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Modeling the Effect of Temperature for Enhanced Oil Recovery (EOR) using Steam Injection Technique

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ABSTRACT

*Viscosity of crude oil in reservoir hinders the oil flow rate during production, and this factor has been a major problem in crude oil production sectors. In this work, basic mathematical models are developed and simulated using MATLAB to access they models effectiveness towards the evaluation of temperature effects on heavy oil horizontal wellbore, undergoing steam injection EOR. Steam injection temperature of 800 °F (699.817K) and pressure 3 Pa, with other parametric variables, are applied in validating the developed models, to ascertain their dynamic effects on heavy oil reservoir. Results indicate that increase in the temperature of the reservoir through from 100°F (310.928K) to 823.4987°F (712.872K) decreases the heavy oil viscosity from 9.9403 Pa.s 2. 6970Pa.s, hence, enhances flow of fluid from the well. The porosity of 30% using the model developed, shows an increase in the fluid flow velocity from 4.0333*10^{-6} m^2/day to 1.4955*10^{-5}m^2/day, while from 3.0250*10^{-6} m^2/day to 1.1216*10^{-5} m^2/day for a porosity of 40%. The results when been compared with other literature results, proves the models developed in this work perfect and valuable as tools for studying steam temperature effects on heavy oils reservoir as an enhanced oil recovery approach, dynamically.*

KEYWORDS: Viscosity, Crude oil, Steam injection, Simulation studies, Enhanced Oil Recovery (EOR), Hydrocarbon.

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1. INTRODUCTION

The engineering act of recovering additional oil from heavy oil reservoirs after primary production processes (i.e., cold production), requires a great deal of actions collectively classified as oil enhancing methods (OEMs). These methods are being applied in displacing un-swept oils from production wells, in turn promoting productivity. These methods are developed strategies and technologies capable of minimizing production costs (Davarpanah, 2018b; Eastoe *et al*., 2013; Ebadati *et al.*, 2018), by focusing on increasing oil productivity. Steam flood process, among other EOR methods, is a sustainable and reliable recovery means of producing the upswept oil-in-place (OIP) (Eastoe *et al*., 2013) crude from heavy oil reservoirs. Steam injection method which uses superheated steam of above 200°C, is the most reliable and extensively adopted enhanced oil recovery (EOR) steam flood process, this is because it has greater effects on the vis--breaking of heavy oils from reservoir. This act of oil recovering using steam, promotes the flowing ability of heavy oil, which significantly improve the well oil production capacity, especially on horizontal reservoirs under cyclic superheated steam stimulation processes. This is because horizontal wells are of larger contact areas, which promotes steam injection capacity, with higher

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productivity (Akin, 2005).

Presently the world energy demand is increasing rapidly, cognitively to industrial and life developments, with energy been one of the most important things needed by man (Ugi *et al.,* 2022), the annual demand for oil tends to be increasing, pushing the oil producing countries on finding various ways to increase or improve their production scheme. Basically, fossil fuels (especially crude oil, and natural gas) with some biofuels, plays major roles in providing today's classical energy, but none except crude is maximally consumed, for this reason, it is necessary to increase the petroleum production capability, above the normal capacity acquired from the application of the primary recovery wells methods. These primary methods are of a high control differential pressure, capable of pulling the oil towards the production well sometimes with a little application of pressure aiding techniques, but the lacks the ability of operation in heavy hydrocarbons wells. Several methods have been proposed to reduce the viscosity of heavy crude oil to ease the production (Simangunsong *et al.*, 2006; Alshmakhy & Maini, 2012, Shedid & Abbas, 2000, Bryan & Kantaz, 2008, Davarpanah & Mirshekari, 2018; Kumar & Mandal, 2007; Ampomah *et al.*, 2017; Lei *et al.*, 2010; Al-Bahlani & Babadagli, 2009), by direct or co-injection means or application.

Co-injection process involves steam been injected in combination with some additives (solvent or non-condensable gas) (Butler, 2004; Nasr *et al.*, 2003). This process is highly used in most areas of heavy crude production. The main functions of the additives are to extend the steam chamber and reduce oil viscosity beyond what is obtainable from the steam-alone (direct) process (Butler, 2004; Nasr *et al.*, 2003). These additives could be the commonest non-condensable gas (NCG) additives (CO2, flue-gas, natural gas (Butler, 2004), light hydrocarbons such as propane, butane and naphtha (Ayodele *et al.*, 2009; Nasr *et al.*, 2003), or could be the solvent co-injection additives, that vaporizes in the formation, as well travelling to the leading edge of the steam chamber where it dissolves into the cold bitumen, diluting and mobilizing the oil (Sharma & Gates, 2010).

