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An Integrated Well-Reservoir Steam Injection Modelling for Steam Injection Optimization

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Abstract— *The limitation of Steam Injection to depths has been a subject of concern in the application of Steam Injection for heavy and extra heavy oil recovery. This is usually as a result of the complex mechanism of heat loses occurring in the wellbore and consequently the heat loss distribution in the reservoir. A conventional approach to the optimization of steam injection has been based on isolated analysis of the well system aimed at maintaining adequate steam quality at the sandface at optimal injection rate, pressure, temperature and overall heat transfer coefficient. This often results to total neglect of the effect of the interaction between the well system and the reservoir system in the Model results. This research presents an integrated approach in the modelling of steam injection project that incorporates both the well system and the reservoir system. In this study, a three case-study wells were analyzed which are located at INJ1 (1, 1), PROD1 (5, 5) and PROD2 (9, 1) respectively. The results of the findings reveals that the conventional practice of maintaining sufficient SQ at the sandface is not the last optimization strategy in real field scenario. This is because the efficiency of the heavy oil displacement by the steam is a co-function of the effective SQ at the sandface, the FHLR/FHLT and the relative distance of the injector(s) from the producer(s) which are characterized by the thermal properties of the reservoirs. As part of the objectives of this study, a novel numerical approach using PROSPER wellbore simulator is presented for analysing the impact of reservoir back pressure on the estimated SQ. The results as presented in the work shows that wrong estimations of downhole SQ can result from the total neglect of Reservoir Pressure especially in relatively deeper wells.*

Keywords— ***Integrated, Modeling, Optimization, Reservoir, Steam.***

I. INTRODUCTION

The global rise in oil price and the increasing worldwide energy demand are clear indications that many proved undeveloped hydrocarbon reserves has to be developed using available technology. These reserves have been identified as either conventional or unconventional based on its source. The OPEC Annual Statistics (2017) reported the world's total proven reserves as of 2016 to be **1,492,164Mbbl.** According to PetroWiki (2017) classification, the unconventional sources of hydrocarbons include heavy oil, extra-heavy oil and Bitumen amounting to a total of 9 trillion barrels of oil (from both conventional and unconventional sources), accounting for about 83.42% of the world's total proven reserves. The efficient operation of steam injection requires the injection of steam of sufficient quality at sufficient rates. However, the cost of generating steam is quite high making up about a half of the overall cost of running the whole operation. Hence, the optimized use of the injected steam has been the industrial practice (Hong, 1994). For optimal application of steam, the reservoir depth must be duly considered as this poses a constraint to the efficiency of the operation.

The limitation of steam injection thermal EOR to depths not more than 5,000ft is due to significant heat losses in the wellbore, the formation and consequently, steam quality reduction. The development of models/ simulators is an important optimization tool in a more modern industrial society today. Thus, this enables the utilization of computer assisted numerical methods for the optimization of the parameter of interest over any possible number of ranges for convergence. Hence, an integrated model that can compensate for injection/reservoir pressure effect, choice of completion design and the reservoir response to steam will certainly be highly invaluable in the design and optimization of steam injection. This research provides an integrated ECLIPSE-PROSPER Steam Injection Model for steam measurements along the injection as well as the reservoir response to steam thermal energy.

Thermal processes are generally classified as those EOR methods that involve the introduction of external heat energy into the reservoir to heat up the high viscous crude in the reservoir and as such make it more mobile. The temperature dependence of viscosity is of empirical basis. This forms the basics of every thermal recovery procedures since the entire aim is to raise the reservoir temperature for viscosity reduction. The viscosity of liquids as a function of temperature can be estimated using any of the following correlations:

- *The Andrade's exponential correlation*

$$\mu = Ae^{(B/T)} \quad (1.1)$$

Where;

μ= dynamic viscousity, cp

T= absolute temperature, K

A and B = constants which varies from liquid to liquid.

- *The Braden's correlation for oil*

$$\log(\nu_2 + C) = (\frac{T_1}{T_2})^D \log(\nu_1 + C) \quad (1.2)$$

Where;

T_1 and T_2 = absolute temperature at the original condition and the final conditions (when temperature is raised) respectively

ν_1 and ν_2= kinematic viscosity,cSt

C= constant (equal to o.6 for ν>1.5 cSt)

D= constant of the order 3.5 to 4 (Latil, 1980)

Generally, hot fluid injection can be classified as hot water injection, cyclic steam injection (also known as 'huff and puff') and direct steam injection (also known as steamflooding), (Latil, 1980). For the scope of this study, the attention is going to be concentrated on steam. The cyclic steam injection also known as steam stimulation or the huff 'n' puff is a practice that uses a single well alternately as injector and producer for a more efficient utilization of the heat injected. It basically involves three phases of operation for a given cycle:

- The steam injection phase(which is similar in operation with normal direct steam injection i.e. steamflooding)
- The soak period and
- The production phase.(Latil 1980)

In the assessment of the efficiency of the steam injection design, the major optimization criteria are to maintain optimum steam quality at a sufficient injection rate using the '*rule of thumb* (Hong, 1994). However, such rate must economically be considerable to compensate for the high cost of steam generation. For most practical consideration, the '*the rule of thumb'* is to maintain an injection rate of 1.5B/D cold water equivalent(CWE) per acre foot of the reservoir and a steam quality of 40% at the sandface (Bursell et al, 1975; Farouq Ali,1979 and Doscher et al,1979).

The first paper ever presented on steam injection was done by Ramey, (1962) in which he developed equations for the estimation temperature profile as a function of depth and time for a single phase flow. The modelled generated was improved by (Satter, 1965)by considering the changes in steam quality, Overall heat transfer coefficient and the fluid properties which were not accounted by Ramey (1962). He thus presented better equations that compared the per cent of heat loss for superheated steam, saturated steam and understated steam.

(Hoist & Flock, 1966) was able to account for the effect of frictional loss and kinetic energy changes by dividing the entire injection system into three- *(a)* flowing fluid, *(b)* wellbore, and (c) formation with each part being treated separately and assuming they were interconnected only by heat transfer. This study shows that steam quality can be greatly affected by friction losses.

As an important steam optimization parameter, (Willhite, 1969) presented an iterative method for predicting the overall heat transfer coefficient by considering the various heat transfer mechanisms and thus presenting a method for the calculation of heat transfer coefficient for radiation through the annulus *(hr)* and the heat transfer coefficient for natural convection and conduction in the annulus *(hc)*.

Earlougher (1969) applied a depth-step technique similar to Satter's for calculating heat losses and downhole conditions. He extended Satter's approach by including the effects of pressure changes in the injection tubing and the effect of casing cement on heat transfer and studied the effects of various well completion schemes. He was able to demonstrate the importance of including the static pressure term in the pressure change. He also showed that by using insulated tubing heat loss could be reduced significantly. Earlougher concluded that the bottomhole properties of steam are a function of injection conditions and well completion, and also emphasized that the pressure change cannot be neglected in heat transfer calculation of steam injection. Pacheco &Farouq (1972) presented an analysis of wellbore heat losses and pressure drop for steam injection assuming the steam to be a perfectly homogeneous two-phase flow. Their studies showed that an increase of injection rate reduced heat loss and illustrated that frictional losses are important in determining downhole steam pressure, quality and temperature. This study was followed by Farouq Ali (1981) developed a comprehensive mathematical model to simulate the vertical upward and

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downward flow of wet steam in a well. This model is a combination of the Paceco&Farouq(1972) model and the pressure/flow regime correlations of Gould et al (1974), Chierici et al (1974), and Duns and Ros (1961).

Farouq Ali (1986) used the Duns and Ros flow pattern map to determine flow regime for wet steam flow. His study showed it is necessary to include slip and flow regime in calculating the pressure change. Furthermore, using the Duns and Ros flow regime map, the flow regime was found to be predominantly in the Slug-Froth flow. Still on flow regime map, Sylvester (1984) has shown that the Taitel*et al* (1980) flow regime map is superior to the Duns and Ros map since it predicted the annular-mist flow at much lower superficial gas velocities especially at higher pressures.

As an improvement to Pacheco &Farouq (1972), Fontanilla& Aziz (1982) developed a mathematical model for wellbore heat loss that incorporated empirical two-phase flow correlations using Beggs& Brill (1973), Aziz et al (1972) and Yamazaki & Yamaguchi (1979) correlations. Yao and Sylvester (1987) have shown that the Beggs and Brill correlation is unsatisfactory for vertical annular-mist flow.

