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Analysis of Water Injection in an Artificially Fractured Reservoir

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Abstract: *Water injection is a notable method used primarily for reservoir pressure maintenance and voidage replacement which boosts oil recovery. A problem associated with water injection operation is the injectivity loss due to rock porosity and fluid resistance to displacing oil to producing well, formation damage caused by accumulation of oil and solid particles present in water which lowers displacement efficiency, reduces the permeability around the wellbore and not able to maintain its injection rate. Optimal injection rates could not be reached on the occurrence of injectivityloss. Nonetheless, the injectivity loss was avoided or reduced by water injection with fracture propagation pressure (IFPP) by thermally induced fracture (Artificial fracture) which aimed at restoring injection capacity. To analyze this process, a geo-mechanical simulator for fracture modeling combined with a commercial reservoir simulator (**REVEAL 3.3**) was used to model and to optimize the operational conditions of water-injector wells. The fracture was represented by dimensionless fracture conductivity, fracture half-length, skin factor, a vertical well, a virtual horizontal well. This research paper aims to study and compare a case with loss-no fracture and with loss-with fracture. The simulation model studied was a synthetic reservoir with Black oil type variation (41^0, API). The IFPP was evaluated using the net present value (NPV), cumulative oil and water produced. This study showed that the technique was only advantageous when there was significant injectivity loss, which the IFPP assisted in restoring injectivity, increased oil production and NPV. Injecting with higher rate reduced the NPV. It also showed that the mobility ratio was less than unity and the water injection had a favorable and stable displacement, likewise a low water cut. It showed that the rate of fracture growth depends on the injection rate, water quality, temperature and mechanical properties of the rock and the injectivity was primarily dependent on the insitu-stress, injection rate and the water quality. It was shown to be economically beneficial and profitable to invest on.*

Keywords:*Injectivityloss, waterinjection, artificialfracture, thermal fracturing, reservoir numerical simulator.*

I. INTRODUCTION

Water injection has been the most useful secondary recovery method in petroleum industry for reservoir pressure maintenance and voidage replacement due to its low cost of operation, simple to operate and its availability from nearby rivers, streams, oceans, or from wells drilled into less deep or deeper subsurface aquifers and favorable characteristics of displacement. This operation was necessary to achieve optimum production and maximize ultimate recovery when the primary energy of the reservoir tends to deplete or is not sufficient to maintain an economic oil rate. Operations in either offshore or onshore, injector wells has not achieved the optimal proposed injection project when it is associated to a technical problem known as" Injectivity loss". Injectivity loss (well impairment) is the inability of a displacing fluid (water) to maintain its injection rate and displace oil to the producer well. Injectivity loss could result from formation damage, scales, oil droplets and solid particles present in the water that reduces the permeability around the wellbore. In other words, it is related to a well not being capable of maintaining a constant water injection rate and its direct relationship with the quality of water injected. It is therefore necessary to have trusted models to predict the behavior of water injection wells. In recent times, an option to combat injectivity loss is to inject with fracture propagation pressure or increase the injection pressure above the formation fracturing pressure which creates high conductivity channels (fractures).

Once there is insufficient reservoir energy to maintain an economic oil rate, different recovery methods could be utilised to maintain constant reservoir pressure and oil rates. Singh (1982) and Palsson et al. (2003)

stated that it is well proved and accepted in the oil industry that the process of water injection is a useful method in the improvement of oil recovery, but most times injectivity decline takes place and this results in the injector well not being able to achieve the proposed injection project, They further stated that inspite of the numerous benefits of water injection, a technical problem, the injectivity loss, has a significant economic effect. In view of the foregoing, Sharma et al. (2000) described the injectivity loss as one of the most important problems in water injection operation and is more severe in offshore operations. Hence, Sharma et al. (2000) further stated that it is a phenomenon that has a strong influence in the injection performance since it is directly related to the capacity to maintain pressure and fluid rates in the reservoir. For instance, in the Gulf of Mexico; Scale formation, porous media being plugged by fine particles, oil droplets and the poor quality of water injected were the cause of injectivitylosses. They went on to develop an analytical model to study the injection decline caused by the injection of fines and their effect on the performance of injectors and to determine the parameters of injection water quality, it was found out that oil production was drastically reduced as the water injection rate reduced. Bedrikovetsky et al. (2001) further developed a mathematical model with two parameters (formation damage and filtration coefficient) to compute the necessary information in order to determine the injector well impairment from laboratory and field tests.

In view of the aforementioned, in order to avoid or reduce the injectivity loss, various procedures may be utilised. The best option should be dependent on technical, economic and environmental considerations. Montoya et al (2005) discovered an increase in the cost of operation as a result of injectivity loss due to prolonged filtration of the water injected, which cost is dependent on the particle size in suspension, the addition of chemical agents to restrain scale formation, destroy bacteria and the substitution of parts of the injection system that are generally uncomplicated or cheap, and further stated that injection of water above fracture pressure is a method that combats injectivity loss as a result of generation of fractures with high conductivity, which leads to high injectivity. And that this method has been applied in various offshore and onshore fields around the globe. Due to the challenge of injectivity loss, Nazir and Peng (1994) made some discovery when the Valhall field, in North Sea, was subjected during three years, to water injection with pressure above the parting fracture in order to improve the injectivity, and found out that its effect in water breakthrough was minimal. Souza et al (2005) also discovered several Petrobras's wells in onshore fields where the injection of water with pressure above the fracture pressure could be advantageous in relation to the injectivityloss, unfavorably reduce the sweep efficiency since the water channels into the fractures. They further stated that IFPP could be a better option than the usual ways of solving this challenge such as improving on the quality of water injected or carry out well work over. Costa et al (2009) studied some water injection cases to verify in which situation the use of injection with fracture propagation pressure was convenient particularly in light, intermediate and heavy oil with oil type variation (41, 31 and 21 API degrees) respectively using a geomechanical simulator for fracture modeling combined with a commercial reservoir simulation were carried out and it was discovered that for cases of intermediate and heavy oil, the formation fracture pressure was only reached in the absence of injectivity loss due to rock and fluid characteristics and had an increased oil production while, in the case of light oil, the IFPP technique was only advantageous in the presence of injectivity loss where it assisted in restoring injectivity and could not improve oil production. Montoya (2006) stated that in order to model the well impairment, there should be an alteration in the injectivity index in order to consider the permeability declination as a function of time. The alteration of permeability around the injector well, which is in relationship with formation damage, was modeled by an analytical expression as shown in equation (1):

$$K_s = \frac{K}{(1+a_i nt)^{1/n}} \tag{1}$$

Where K_s is the absolute permeability of damaged region, k, the block original permeability, t is time, a_i and n (0.009 and 1.0) respectively are the constant that determines the decline trend of curve. Gadde and Sharma (2001) and Noirot et al. (2003) also stated that in order to corrigibly model the formation fracture and its effects in the reservoir oil production, a Black-Oil reservoir simulator must be associated to geo-mechanical models, which describes how fluid flow when the rock properties are changing over time. In view of the foregoing, Souza et al. (2005) stated that in the absence of this simulators, ordinary reservoir simulators are utilized and the presence of fractures and injectivity losses are considered using, for example, mathematical models, grid refinement and transmissibility modifiers, they went on to associate a non-commercial geo-mechanical software to model the growth of fracture and its propagation to a commercial reservoir simulator.

