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Modeling of Wellbore Heat Transfer in Geothermal Production Well

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ABSTRACT. Electricity supply in Nigeria has been insufficient to aid development. It has also been observed that fossil fuels that supply energy has not been friendly to the environment, as a result an alternative energy source is needed. Geothermal energy has come to fill this gap. This work modelled wellbore heat transfer in geothermal wells and investigated the best heat mining fluid that will conserve heat during heat transfer at the wellbore during heat production. This work employed the mechanisms that greenhouse gases use to absorb heat from the sun and retain it to warm the earth. Simulation of heat extraction capability of steam and CO_2 were studied. It was observed at reservoir conditions (248 ^{O}F) that steam Mass heat capacity (2.433 KJ/kg ^{O}F) is higher than that of CO_2 (1.088 KJ/kg ^{O}F). At 204. 8 ^{O}F mass heat capacity of CO_2 is 1.1915KJ/kg OF and that of steam is 2.4058 KJ/kg ^{O}F. This implies that steam retains more heat than CO2. From the study at wellbore fluid temperature of 276.8 ^{O}F, and at a flow rate of 1300 lb/hr, the wellbore heat transfer from steam (0.158 mmbtu/day) is slightly higher than that of CO_2 (0.105 mmbtu/day). CO_2 conserves more heat than steam when used as a heat transfer fluid. The heat transfer capabilities of the mining fluids determine the production capability of the heat resources and the quantity of electricity generation. The study recommended CO_2 deployment as heat mining fluid in the exploitation of heat in geothermal resources in Nigeria. This will reduce the greenhouse effect of CO_2 in our environment while also encouraging rapid development and economic growth, more especially with the rising cost of energy from fossil. Availability of geothermal energy will increase the supply of electricity in Nigeria.

Keywords: carbon dioxide, mining fluid, geothermal resources, wellbore heat transfer, temperature.

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1. Introduction

Wellbore heat transfer analysis is a critical and important factor in oil and gas and geothermal operations. Heat is transferred in the wellbore owing to fluid flowing from the reservoir to the surface. Heat transfer analysis becomes more critical in geothermal, oil and gas production when the operation involves high pressure high temperature (HPHT) wells [1,2] However, wellbore heat transfer analysis is more akin to geothermal wells. Heat transfer analysis encompasses operations such as drilling, completion, injection, and production. Geothermal system evaluations involve site exploration and resources assessment [3], extraction of the heat and conversion of heat energy to electrical energy. Proper understanding of heat flow which enables accurate estimation of heat production is necessary to maximize heat extraction from the reservoir. Simulation study conducted on geothermal energy in Nigeria reveals that geothermal resources hold great potentials for electrical energy generation and should be put to developmental use in Nigeria as a means to increase the total power generation and increase the portion of renewables in Nigeria energy value chain [4]. Nigeria has the potential of generating 74Megawatts of electricity from just one geothermal reservoir which could provide electricity for villages and small towns [5].

Geothermal resources may be classified as low temperature, medium temperature or high temperature depending on the quantity of heat store in the reservoir. In other word the heat contained in the reservoirs may be regarded as low potential, medium potential or high potential [6]. There are various surface evidences [7] like hot spring, volcanoes and geysers that necessitated the use of different exploration techniques [8] to establish the presence of geothermal resources in Nigeria. Some parameters like heat flux [9] was used in the assessment. The heat flux in Nigeria and its environs were shown in decreasing order of magnitude; Basement Complex, Anambra basin, Niger delta basin, Dahomey basin, Mid-Benue basin, Sokoto basin, Chad basin, Bida basin and Upper Benue basin.

In geothermal wells, fluid production is faced with continual heat transfer to the colder surrounding formation as it moves from the reservoir to the wellhead. Geothermal wells are characterized by lower reservoir pressure and higher reservoir temperature [10]. The high temperature creates stress on the walls of the production tubing during geofluid production [11]. As the fluid flows from the production depth up the tubing, heat is transferred from the fluid to the tubing, to the casing, cement and to the surrounding formation. The heat transfer in the wellbore due to wellbore fluid movement depends on the formation temperature, the difference in fluid temperature and the thermal properties of the media within the wellbore elements [12,13]. As heat is transferred, the temperature value of the lower temperature axis increases causing heat sink in the tubing. This corresponds to a reduction of the temperature of the geofluid in the tubing and a gradual heating of the surrounding media [14].

Depending on the rate of heat transfer, wellbore heat transfer which results to heating of the tubing and casing may present technical challenges related to the structural integrity of the tubing/casing system. Temperature increases results in higher induced pressure which may lead to burst/collapse.

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Wellbore heat transfer process can also affect the overall design of the well and affect many phases of the geothermal operations [15]. Thus, accurate modelling and simulation of wellbore heat transfer process is pivotal. This can be achieved by a comprehensive investigation of the heat transfer processes comprising all underlying heat balance and energy equations that characterize the heat flow [16,17].

This study evaluates wellbore heat analysis in geothermal wells. Effort is made to determine the wellbore fluid temperature at certain depths of the wellbore and the corresponding wellbore heat loss as the fluid flows from the production depth to any length up the tubing to the wellhead.