Another innovative study on steam injection was done by Jianshe*et al* (2010). Their approach was able to account for the effect of the reservoir back pressure on the injection rate and consequently the steam quality by using a Nomograph developed for the Mukhaizna Field as against the conventional classical models that neglect the impact of the reservoir back pressure.

Most of the various classical models above has been used to develop the algorithm used by many steam injection softwares but the most common approach has been the independent analysis of the injection well and the reservoir.

II. MODEL FORMULATIONS

Considering a steam injection well model as shown in Figure (1) transferring a steam-hot water mixture through a control mass, ΔM, the general energy equation for the system at any two unique conditions (points) can be written as:

$$h_{m1} + \frac{g}{g_c}.\frac{Z_1}{J} + \frac{V_{m1}^2}{2g_cJ} = h_{m2} + \frac{g}{g_c}.\frac{Z_2}{J} + \frac{V_{m2}^2}{2g_cJ} \qquad (2.1)$$

In differential form, Equation (3.1) becomes

$$dh_m + \frac{g}{g_c}.\frac{dZ}{J} + \frac{V_m dV_m}{2g_cJ}=0 \qquad (2.2)$$

If we include the heat loss term and assuming no work done by or on the steam, we have;

$$dh_m + \frac{g}{g_c}.\frac{dZ}{J} + \frac{V_m dV_m}{2g_cJ} - dQ=0 \qquad (2.3)$$

Equation (2.3) describes a general energy equation for the energy balance of the steam-hot water mixture in the system. For a general concern, it is often desired to express the energy equation as a gradient of the depth for the injection well optimization. Hence we can have,

$$\frac{dh_m}{dz} + \frac{g}{g_c}.\frac{1}{J} + \frac{V_m}{g_cJ}\frac{dV_m}{dz} - \frac{dQ}{dz} = 0 \qquad (2.4)$$

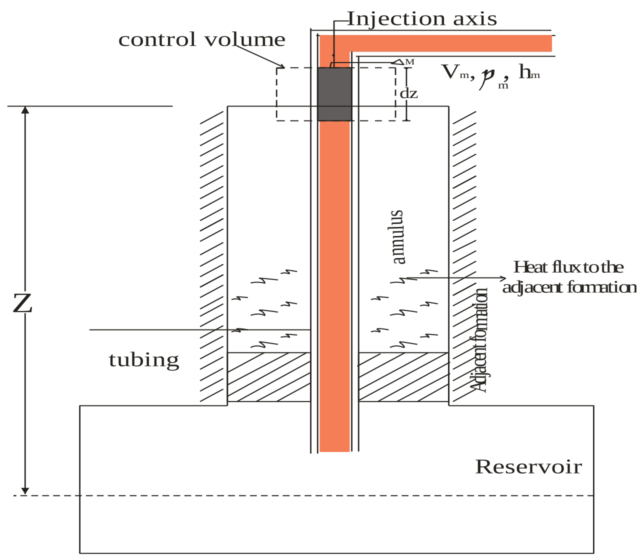

Fig.1: A Steam Injection Well Model

Sometimes, it is more convenient to express the steam mixture velocity, $V_m$in terms of the superficial velocity or the mass flux rate and specific volume of the individual components of the steam stream. By definition,

$$V_m = V_{sl} + V_{sg} = G_l v_l + G_g v_g \qquad (2.5)$$

$$dV_m = G_l dv_l + G_g dv_g \qquad (2.6)$$

Where;

V_{sl} = Liquid (hot water) superficial velocity, ft/hr

V_{sl} = gas (vapour) superficial velocity, ft/hr

G_l = liquid mass flux rate, lb/hr-ft^2

G_g = gas mass flux rate, lb/hr-ft^2

v_l =liquid specific volume, ft^3/lb

v_g = gas specific volume, ft^3/lb

Putting (2.4) and (2.5) into (2.6), we have the following result;

$$\frac{dh_m}{dz} + \frac{g}{g_c}.\frac{1}{J} + \frac{1}{g_cJ}\left[v_l G_l^2 \frac{dv_l}{dz} + v_l G_l G_g \frac{dv_g}{dz} + v_g G_g G_l \frac{dv_l}{dz} + v_g G_g^2 \frac{dv_g}{dz}\right] - \frac{dQ}{dz} \qquad (2.7)$$

Some of the essential properties of the steam that is of primary interest to this study are the mixture enthalpy, gas specific volume and liquid specific volume defined as;

$h_m = f(X, P)$, hence, $\frac{\boldsymbol{dh_m}}{\boldsymbol{dz}}$can be evaluated as follows;

$$\frac{dh_m}{dz} = \frac{\partial h_m}{\partial X}.\frac{dX}{dz} + \frac{\partial h_m}{\partial P}.\frac{dP}{dz} \qquad (2.8a)$$

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More so,

$$\frac{dv_g}{dz} = \frac{\partial v_g}{\partial P} \cdot \frac{dP}{dz} \qquad (2.8b)$$

$$\frac{dv_l}{dz} = \frac{\partial v_l}{\partial P} \cdot \frac{dP}{dz} \qquad (2.8c)$$

Substituting Equations (3.8a-c), and solving for steam quality gradient, we can have the following result;

$$\frac{dX}{dz} = \frac{1}{\left[\frac{\partial h_m}{\partial X}\right]}\left[-\frac{\partial h_m}{\partial P}\frac{dP}{dz} + \frac{g}{g_c}\cdot\frac{1}{J} - \frac{1}{g_c J}\cdot\frac{dP}{dz}\left(v_l G_l^2 \frac{\partial v_l}{\partial P} + v_l G_l G_g \frac{\partial v_g}{\partial P} + v_g G_g G_l \frac{\partial v_l}{\partial P} + v_G G_g^2 \frac{\partial v_g}{\partial P}\right) - \frac{dQ}{dz}\right] \qquad (2.9)$$

The Equation (2.9) above is a first order differential equation that can be used to estimate the steam quality gradient analytically.

To estimate the pressure drop term, $\frac{dP}{dz}$, we establish the momentum balance equation in terms of the mechanical energy balance of the system. This is also sometimes conventionally expressed as the pressure drop equation for fluid flow through a pipe section. Hence we can write that;

$$\frac{dP}{\rho_m} - \frac{g}{g_c}dz + \frac{V_m dV_m}{g_c} + dW_s + dW_f = 0 \qquad (2.10a)$$

Where:

dP= total Pressure differential, lb/ft^2 (Psf)

dW_s = Work done by or on the fluid, lb-ft/lb

dW_f = Frictional work, lb-ft/lb

For dPin Psi, we can rewrite (3.10a) as;

$$\frac{144dP}{\rho_m} - \frac{g}{g_c}dz + \frac{V_m dV_m}{g_c} + dW_s + dW_f = 0 \qquad (2.10b)$$

Since there is no Work done on or by the steam stream (expansion or compression of the fluid (steam)), $\xrightarrow{dW_s}$ 0 such that Equation (3.10b) becomes,

$$\frac{144dP}{dz} - \frac{\rho_m g}{g_c} + \frac{V_m dV_m}{g_c dz} + \rho_m \frac{dW_f}{dz} = 0 \qquad (2.11)$$

As usual by solving for the total pressure gradient, we can establish this equation below;

$$\frac{dP}{dz} = \frac{\rho_m \frac{g}{g_c} - \left(\frac{dP}{dz}\right)_{frictionlosses}}{144 + \frac{\rho_m}{g_c}\left[v_l G_l^2 \frac{\partial v_l}{\partial P} + v_L G_l G_g \frac{\partial v_g}{\partial P} + v_g G_g G_l \frac{\partial v_l}{\partial P} + v_G G_g^2 \frac{\partial v_g}{\partial P}\right]} \qquad (2.12)$$

In this study, the steam properties and the injection well conditions will be generated using PROSPER and a sensitivity test will be run using critical parameters as presented in the next chapter.

1. The Reservoir Back-Pressure Effect

It is a common experience that the reservoir pressure causes a significant constraint during steam injection. Therefore, a total neglect of this phenomenon will limit the accuracy of the predicted steam properties. The back-pressure phenomenon can be modeled using the figure below (Figure 2).

