2-Dimensional Modeling of Hot Water Injection Application in Thermal Recovery Processes, (A Frontal Advance Approach).

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Abstract— The frontal advance equation developed by Buckley-Leveret which is most widely used for the modeling of immiscible fluid displacement is analyzed in 2- dimensions for this study. The investigation takes into account the injection of hot water at a temperature of 250^{O}F and the recovery mechanism is modeled as a thermal process. Some thermal parameters of the reservoir rock and fluid system are incorporated into the B-L equation under a variety of assumptions and the resulting predictive model showed that a farther radius of invasion as well as improved heavy oil mobility is achieved when compared to conventional waterflooding process. A sensitivity analysis conducted also revealed that heavy crude viscosity reduces significantly with increase in the temperature of injected hot water. Percentage oil recovery and fluid saturation profiles after this process showed that hot water injection can be an alternative for convectional water injection as it tackles a variety of oil mobility difficulties.

Index Terms— Buckley-Leveret, Enhanced Oil Recovery, Frontal Advance Equation, Heavy crude, Hot water Injection, Thermal recovery, viscosity reduction.

1 INTRODUCTION

Some petroleum reservoirs can be produced from its natural energy over a long period of time, this is as a result of several environmental and petro-physical configurations inherent these reservoir systems. On the other hand, some reservoirs with large accumulations find it difficult to be naturally produced. When faced with these challenges, the engineer is charged with the responsibility of evaluating extremely cost effective and dynamic design criteria for production optimization of these reservoirs. Depending on the reservoir characteristics, suitable improved oil recovery methods are selected. For example, thermal recovery methods can be a good consideration for heavy crude recovery, surfactant flooding can be suitable for reservoir systems with high interfacial tension and most common being water injection for maximum volumetric sweep / pressure maintenance. For most enhanced oil recovery projects, a target fluid is usually injected at specific design requirements and a thorough evaluation of the mechanism by which one fluid is displaced by another in the reservoir is essential to the comprehension of the fundamental process by which oil is recovered.

For most water flooding processes which is generally considered to be an immiscible displacement mechanism, the frontal advance equation defined by Buckley – Leverett serves as a basis for the modeling and evaluation of a water flood performance in linear porous media [1], though applications are not limited to linear systems alone. The frontal advance equation defines the distance of the leading edge in an immiscible fluid displacement mechanism. Although most prominently used, assumptions for its development have limited the accuracy of its adaptation to extremely complex reservoir systems. The knowledge of the distance of the leading edge of the injected fluid (usually water) is very important in the prediction of expected water production over time. Water though denser than oil has the capacity to effectively maintain high level of volumetric sweep efficiency but in some cases, lacks the capacity to tackle certain inherent mobility dependent factors [1], [2].

Light oils are extracted under primary and secondary recovery methods which involve allowing the liquid to flow out under the natural pressure of its surrounding. These methods cannot be applied to the extraction of heavy oils, whose viscosity is far too high for such methods to be effective; their viscosity needs to be reduced. This is achieved by various thermal stimulation techniques like hot water flooding, steam injection, in-situ combustion and so on which raise the temperature of the oil [3].

In heavy crude reservoir systems found in tar sands of Venezuela, Canada, and Russia etc. with large accumulation of hydrocarbon deposits, water injection may not be considered as a displacing fluid by virtue of the low API gravity nature of the hydrocarbons. Displacement efficiency and overall mobility of the entire process may prove less productive. However, for such cases, thermal alterations in reservoir properties may be analyzed for significant oil recovery. Its considerations owe to the fact that the reservoir fluids lack the requisite transmissibility and hydraulic conductivity to make it producible. Application of heat to these distinct classes of reservoir systems will help alter the petro-physical properties of the reservoir rock and fluids, making these fluids more mobile by means of viscosity and interfacial tension reduction [4].