One major concern of this process is the recovery of the solvent, which is a key contributor to project costs (Hart, 2006). On the other hand, NCG may accumulate above the steam chamber, forming a thermal-insulation layer that curtails heat losses to the adjacent formation (Butler, 2004). But NCGs usually reduces the steam saturation temperature, undermining the release of latent heat (Butler, 2004). To continue oil production at relatively lower costs, the substitution of steam with CO_2, N2 or flue-gas has been proposed (Bagci *et al.,* 2008; Law *et al*., 2003; Yee & Stroich, 2004), also the use of highly superheated steam is suggested.

Zhang *et al.* (2018) performed simultaneous injection of steam and flue gas∗ (80-85% N2, 10-15% CO_2), including a foaming agent, in a CSS project in the Chinese blocks Jin-45 and Jin-7, containing 3350 cP crude. Apart from the benefits of improved and accelerated oil recovery over that of steam-alone, they noted better steam conformance, reduced operating costs and emissions, as well as delayed water production.
No and Park (2002), using an analogy of the conservation laws, derived a condensation model for steam-NCG mixture in a vertical tube. The model predictions were reportedly in excellent agreement with the experimental datasets. Their results, valid for tubes with isothermal walls, indicate that the total heat-transfer coefficient decreases as the condensing fluid flows through the tube.

It is observed from all reviewed, that in their models, they show less clarity on models developed as well as their applications towards steam enhancing approach. Another limitation to of their models lies on the fact that they are not radially applicable on horizontal wells. Also, they

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reviewed models are not aimed on cyclic steam injection approach of enhancing oil from heavy oil wells. Several methods have been applied towards studying reservoirs behaviors under thermally enhanced techniques. But none has a clearer mathematical model developed and validated in reference to radial step-temperature profile, relating the oil well temperature, length, and vis-breaking to enhancement of crude oil from heavy oil reservoir.

This work modeled the effect of temperature in a hydrocarbon reservoir undergoing steam injection, idealized as a radial two-zone system with a step-temperature profile, in which the heated (stimulated) zone is instantly raised to the steam temperature while the cold (unstipulated) zone remains at the initial temperature, based on the following objectives:

i. Develop models considering thermodynamic, volumetric, and functional parameters, used to ascertain the temperature effects of steam as an EOR technique on oil wells.
ii. simulation of the developed models using MATLAB-Simulink
iii. Use of certain porosity data to predict the flow velocity of the reservoir with relation to the temperature effect on the oil viscosity changes.

2 MATERIALS AND METHODS

2.1 Materials

They materials used in this work include MATLAB simulative tool, a computer system, some Petroleum Engineering Handbook and Literature materials.

2.2 Methods

Mathematical method is applied in developing models the well properties such as Temperature, Viscosity and Well area determination.

Basic Assumptions of the Mathematical Model

The mathematical model is subject to the following basic assumptions:

(i) The horizontal wellbore is located in the centre of the formation and the steam override effect is ignored due to thin formation thickness.

(ii) When the superheated steam flows along the wellbore, it may undergo phase change, the superheated steam may change to saturated steam at some point of the wellbore.

(iii) Before phase change occurs, the heating process is divided into four stages and three zones are formed in the heating area: superheated zone, steam zone, and hot fluid zone. After phase change occurs, the heating process is divided into three stages and two zones remain in the heating area: steam zone and hot fluid zone.

(iv) The temperature of superheated zone equals the arithmetic mean value of superheated steam temperature and saturated steam temperature, the temperature of steam zone equals the saturated steam temperature, and the temperature of hot fluid zone equals the arithmetic mean value of saturated steam temperature and initial reservoir temperature.

(v) The formation temperature is assumed to be the initial reservoir temperature at each cycle of steam injection, and the remainder heat is added to the next cycle of steam injection.

(vi) The $E_{r,sh,i}$ "the previous cycle remainder heat of superheated zone at the i-th segment" which is to be redirected into the well after been reheated to ensure the process is a steady state steam injection activity.

2.3 Data for Model Simulation

The data and their source(s) used for the validation of the developed models, are presented as table 1, located at the appendix section of this work.