2 Wellbore heat loss and temperature estimation

With the established equations for wellbore heat transfer for injection and production wells relevant to oil and gas wells and geothermal wells, the equations were used to evaluate the heat transfer.

Let's consider a heat balance in the radial direction on a section of a well with height dz, losing heat at rate dq from the casing to the formation [15], such that

$$\frac{dq}{dz} = \frac{2\pi r_1 uk}{k + r_1 uf(t)}\left(T_f - T_e\right) \qquad 1$$

Where;

T_f is the temperature of the fluid in the tubing,

Te is the temperature of the formation,

k is the earth thermal conductivity,

r_1 is the inside radius of the tubing,

U is the over-all heat-transfer coefficient between the inside of the tubing and the outside of the casing Btu/hr ft^2 ^{O}F

f(t) is a dimensionless time function described by [15].

For a long time $f(t)$ can be given as

$$f(t) = -In\frac{r_2}{2(\alpha t)^{0.5}} - 0.290 \qquad 2$$

Where

r_2=is outside radius of the casing, ft

α is the thermal diffusivity of the earth in ft^2/day

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t is the production time in days.

According to [12], the changing fluid temperature in an injection well as it flows through the tubing is given as

$$T_f = az + b - aA + (T_o - b + aA)e^{\frac{-z}{A}} \qquad 3$$

Where

T_f is the temperature of the fluid in the tubing, °F

az + b = Te , the formation temperature (assuming linear geothermal gradient), ft

b is the surface temperature, °F

z is depth measured downward, ft

To is the injection temperature, °F

A is a group of variables defined as

$$A = \frac{wc(k + r_1 Uf(t)}{2\pi k r_1 U} \qquad 4$$

Where

w is the mass flow rate of the fluid, lb/hr

c is the specific heat of the fluid, Btu/lb-°F

k is the earth thermal conductivity, Btu/(hr ft °F)

r_1 is the inside radius of the tubing, ft

U= over-all heat transfer coefficient based on the outside tubing surface and the temperature difference between fluid and cement-formation interface, Btu/hr sq ft ^{O}F

Integrating equation 1 with respect to z at T_f=T_0 gives

$$q_{max} = \frac{2\pi r_1 Uk}{k + r_1 Uf(t)}(T_o - b)H - \frac{aH^2}{2} \qquad 5$$

By substituting the actual value of T_f from equation 2, the equation becomes

$$q = -wc\left[aH - (T_0 - aA - b)\left(1 - e^{\frac{-H}{A}}\right)\right] \qquad 6$$

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2.1 Production Well

In the case of a well producing hot fluid such as a geothermal well, the temperature of the fluid in the well as a function of height is given as

$$T_f = (T_0 - ay) + aA\left(1 - e^{\left(\frac{-y}{A}\right)}\right) \qquad 7$$

$$y = H - Z \qquad 8$$

$T_0 - ay$ = the temperature of the earth, °F

$T_0 =$ Temperature of the fluid entering the wellbore, °F

y is height above the producing depth, ft

H= the production depth, ft

Z= depth of consideration from the surface, ft

y= depth of interest from the production depth

Then, the maximum total heat flow rate from a well of depth H would be

$$q_{max} = \frac{\pi k a H^2}{f(t)} \qquad 9$$

However, the actual total heat flow is given as

$$q = awc\left[H + A\left(e^{\frac{-H}{A}} - 1\right)\right] \qquad 10$$

2.2 The overall heat transfer coefficient

Radial heat transfer occurs from the heat flow in the tubing to the surrounding formation, overcoming resistances offered by: the tubing wall, the tubing insulation, the tubing-casing annulus, the casing wall, and cement.

The overall heat transfer coefficient is given by U

$$U = (R_f + R_t + R_{ins} + R_a + R_c + R_{ce})^{-1}/r_{to} \qquad 11$$

$$\frac{1}{U} = \frac{r_{to}}{r_{ti}h_f} + \frac{r_{to}\ln\left(\frac{r_{to}}{r_{ti}}\right)}{k_t} + \frac{r_{to}\ln\left(\frac{r_{ins}}{r_{to}}\right)}{k_{ins}}$$

$$+ \frac{r_{io}}{r_{ins}(h_c + h_r)} + \frac{r_{to}In(\frac{r_{co}}{r_{ci}})}{k_{cas}} + \frac{r_{to}In(\frac{r_{cf}}{r_{co}})}{k_{cem}} \qquad 12$$

Where

r_{ti}= radius of inside tubing, ft

r_{to}= radius of outside tubing, ft

r_{ins}= radius of radius of tubing insulation, ft

r_{ci}= radius of inside casing, ft

r_{co}= radius of outside casing, ft

r_{cf}= radius of cement/formation interface, ft

k_t= the thermal conductivities of the tubing wall, Btu/(hr ft °F)

k_{ins}= the thermal conductivity of the tubing insulation, Btu/(hr ft °F)

k_{cas}= the thermal conductivities of the casing wall, Btu/(hr ft °F)

k_{cem}= the thermal conductivities of the cement, Btu/(hr ft °F)

h_f= the convective heat transfer coefficient between the fluid film in tubing and the tubing wall, Btu/(hr ft2 °F)

h_c= the convective heat transfer coefficients of fluid inside annulus, Btu/(hr ft2 °F)

h_r= the radial heat transfer coefficients of fluid inside annulus, Btu/(hr ft2 °F)

Equations 6 through 12 are used in the simulation study.