By capillary effect, the in-situ fluid tends to rise through the vertical column of the injector. For this set up, if we assume that the steam generator discharge pressure remains unchanged at the wellhead, the total pressure of the injection well system at a constant injection rate can be established thus;

$$P_{inj} + (P_{res} - 0.052\rho_o dh) = P \qquad (2.13)$$

Where;

P= Actual Downhole Steam Pressure (which is equivalent to the total pressure of the system under injection conditions), Psi

ρ_o = Oil density, ppg

P_{inj} = Injection Pressure at depth dz, psi

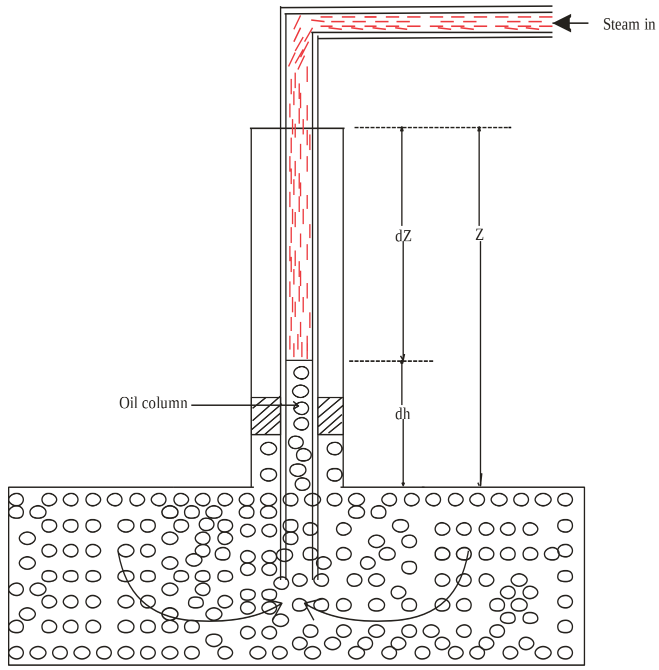

Fig.2: A well Model for Reservoir Back Pressure Effect

It is worth noting that this pressure (P_{inj}) at the sandface (dz=Z) can be greater or less than the injection constraint at the wellhead (dz=0) depending on the dominating factor during the steam transfer to the downhole. If gravity dominates flow, $[P_{inj}]_{dz=Z} > [P_{inj}]_{dz=0}$ but when frictional drag dominates the steam flow, $[P_{inj}]_{dz=Z} < [P_{inj}]_{dz=0}$. It only becomes unchanged when both the gravity losses and the friction losses have approximate equal impacts on the injection system.

As '*dh*' approaches zero TVD, the influence of the reservoir pressure due to the capillary column of the rising becomes less significant.

In practice, the injection well is totally filled with the steam column such that dzapproaches Z. This is certainly the case for heavy oil wells which do not readily flow by natural effect and also as a result of external constraint of the injection pressure. Therefore, we can rewrite Equation (2.13) as,

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$P_{inj} + P_{res} = P$ (2.14)

In other words;

$P_{inj}\left(1 + \frac{P_{res}}{P_{inj}}\right) = P_{inj}(1 + \psi_P) = P$ (2.15)

Where $\psi_P$is defined as the pressure ratio of the reservoir to the Steam injection pressure.The term $(1 + \psi_P)$ is defined as the reservoir back pressure (RBP) correction factor denoted in this study as 'ξ_P'. Therefore, the corrected pressure of the steam system can be expressed as,

$P = P_{inj}.\xi_P$ (2.16)

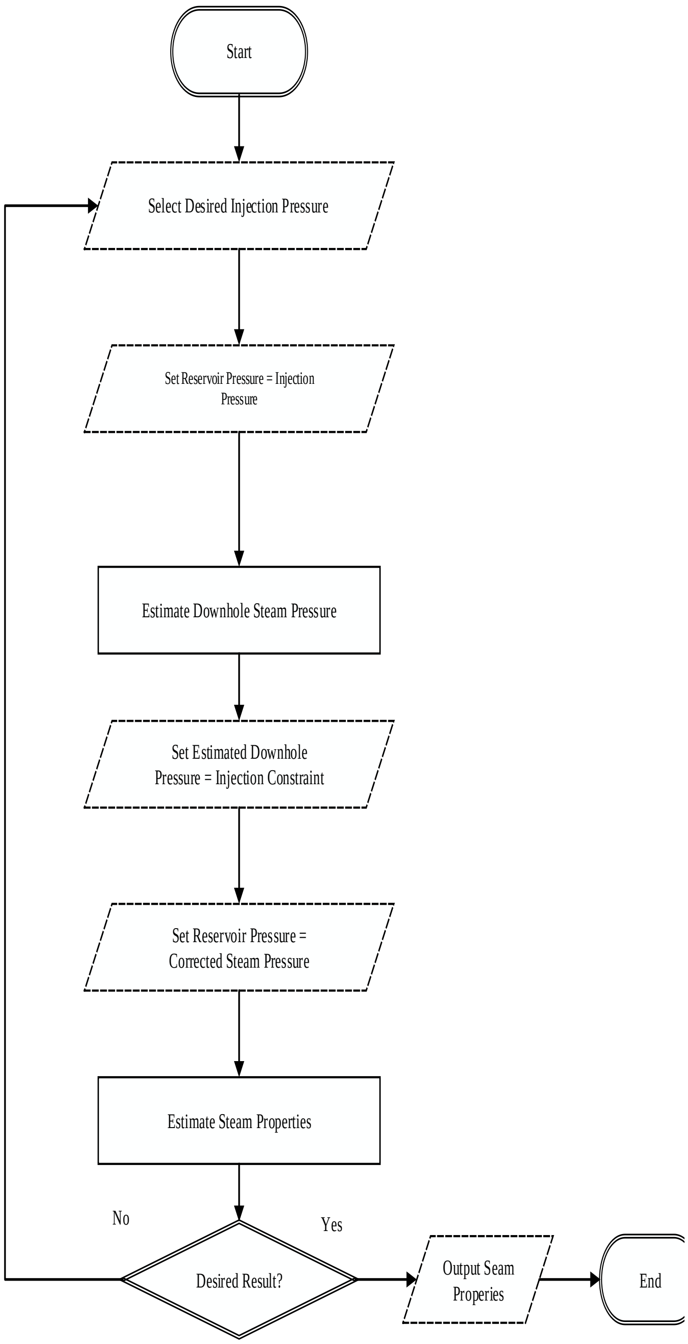

Fig.3: Algorithm for Reservoir Back Pressure Analysis

The implication of the above Equation (2.16) is that a less accurate steam quality (overestimation) will be made by ignoring the reservoir back pressure especially for relatively high pressure reservoirs as this tends to constrain the injection pressure and consequently the injection rate of the steam. For convenience sake, this equation will be used to establish a table of values of ξ_P for different pressure ranges as presented in the appendix section. The effect of reservoir back pressure on the steam properties and the injection well system was analyzed numerically using PROSPER simulator and the result presented in the next chapter. To achieve this, the reservoir pressure was set at the corrected pressure based on Equation (3.16) using the following algorithm.

2. The Wellbore Heat Loss Calculations

In the literature review of this study as presented in the preceding chapter, it is clearly identified that the most influencing factor for the optimization of steam injection is the choice of completion. This is because the completion design directly affects the heat losses that occur in the injection well. A typical model for this is given in the figure below (Figure 4)

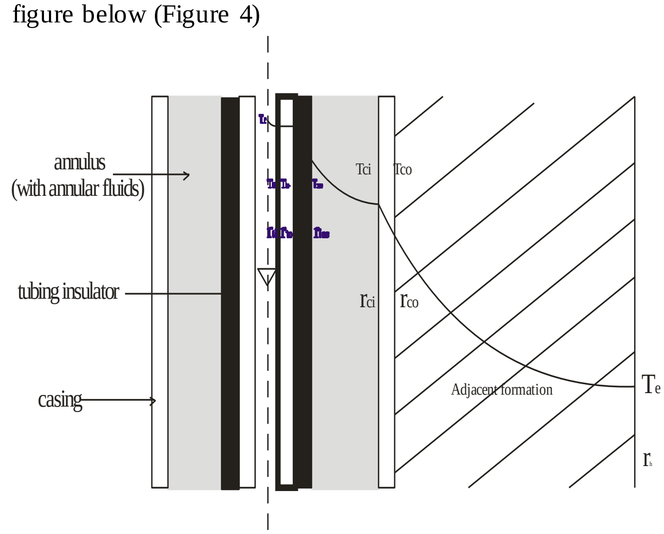

Fig.4: A Steam Injector Heat Loss Schematic Based on Tubing-Inserted-in-Tubing Model

Using the figure above, the heat transfer mechanism by conduction, convention and radiation can be modeled based on the following considerations/assumptions.

- Heat transfer in the injection well system is at pseudo-steady state
- The tubing and the casing are symmetrically vertically placed
- There is no annular refluxing
- The overall heat transfer coefficient is independent on depth

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If we proceed with these assumptions, the following heat transfer summary can be written for the Model above in Figure (4).