2.4 Reservoir Modeling

Superheated steam flows along the horizontal wellbore, its mass flow rate, temperature, and steam quality change over the horizontal well

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length. Consequently, the heat temperature changes along the horizontal wellbore as the supper saturated steam travels with time. To accurately calculate or develop a model to predict the temperature effect on a carbonated horizontal wellbore, the distribution of those thermo-physical parameters along the horizontal wellbore first needs to be determined, as the derivation process of the saturated steam is like the superheated steam after phase change occurs, this work only derives the temperature effects based on the superheated steam. Considering a horizontal well as the Figure 1.

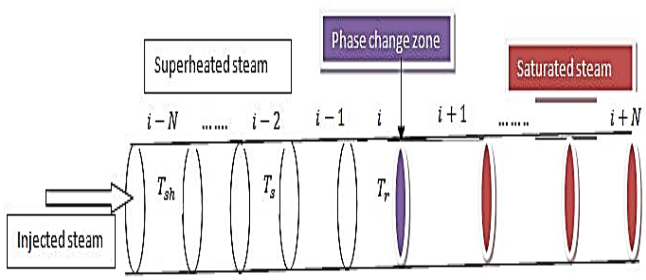

Figure 1 Schematic represent of a horizontal reservoir well undergoing steam injection.

Taking the system material balance considering the energy conservation principles for an opened system as in Equation (1).

$$\begin{Bmatrix}\text{Rate of Input}\\ \text{of heat}\\ \text{by Steam}\end{Bmatrix} - \begin{Bmatrix}\text{Rate of Output}\\ \text{of heat}\\ \text{by Steam}\end{Bmatrix} + \begin{Bmatrix}\text{Rate of Previously}\\ \textit{recycled heat}\end{Bmatrix} = \begin{Bmatrix}\text{Accumulated rate}\\ \textit{of heat in the}\\ \textit{reservoir defined}\\ \textit{Area}\end{Bmatrix} \quad (1)$$

Defining the terms in equation 1.

$$\begin{Bmatrix}\text{Rate of Input}\\ \text{of heat}\\ \text{by Steam}\end{Bmatrix} = \{I_i\rho_i(h_{sh,i} - h_{s,i})\} \text{ in (J/hr)}$$

$$\begin{Bmatrix}\text{Rate of Output}\\ \text{of heat}\\ \text{by Steam}\end{Bmatrix} = \{pd(T_{sh,i} - T_r)\} \text{ in (J/hr)}$$

$$\begin{Bmatrix}\text{Rate of Previously}\\ \textit{recycled heat}\end{Bmatrix} = \{E_{r,sh,i}\} \text{ in (J/hr)}$$

$$\begin{Bmatrix}\text{Accumulated rate}\\ \textit{of heat in the}\\ \textit{reservoir defined}\\ \textit{Area}\end{Bmatrix} = \left\{M_R \Delta L(\overline{\overline{T_{shi}}} - T_r)\frac{dA_{sh,i}}{dt}\right\} \text{ in (J/hr)}$$

$$\{I_i\rho_i(h_{sh,i} - h_{s,i})\} - \{pd(T_{sh,i} - T_r)\} + \{E_{r,sh,i}\} = \left\{M_R \Delta L(\overline{\overline{T_{shi}}} - T_r)\frac{dA_{sh,i}}{dt}\right\}$$

Where.
$I_i =$ Steam volumetric inflow rate at the i-th segment at defined temperature = Td (m^3/hr).
$\rho_i =$ Steam density at the i-th segment (kg/m^3).
$p =$ Well pressure (N/m^2).
$d =$ Well volumetric flow-out rate constant at definite well temperature (m^3/hrK).
$E_{r,sh,i} =$ Recycle remainder heat rate of superheated zone at the i-th segment (J/hr).
$h_{sh,i}$ and $h_{s,i}$ = are the specific energy of superheated and saturated steam, at the i-th segment (J/kg).
$\Delta L =$ Segment length (m)
$\overline{\overline{T_{sh,i}}}$ = Superheated zone temperature (K).
$T_{sh,i}$ & $T_{s,i}$ = Superheated steam temperature and saturated steam, respectively (K).
$T_r =$ Reservoir temperature (K)
$A_{sh,i} =$ Superheated steam zone area at the i-th segment
$V_{sh,i} =$ Superheated steam zone volume at the i-th segment which is equivalent to the volume of superheated steam injected into the well (m^3).
t_1 = Steam injection time (hr).
t_2 = Time taking for transferring "m" amount of the melted crude from the heating source to the production bases (hr).
$M_R =$ Reservoir Volumetric heat capacity (J/m^{3}K)

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A = Cross sectional Area of the heated section (m^2).