The reservoirs of heavy oil are shallow and have less effective seals (up to 1000 meters below the surface line), which is the reason for the low reservoir temperature (40-60 °C) [5]. Low sedimentary overburden tends to ease the biodegradation, and the presence of the bottom aquifers further facilitates the process. Less effective seal is due to the low seal pressure, which may cause the dissolved gases to leave the oil, increasing its viscosity [5], [6]. The reservoir lithology is usually sandstones deposited as turbidity with high porosity and permeability; the elevated viscosity is compensated by high permeability. [4], [6]

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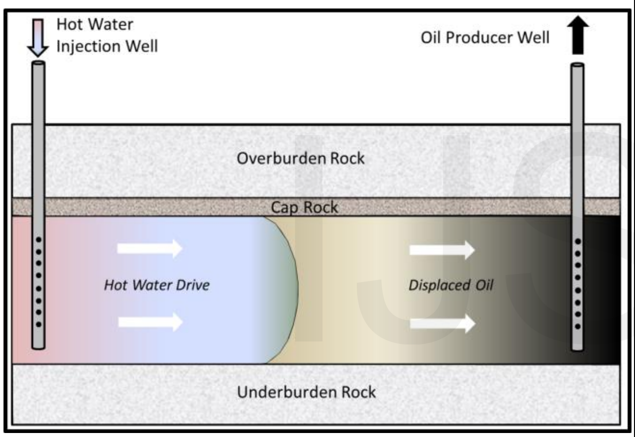

Fig. 1. Schematics of hot water injection process (Zargar, 2013)

The importance of the knowledge of thermal properties of the surrounding rock in heat application is obvious. Rocks need to be sufficiently conductive to prevent excessive energy loss, this is as important as their thermal expansion characteristics in the process. Because of the multi-mineral composition of rocks, heating causes micro-fracturing due to differential thermal expansion of mineral grains. [3], [7].

2 RESEARCH METHODOLOGY

2.1 Mathematical Modeling for Determination of the Heating Front of injected water in x and y Coordinates

Recall a material balance evaluation of a linear media undergoing fluid injection;

Volumetric Entry – Volumetric Exit = Volumetric Accumulation (1)

Volumetric Entry = $q_t\, f_{hw}\, dt$ (1a)

Volumetric Exit = $q_t\,(f_{hw} - df_{hw})\, dt$ (1b)

Volumetric Accumulation = $(\emptyset\, A\, \Delta x\, dS_w) / 5.615$ (1c)

Equation 1 now becomes;

$$q_t . f_{hw} . dt - q_t (f_w - df_w)\, dt$$
$$= q_t . f_{hw} . dt - q_t (f_w - df_w)\, dt = (\emptyset\, A\, \Delta x\, dS_w) / 5.615 \quad (2)$$

The above equation is the classical B-L account for material balance and can be simplified into;

$$q_t . f_w . dt = \frac{\emptyset\, A\, \Delta x\, dS_w}{5.615} \quad (3)$$

On the assumption of a thermal recovery process, hot water injection is done in place of water and the accumulation term of the volumetric balance equation determines the efficiency of the process.

The volumetric heat capacity C_{th} of the system in (Btu/lb °F), the thermal conductivity of the dead oil, K_{ho} in (Btu/ft-hr °F), dead oil viscosity, μ_O in cp from Beggs-Robinson correlation and reservoir thickness in (ft) are all inherent factors that influence heavy oil mobilization. The composite combination coefficient is given as;

$$K_{ho}\, k/\mu_0'\, h\ \ C_{th} \quad (4)$$

Where,

$$1.62\,(1-3)(T-32) \times 10^{-4}/\gamma_o \quad (5)$$
$$\gamma_o = 141.5/(131.5+API)$$

$$\mu_0' = A.\, \mu_{OD}^{B} \quad (6)$$
$$\mu_{OD} = 10^{x} - 1$$
$$X = YT^{-1.163}$$
$$Y = 10^{Z}$$
$$Z = 3.0324 - 0.02023\gamma_o$$
$$A = 10.715\,(R_s + 100)^{-0.515}$$
$$B = 5.44\,(R_s + 150)^{-0.338}$$

Where R_s is measured GOR (Scf/Stb).