Montoya et al. (2005) studied the effect of injectivity losses in the Net Present Values for models as time function was carried out and it was found out that the models which considered injection with fracture propagation pressure, virtual horizontal wells or transmissibility modifiers presented an NPV that was higher than the model with injectivity loss and without fracture. The fracture was studied only in the direction of injector-producer well by utilizing a simple geometry pattern (direct line pattern) between injectors and producers wells and the numerical flow model was constituted by a 27× 47×1 Cartesian grid number and were analyzed through a Black-oil commercial reservoir simulator likewise the injector-producer distance and the injection pattern. In view of the aforementioned, studies has shown that some economic factors have to be considered, particularly in calculating NPV in petroleum industry, such as revenue, capital expenditure, operating expenditure, overhead cost recovery, state tax, as well as amortization. Udie et al. (2013) stated that revenue is mainly relying on the market price, produced fluids and equally relies on the market modifier factor. Moreso, Berks et al. (2015) stated that the flow of incoming and outgoing cash flow could also be described as beneficial and cost cash flows respectively and the NPV is the summation of all terms. Perkins and Kern (1961) stated that there would be an increase in fracture width when the injection rate, the fracture fluid viscosity and the fracture length increases, or a decrease in formation modulus. They showed how the variables affect fracture propagation, and stated that it conforms to the Perkins-Kern-Nordgren (PKN) fracture geometry.

1.1Mobility Ratio

Tarek (2006) stated that the "mobility of any fluid, $\lambda$is the ratio of the effective permeability of the fluid viscosity". Hence the mobility ratio M is also defined as the movement of the displacing fluid to the movement of the displaced fluid, or:

$$M = \frac{\lambda_{displacing}}{\lambda_{displaced}} \tag{2}$$

$$M = \frac{K_{rw} / \mu_w}{K_{ro} / \mu_o} \text{or} \frac{K_{rw}\, \mu_o}{K_{ro}\, \mu_w} \leq 1 \tag{3}$$

Where $k_{rw}$is relative permeability of water, $k_{ro}$is relative permeability of oil,μ_o is oil viscosity and μ_w is water viscosity." If M ≤ 1, this indicates a favorable and unconditionally stable displacement, it therefore means that under an imposed pressure differential, the oil is capable of moving with a velocity equal to, or greater than that of the water. Since it is the water that is pushing the oil, there is therefore, no tendency for the oil to be by-passed. If M> 1, this indicates an unfavorable and unstable displacement, and there is a tendency that water would by-pass oil."

1.2 Fractional Flow (Water cut)

Tarek (2006) further stated that the creation of the fractional flow equation is ascribed to Buckley-Leverette (1941). For two fluids that are not mutually soluble, oil and water, the fractional flow of water, f_w (or any non-mutually displacing fluid), is defined as the rate of water flow divided by the total rate of flow, or

$$f_w = \frac{q_w}{q_t} = \frac{q_w}{q_w + q_o} \tag{4}$$

Where $f_w$is fraction of water in the flowing stream, q_t is total flow rate, q_o is oil flow rate, $q_w$iswater flow rate. In water injection computations, the reservoir water cutf_w, and the water – oil ratio, WOR are both commonly expressed in two different units. The interrelationships that exist between these two parameters are conveniently presented in equation (5) below:

$$WORs = \frac{B_o}{B_w\left(\frac{1}{f_w} - 1\right)} \tag{5}$$

Where B_w is water formation volume factor, B_o is oil formation volume factor.

1.3 Fracture Pressure

Park (2005) stated that fracture is a separation, dissociation or crack in a geologic formation when it exceeds its rock stress. It is further stated that fracture pressure is the pressure inherent in the wellbore that causes the separation or crack in the rock formation by causing the rock to lose intermolecular forces along its weakest plane. In view of the aforementioned, the stress within a rock can be resolved into three principal stresses. A formation would only fracture when the pressure in the borehole exceeds the least of the stresses within the rock structure. Normally, these fractures will disseminate in a direction perpendicular to the least principal stress as shown in figure 1 below.

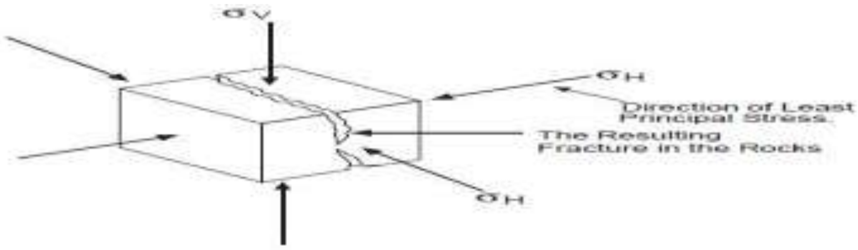

Figure 1: Three Principal Compressive Stresses (Spring, 2013)

Based on the experimental data analysis from the laboratory, Hubbert and Willis (1956) stated that the least principle stress in the less deep sediments was nearly one-third of the matrix stress due to weight of the overburden, hence in order to determine the formation fracture pressure; equation (6) should be used.

$$P_{ff} = \frac{\sigma_{ob} + 2P_f}{3} \tag{6}$$

Where P_{ff} is the fracture formation pressure, psi, P_f is formation pressure, psi, σ_{ob} is overburden stress, psi.

1.4 Thermal Fracturing

Fjaer et al. (2008) stated that thermally induced fracture (artificial fracturing) is normally observed during water injection, especially when there is a great difference in temperature change between the injected water (cold) and the reservoir (hot). This may result in shrinkage in the reservoir rock being gradually cooled during injection of the cold water. Perkins and Gonzalez (1985) stated that it is quite obvious that during water injection, a fracture will be initiated in the near wellbore region, if the well flowing pressure becomes greater than the sum of opposing pressure.