Now considering the mathematical modeling basic assumption 1 stated above, which stands that the steam override effect is ignored due to thin formation thickness.

$$\{I_i\rho_i(h_{sh,i} - h_{s,i})\}dt - \{pd(T_{sh,i} - T_r)\}dt + \{E_{r,sh,i}\}dt = \{M_R\Delta L(\overline{\overline{T_{shi}}} - T_r)dA_{sh,i}\} \quad (2)$$

Now let:

$$Z_{shi} = [\{I_i\rho_i(h_{sh,i} - h_{s,i})\} - \{pd(T_{sh,i} - T_r)\} + \{E_{r,sh,i}\}] \quad (3)$$

$$Z_{shi}dt = M_R\Delta L(\overline{\overline{T_{shi}}} - T_r)dA_{sh,i} \quad (4)$$

Taking the boundary conditions.

$t_o = t_1$; $T = T_r$

$t_f = t_2$; $T = T_{Shi}$

Integrating both sides with respect to the above defined boundary conditions gives Equation (5).

$$Z_{shi}\int_{t_1}^{t_2} dt = M_R\Delta L(\overline{\overline{T_{shi}}} - T_r)\int dA_{sh,i} \quad (5)$$

$$Z_{shi}(t_2 - t_1) = M_R\Delta L(\overline{\overline{T_{shi}}} - T_r)\int dA_{sh,i} \quad (6)$$

$$(\overline{\overline{T_{shi}}} - T_r) = \frac{Z_{shi}(t_2 - t_1)}{M_R\Delta L\int dA_{sh,i}} \quad (7)$$

$$\overline{\overline{T_{shi}}} = \frac{Z_{shi}(t_2 - t_1)}{M_R\Delta L\int dA_{sh,i}} + T_r \quad (8)$$

$$\overline{\overline{T_{shi}}}M_R\Delta L\int dA_{sh,i} = [\{I_i\rho_i(h_{sh,i} - h_{s,i})\} - \{pd(T_{sh,i} - T_r)\} + \{E_{r,sh,i}\}]\int_{t_1}^{t_2} dt + M_R\Delta L\int dA_{sh,i}\,T_r \quad (9)$$

Linearizing equation 7 and replacing Z_{shi} with the defined terms of equation 3 yields:

$$\overline{\overline{T_{shi}}}M_R\Delta L\int dA_{sh,i} = [\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}]\int_{t_1}^{t_2} dt - \{pd(T_{sh,i} - T_r)\}(t_2 - t_1) + M_R\Delta L\int dA_{sh,i}\,T_r \quad (10)$$

$$\overline{\overline{T_{shi}}}M_R\Delta L\int dA_{sh,i} - [\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}](t_2 - t_1) + (t_2 - t_1)pdT_{sh,i} = (M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)T_r \quad (11)$$

$$T_r = \frac{\overline{\overline{T_{shi}}}M_R\Delta L\int dA_{sh,i}}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)} - \frac{[\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}](t_2 - t_1)}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)} + \frac{(t_2 - t_1)pdT_{sh,i}}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)} \quad (12)$$

$$\int dA_{sh,i} = \frac{V_{shi}}{\pi r_r} \quad (13)$$

Where the reservoir radius base on studied zone is,

$$r_r = \frac{r_{si} + r_{hi}}{2} \quad (14)$$

r_{si} = The radius of the steam zone section where the reservoir temperature is of a vis-breaking level.

r_{hi} = The radius of the zone beyond the steam zone, which is the saturated/ hot zone.

$$\therefore T_r = \frac{\overline{\overline{T_{shi}}}M_R\Delta L}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)}\frac{V_{shi}}{\pi r_{rr}} - \frac{[\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}](t_2 - t_1)}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)} + \frac{(t_2 - t_1)pdT_{sh,i}}{(M_R\Delta L\int dA_{sh,i} + (t_2 - t_1)pd)} \quad (15)$$

According to Darcy's law for hydraulic fluids,

$$\Delta L = -\frac{KA\Delta P}{\mu Q} \quad (16)$$

$$= -\frac{KA(P_2 - P_1)}{\mu Q} \quad (17)$$

where.