2.3 Simulation

The properties of the reservoir fluids such as mass density, mass heat capacity with varying reservoir temperature and pressure were determined using Hysys v11 software. The simulation of the wellbore heat transfer models was accomplished using MATLAB R2014 software. MATLAB scripts were written to account for the wellbore heat transfer, heat losses and the temperature of the fluid flowing from the reservoir to the surface at instant of time. Sensitivity analyses were performed to investigate the effects of fluid flowrate on the tubing fluid temperature and heat loss.

The simulation procedures are summarized in the block diagram below (Figure 1).

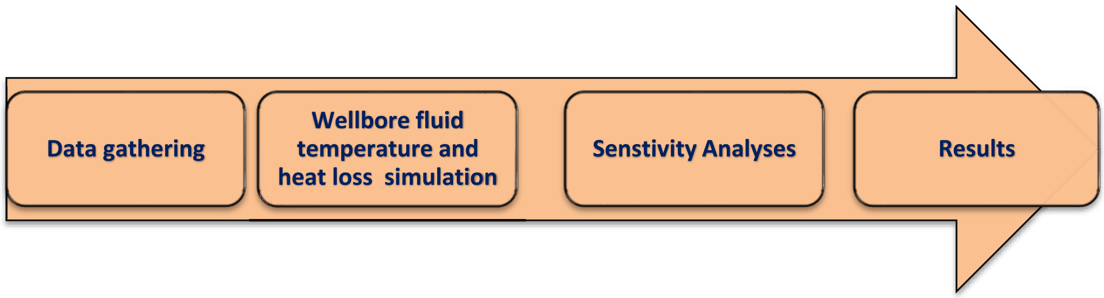

Figure 1: Simulation block diagram

2.4 GEOTHERMAL RESOURCES IN NIGERIA AND DATA GATHERING

This study identified seven geothermal fields as shown in table 1. These fields are rather low enthalpy geothermal reservoirs. The input data used for this simulation comprises the geothermal reservoir data for notable geothermal fields in Nigeria. Table 1 also gives the geothermal characteristics of notable geothermal fields in Nigeria, while Table 2 displays the other data used for the simulation.

Table 1: Geothermal Reservoir Properties

S/N	Location	Reservoir Temp. °C	Reservoir Temp, °F	Reservoir Pressure, psia	Well Depth, m	Well Depth, ft	Porosity, %	Area, m^2	Pay Thickness, m
1	URAN 1	122	248.75	3992	2438.4	8000	25	15	500
2	ANUA 1	112	230.94	3992	2438.4	8000	25	15	500
3	UGADA 1	82	178.05	3992	1828.8	6000	25	15	500
4	URAN 2	92	195.9	3992	1828.8	6000	25	15	500
5	ANUA 2	91	194.11	3992	1828.8	6000	25	15	500
6	TSEKELEWU	104	217.32	3992	1828.8	6000	25	15	500
7	ESCRAVOS BEACH	96	202.46	3992	2438.4	8000	25	15	500
8	FORCARDOS YORKI	102	213.14	3992	2438.4	8000	25	15	500
9	CENTRAL DELTA	58	134.82	3992	2438.4	8000	25	15	500
10	COASTAL AREA	58	134.82	3992	2438.4	8000	25	15	500
11	OFFSHORE	90	191.77	3992	2438.4	8000	25	15	500
12	NORTHERN DELTA	120	245.19	3992	2438.4	8000	25	15	500
13	ELEPA	98	206.02	3992	2438.4	8000	25	15	500
14	AGBADA	98	206.02	3992	2438.4	8000	25	15	500
15	UMUECHE M	98	206.02	3992	2438.4	8000	25	15	500
16	SOKOTO	139	279.83	3992	1828.3	6000	25	15	500
17	ANAMBR A	134	270.13	3992	2438.8	8000	25	15	500

Table 2: Other Simulation Data

Parameters	**Unit**	**Value**
The height of fluid from the producing depth	ft	8000
Thermal conductivity of the earth	Btu/hrft°F	1.4
The outside radius of the casing	ft	0.359375
Temperature at the cement formation interface	°F	
The outside radius of the tubing	ft	0.229166667
The inside radius of the tubing	ft	0.203833333
The radius of the tubing insulation	ft	0.291666667
The inside radius of the casing	ft	0.321875
The radius of the cement/formation interface	ft	0.447916667
The thermal conductivity of the tubing wall	Btu/hrft°F	24.95664

The thermal conductivity of the tubing insulation	Btu/hrft°F	0.011554
The thermal conductivity of the casing wall	Btu/hrft°F	24.95664
The thermal conductivity of the cement	btu/hrft°F	0.595031
Convective heat transfer coefficient b/w the fluid film in tubing and the tubing wall	Btu/(hr ft^2 °F)	99.9
Convective heat transfer coefficient of fluid inside annulus	Btu/(hr ft^2 °F)	99.9
Radiative heat transfer coefficients of fluid inside annulus	Btu/(hr ft^2 °F)	2
the production time	days	75
The thermal diffusivity of the earth	ft^2/day	0.96

3. Results and Discussion

The results of the heat transfer modeling and simulation are given in this section. Results show the variations of wellbore and wellhead temperature with the transfer fluids. The results of the analysis performed on transfer fluids in terms of heat capacity, mass density, wellbore fluid temperature and wellbore heat loss are given for steam and CO_2 as the wellbore fluid.