- The heat transfer to the inner tubing wall due to steam motion is by convention
- The heat transfer between the inner tubing wall and the outer tubing wall is by conduction
- The heat transfer between the outer tubing wall and the solid insulation (for insulated tubing) is by conduction
- The heat transfer between the insulator and the annular space is by the annular fluid convention and conduction (if there is annular fluid) and the insulator radiation
- The heat transfer between the annulus and the inner casing wall is by conduction
- The heat transfer between the inner casing wall and the outer casing wall is by conduction
- The heat transfer between the outer casing wall and the cement bond is by conduction
- The heat transfer between the cement bond and the adjacent formation is by conduction

From Equations (2.4), (2.5) and (2.6), the 1-D heat transfer Model through a hollow cylinder can be written thus;

$$\frac{dq}{dz} = \frac{2\pi k}{In\left(\frac{r_o}{r_i}\right)}(T_i - T_o)\{for heat conduction\} \quad (2.17)$$

$$\frac{dq}{dz} = 2\pi r_i h(T_i - T_o)\{for heat convention\} \quad (2.18)$$

$$\frac{dq}{dz} = 2\pi r_i h_r(T_i - T_o)\{for heat radiation\} \quad (2.19)$$

From the heat transfer summary, we can solve for temperature differences as follows so as to define the overall heat transfer coefficient

$$T_f - T_{ti} = \left(\frac{dq}{dz}\right)\Big/ 2\pi r_{ti} h_s \quad (3.20a)$$

$$T_{ti} - T_{to} = \left(\left(\frac{dq}{dz}\right)\Big/ 2\pi k_t\right). In\left[\frac{r_{to}}{r_{ti}}\right] \quad (3.20b)$$

$$T_{to} - T_{ins} = \left(\left(\frac{dq}{dz}\right)\Big/ 2\pi k_{ins}\right). In\left[\frac{r_{ins}}{r_{to}}\right]$$ (For insulated tubing) (3.20c)

$$T_{ins} - T_{ci} = \left(\frac{dq}{dz}\right)\Big/ 2\pi r_{ins}(h_c + h_r) \quad (3.20d)$$

$$T_{ci} - T_{co} = \left(\left(\frac{dq}{dz}\right)\Big/ 2\pi k_c\right). In\left[\frac{r_{co}}{r_{ci}}\right] \quad (3.20e)$$

$$T_{co} - T_e = \left(\left(\frac{dq}{dz}\right)\Big/ 2\pi k_{cem}\right). In\left[\frac{r_h}{r_{co}}\right] \quad (3.20f)$$

Using the Equations (3.26a-f), the overall temperature difference becomes

$$Overall temperature difference = T_f - T_e \quad (3.21)$$

Hence, the final equation for the overall heat transfer of the steam injection system becomes;

$$\frac{dq}{dz} = 2\pi r_{to} U_{to}(T_f - T_e) \quad (3.22)$$

This Equation can be equated to the Ramey's premier heat loss per unit length of injection path given as;

$$\frac{dq_l}{dz} = 2\pi r_{to}.\frac{1}{R_{to}}(T_f - T_e). \quad (3.23)$$

Where;

R_{to} = overall thermal resistance

During steam injection, the compensation for heat losses is basically by reducing U_{to} as low as possible by both tubing and annular insulation. If we therefore solve for $U_{to,}$ using Equations (3.20a-f) through (3.23) it will give;

$$U_{to} = \frac{1}{\left[\frac{r_{to}}{r_{ti}h_f} + \frac{r_{to}\ln\frac{r_{to}}{r_{ti}}}{k_t} + \frac{r_{to}\ln\frac{r_{ins}}{r_{to}}}{k_{ins}} + \frac{1}{(hc+hr)} + \frac{r_{to}\ln\frac{r_{co}}{r_{ci}}}{k_c} + \frac{r_{to}\ln\frac{r_h}{r_{co}}}{k_{cem}}\right]} \quad (3.24)$$

For a steel casing and tubing (or any other high conductive metals),

$k_t = k_c \gg k_{ins}, k_{cem}, hc and hr$. Therefore, Equation (3.24) can be simplified to the following;

$$U_{to} = \frac{1}{\left[\frac{r_{to}}{r_{ti}h_f} + \frac{r_{to}\ln\frac{r_{ins}}{r_{to}}}{k_{ins}} + \frac{1}{(hc+hr)} + \frac{r_{to}\ln\frac{r_h}{r_{co}}}{k_{cem}}\right]} \quad (3.24.a)$$

If no insulation of the tubing, $U_{to} =$

$$\frac{1}{\left[\frac{r_{to}}{r_{ti}h_f} + \frac{1}{(hc+hr)} + \frac{r_{to}\ln\frac{r_h}{r_{co}}}{k_{cem}}\right]} \quad (3.24.b)$$

For no annular insulation and tubing insulation, $U_{to} =$

$$\frac{1}{\left[\frac{r_{to}}{r_{ti}h_f} + \frac{1}{hr} + \frac{r_{to}\ln\frac{r_h}{r_{co}}}{k_{cem}}\right]} \quad (3.24.c)$$

The terms, hc and hr can be evaluated independently based on empirical correlations/ charts for the different choice of insulation material as presented in Fidan (2011) studies. Also using PROSPER wellbore simulator by selecting *Enthalpy Balancing Model*, the overall heat transfer of the injection well can be calculated if there is adequate data for formation lithology and the completion status.

For the purpose of this study, in order to numerically analyze the impact of injection well completion, a sensitivity test was run for known values of overall heat transfer coefficient.

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3. Study Simulation Methodology

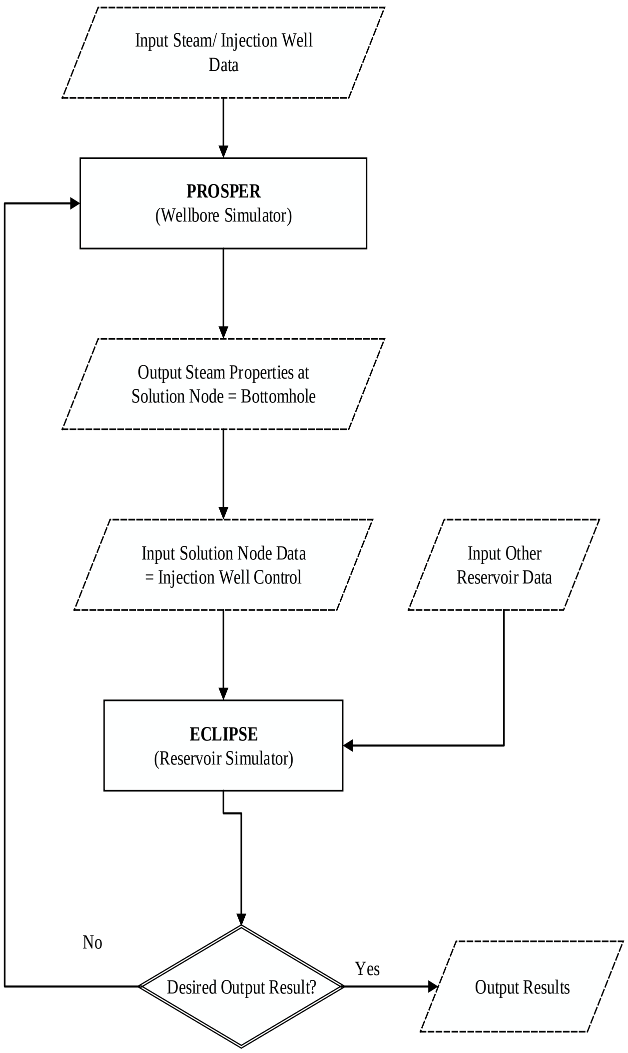
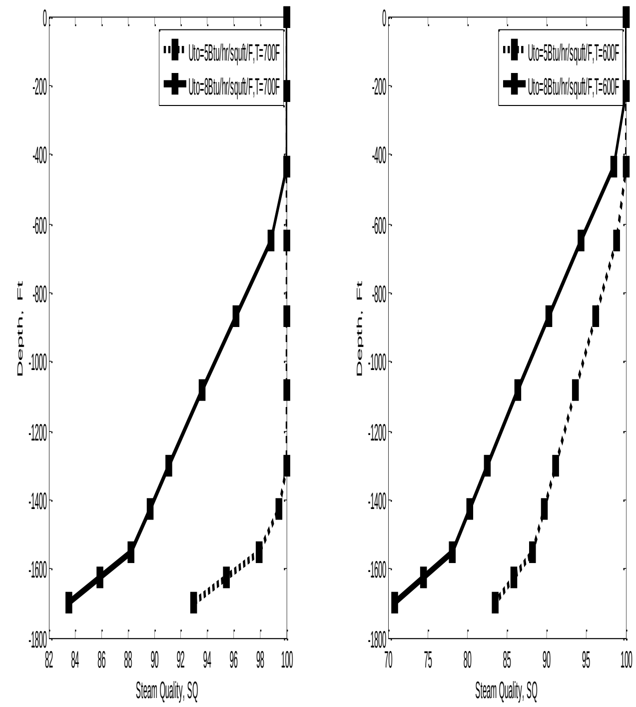