Q = Fluid velocity (m^2/hr)

Hence;

$$T_r = \frac{[\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}](t_2 - t_1)}{\left(\frac{M_RKA(P_2 - P_1)V_{shi}}{\mu Q\pi r_r} + (t_2 - t_1)pd\right)} - \frac{(t_2 - t_1)pdT_{sh,i}}{\left(\frac{M_RKA(P_2 - P_1)V_{shi}}{\mu Q\pi r_r} + (t_2 - t_1)pd\right)} + \frac{V_{shi}\overline{\overline{T_{shi}}}M_RKA(P_2 - P_1)}{\left(\frac{M_RKA(P_2 - P_1)V_{shi}}{\mu Q\pi r_r} + (t_2 - t_1)pd\right)} \quad (18)$$

$$T_r = \frac{[\{I_i\rho_i(h_{sh,i} - h_{s,i})\} + \{E_{r,sh,i}\}](t_2 - t_1) - (t_2 - t_1)pdT_{sh,i} + V_{shi}\overline{\overline{T_{shi}}}M_RKA(P_2 - P_1)}{\left(\frac{M_RKA(P_2 - P_1)V_{shi}}{\mu Q\pi r_r} + (t_2 - t_1)pd\right)} \quad (19)$$

Equation 19 is the reservoir temperature model for steam EOR process.

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2.4 Well Area – Time Model

Considering equation (1) which states that

$$\{I_i\rho_i(h_{sh,i} - h_{s,i})\} - \{pd(T_{sh,i} - T_r)\} + \{E_{r,sh,i}\} = \left\{M_R \Delta L(\overline{\overline{T_{shi}}} - T_r)\frac{dA_{sh,i}}{dt}\right\}$$

The Area – Time model is:

$$\frac{dA_{sh,i}}{dt} = \frac{\{pd(T_{sh,i} - T_r)\} - \{E_{r,sh,i}\} - \{I_i\rho_i(h_{sh,i} - h_{s,i})\}}{M_R \frac{KA(P_2-P_1)}{\mu Q}(\overline{\overline{T_{shi}}} - T_r)} \quad (20)$$

This model describes the rate of change in the well area which is acted by the super-heated steam over period of heat inoculation time.

2.5 Measurement of Permeability via Reservoir Porosity Model

Darcy found that flow rate was proportional to pressure gradient should be described with Darcy's equation for calculating volumetric flow rate *q* for linear, horizontal, single-phase flow is

$$q = 0.001127\frac{K_r A}{\mu}.\frac{\Delta P}{\Delta L} \quad (21)$$

(Steven *et al*., 2015).

The units of the physical variables determine the value of the constant (0.001127) in Eq. (21).

The fluid viscosity (μ) is the relationship of the volumetric flow rate of the oil to the cross-sectional area, expressed as:

$$u = \frac{q}{A_\perp} \text{ units.} \quad (22)$$

The interstitial velocity *v* is the superficial velocity *u* divided by porosity ϕ, or

$$v = \frac{u}{\phi} = \frac{q}{\phi A_\perp} \quad (23)$$

(Steven *et al*., 2015).

Interstitial velocity is larger than superficial velocity since porosity is a fraction between 0 and 1.

Where.

ΔP = Total pressure drop on the reservoir (N/m^2)

$A = A_\perp$ = cross-sectional area (m^2)

$Q = q$ = Volumetric flow rate (m$^3/hr$) from the supper heated steam zone

μ = Dynamic viscosity of the crude (Pa.s)

$K = \frac{V_{sh,i}}{K_r}$ = Permeable depth (m)

K_r = Reservoir permeability (d)

N/B: 1d (1 darcy) = 9.8692x10^{-13}m^2

3 RESULTS AND DISCUSSION

Validation of the developed models has been carried out using literature data presented as Table 1. The data has been used to simulate the developed models using MATLAB and the results obtained as plots are described as seen below, with compared results to other researchers view on similar EOR method.