3.1 Heat Capacity

The heat capacity as a function of reservoir fluid for the various geothermal reservoirs is given in Figure 2.

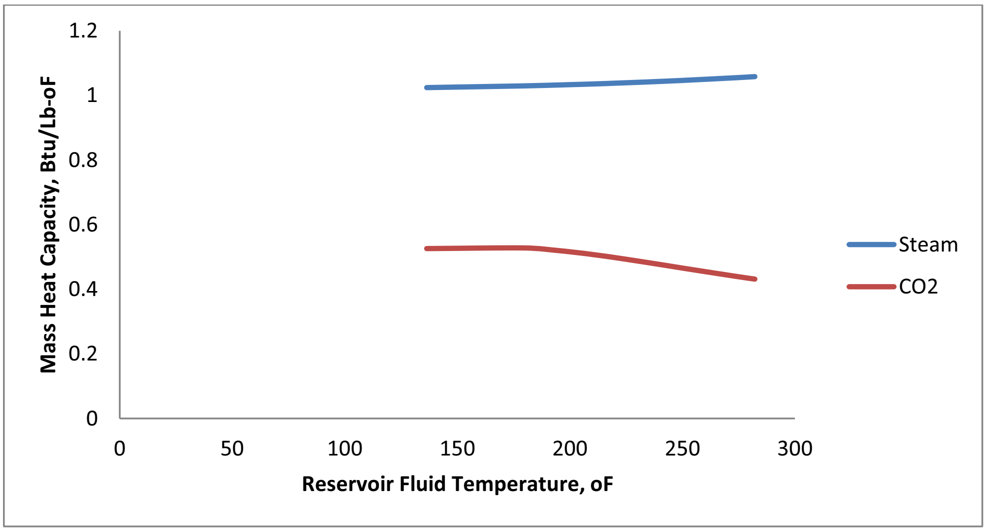

Figure 2: Heat capacity of geothermal wellbore fluids

Figure 2 shows the heat capacity at reservoir temperature and pressure corresponding to the geothermal fields. From Figure 2, it can be observed that steam heat capacity at reservoir condition is higher than that of CO_2. As the reservoir temperature increases above 194 ^{O}F, the heat capacity of water increased slightly while the heat capacity of CO_2 decreased at a faster rate. This implies that steam carries more heat than CO_2.

3.2 Mass Density

The mass density of the wellbore fluid due to difference in reservoir temperature is shown in Figure 3.

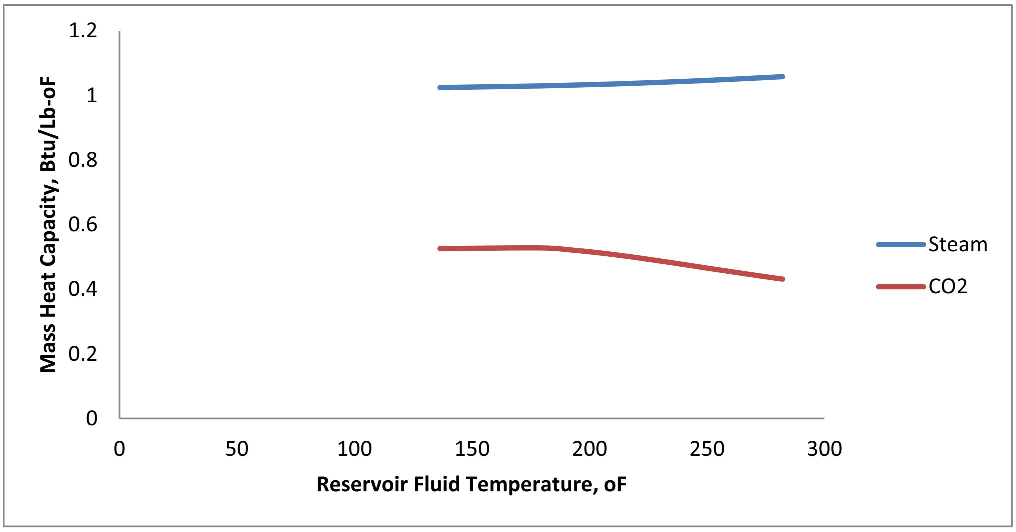

Figure 3: Mass density of geothermal extraction fluids

Figure 3 shows the mass density of the geothermal extraction fluids at equilibrium conditions in the reservoir. The geothermal extraction fluids are injected into the reservoir from the surface to extract the heat from the reservoir. At equilibrium conditions in the reservoir, the temperature of the reservoir equals the temperature of the injected fluids.

It can be seen from Figure 3 that the mass density of steam is higher than that of CO_2 at reservoir conditions.