Fig. 5: Simulation Flow Chart

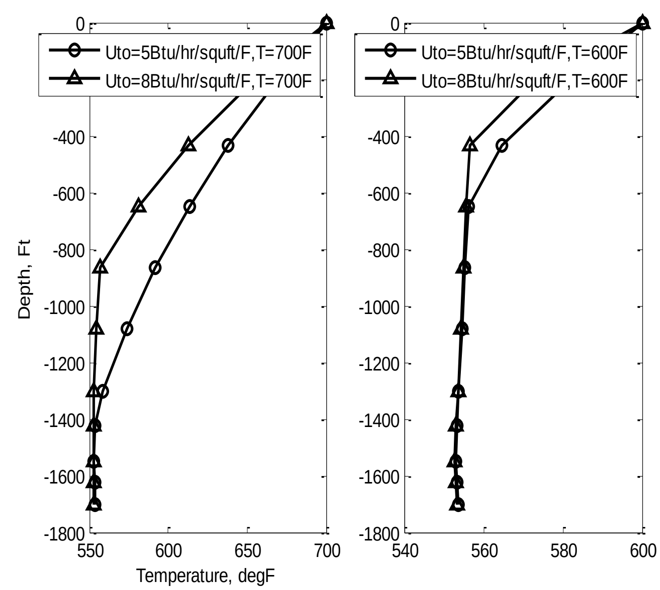
III. MODEL RESULTS AND DISCUSSIONS

The analysis of steam injection starts with the specification of the input steam data and then the injection well configuration. A special consideration was made for injecting at the same tempeerature and different overall heat transfer coefficient and injecting at the same overall heat transfer coefficient and different temperatures.

Based on the specified data of the input steam and the injection well configuration used in this study, the steam data generated at a pressure of 1100psiwas presented in Fig 6 and Fig 7.



(a) Injection Temp=700^{0}F (b) Injection Temp=600^{0}F
Figure 6: Steam Quality Gradient at Different Injection Temperature and Uto



(a) Injection Temp=700^{0}F (b) Injection Temp=700^{0}F
Fig.7: Steam Temperature Gradient at Different Injection Temperature and Uto

From the figuers above, it can be noted that though temperature of 700^{0}F gave a good SQ but in as much as a sufficient steam quality can be generated, it will be more

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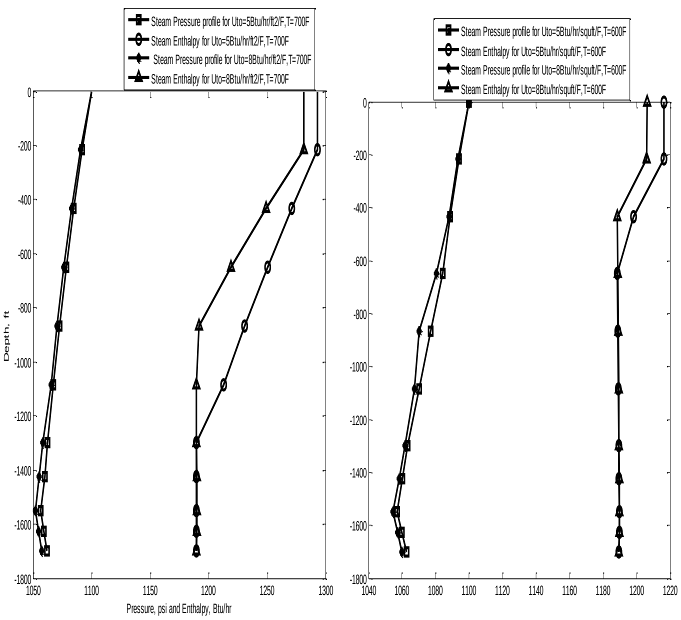
economical to consider injecting at 600^0F. The differences in the Overall heat transfer coefficeint was used to analyse the possible necessity of insulating the wellbore or improving the insulation efficiency. Using this as a design guide shows that an overall heat transfer coefficient of 8Btu/hr/Ft2/^{0}F can be adequate for this operation since it gave a sufficient SQ used to specify the Injection well control of the ECLIPSE programme.



(a) Injection Temp=700^0F *(b) Injection Temp=600^0F*

Fig.8: Steam Pressure and Enthalpy Gradients

1. Reservoir Back Pressure (RBP) Sensitivity Analysis

A major limitation to classical wellbore SQ analysis is total neglect of the effect of reservoir back pressure on the steam injection rate and consequently the SQ. The result in Table (1) is a sensitivity study performed with a 5000ft steam injector where the impact of reservoir back pressure is more pronounced. Hence, it was observed that the reservoir back pressure causes a significant constraint to the injection rate with a resultant significant SQ drop. Therefore, an optimal performance of steam injection design will require a negligible reservoir pressure. The phenomenon of RBP is also graphically illustrated in Figure (9) using a simple MATLAB multiple plot tool.

Table.1: SQ Vs Depth at Different Reservoir Pressure (RBP Sensitivity Analysis)

DEPTH (ft)	**SQ @ $\xi_P = 1$**	**SQ @ $\xi_P = 1.1429$**	**SQ @ $\xi_P = 1.2857$**	**SQ @ $\xi_P = 1.4286$**	**SQ @ $\xi_P = 1.57$**
0	100	100	100	100	100
250	100	100	100	100	100
500	100	100	100	100	100
750	100	100	100	100	100
1000	100	100	100	100	100
1250	100	100	100	98.22	94.96
1500	100	99.3	97.07	94.14	90.22
1750	98.22	96.14	93.51	90.07	85.51
2000	95.37	92.98	89.96	86.02	80.8
2233.3	92.75	90.08	86.69	82.3	76.42
2466.7	90.22	87.25	83.5	78.65	72.1
2700	87.75	84.5	80.4	75.05	67.82
2933.3	85.35	81.81	77.36	71.5	63.6
3166.6	83.02	79.22	74.37	67.99	59.41
3400	80.75	76.68	71.41	64.51	55.26
3633.3	78.57	74.18	68.5	61.09	51.14
3866.6	76.43	71.72	65.62	57.7	47.05
4100	74.33	69.3	62.78	54.34	42.99
4333.3	72.28	66.91	59.98	51.01	38.96
4566.6	70.26	64.56	57.21	47.71	34.94
4800	68.27	62.24	54.48	44.4	30.94
4900	65.91	59.5	51.28	40.66	26.38
5000	63.57	56.79	48.11	36.9	21.8
<u>NOTE</u> Well head Constraints =1400Psig, 700^0F and Uto=5Btu/hr/ft2/F	Liquid Rate @RBP =0Psig **1996.4 STB/d**	Liquid Rate @RBP= 200Psig **1801.7 STB/d**	Liquid Rate @RBP= 400Psig **1607.1 STB/d**	Liquid Rate @RBP= 600Psig **1412.4 STB/d**	Liquid Rate @RBP= 800Psig **1217.8 STB/d**

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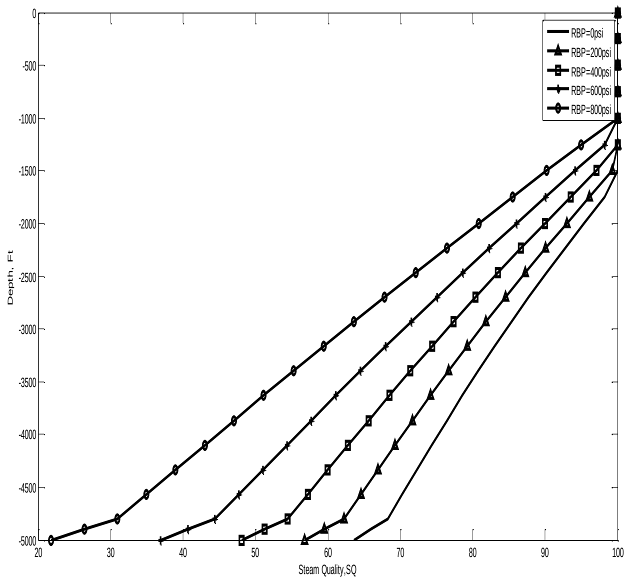

Fig.9: Reservoir Back Pressure Sensitivity

2. Reservoir Grid Definition

Reservoir X is a 9x5x4 reservoir with active cells specified in X-Y plane. There are Three wells- an injector at (1,1) and two producers at (5,5) and (9,1) respectively with different transmissibities at each Z-layer. An injection design was specified for 10 years injection and a timestep of 365 days for selected for analysis.