Table 1: Data and Source Gathered for Simulation Study

Data	Value/Source	Data	Value/Source
I_i	**212 m^3/*hr***[*Guo et al, 2017*]	$E_{r,sh,i}$	0 "*reheated before use*"
ρ_i	**12.185 kgm^{-3}** [*Steam table*]	t_2	240 hours [Estimated]
$h_{sh,i}$	**5.949 kjkg^{-1}**[*Steam table*]	t_1	1 hour [Estimated]
$h_{s,i}$	**26.76 kjkg^{-1}**[*Steam table*]	P	10 Pa [*Guo et al, 2017*]
$T_{sh,i}$	**800 °*F***[Estimated]	V_{shi}	1500 m^3 [*Guo et al, 2017*]
$T_{s,i}$	**350 °*F***[Estimated]	M_R	4.0 kJ/m^3 k [*Mikhail et. al 2012*]
d	**100** m^3/(*hrK*)[Estimated]	K	0.18 *m*[*Guo et al, 2017*]
$I_{sh,i}$	**322 m^3/*hr***[Estimated]	A	1 m^2 [*Sujit, 2013*]
$P_2 - P_1$	**3 *pa***[*Guo et al, 2017*]	$\mu = \mu_p$	9.9 *pa. sec* [*engineers' edge 2021*]
Ø	**30 and 40 %** [Estimated]	ΔL	100 m –1000 m [*Guo et al, 2017*]
r_{si}	**9.6 m** [Estimated]	r_{hi}	12 m [Estimated]

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a	**0.9m** [*Sujit, 2013*]	K_r	35.8 d [*Katherine et. al 2005*]

3.1 Reservoir Temperature Relationship with change in Reservoir's Length

Figure 2 is a plot obtained from studying equation 19 over change in well length.

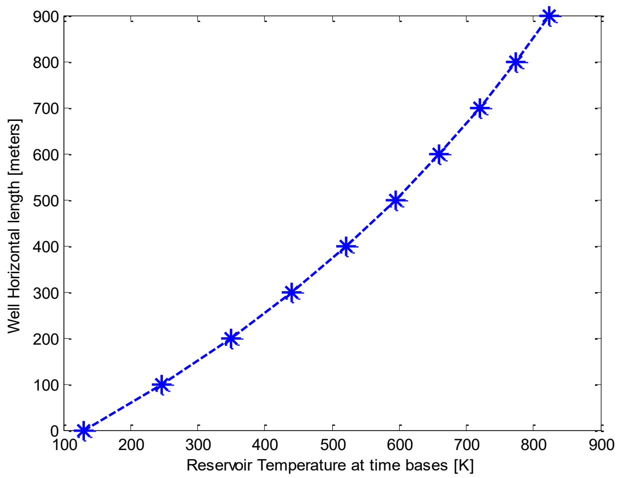

Figure 2: Change in reservoir temperature on length bases versus well length.

This plot shows the reservoir temperature proportionally increasing with respect to the volume of continuous injected steam to satisfy the well length. The well temperature is proportional to the volume of super-heated steam injected into the well which results in an increase in the reservoir temperature over the residual time bases. This result is in acceptance to plot Figure 4 and its description, by Diana-Patricia et al. (2009)

3.2 Reservoir Temperature Relationship over the Process steam Resident Time

Figure 3 is a plot obtained from studying equation 19 over change in the steam resident time during $(t_1 - t_2)$.

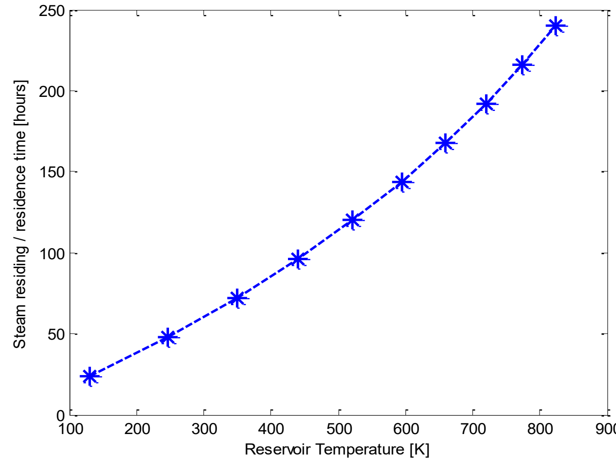

Figure 3: Change in reservoir temperature on time bases versus Process time

The plot indicates that during the process, the reservoir temperature increases with increase in time, from $t = 0$ hours, the T_r increases directly proportional from $T_r = 100K$ to $T_r = 823.4987K$ at $t = 24$ hours, after which the reservoir temperature begins to normalize by gaining heat via heat sharing technique in accordance to the zeroth law of thermodynamics. The increase in the reservoir temperature is because of heat transfer from the steam to the well as via conduction and convection, which will alternatively reduce proportionally to the well length, which is in conformity to the plot and discussion of Figure 3 in the Lawal (2011) publication.