3.3 Wellbore Fluid Temperature

The wellbore fluid temperature result is presented in this section. The point of consideration is at the wellhead. The wellhead temperature corresponds to the final temperature of the heat extraction fluid (steam or CO_2) from the reservoir. at reservoir. The fluid at the wellhead has lost some of its heat to the surrounding formations via the tubing, the casing, and the cement interfaces. The temperature of heat extraction fluid at the wellhead signifies the reduced temperature after heat loss has occurred. Figure 3 and Figure 4 show the wellhead fluid temperatures with respect to reservoir temperature and geothermal fields respectively.

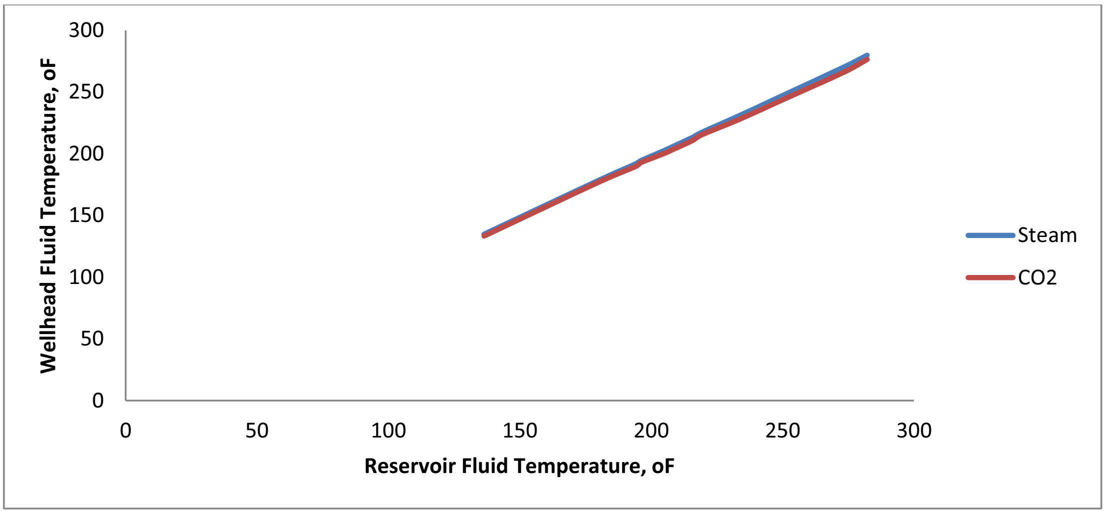

Figure 4: Geothermal extraction fluid temperature at the wellhead

Figure 4 shows the temperature of the two geothermal extraction fluids at the wellhead. It can be seen that although the temperature of the steam is higher than that of CO_2, the difference is very minimal. This shows that the heat loss due to steam flow and CO_2 flow in the wellbore are almost equal with minimal differences. It can also be seen that for both steam and CO_2 fluid flow the difference in the wellhead temperature from the reservoir temperature is not profound. The maximum difference in temperature from the geothermal extraction fluid between the reservoir and the wellhead is 3.07^0F for steam and 7.27^0F for CO_2. This corresponds to Anambra geothermal field with a depth of 8000ft and reservoir temperature of 273.2^0F.

Figure 5 shows the fluid wellhead temperature corresponding to the geothermal extraction fluid (steam and CO_2) from several geothermal fields in Nigeria.

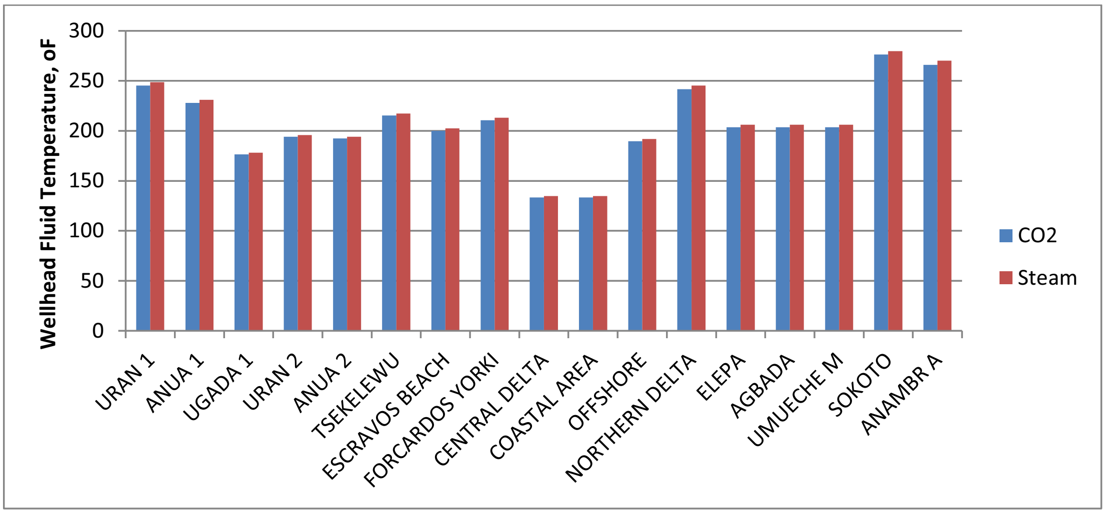

Figure 5: Fluid Wellhead Temperature of geothermal fluids from several geothermal fields in Nigeria

From Figure 5, it can be observed that for each of the geothermal fields in Nigeria, the temperature of steam geofluid at the wellhead is slightly higher than that of CO_2. Thus, there was higher temperature reduction from the CO_2 than steam.