1.5 Fracture Optimization and Modeling

Phani and Makul (2001) stated that fracture conductivity is a measure of how easily fluid moves through a fracture. It was further defined as the product of fracture permeability and fracture width. As shown in equation (7):

$$F_C = k_f w_f \tag{7}$$

When the value of flow capacity is divided by product of formation permeability (k) and fracture half length (x_f), the results is known as the dimensionless fracture conductivity defined as equation (8):

$$F_{cd} = \frac{K_f w_f}{k x_f} \tag{8}$$

This ratio, F_{cd}, must be large to have a substantive, long-term increase in production. For low permeability formations, the denominator becomes small, and efforts to make high conductivity fractures are less important. Cinco-Ley and Samaniego (1978) introduced the concept of finite flow-capacity fractures for the case of very lengthy fractures and low capacity fractures; they used semi analytical approach to point out the need to consider fracture to be finite if the dimensionless fracture conductivity is below 300.

These authors showed that the impact of injection with fracture propagation pressure could be high depending on the injection pressure, velocity and direction of fracture propagation, the type of well (vertical or horizontal). They further showed that injecting with fracture propagation pressure (IFPP) could be a favorable option to reduce or avoid injectivity loss when coupled with geomechanical simulators which is considered as best tool to analyze and study fracture behavior under water injection condition. However, this kind of software is usually time consuming and it is important to note that available numerical simulators for fracture modeling are always related with hydraulic and natural fracture modeling, and oftentimes, they are not related to fractures induced (artificial fracture) by water injection, rather they are represented using virtual horizontal well or an effective radius to represent the fracture behavior. In view of the foregoing, they failed to monitor and represent the fracture growth and sizes (fracture length) it was further found that the mobility ratio is a key player in determining the favorability of oil displacement. In as much as water injection projects operational costs are on the increase because operational performance is hampered by injectivity loss. Injectivity loss makes it impossible for the injector wells to maintain pressure and the desired fluid rate in the reservoir. Hence, in addition to their methodology, a mathematical model that considers and monitors the presence of fractures and injectivity loss in an injector well would be used to model the fracture half-length and fracture growths as well as its propagation to a commercial reservoir simulator (REVEAL 3.3) ensure that they are properly analyzed.

The objective of this paper is to study the effect of injectivity losses in a non-fractured reservoir in order to analyze the impact on oil and water production and to model water injection with fracture propagation pressure (IFPP) in order to reduce injectivity loss and improve production performance with the aid of REVEAL 3.3 reservoir simulator, compare the case with injectivity loss and the case with IFPP in order to quantify the variation in cumulative oil and water produced and net present value (NPV) and to find an optimal injection rate. This paper is organized as follows: Section 2 presents the methodology, Section 3 presents the results and discusses the application of the result to a water injection field case, and Section 4 finally presents the conclusion.

II. METHODOLOGY

2.1 Data Acquisition

The reservoir data used for the simulation were collated from a Niger Delta field, National Petroleum Investment Management Services (NAPIMS),Organization of Petroleum Exporting Countries (OPEC) and as such includes: an injector (vertical) well and a producer (virtual horizontal well), model dimensions and reservoir data (Table 1), reservoir fluid properties (Table 2), mechanical and rock properties (Table 3),properties of injection water (Table 4),relative permeability data (Table 5),Operational conditions for both cases (Table 6 and Table 7) and economic data (Table 8).The reservoir properties were assumed to be uniform across the entire model, the net to gross ratio was equal to 1.0 and the capillary pressure effect were neglected. The reservoir simulations were carried out using a Black-oil and a geomechanical simulator combined with commercial reservoir simulator (REVEAL 3.3).The total simulation time was 3653days (10years).

Table 1 presents the reservoir data and model dimensions used for the reservoir simulation.

Table 1: Model Dimensions and Reservoir Data

Parameter	Symbols	Values	Units
Total grid numbers	Nx, Ny, Nz	25, 25, 10	-
Grid Size	Δx, Δy, Δz	500, 500,50	ft
Grid total dimension		$12500 \times 12500 \times 500$	ft
Reservoir area	A	192	acres
Porosity	ϕ	0.25	-
Horizontal permeability	K	0.1	md
Vertical permeability	K	0.1[1-8],1000[9-10]	md
Reservoir compressibility	C	3×10^{-6}	Ps^{-1}
Model top depth	-	10000	ft
Water viscosity	μ_w	0.33	Cp
Water compressibility	C_w	3.22×10^{-6}	Ps^{-1}
Reservoir thickness	H	700	ft
Reservoir temperature	T	220	^{o}f
Equivalent radius	r_e	39	ft
Well bore radius	r_w	0.354	ft
Damage radius	r_s	3.0	ft
Initial water saturation	S_{wi}	17	%
Initial Reservoir Pressure	p_i	5000	Psi
Bubble Point Pressure	P_b	878	Psi
Oil Formation Volume Factor	B_o	1.31	bbl/stb
Water Formation Volume Factor	B_w	1.03	bbl/stb

Source: Niger Delta Offshore Field

Table 2 presents the reservoir fluid properties used for this model.

Table 2: Reservoir fluid properties

Parameter	Oil Type Value
	Black Oil
Viscosity, Cp	0.62
API	41

Source: Niger Delta Offshore Field

Table 3 presents the mechanical and rock properties used for the geomechanical simulator and Table 4 present the water injection properties and Table 5 presents the relative permeability data which was used for both cases.

Table 3: Mechanical and Rock Properties

Parameter	Value	Unit
Young's modulus, ε	50	Psi
Tensile Strength T_o	50	Psi
Overburden pressure, p	9396	Psi
Poisson ratio, v	0.2	-
Biot's constant, α	0.90	-
Thermoelastic coefficient	8	Psi/^{0}f
Critical stress intensity	200	Psi/ft^{½}
Poroelastic coefficient	0.5	-

Source: Niger Delta Offshore Field

Table 4: Properties of Injection Water

Parameter	Values	Unit
Surface Viscosity, μ_w	0.982	Cp
Bottom Viscosity, μ_w	0.337	Cp
Temperature, T	60	^{o}f

Source: Niger Delta Offshore Field

Table 5: Relative Permeability Data

Water Saturation S_w	Relative Permeability, Oil K_{ro}	Relative Permeability, Water K_{rw}
0.17	0.58	0.00
0.20	0.52	0.00
0.30	0.36	0.01
0.40	0.25	0.04
0.50	0.15	0.09
0.60	0.07	0.17
0.65	0.04	0.21
0.70	0.02	0.26
0.75	0.01	0.31
0.80	0.00	0.36

Source: Niger Delta Offshore Field

Table 6, 7 and 8 presents the wells operational condition for case with fracture propagation (WLWF), case without fracture propagation (WLNF) and economic data respectively.