The expanded volumetric heat capacity is given as;

$$C_{th} =$$
$$(1-\emptyset)(\,0.00006T + 0.18\,)\rho_r + \emptyset\left(S_o\rho_o\left(\frac{(0.388+0.000043\,T}{\sqrt{\frac{141.5}{131.5+API} - \frac{0.3444T-11.022}{1000}}}\right) + S_w\rho_w(1.0504 - 605 \times 10^{-4}T + 1.79 \times 10^{-6}T)\right) + \emptyset S_g\left[f\,\rho_g c_g + (1-f)\left(\frac{\rho_s L_v}{\Delta T}\right) + \rho_s(1.0504 - 605 \times 10^{-4}T + 1.79 \times 10^{-6}T)\right] \quad (7)$$

Simplifying the above equation, we obtain;

$$C_{th} = (1-\emptyset)c_r\rho_r + \emptyset(S_o\rho_o c_o + S_w\rho_w c_w) + \emptyset S_g\left[f\rho_g c_g + (1-f)\left(\frac{\rho_s L_v}{\Delta T}\right) + \rho_s c_w\right] \quad (8)$$

Where the heat capacity of oil water and gas is defined as;

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$C_r = 0.00006T + 0.18$

$c_w = 1.0504 - 605 \times 10^{-4}T + 1.79 \times 10^{-6}T$

$$c_o = \frac{(0.388+0.000043\ T}{\sqrt{\frac{141.5}{131.5+API} - \frac{0.3444T-11.022}{1000}}}$$

c_o can also be deduced from charts at corresponding temperatures and API.

The driving force is a function of the ratio of the pressure of the injected steam P_{inj} to the thermal resistance of the system β_s.

Hence, Equation (4) becomes;

$$\frac{\lambda_{ho}\ k\ P_{inj}}{\mu_0'\ h\ C_{th}\ \beta_s} \tag{9}$$

Recall frontal advance volumetric balance in Eqn (3) and combining with equation (9), we obtain;

$$q_t \cdot df_{hw} \cdot dt = \frac{\emptyset\ A\ dx\ \lambda_{ho}\ k\ t_{max}^2\ A'\ P_{inj}\ dS_w}{5.615\ \mu_o'\ h\ C_{th}\ \beta_s} \tag{10}$$

The above now becomes

$$q_t \cdot df_{hw} \cdot dt\ \ \mu'_o\ h\ C_{th}\ \beta_s \cdot 5.615 = \emptyset\ A\ dx\ K_{ho} \cdot k \cdot t_{max}^2\ A'\ P_{inj} .dS_w \tag{11}$$

In terms of injected hot water velocity, water fraction – saturation ratio;

$$\frac{df_{hw}}{dSw} = 5.615\ (q_t \cdot dt\ \mu'_o\ h\ C_{th}\ \beta_s) = \emptyset\ A\ dx\ \lambda_{ho} \cdot k\ t_{max}^2\ A' \cdot P_{inj}\ \frac{dx}{dt} \tag{12}$$

Therefore,

$$\frac{dx}{dt} = \frac{5.615\ q_t\ h\ C_{ho}\ \beta_s\ \mu'_o}{\emptyset\ A\ \lambda_{ho}\ t_{max}^2\ A'\ k\ P_{inj}} \cdot \frac{dfw}{dSw} \tag{13}$$

A thorough investigation of the distance covered by the heating front of the injected hot water in the x-coordinate will serve as an important criterion for the prediction of expected water production. Therefore, to account for distance covered, we integrate Equation (13) as defined by Buckley-Leveret, Hence:

$$\int_0^x dx = \frac{5.615\ q_t\ dt\ h\ C_{ho} \beta_s\ \mu'_o}{\emptyset\ A\ \lambda_{ho}\ t_{max}^2\ A'\ k\ P_{inj}}\ \ \frac{df_{hw}}{dSw} \int_0^x dt$$

$$x_{hf} = \frac{5.615\ q_t\ t\ h\ C_{ho}\ \beta_s}{\emptyset\ A\ \lambda_{ho}\ t_{max}^2\ A'\ k\ P_{inj}} \cdot \frac{df_{hw}}{dSw} \tag{14}$$

q_t = Injection rate of 250 °F hot water (bbl/day)

t = Time of investigation, (days)

μ'_o = Corrected Heavy oil Viscosity (cp)

h =Net pay thickness of tar sand, ft

β_s = Thermal resistance of Reservoir Sand inverse of thermal diffusivity (day/ft²)

A and A′ = Reservoir Area and wellbore area respectively (ft²)

t_{max} = Maximum injection period (days)

$\emptyset$ = formation porosity

λ_{ho} = Thermal conductivity of heavy oil (Btu/lb-hr-°F)

k = Reservoir Horizontal Permeability (mD)

P_{inj} = Pressure of injected hot water (psia)

X_{hf} = distance of the heated front (ft)

For y-coordinate,

$$Y_{hf} = X_{hf} \frac{P_i}{g.\ \rho_{hw}\ \sin\alpha} \tag{15}$$

3 RESULTS AND DISCUSSION

After an appropriate resolution and validation of model equation, a thorough comprehension of the thermal process was achieved. Results from this investigation were compared to that of a conventional water injection process. It was observed that due to the temperature of the injected hot water, the thermal properties of the reservoir rock system can be altered to achieve a better sweep. This inference was drawn based on the fact that the distance of the leading edge (heated front) was farther away from the injector as compared to that of conventional water injection.