3.4 Wellbore Heat Transfer

The wellbore heat loss corresponds to the amount of thermal energy transfer from the wellbore fluid to the surrounding formation as the fluid moves from the production depth up the tubing to the wellhead. Heat is transferred by conduction, convection, radiation and their combinations. Figure 6 shows the wellbore heat loss corresponding to steam and CO_2 geothermal fluids with regard to several geothermal reservoir temperature characteristic of the geothermal fields in Nigeria.

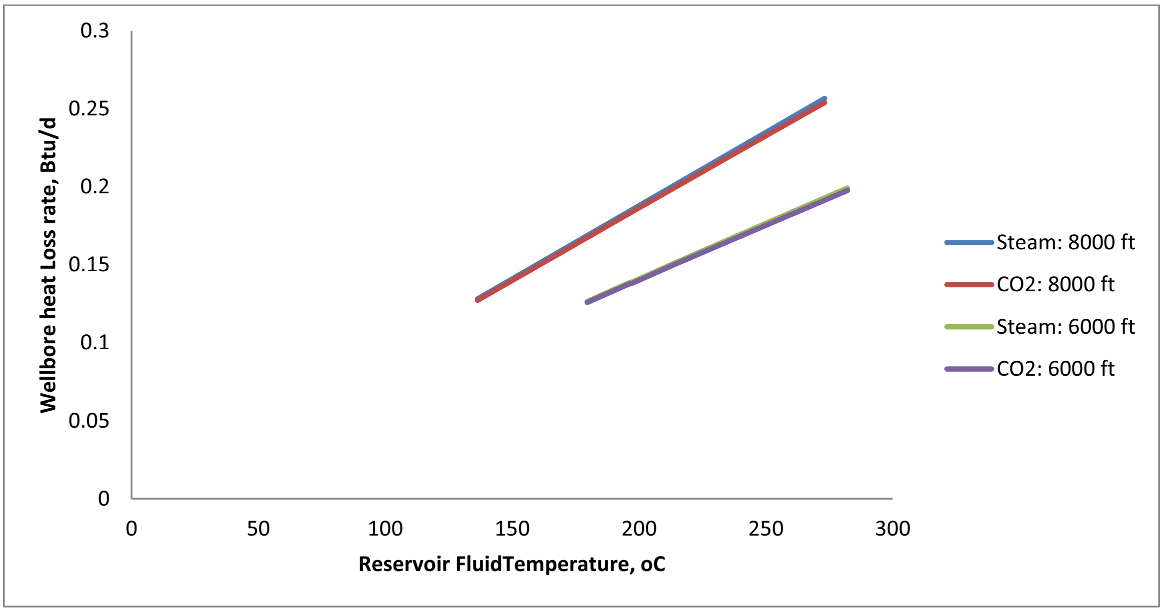

Figure 6: Wellbore heat loss

From Figure 6 it can be observed that the wellbore heat loss from steam is slightly higher than that of CO_2. This is because steam has higher mass heat capacity than CO_2. Thus, steam loses more heat per unit reduction in temperature to the surrounding formation than CO_2. This implies that CO_2 conserves more heat than steam when used as a heat mining fluid or heat transfer fluid and as such it is a better heat mining fluid.

Comparative analyses of Figure 4 and Figure 6 reveals that higher temperature drop does not necessarily imply higher heat loss as the intrinsic factors of the fluid such as the mass heat capacity is crucial in determination of the wellbore heat loss. The temperature drop from CO_2 was higher than that of steam, but the wellbore heat loss from steam geofluid is higher than that of CO_2 due to higher mass heat capacity of steam than CO_2.

The wellbore heat loss for geofluids from the geothermal fluids in Nigeria is shown in Figure 7