Table 6: Operational Conditions for WLWF model

Parameter	Values	Units
Well head Pressure for producer	2000	Psi
Wellbore flowing Pressure (BHP) for producer	4000	Psi
Minimum BHP for producer	P_b(878)	Psi
Maximum BHP for injector	$>p_{ff}$	Psi
Maximum STL for producer	6610	stb/d
Maximum STW for injector	50000	stb/d
Formation fracture pressure, p_{ff}	6465	Psi

Source: Niger Delta Offshore Field

Table 7: Operational Conditions for WLNF model

Parameter	Values	Unit
Min BHP for producer	878	Psi
Max BHP for injector	$<P_{ff}$	Psi
Max STL for producer	6610	Stb/d
Max STL for injector	50000	Stb/d

Source: Niger Delta Offshore Field

Table 8: Economic Data

Price, Cost and Tax	US$/*bbl*
Current Oil Price	42.96
Current Oil production Cost	4.25
Water injection Cost	4.0
Injected Water Treatment	4.0
Well Cost	6.0×10^6
Discount Rate	13(%)

Source: NAPIMS, OPEC

2.2 Analysis Procedures

Two cases of reservoir model were analyzed: (1) an initial base case of with loss-no fracture (WLNF) model was simulated assuming the presence of injectivity loss without considering fracturing presence as a control test or modeling by ensuring that the well operational conditions were met. In view of the foregoing, Hubbert and Willis (1956) equation was used to determine the pressure required to fracture the formation or to overcome the least principle stress. Such that the water was injected below the determined fracture pressure during the simulation. The fracture formation pressure was determined through equation (9):

$$P_{ff} = \frac{\sigma_{ob} + 2P_f}{3} \tag{9}$$

where P_{ff} is the fracture formation pressure, P_f is formation pressure and σ_{ob} is overburden stress.

In order to restore injectivity or create the fracture,:(2) a second case of with loss-with fracture (WLWF) model was simulated, inducing an artificial fracture by injecting with IFPP or above the already determined fracture pressure by ensuring that the operational conditions were met.The simulator applied the principle of thermal fracturing due to the rock stress being temperature dependent.Hence,the fracture due to skin during the simulation was represented using the equation presented in Cinco-Ley Samaniego (1978) and determined how the fracture grew with time from the injector through equations (10) and (11):

$$s_f = -0.6751Ln(F_{DC}) - Ln\left(\frac{L_f}{r_w}\right) + 1.508 \tag{10}$$

$$F_{DC} = \frac{k_f w}{k_b L_f} \tag{11}$$

Where, F_{DC} is the dimensionless fracture conductivity, L_f is the fracture length, r_w is the wellbore radius, $S_f$is fracture due to skin, k_f is the fracture permeability, k_b is the block permeability, w is the fracture width. For the both cases, the reservoir parameters analyzed were the cumulative oil and water produced, cumulative water injected and injection rate. The net present value (NPV) was calculated using economic equations presented in Udie et al. (2013) and Berks et al. (2015) alongside with an EXCEL spread sheet, the equations are expressed below:

$$\text{Revenue}_1 = \frac{N_p X_{s\,(Sm-0.02(40-API))}}{t_{life}} \tag{12}$$

$$\text{Royalty} = \frac{1}{8} Rev_1 = \frac{0.0125\, N_p X_{s\,(Sm-0.02(40-API))}}{t_{life}} \tag{13}$$

$$\text{Working interest} = {}^{7}/_{8}\ Rev_1 = \frac{0.875\, N_p X_{s\,(Sm-0.02(40-API))}}{t_{life}} \tag{14}$$

$$\text{Overhead cost recovery} = 10\% \frac{INV}{t_{life}} = \frac{0.1\,(OPEX)}{t_{life}} \tag{15}$$

$$\text{State tax (Stax)} = 8\%\ INV = \frac{0.08(Opex)}{t_{life}} \tag{16}$$

$$\text{NCF} = (\text{Rev} - \text{Royalty} - \text{Stax} - \text{Opex} - \text{Capex} - \text{OHDCR}) \tag{17}$$

$$\text{NPV} = \frac{R_t}{(1+i)^t} \tag{18}$$

Where R_t is the net cash flow (NCF), Xs is market modifier factor, Sm is market price,t_{life} is total time, i is the discount rate, Np is cumulative oil produced,Rev_1 is yearly revenue, Stax is state tax, Opex is operating expenditure, Capex is capital expenditure and OHDCR is overhead cost recovery.

III. RESULTS AND DISCUSSION

Figure 2, 3, 4, 5, 6, 7, 8, 8(A) and Table 6 below shows analysis of the simulation results.

Figure 2: Comparison between WLNF and WLWF model on oil production

Figure 2 above presents the simulation result comparison of cumulative oil produced between the case of WLNF and WLWF model. It showed that the case of WLNF model produced less amount of oil compared to the case of WLWF model due to injectivity loss effect and the WLWF model produced high amount of oil over time due to the induced fracture (IFPP) in the injector well which was able to restore injectivity within the wellbore and improved oil production, although the improvement in oil recovery was marginal. The blue and red dotted lines represent WLWF and WLNF models respectively.

Figure 3: Comparison between WLNF and WLWF model on water production

Figure 3 above presents the simulation result comparison of cumulative water produced between the case of WLNF and WLWF model. It showed that WLWF model produced more water than that of WLNF in a marginal form due to interception of producing well by the fracture. Hence, they both produced less water. The blue and red dotted line represents WLWF and WLNF models respectively.