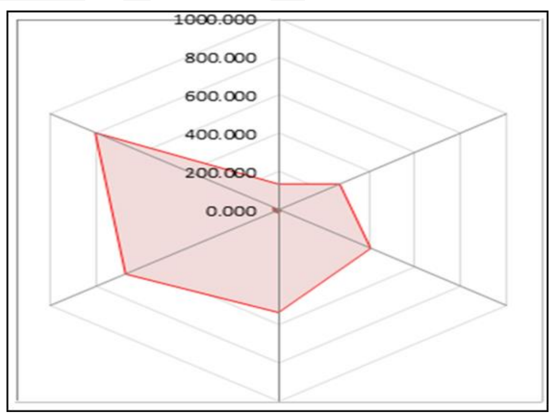

Fig. 2. Simulated Plan View of Reservoir Undergoing Hot Water Injection

Figure 2 shows that after a period of 5 through 30days of hot water injection. From the results, the distance of the heated front from the injector was about 623ft away from the injector after 30 days of continuous hot water injection. By virtue of the heat in the water and mass balance principles, the heated area originally tends to replace the displaced hydrocarbon occupied by heavy oil. This displacement tends to push the less viscous components further towards the producer. Water injection also shows the same profile but records a lower radius of invasion when compared to hot water injection. The water injection profile is shown in figure-3 with the injector well at point-0

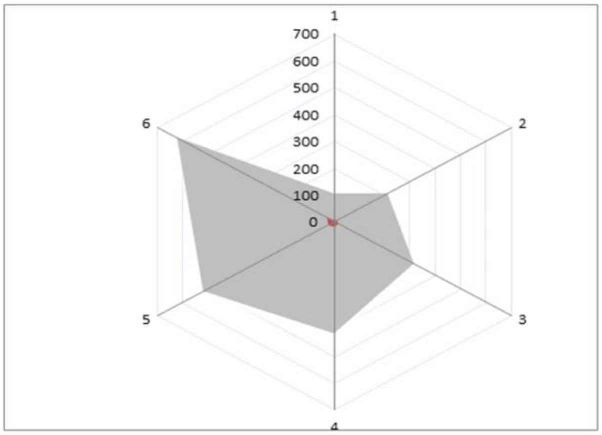

Fig. 3. Simulated Plan View of the Reservoir Undergoing Water Injection.

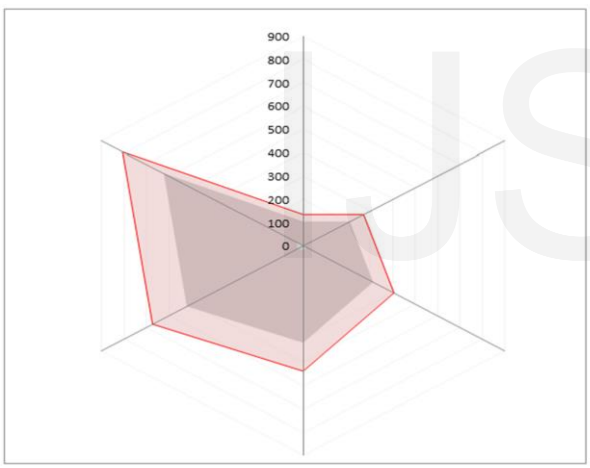

Fig. 4. Simulated Plan View of the Reservoir Showing a Comparison of Displaced Fronts for water and Hot water Injection Processes.

The differences in both methods are explicitly presented in Figure 4. It shows the supremacy of the heated water over ordinary water injection. The greater the magnitude of heavy oil displacement, the higher the tendency of an increase fluid mobility. The maximum displacement of the reservoir fluid for the water injection process after 30 days of water injection was about 447ft away from the injection well. This phenomenon can be traceable to the fact that water can displace oil by virtue of its injected pressure and its higher density, but has little or no control over other mobility dependent factors such as the hydraulic conductivity of the formation, heavy crude viscosity and others.