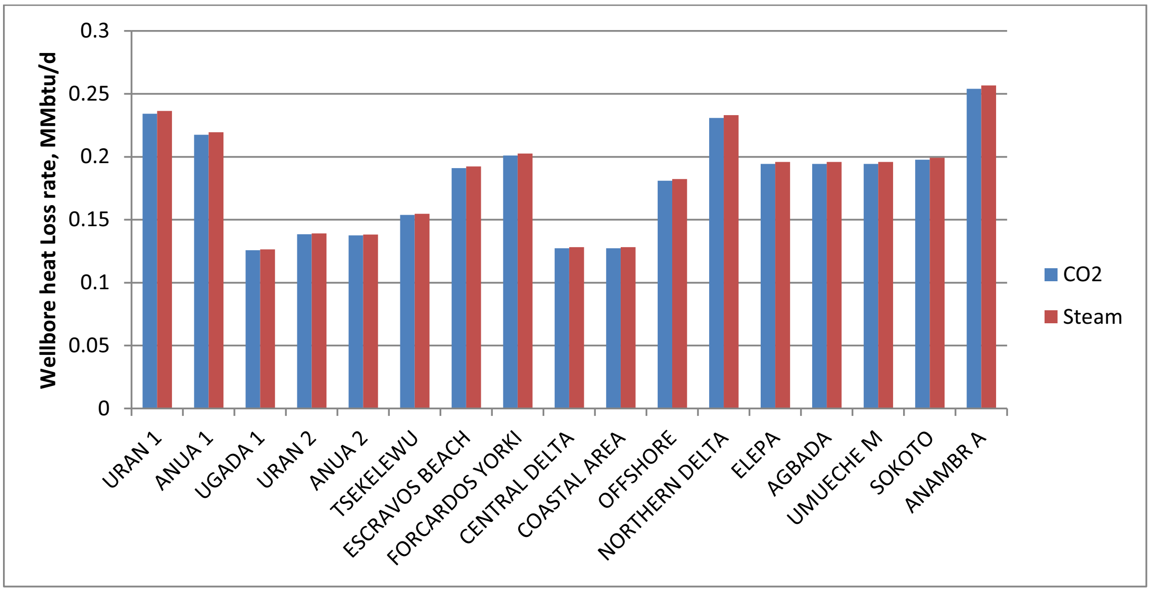

Figure 7: Wellbore heat loss from geothermal fields in Nigeria.

From Figure 7, it can be seen that wellbore heat loss for steam is slightly higher than that of CO_2 geofluid for all geothermal fields studied in Nigeria that were investigated. This shows that CO_2 is a better geothermal heat extraction fluid than steam because of the lower heat loss rate.

3.5 Sensitivity Analyses

Sensitivity analyses were performed to investigate the effect of mass flowrate of heat transfer fluids on the wellhead temperature of the fluid and the wellbore heat loss. For base case, the mass flowrate of steam was kept constant at 79366 lbs/hr (10kg/s). Sensitivity analyses consider the variation of the wellhead fluid temperature and wellbore heat loss over mass flowrate of transfer fluids in the range of 100 to 100,000 lbs/hr.

Figure 8 shows the effect of heat transfer fluid mass flowrate on the geofluid temperature at the wellhead for reservoir temperature of 122°C. It can be seen that the wellhead temperature of the steam and CO_2 geofluids increases with increase in mass flowrates. The geothermal fluid wellhead temperatures corresponding to mass flowrate is critical to analyze the variations in fluid wellhead temperature corresponding to changing mass flowrate.

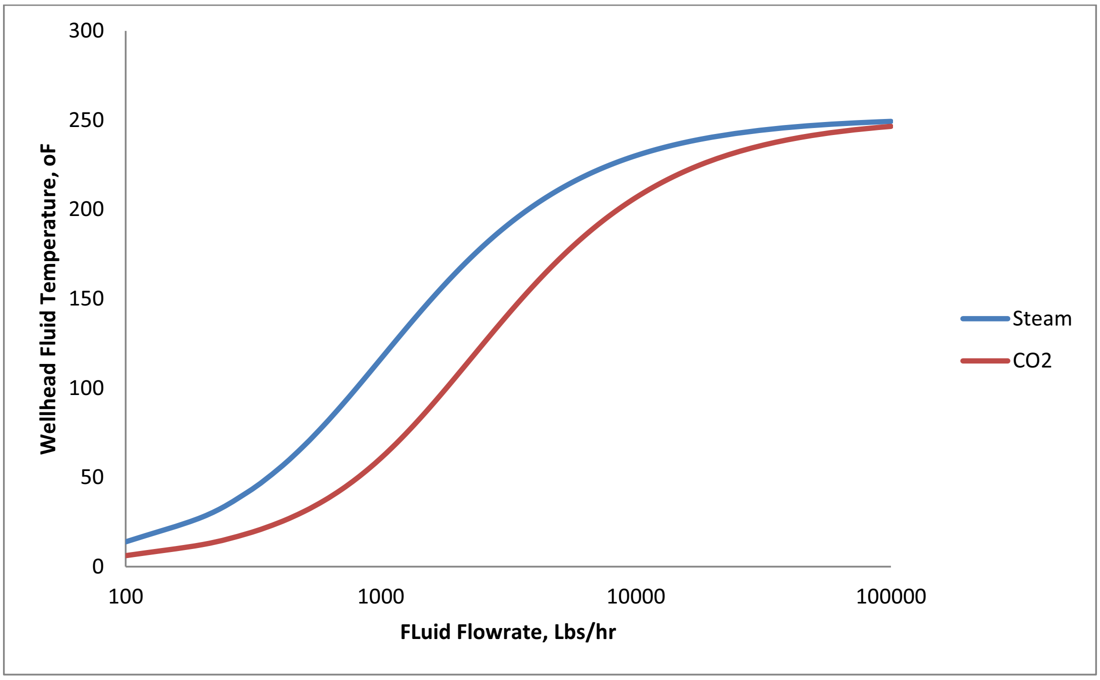

Figure 8: Effect of geofluid mass flowrate on geofluid wellhead temperature

Thus, it can be seen that to achieve higher fluid wellhead temperature, the mass flowrate of the fluid should be increased. It can also be observed that for the varying mass flowrate, the wellhead temperature of the steam geofluid is higher than that of CO_2. The disparity in the wellhead temperatures of steam and CO_2 geofluid corresponding to their varying mass flowrate is smaller at the extremes than at the middle flowrate. For instance, the wellhead temperature difference between steam and CO_2 at mass flowrate of 100 lbs/ hr and 100,000 lbs/hr are 7.73^{o}F and 2.79^oF respectively. However, at 1000 lb/hr and 10,000 lbs/hr mass flowrate of geofluid, the difference in wellhead temperatures between the steam and the CO_2 geofluids are 55.58^{o}F and 23.49^{o}F respectively.