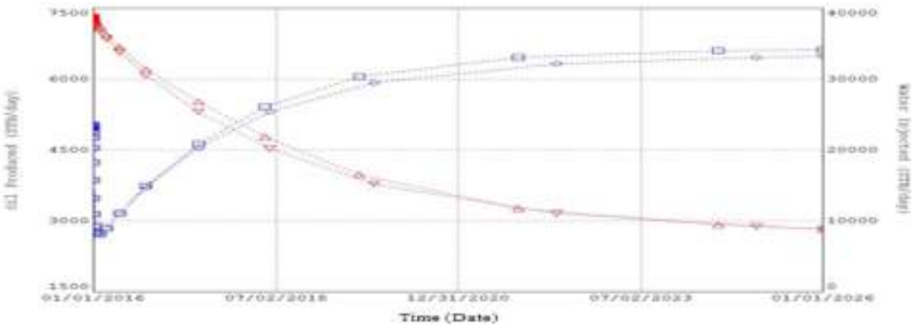

Figure 4: Comparison between WLNF and WLWF model on Oil production rate/water injection rate

Figure 4 above presents the simulation result comparison of production rate and injection rate between WLNF and WLWF model. It showed that at low water injection rate of 8897stb/d for WLWF model the oil production rate increased more than the rate of 8877stb/d for WLNF model because as the fracture length increases, the areas previously unswept are better swept. More so, injecting at a lower rate was due to the fact that the fracture has been opened already in order to maintain the fracture propagation created in WLWF model.

In view of the foregoing, the injection rate of 8897stb/d was seen to be the optimal injection rate since it gave the highest oil production rate. The blue dotted lines represent WLWF and WLNF models respectively for oil production rate and red dotted lines represent WLWF and WLNF models respectively for water injection rate.

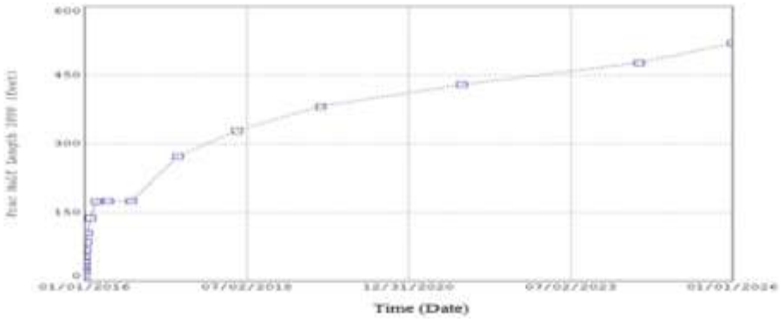

Figure 5: Fracture half-length curve

Figure 5 above presents the simulation result of the fracture half length. It showed that the injection rate significantly increased the fracture growth rate, and as the fracture growth increases, oil recovery increases. High injection rates resulted in earlier formation fracturing because high bottom-hole pressures are required to inject at high rates. The step-like curve was caused due to the time values used for the simulation. It further showed that the induced fracture was successful.

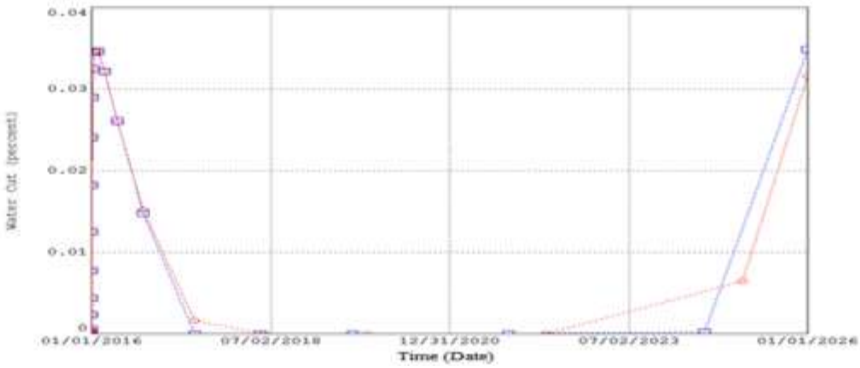

Figure 6: Water Cut Curve

Figure 6 above presents the simulation results of water cut comparison between the case of WLNF and WLWF model. It showed that WLWF model (3.5%) has slightly higher water cut than that of WLNF model (3.2%), generally, the both models are marginal and has low water cut due to reservoir perforation and reduced injection rate. The blue and red dotted lines represent WLWF and WLNF models respectively.

Table 9: Mobility ratio and WOR

Parameter	Value
M	0.74
WOR	0.042 [WLNF model] 0.046 [WLWF model]

Source: Generated from equations 3 and 5

Table 9 above presents the result of mobility ratio and water oil ratios of WLNF and WLWF model. The mobility ratio as determined from equation (3), was got as (M=0.74), which was an indication that the mobility ratio remained constant from the start of the injection until water breakthrough occurred. Hence, the mobility ratio increased after breakthrough due to continuous increase in the average water saturation. It further indicates that the water injection had a favorable and unconditionally stable displacement since M<1 before breakthrough, meaning that water did not bypass the oil due to the fact that both water and oil moved at the same velocity. And had an unfavorable displacement when M>1 after breakthrough which also indicates that water bypassed the oil due to the fact that both water and oil were not moving at the same velocity at that point. The water oil ratio was determined from equation (5), and was got as 0.046 for WLWF model and 0.042 for WLNF model respectively, meaning that the ratio of water to oil was less.

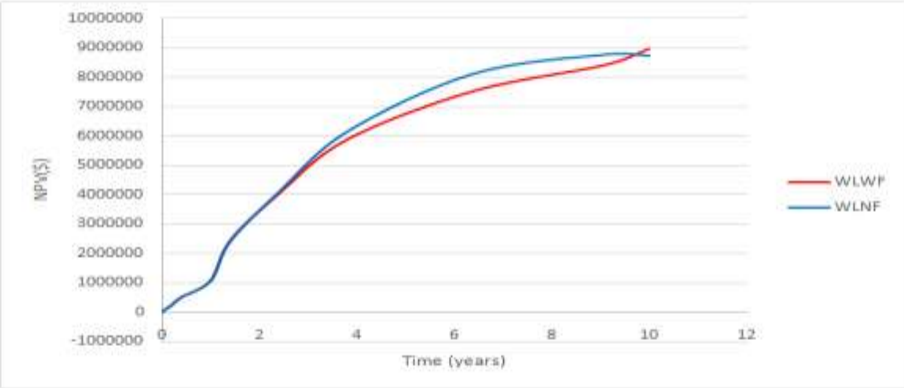

Figure 7: NPV Curve

Figure 7 above presents the result comparison of economic evaluation between WLNF and WLWF model. The NPV comparison showed that the WLWF model has the highest NPV compared to WLNF model in a marginal form. This further indicates that the injection with fracture propagation pressure (IFPP) increased the net present value and the injectivity loss reduced the NPV.