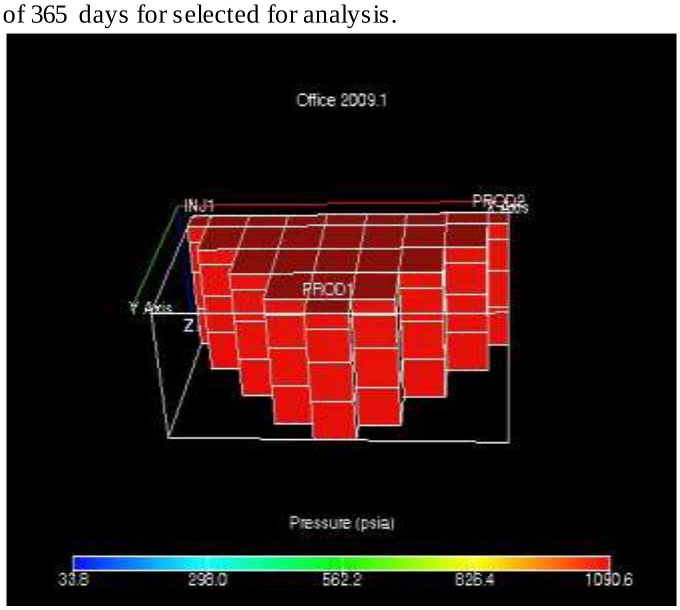

Fig.10: Reservoir Grid Layerout in 3-D

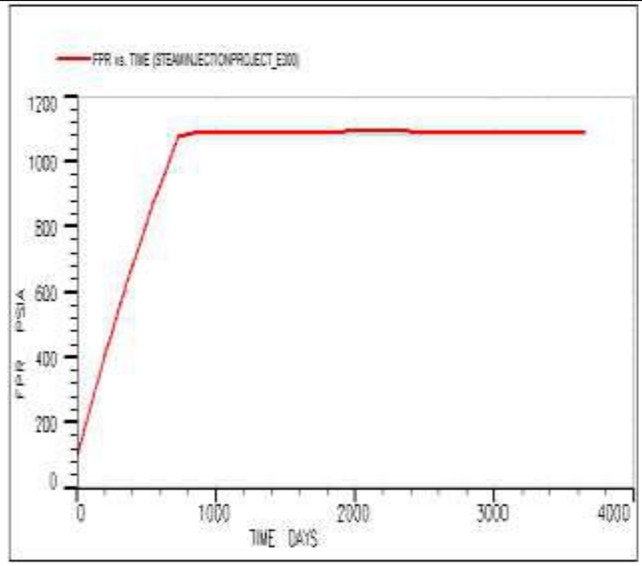

Fig.11: Field Presure History for the 10yrs injection Period

3. Field Pressure Response

The Figure 11 above displays the pressure response of the steam injection from an initial datum depth pressure of 75psi to a stablized pressure of about 1090psi which shows that steam does not just add thermal energy to the reservoir, hence, it also provides a water drive to the reservoir thereby aiding the area sweep efficiency.

4. Field Heat Loss Rate (FHLR) and Heat Loss Total (FHLT)

When steam is finally introduced into the reservoir at a particular SQ, the efficiency of the heavy oil displacement will be characterized by the rate of heat loss throughout the injection-period.

Figure 12-(a): Field Heat Loss Rate

Figure 12-(b): Field Heat Loss Total.

Figure 1(a) shows the simulated field rate of heat loss behavoiur. It can be clearly seen that the FHLR increses at the initial period of injection of about 2years (700days) of injection before a decline in the FHLR. This is because at earlier stage of injection, the rate of heat conduction to the overlaying formation is high and it is propagated similarily as a pressure transient. Hence, more heat is needed to warm up the reservoir than to keep it at a stablized temperature. This is more clearly illustrated in Figure 12(b) which shows that at a later stage of the injection, FHLT becomes near constant. The resulting field temperature profile during the periods of injection is shown in Figures 13(a) to 13(c).

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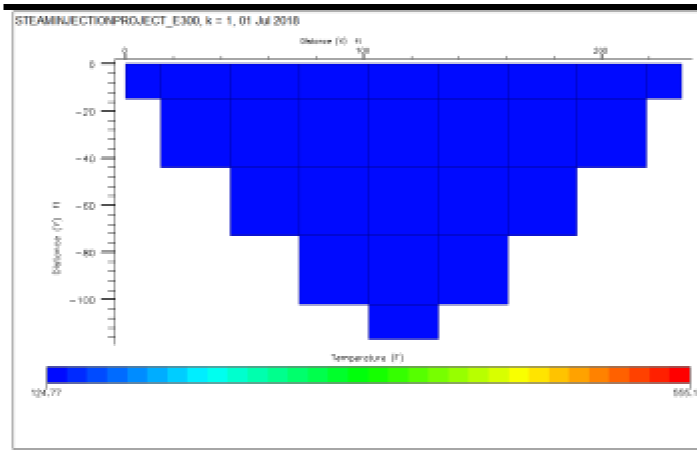
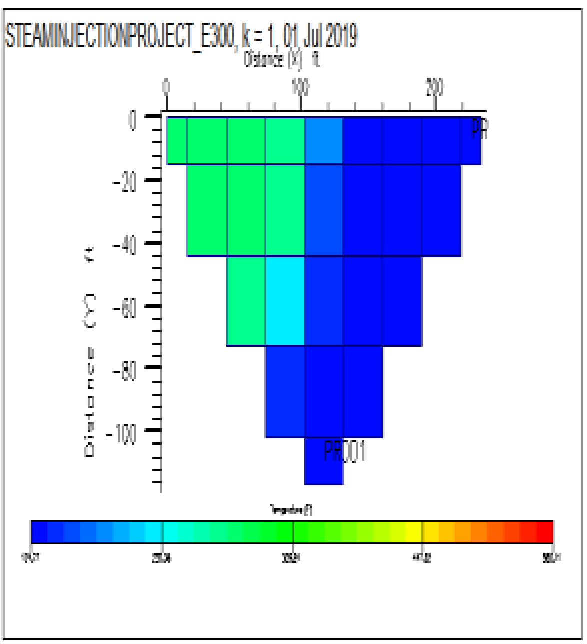


Fig,13(a): Field Temperature Profile Before Steam Injection (125^0F)

Fig 13(b) shows that after 1yr of injection both PROD1 and PROD2 has not been adequately heated up while after 2yrs, PROD1 has been well affected by the steam injection while PROD2 remains slighly affected as shown in Fig 13(c). This is because PROD1 is closer to the INJ1 since heat distribution is both time and space dependent.



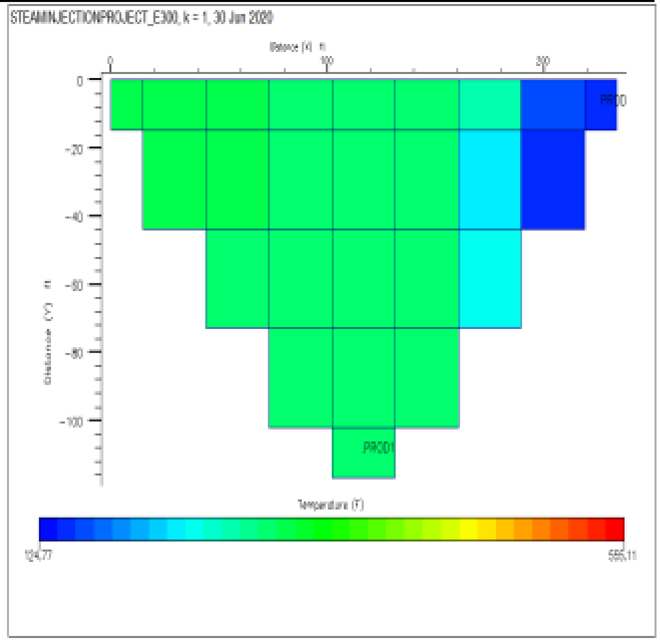


Fig.13: (b) Field Temp. Profile after 1 yr (c) Field Temp. Profile after 2 yrs

5. Field WaterProduction and Field Oil Production Analysis

A comon experience with steam injection project is the increased water cut as the water-oil front changes with time and space and therefore tends to the producers. As a result of excessive turbulence in the reservoir caused by the injection, the condensed steam in the hot water zone are produced along with the heated oil bank. Henec, water production/water cut increases with time. A good advantage of this process is that it results to a secondary water drive mechanism that effects the sweeping of the heated oil bank. Figures 14(a) to 14(c) shows the field water production profile and the individual contibutions of the two producers-PROD1 and PROD2.

