisson's ratio will increase as fracture width increases. Since shale formation has low strength compared to conventional formation, expected Poisson's ratio in shale will be higher than any other formation. Tensile strength increases the required break-down pressure which is proportional to the fracture width. Also, propant permeability is equally proportional to fracture width which will initiate flow. Therefore, the conductivity which is dimensionless increases as permeability increases in a well.

Conclusion and Recommendation

The rock properties, Poisson's ratio and formation tensile strength affects the fracture geometry and expected production rates. As assumed by the PKN model, fracture height should not be fixed and should not be assumed to be larger than the formation thickness but should be larger, smaller or even equal to the formation thickness depending on the rock properties. Poisson's ratio increases fracture width, increases propant permeability also as a result of increasing fracture conductivities. The various increase effect on fracture width and fracture conductivity is positive as it also increases the fracture height but inversely affects the half-height whose result causes reduction of fracture width.

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