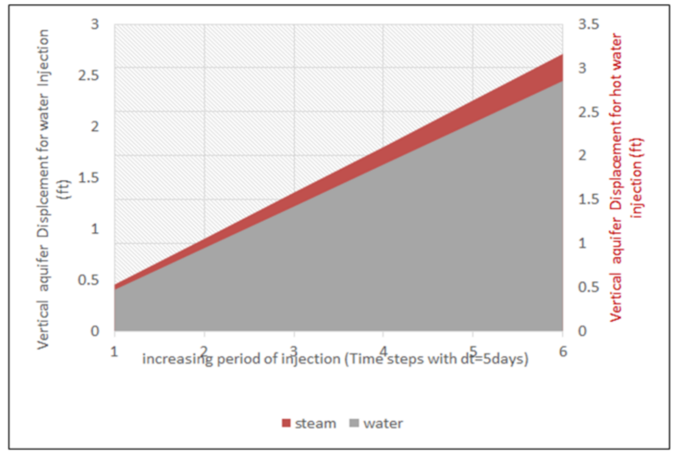

Fig. 5. Vertical Displacement of Heavy Oil

For the y-coordinate system, the effect thermal alteration in the system with respect to vertical displacement was almost insignificant. This was the case as well for the convectional water injection process. This observation outlines the fact that the B-L equation is limited only to horizontal displacement during flooding and the model is not valid for the assumption of a vertical displacement. However, the insignificance of thermal alteration of thee displacing fluid in the y-coordinate can be traceable to the fact that energy is lost to the underlying aquifer and as such possesses a driving force equivalent to that of a normal water injection process. From figure 5, it is observed that the difference in vertical displacement for both methods record just about 0.3ft.

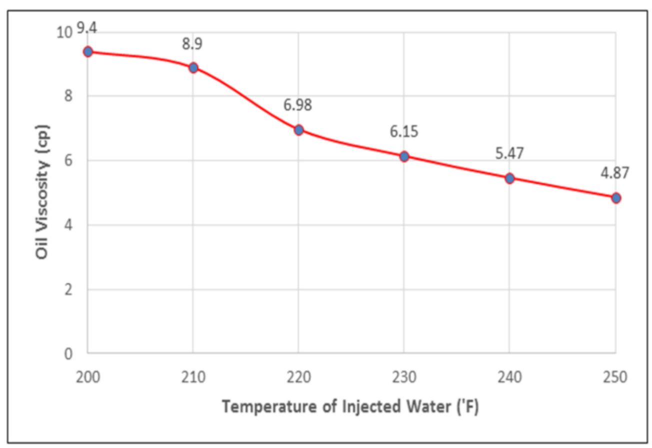

Fig. 6. Viscosity Reduction with Temperature Increase

A sensitivity analysis to ascertain effects of temperature variation on the heavy oil viscosity was conducted. This was done by altering the temperature dependent variable in the model using a temperature range of from 200°F to 250°F. it was observed that the higher the temperature, the lower the heavy oil viscosity and the more the tendency of its productivity. The temperature – viscosity variation is presented in figure 6 as shown..

Table 2 of appendix shows the relationship of several thermal dependent properties on variations in temperature of the injected water. Viscosity of the heavy oil vary inversely with temperature increase. However, volumetric heat capacity, C_{th} was observed to have be directly proportional to temperature increment.

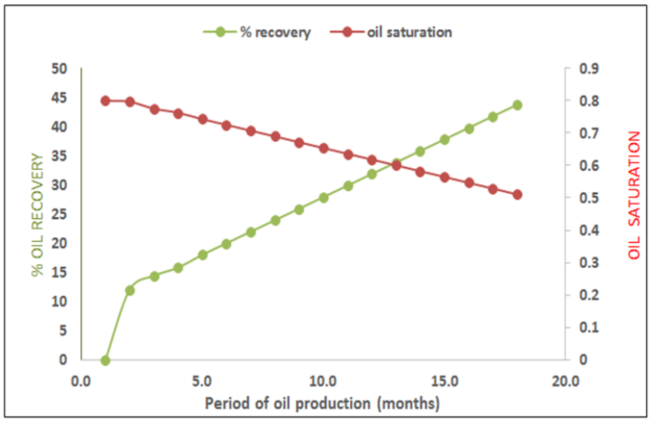

Fig. 7. Percentage Oil Recovery Increase and Oil Saturation Decline with Time.