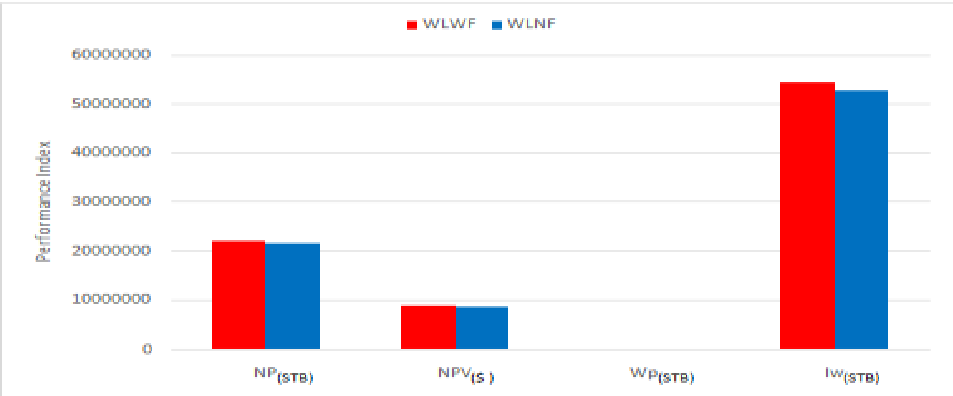

Figure 8: Performance chart

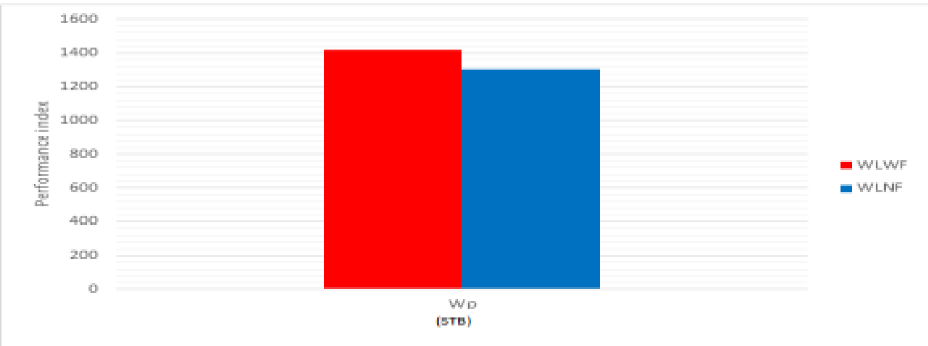

Figure 8(A): Performance Chart

Figure 8 and 8(A) above presents the performance index analysis of the models studied. Generally, it shows the performance index that expressed quotient amongst the models studied. It further showed that the fracture presence (WLWF model) reestablished the cumulative oil production level and further increased the oil production, for WLNF model, when injectivity loss effect was observed; the NPV, cumulative oil and water produced were considerably reduced due to injectivity loss.

IV. CONCLUSION

An analysis of reservoir simulation to study water injection in an artificially fractured reservoir has been carried out. The determination of optimal water injection rate was required to make a comparison for the models to be used in this research work. The option was based on the economic scenario, production and water treatment cost. The effect of injectivity loss reduced the cumulative oil and water produced. Formation fracture pressure was only reached in the presence of injectivity loss. The creation of fractures in injector well accelerated oil production but led to early water breakthrough.

The results showed that injecting with higher rate created the fracture, while injecting at lower rate higher than the rate of WLNF model improved the cumulative oil production, increased cumulative water production and NPV in WLWF model marginally. Study showed that the IFPP technique was only advantageous when there was injectivity loss where it assists inrestoringinjectivityand anticipated oil production. The rate of fracture growth depends on the injection rate, water quality, temperature as well as the mechanical properties of the rock. The Injectivity was primarily dependent on the in-situ stress, injection rate and water quality. It further showed that growing injection well fracture could have a significant impact on the sweep and oil recovery.

The mobility ratio was less than unity and the water injection had a favorable and unconditionally stable displacement. It had a low water cut and generally shows that it is economically beneficial and viable to invest in this operation. Fracturing is usually induced during the course of injection and these fractures grow over time. In order to model real cases, for any water injection work, information about the water quality should be considered in the models in order to have better predictions on the impact of the injectivity loss in the reservoir performance and evaluate development strategies that may include different parameters of the fractures. High injection rate should be avoided in order to avoid water coning, particularly after creating the fracture to maintain high oil production rate and the fracture propagation.

V. NOMENCLATURE

Ks = Permeability of damaged region, md
K = Original block permeability, md
t, t_{life}= time, years
Kro = Relative permeability of oil, md
Krw = Relative permeability of water, md
μ_o =Oil viscosity, cp
μ_w = Water viscosity, cp
M = Mobility ratio
Fw = Fraction of water
q_o = Oil flow rate, stb/d
q_w = Water flow rate, stb/d
WORs = Water oil ratio at surface
F_c = Fracture conductivity
F_{cd} = Dimensionless fracture conductivity
L_f ,X_f = Fracture half length, ft
W_f ,W = Fracture width, ft
P_{ff} = Fracture formation pressure, psi
P_f = Formation pressure, psi
σ_{ob} = Overburden pressure, psi
r_w = Wellbore radius, ft
NPV = Net present value, $
NCF, R_t = Net cash flow, $
Xs = Market modifier
Sm = Market price
i = Discount rate, %
Np = Cumulative oil produced, stb
Wp = Cumulative water produced, stb
Iw = Cumulative water injected, stb
IFPP = Injection with fracture propagation pressure
WLNF = With loss no fracture
WLWF= With loss with fracture