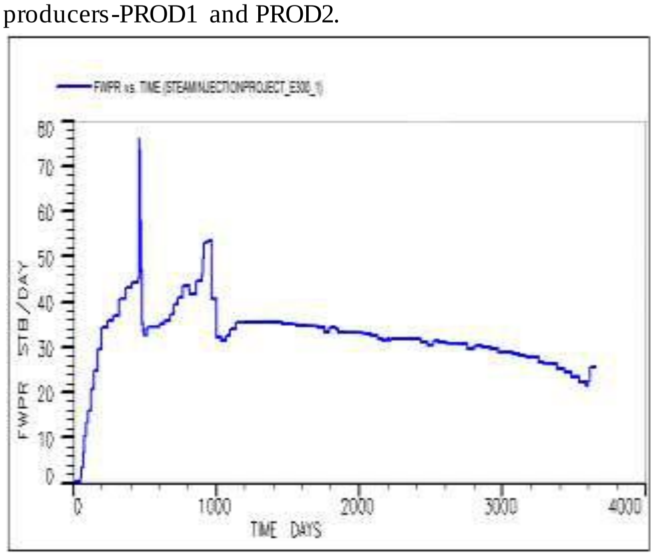


Fig.14(a): Field Water Production Rates

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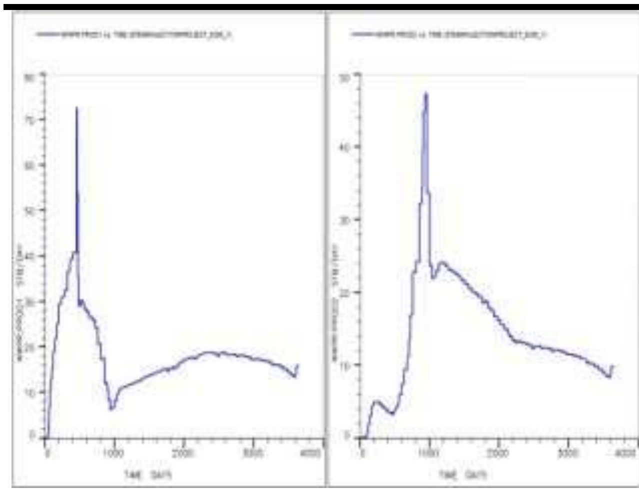


Fig.14(b): Field Water Production Rate (PROD1)
Fig.14(c): (PROD2)

A similar analysis of Field Water cut is shown in Figures 15(a) to 15(c). It is observed that PROD1 responds faster to water cut than PROD2 which responds slower. This can be attribited to the differences in the location of the Producers with respect to the Injectors. The steam front during injection reaches PROD1 earleir than PROD2. The implication of this as illustrated in the simulation results is that subsequently at a much later period, the PROD1will be dominated by hot water zone.

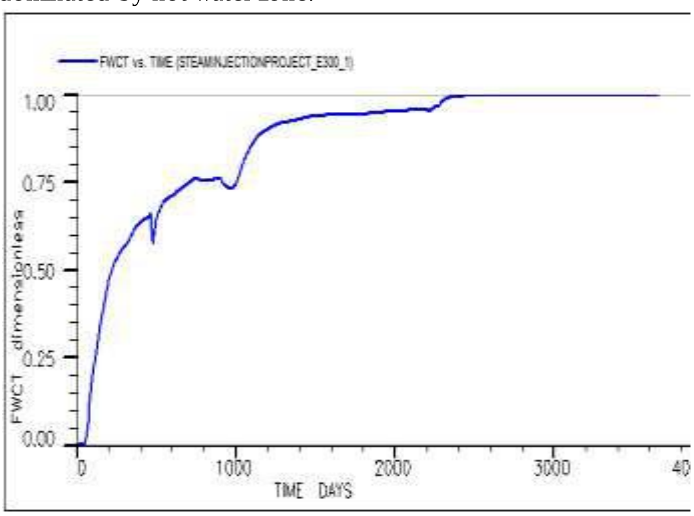
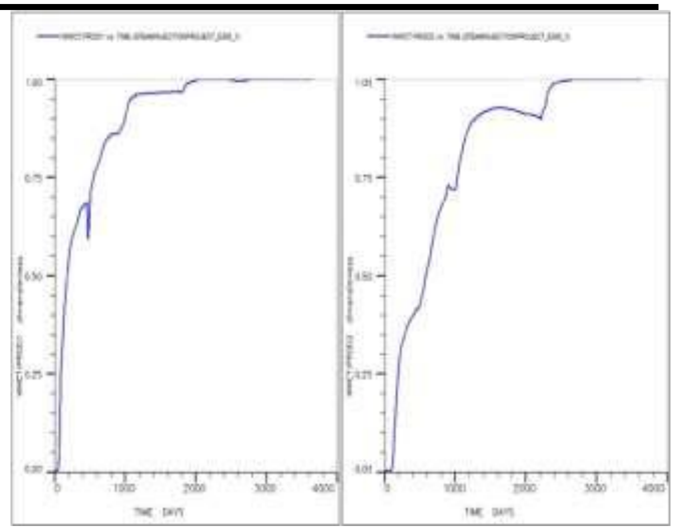


Fig.15(a): Field Water Cut History



(a) PROD1 *(b) PROD2*

Fig.15: Well Water Cut History

A comparative Analysis of Field Oil Production Rate-Field Water Production Rate and Field Oil Production Total-Field Water Production Total are given in Figures 16(a) and 16(b). The plots shows that as water production rate increases, oil production Rate decreases. The Figure 16(b) precisely displays a saturation rate growth model and a near linear relationship for the oil production and water productions Total(s) of the injection period respectively.

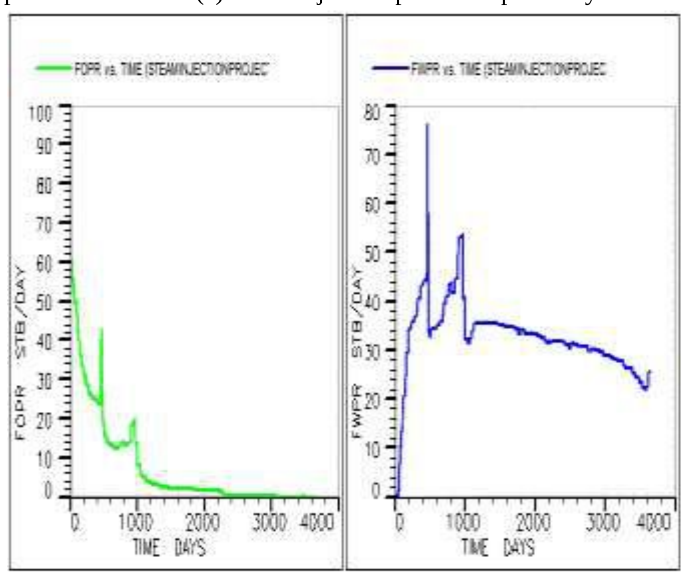


Fig.16(a): (i) Field Oil Production Rate
(ii) Field Water Production Rate

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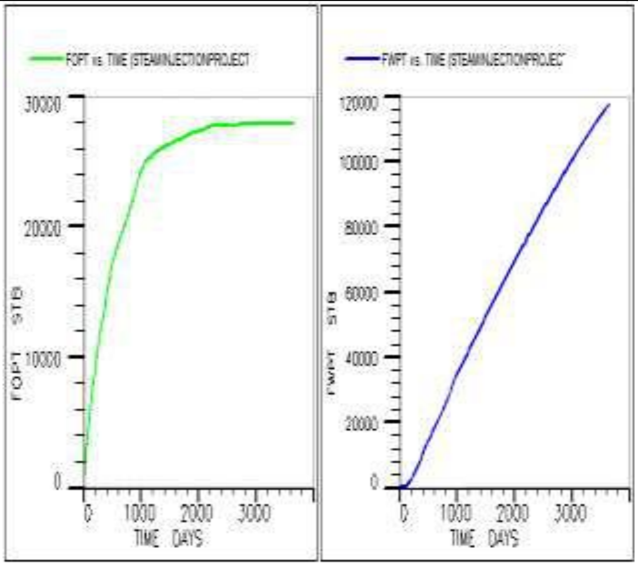