Figure 9 shows the effect of the mass flowrate of geofluids on wellbore heat loss as well as the wellbore heat loss corresponding to varying mass flowrate of steam and CO_2 geofluid at 122^{o}C.

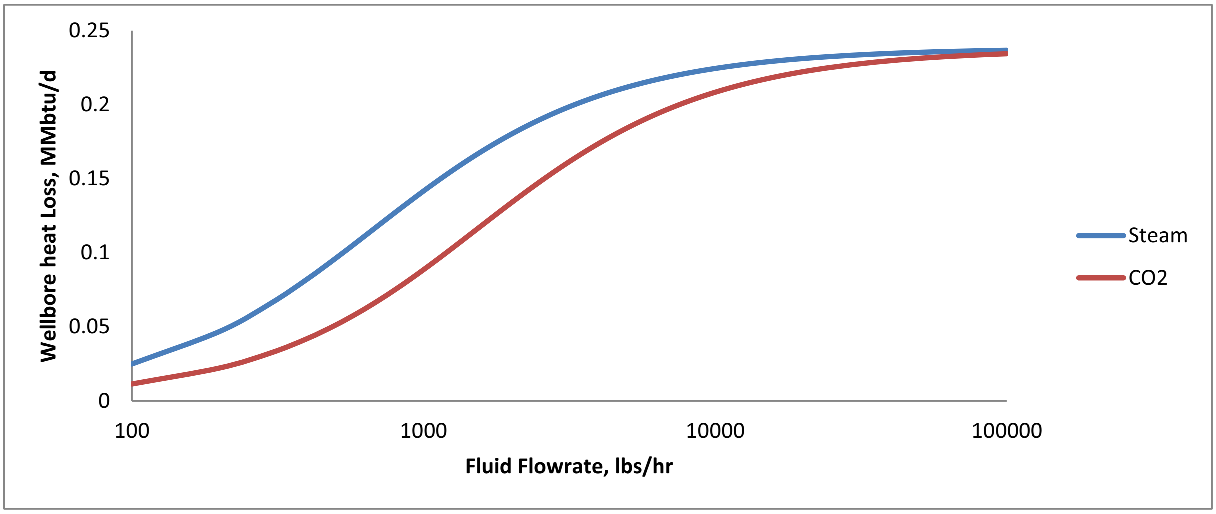

Figure 9: Effect of geofluid mass flowrate on wellbore heat loss

From Figure 9, it can be observed that the wellbore heat loss for steam and CO_2 geofluids all increased with increase in their mass flowrates. This means that the higher the mass flowrates of the geofluid, the higher the wellbore heat loss. However, it was observed that steam geofluid had higher wellbore heat loss than CO_2 for varying mass flowrates. Similar to figure 8, the difference in wellbore heat loss for steam and CO_2 geofluids corresponding to mass flowrates was lower at the extreme mass flowrates than at the middle.

4. Conclusion

Heat transfer analyses for geothermal fluid production have been investigated. Models were developed to account for wellhead fluid temperature and wellbore heat loss corresponding to different geofluids used for heat mining from the geothermal resource. Several geothermal fields in Nigeria were assessed to determine their wellbore heat transfer responses to geothermal fluids during geothermal exploitation. From the study, the following conclusions were reached.

1. Both CO_2 and steam show characteristically good performance as geofluids for geothermal heat extractions from geothermal resource
2. Geothermal fields in Nigeria are characteristically low and medium temperature resources. So, heat management is a crucial issue. However, if the heat is effectively exploited could address the energy needs of Nigeria to a large extent [3].
3. The temperature of the geofluid decreases as the fluid moves from the production depth to the wellhead. The extent of temperature difference depends on factors such as reservoir

temperature of the fluid, temperature difference between the fluid and the geothermal temperature of the surrounding formation, the insulations used and the depth of the reservoir.

4. Heat is transferred to the surrounding colder formations as fluid flows from the reservoir via the wellbore to the wellhead.
5. The fluid wellhead temperature for steam is higher than that of CO_2 at the same well depth and reservoir temperatures.
6. The wellbore heat loss for steam is higher than that of CO_2 for same well depth and reservoir temperatures. Thus, CO_2 conserves more heat than steam as geofluid
7. CO2 conserves more heat than steam when used as a heat transfer fluid.
8. Both the wellhead temperature and wellbore heat loss increase with increase in the mass flowrate of the geothermal extraction fluids.

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