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Figure Tables

TABLE A1: STREAM - WITH LOSS NO FRACTURE

Time		Oil Produced (Stb/Days)	Water Injected (Stb/Days)	Water Cut (Percent)	Cum Water Produced (Stb)	Cum Oil Produced (Stb)	Cum Water Injected (Stb)
Date	Days						
1/1/2016	0.001	5027.97	38754.31	0	0	5.028	38.7543
1/1/2016	0.003	5022.83	38709.96	0	0	15.0736	116.1742
1/1/2016	0.007	5012.62	38651.57	0	0	35.1241	270.7805
1/1/2016	0.015	4992.52	38587.72		0.0001	75.0643	579.4822
1/1/2016	0.031	4953.56	38528.51	0.001	0.0006	154.3212	1195.9384
1/1/2016	0.063	4884.53	38480.26	0.002	0.0043	310.6263	2427.3066
1/1/2016	0.127	4756.1	38435.6	0.004	0.0177	615.0169	4887.1851
1/1/2016	0.255	4545.12	38390.87	0.008	0.0628	1196.7928	9801.2168
1/1/2016	0.511	4239.92	38340.81	0.013	0.1989	2282.2119	19616.4648
1/2/2016	1.023	3864.21	38277.32	0.018	0.5598	4260.686	39214.4531
1/3/2016	2.047	3476.24	38187.73	0.024	1.4164	7820.3594	78318.6953
1/5/2016	4.095	3141.5	38050.06	0.029	3.282	14254.1426	156245.2188
1/9/2016	8.191	2896.37	37819.13	0.032	7.1383	26117.6816	311152.375
1/17/2016	16.383	2750.36	37414.88	0.034	14.9127	48648.6133	617655.0625
2/2/2016	32.767	2722.28	36752.7	0.035	30.3509	93250.3984	1.22E+06
3/6/2016	65.535	2843.75	35702.82	0.032	60.2941	186434.375	2.39E+06
5/11/2016	131.071	3156.11	33810.19	0.026	114.0006	393273.1563	4.61E+06
9/19/2016	264.143	3716.27	30559.51	0.015	187.9753	880371.9375	8.61E+06
6/8/2017	524.287	4550.45	25406.47	0.002	207.798	2.07E+06	1.53E+07
6/1/2018	882.459	5308.63	20200	0	207.798	3.97E+06	2.25E+07
11/6/2019	1405.25	5922.53	15206.46	0	207.798	7.07E+06	3.05E+07
5/8/2022	2319.52	6325.84	11074.01	0	207.798	1.29E+07	4.06E+07
2/1/2025	3319.52	6456.39	9254.94	0.006	626.4934	1.93E+07	4.98E+07
1/1/2026	3653	6475.79	8877.23	0.032	1307.4891	2.15E+07	5.28E+07

Source: (Generated by simulator)

TABLE A2: STREAM- WITH LOSS WITH FRACTURE

Time		Oil Produced (Stb/Days)	Water Injected (Stb/Days)	Water Cut (Percent)	Cum Water Produced (Stb)	Cum Oil Produced (Stb)	Cum Water Injected (Stb)
Date	Days						
1/1/2016	0.001	5027.97	38754.31	0	0	5.028	38.7543
1/1/2016	0.003	5022.83	38709.94	0	0	15.0736	116.1742
1/1/2016	0.007	5012.63	38651.53	0	0	35.1241	270.7803
1/1/2016	0.015	4992.53	38587.69	0	0.0001	75.0644	579.4818
1/1/2016	0.031	4953.54	38528.48	0.001	0.0006	154.321	1195.9375
1/1/2016	0.063	4884.51	38482.17	0.002	0.0043	310.6254	2427.3669
1/1/2016	0.127	4756.08	38445.13	0.004	0.0177	615.0148	4887.855
1/1/2016	0.255	4545.11	38400.45	0.008	0.0628	1196.7886	9803.1123
1/1/2016	0.511	4239.91	38354.2	0.013	0.1989	2282.2048	19621.7852
1/2/2016	1.023	3864.2	38302.98	0.018	0.5596	4260.6753	39232.9102
1/3/2016	2.047	3476.25	38415.52	0.024	1.4162	7820.356	78570.4063
1/5/2016	4.095	3141.73	38438.6	0.029	3.2813	14254.6104	157292.6563
1/9/2016	8.191	2897.58	37982.79	0.032	7.1365	26123.0879	312870.1563
1/17/2016	16.383	2753.96	37885	0.034	14.9095	48683.5273	623224
2/2/2016	32.767	2721.37	37186.95	0.035	30.3445	93270.4688	1.23E+06
3/6/2016	65.535	2844.19	36194.57	0.032	60.295	186468.7656	2.42E+06
5/11/2016	131.071	3162.46	34449.71	0.026	114.3294	393723.4688	4.68E+06
9/19/2021	264.143	3738.09	31363.26	0.015	186.8144	883682.3125	8.79E+06
6/8/2017	524.287	4627.22	26791.25	0	186.8144	2.10E+06	1.58E+07
5/9/2018	882.459	5415.79	21870.93	0	186.8144	3.91E+06	2.31E+07
8/23/2019	1405.25	6049.69	16523.52	0	186.8144	6.76E+06	3.09E+07
10/26/2021	2319.52	6459.87	11745.39	0	186.8144	1.19E+07	4.03E+07
7/22/2024	3319.52	6597.68	9487.71	0	203.0338	1.85E+07	4.97E+07
1/1/2026	3653	6615.4	8896.98	0.035	1419.3257	2.20E+07	5.44E+07

Source :(Generated from simulator)