3.3 Reservoir Temperature and the well Horizontal Length Relationship over Well Area

Figure 4 is a plot obtained from relating equation 20 with the well length (ΔL) and as well with the reservoir temperature (T_r).

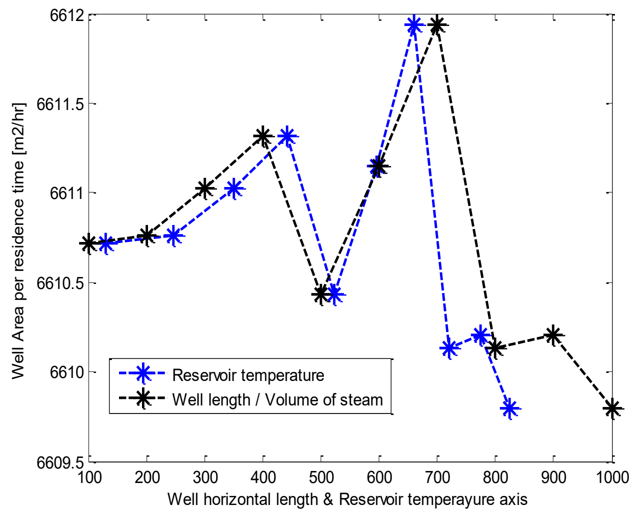

Figure 4: Change in well area over time versus well length and reservoir temperature.

This plot reveals that there is no steady change of the well area during steam injection over time when factored on the well length or the well temperature. The well area will be falteringly changing over increase in either the well length or temperature over time, and this is because the reservoir viscosity as well as porosity will not be the same in all sections of the well. There will be some places of higher viscosity or porosity which will generates lower vis-breaking products due to insufficient steam temperature capability to attain all the stands of the $K = \frac{V_{sh,i}}{\mathrm{K_r}}$ = Permeable depth (m), this as seen from the Figure 3 is the fall in the plot. While the rise in the plot in areas where the viscosity or porosity of the well is lower than the injected steam temperature, leading to higher vis-breaking products of the reservoir well.

3.4 Reservoir Temperature Relationship over the Reservoir Viscosity

Figure 5 is obtained from the relationship of equation 19 and 22.

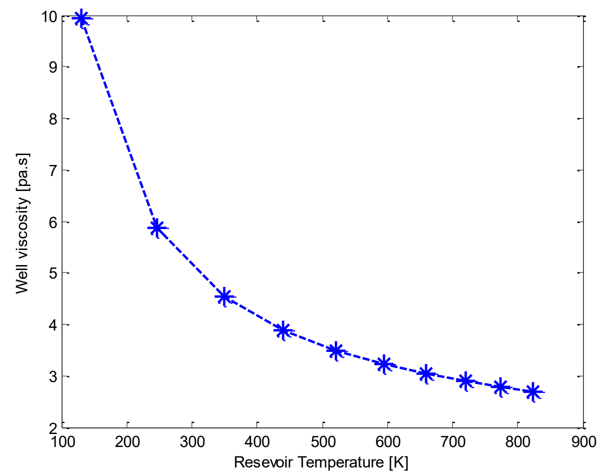

Figure 5: Change in reservoir viscosity at time bases versus reservoir temperature

Figure 5 shows a decrease in the reservoir viscosity from 9.9403 Pa.s to 2.6970 Pa.s with respect to the increase in the reservoir temperature, this will lead to increase in oil production. In validation of the model result, this plot of Figure 4 is in conformity to plot Figure 7 of Adango and Brittany (2014) who studied the temperature effects on heavy crude oil viscosity using Microwave Radiation Induced approach.

4 CONCLUSION

i. The models are appropriately developed in consideration of material and heat balance principles, with the focus to be used in ascertaining temperature effects on heavy oil reservoir, undergoing steam injection as an EOR scheme.

ii. The designed models tested with MATLAB-Simulink brought out vital plots that proves the models satisfactory to its designed objectives which is to be used in ascertaining the temperature effects on a steam injection EOR technique of an oil well.

iii. The approach applied in this work is conservative on the area of water used as steam, by reducing the cost of production on bases of water supply.

iv. This recycle approach of Steam injected EOR applied in this work, stands a better chance of high yielding as compared to other related EOR methods, and that is because the steam recycled has the tendency of consisting some certain amount of recovered crude that could not be 100% separated from the produced crude.

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