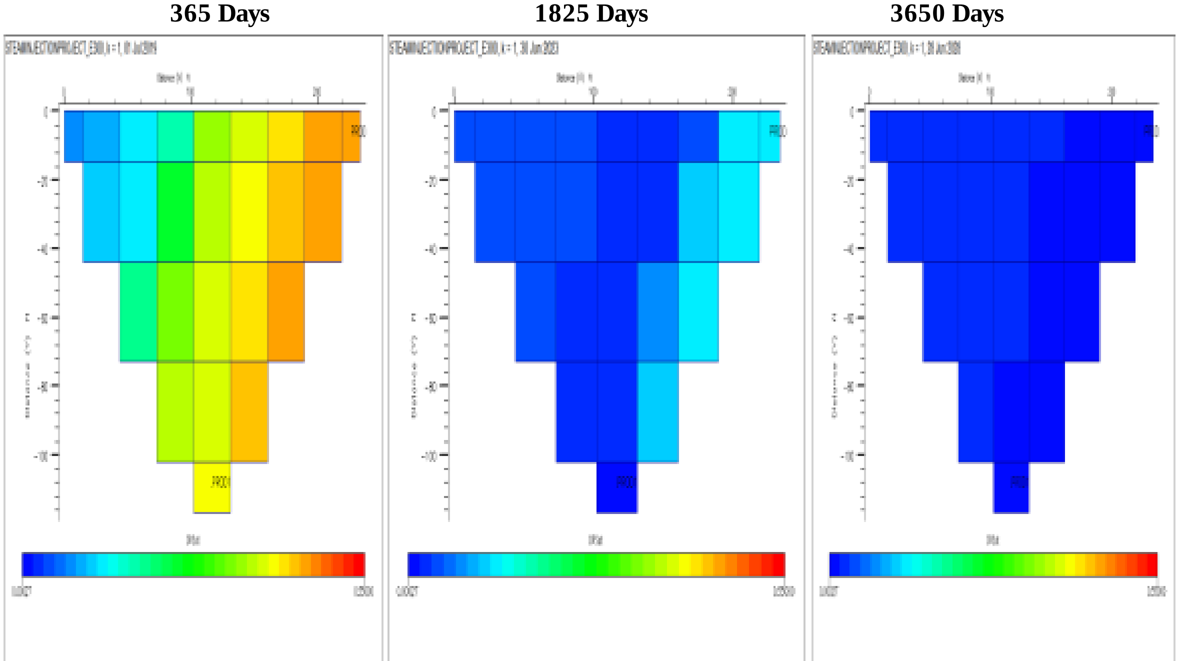
Fig.16(b): (i) Field Oil Production Total
(ii) Field Water Production Total

6. Effect of Steam Injection on Oil and Gas Saturations

Steam injection like water injection causes the in-situ oil saturation to vary with both time and space as the steam front propagates along the reservoir grid cells towards the producers. The counter result of this process is the increase in water saturation. Figure 17(a) shows the oil saturation history of the reservoir for 1year (365 days), 5years (1825 days) and 3years (3650days) of injection respectively.

In the literature review, it was clearly stated that steam injection activates solution gas drive in the reservoir system and also improves the quality of the produced oil by thermal distillation. Hence, steam injection increases the gas saturation as the input thermal energy of the steam helps to liberate the light gas molecules in solution. The economic benefit of this is that recovery by thermal methods upgrades the API gravity of the in-situ oil. Figure (17) shows the oil saturation history while the corresponding gas saturation history of the reservoir is shown in Figure (18).

365 Days **1825 Days** **3650 Days**



(a) *(b)* *(c)*

Fig.17: Field Oil Saturation History

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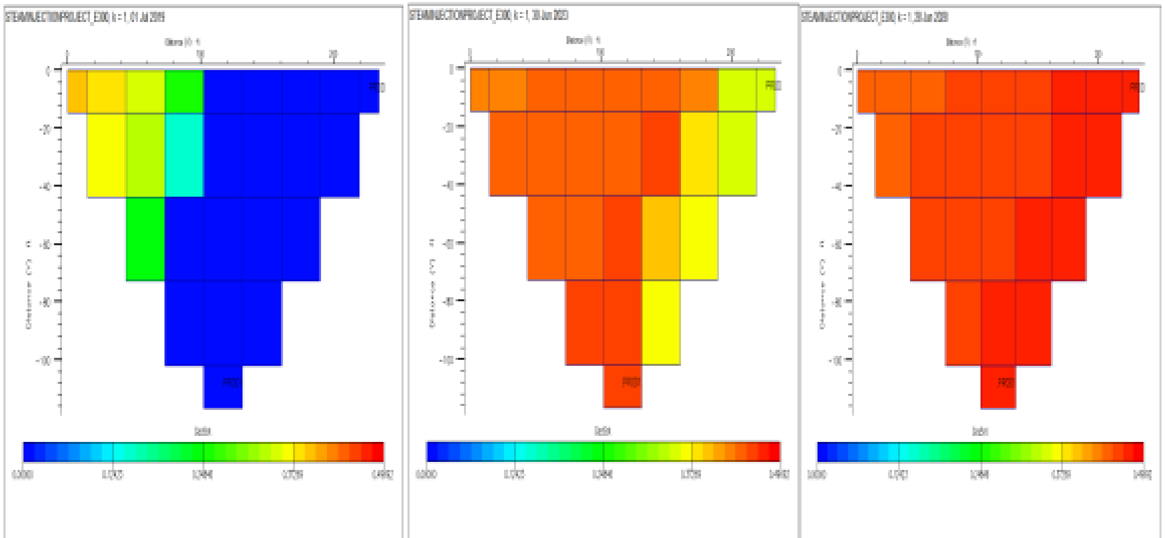
365 Days 1825 Days 3650 Days



(a) (b) (c)

Fig.18: Field Gas Saturation History

IV. CONCLUSION

This study presents an integrated steam injection Model needed for the complete optimization of the steam injection project. The study frame work incorporates a well computer simulator known as PROSPER (An IPM Suit Product) and a reservoir simulator known as ECLIPSE (Eclispse300) for the analysis. Thus, the optimal use of the injected fluid was archived since a semi-iterative procedure can be used for data convergence as shown in simulation flow chart.

The steam properties predicted with this study shows that higher SQ will be generated at higher injection Pressure and Temperature and at lower overall heat transfer coefficient.

By adequately reviewing, formulating and analysing the basic analytics behind the steam injection mechanism, the impact of reservoir back pressure on the SQ and consequently the injection rate was numerically quantified using a 5000ft case study well at a constant injection well head constraint. The results showed that a most efficient steam injection will be achieved at the lowest reservoir initial pressure.

The various sensitivity results generated with ECLIPSE showed that production well spacing relative to the injector have a critical effect on the area sweep efficiency of the injected steam especially in the early stage of injection and hence optimal well spacing should also form the basic development criteria for a given field.

1. Recommendations

The efficiency of steam injection is basically dependent on the effective SQ generated. To generate a high SQ especially in relatively deep wells, the only option has been to effectively thermally insulate the tubing and the annulus which will make the steam injection project a non-attractive venture because of the increased cost of insulation. To compensate for this, a consideration can be made for sourcing the insulation materials locally using the materials in the table below:

Table.2: The Thermal Conductivities of Some Locally Sourced Insulation Materials

Material	Thermal Conductivity (W/m k)	Thermal Conductivity (Btu/Ft ^{0}F)
Shredded Asbestos Sheets	0.17	0.1115
Dry Ash	0.12	0.078744
Cork, Felt	0.05-0.10	0.0328 - 0.0.06562
Freon	0.0083	0.0054465

Moreover, the difficulty involved in integrating two unique simulators made the study more tedious. Based on this, the study only forms a framework of a future integrated steam injection simulator which can be more efficient. Hence, this research work welcomes any idea on the development of a fully integrated steam injection model/simulator.

As part of the above recommendation, such proposed simulator should be able to auto-calculate the overall heat transfer coefficient based on the defined completion status. This is necessary to avoid unnecessary switching between the rigorous analytics involved in the estimation of the overall heat transfer coefficient that often requires a third party simulator.

2. Contributions to Knowledge

This study provides a frame work for the complete optimization of steam injection design and as such constitutes a novel approach to steam injection modelling. Also very important to mention is the novel approach to the analysis of Reservoir Back Pressure impact on Steam Quality predicted during the steam injection processes.

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