Since the process is a combination of immiscible fluid displacement and predominantly a thermal recovery process, in terms of drive indices, a bulk of the percentage will be owed to the contribution of fluid expansion. The rock and formation compressibility drive may also contribute to the overall energy investigation. The vertical and horizontal water displacement mechanism may also be credited, but to an almost insignificant degree. An MBAL simulator was used for the drive energy analysis. The MBAL simulation shows about 90% fluid expansion contribution with little or no contribution from water influx. Figure 7 above shows how recovery factor increases with decreasing oil saturation with respect to time, assuming a forecast is to be made for an 18 month of production.

4 CONCLUSION

The results obtained from this study have shown that hot water injection can be a prospective recovery method if all design considerations meets the requisite reservoir demands. Numerical computations have established that for every linear displacement of oil by water flooding, an estimate of 28.75% additional unit displacement can be achieved by hot water injection. It has also been established that about 52.10% reduction in oil viscosity can be achieved when using hot water with a temperature of 250^{o}F when compared to a 200^{o}F water. This is to say that the higher the temperature of the water, the lower the viscosity of the heavy crude acted upon. However, sound thermal investigation of these rock – fluid systems must be thoroughly outlined so as to establish recovery applications within the thermal tolerances of these systems.

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APPENDIX

TABLE 1
LINEAR DISPLACEMENT OF HEAVY OIL BY THE HEATING FRONT IN BOTH X AND Y COORDINATES

Hot Water Injection			Water injection		
t in Days	X (ft)	Y (ft)	t in Days	X (ft)	Y (ft)
5	134.00	0.533	5	103.98	0.406
10	269.26	1.053	10	207.90	0.813
15	404.69	1.581	15	311.9	1.219
20	538.09	2.100	20	415.96	1.630
25	673.00	2.632	25	519.90	2.037
30	807.00	3.162	30	623.33	2.446

TABLE 2
SENSITIVITY ANALYSIS SHOWING EFFECT OF TEMPERATURE VARIATION ON HEAVY OIL VISCOSITY AND VOLUMETRIC HEAT CAPACITY.

T (°F)	μ (cp)	C_{th} (Btu/lb°F)
200	9.40	34.007
210	8.90	34.080
220	6.98	34.091
230	6.15	34.101
240	5.47	34.108
250	4.87	34.120

q_t = 100 BPD, h =50ft, $\emptyset = 0.21$, A = 200 ft^2, k = 80mD, P_{inj} = 1800psi., P_i = 3000psi, API = 11.5°, ρ_{hw} = 63.96 lb/ft^3 , R_s = 200 scf/stb, C_r =, 0.225, C_o = 0.415, C_g = 0.621, S_{wi} =0.1, S_{gi} = 0.1, S_{oi} = 0.8,

L_v = 4.67, $\beta_s = 1.5267$ ft^2/day

ρ_o , ρ_w , ρ_g ρ_s = Densities (lb/ft^3)

$B = 5.44\,(200 + 150)^{-0.388} = 0.560$

$A = 10.715\,(200 + 100)^{-0.515} = 0.570$

$Z = 3.0324 - 0.02023\gamma_o = 3.0124$

$\gamma_o = \frac{141.5}{131.5+11.5} = 0.9898$

$Y = 10^z$

$X = YT^{-1.163} = 1.6733$

$\mu_{oD} = 10^x - 1 = 46.132$cp

$\mu_o' = 0.570(46.132)^{0.562} = 4.87$cp

$$\lambda_{ho} = \frac{(1-3(250-32)\times10^{-4})1.62}{0.9895} = 1.530 \text{ Btu/ft-hr-°F}$$

$C_{th} = (1-0.21)\, 0.225\times137 + 0.21/0.10\times61.75\times0.415 + 0.18\times 62.4 \times 1) + 0.21\times 0.10\, [(0.5\times 25 \times 0.621) + (1-0.5)\left(\frac{137\times4.7}{250-100}\right) + 137 \times 1]$

= 34.12 Btu/lb-°F

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