TABLE A3: WITH LOSS NO FRACTURE

TIME			Np	REVENUE	ROYALTY	WI	CAPEX	OPEX	OHDCRV	STAX	NCF	NPV
DATE	DAYS	YEARS	(STB)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)
0	0	0	0	0	0	0	6,000,000	0	0	0	-0.6	-0.6
1/1/2016	0.001	0.000003	5.028	16.24999	2.031249	14.21874	6,000,000	61.593	0.61593	0.492744	6.35077	6.350768
1/1/2016	0.003	0.000008	15.0736	48.71637	6.089546	42.62682	6,000,000	184.6516	1.846516	1.477213	20.23793	20.23791
1/1/2016	0.007	0.00002	35.1241	113.5176	14.1897	99.32788	6,000,000	430.2702	4.302702	3.442162	47.95599	47.95588
1/1/2016	0.015	0.00004	75.0643	242.6003	30.32504	212.2753	6,000,000	919.5377	9.195377	7.356301	103.1698	103.1693
1/1/2016	0.031	0.00008	154.3212	498.7507	62.34384	436.4069	6,000,000	1890.435	18.90435	15.12348	212.7356	212.7335
1/1/2016	0.063	0.0002	310.6263	1003.913	125.4891	878.424	6,000,000	3805.172	38.05172	30.44138	428.8137	428.8032
1/1/2016	0.127	0.0003	615.0168	1987.673	248.4591	1739.214	6,000,000	7533.956	75.33956	60.27165	849.6069	849.5758
1/1/2016	0.255	0.0007	1196.783	3867.882	483.4853	3384.397	6,000,000	14660.59	146.6059	117.2847	1653.848	1653.706
1/1/2016	0.511	0.001	2282.212	7375.881	921.9851	6453.896	6,000,000	27957.1	279.571	223.6568	3154.358	3153.973
1/2/2016	1.023	0.003	4260.686	13770.11	1721.264	12048.85	6,000,000	52193.4	521.934	417.5472	5889.426	5887.267
1/3/2016	2.047	0.006	7820.359	25274.62	3159.327	22115.29	6,000,000	95799.4	957.994	766.3952	10810.36	10802.44
1/5/2016	4.095	0.01	14254.14	46067.96	5758.495	40309.47	6,000,000	174613.2	1746.132	1396.906	19704.5	19680.44
1/9/2016	8.191	0.02	26117.68	84409.74	10551.22	73858.52	6,000,000	319941.6	3199.416	2559.533	36104.81	36016.66
1/17/2016	16.383	0.04	48648.61	157227.5	19653.43	137574	6,000,000	595945.5	5959.455	4767.564	67251.85	66923.88
2/2/2016	32.767	0.09	93250.4	301376	37672	263704	6,000,000	1142317	11423.17	9138.539	128909.9	127499.7
3/6/2016	65.535	0.2	186434.4	602537.3	75317.16	527220.1	6,000,000	2283821	22838.21	18270.57	257728.6	251505.2
5/11/2016	131.071	0.4	393273.2	1271020	158877.4	1112142	6,000,000	4817596	48175.96	38540.77	543665.1	517726.1
9/19/2016	264.143	1	880371.9	2845274	355659.3	2489615	6,000,000	10784556	107845.6	86276.45	1217037	1077024
6/8/2017	524.287	1.4	2.07E+06	6700375	837546.9	5862828	6,000,000	25396700	253967	203173.6	2866017	2415288
6/1/2018	882.459	2.4	3.97E+06	12845510	1605689	11239821	6,000,000	48688850	486888.5	389510.8	5494536	4097725
11/6/2019	1405.25	3.8	7.08E+06	22878620	2859828	20018793	6,000,000	86717750	867177.5	693742	9786097	6150515
5/8/2022	2319.52	6.4	1.29E+07	41542843	5192855	36349987	6,000,000	1.57E+08	1574615	1259692	17769530	8127817
2/1/2025	3319.52	9.1	1.93E+07	62411221	7801403	54609818	6,000,000	2.37E+08	2365598	1892478	26695767	8778667
1/1/2026	3653	10	2.15E+07	69388893	8673612	60715281	6,000,000	2.63E+08	2630075	2104060	29680396	8743499

Source :(Generated from Excel spread sheet using economic equations)

TABLE A4: WITH LOSS WITH FRACTURE

TIME			Np	REVENUE	ROYALTY	WI	CAPEX	OPEX	OHDCRV	STAX	NCF	NPV
DATE	DAYS	YEARS	(STB)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)	($\$\times10^6$)
0	0	0	0	0	0	0	6,000,000	0	0	0	-0.6	-0.6
1/1/2016	0.001	0.000003	5.028	16.24999	2.031249	14.21874	6,000,000	61.593	0.61593	0.492744	6.35077	6.350768
1/1/2016	0.003	0.000008	15.0736	48.71637	6.089546	42.62682	6,000,000	184.6516	1.846516	1.477213	20.23793	20.23791
1/1/2016	0.007	0.00002	35.1241	113.5176	14.1897	99.32788	6,000,000	430.2702	4.302702	3.442162	47.95599	47.95588
1/1/2016	0.015	0.00004	75.0644	242.6006	30.32508	212.2756	6,000,000	919.5389	9.195389	7.356311	103.17	103.1695
1/1/2016	0.031	0.00008	154.321	498.75	62.34375	436.4063	6,000,000	1890.432	18.90432	15.12346	212.7353	212.7332
1/1/2016	0.063	0.0002	310.6254	1003.91	125.4888	878.4215	6,000,000	3805.161	38.05161	30.44129	428.8124	428.802
1/1/2016	0.127	0.0003	615.0148	1987.666	248.4583	1739.208	6,000,000	7533.931	75.33931	60.27145	849.6041	849.573
1/1/2016	0.255	0.0007	1196.789	3867.901	483.4876	3384.413	6,000,000	14660.66	146.6066	117.2853	1653.856	1653.714
1/1/2016	0.511	0.001	2282.205	7375.858	921.9822	6453.875	6,000,000	27957.01	279.5701	223.6561	3154.348	3153.963
1/2/2016	1.023	0.003	4260.675	13770.08	1721.26	12048.82	6,000,000	52193.27	521.9327	417.5462	5889.411	5887.252
1/3/2016	2.047	0.006	7820.356	25274.61	3159.326	22115.28	6,000,000	95799.36	957.9936	766.3949	10810.36	10802.43
1/5/2016	4.095	0.01	14254.61	46069.48	5758.684	40310.79	6,000,000	174619	1746.19	1396.952	19705.15	19681.08
1/9/2016	8.191	0.02	26123.09	84427.21	10553.4	73873.81	6,000,000	320007.8	3200.078	2560.063	36112.28	36024.12
1/17/2016	16.383	0.04	48683.53	157340.3	19667.54	137672.8	6,000,000	596373.2	5963.732	4770.986	67300.12	66971.91
2/2/2016	32.767	0.09	93270.47	301440.8	37680.1	263760.7	6,000,000	1142563	11425.63	9140.506	128937.7	127527.2
3/6/2016	65.535	0.2	186468.8	602648.4	75331.05	527317.4	6,000,000	2284242	22842.42	18273.94	257776.2	251551.6
5/11/2016	131.071	0.4	393723.5	1272475	159059.4	1113416	6,000,000	4823112	48231.12	38584.9	544287.6	518319
9/19/2016	264.143	1	883682.3	2855973	356996.6	2498976	6,000,000	10825108	108251.1	86600.87	1221613	1081073
6/8/2017	524.287	1.4	2.10E+06	6776325	847040.6	5929284	6,000,000	25684575	256845.8	205476.6	2898504	2442666
5/9/2018	882.459	2.4	3.91E+06	12647071	1580884	11066187	6,000,000	47936700	479367	383493.6	5409656	4034423
8/23/2019	1405.25	3.8	6.76E+06	21849260	2731157	19118102	6,000,000	82816125	828161.3	662529	9345799	5873789
10/26/2021	2319.52	6.4	1.19E+07	38443451	4805431	33638019	6,000,000	1.46E+08	1457138	1165710	16443796	7521424
7/22/2024	3319.52	9.1	1.85E+07	59764295	7470537	52293758	6,000,000	2.27E+08	2265270	1812216	25563571	8406354
1/1/2026	3653	10	2.20E+07	71050090	8881261	62168828	6,000,000	2.69E+08	2693040	2154432	30390956	8952821

Source: (Generated from Excel spread sheet using economic equations)