Artificial Lift and Mobility Enhancement of Heavy Oil Reservoirs Utilizing a Renewable Energy-Powered Heating Element

Murtada Saleh Aljawad,* Saad Alafnan,* and Sidqi Abu-Khamsin

College of Petroleum Engineering & Geosciences, King Fahd University of Petroleum & Minerals, Dhahran 31261, Saudi Arabia

ABSTRACT: The improvement of heavy oil recovery by steam injection or electric heating has been investigated extensively. However, the potential benefit of placing a permanent heating element around the pay zone has not received significant attention. Previously, numerical models were mainly used to investigate improvements in reservoir fluid mobility but rarely when considering the impact of downhole heating on a wellbore’s vertical lift performance. In this study, a coupled mass and heat transfer model was developed and applied to a reservoir/wellbore system to investigate the impact of a heating element on recovery improvement. The numerical simulations showed that heat propagation due to the heating element did not exceed 10–15 ft while the reservoir’s fluids were being produced. However, much longer distances could be reached through heat conduction under shut-in conditions. It was determined that more than a 40% improvement in the productivity index could be achieved at low production rates. However, no productivity improvement was noticed under convection-dominated heat transfer, which occurs at relatively high production rates. A heating element could also reduce the flowing bottomhole pressure required in a wellbore by more than 200 psi, a result caused by a continuous temperature increase as the fluids flowed into the heated wellbore section.

INTRODUCTION

Heavy oil, which is comprised of highly viscous hydrocarbons that cannot be produced commercially under normal reservoir conditions, makes up a large portion of the world’s current reserves. Thermal alteration of the physical properties of heavy crude could aid in the exploitation of significant oil resources and thus in supplying the increasing global demand for energy.

Traditional thermally enhanced oil recovery (EOR), which includes steam injection, in situ oil combustion, and mining, are widely used for heavy crudes, supplying 3% of the world’s oil demand.1 When thermally stimulated, hydrocarbon properties such as density and viscosity change significantly, facilitating reservoir flow and increasing oil recovery.2−4 Increasing the temperature of heavy crudes from the typical reservoir temperature to 200−300 °F can reduce the oil’s viscosity by a few orders of magnitude, significantly enhancing inflow performance.5 Thermal EOR is an active area of research and development. Thermal methods currently in use and proven successful for the past few decades include hot water flooding, steam and immiscible CO2 injection, and in situ combustion. High porosity sand formations containing heavy and extra heavy crudes of API values less than 20 are the most suitable candidates for thermal EOR processes.6−9 The aforementioned techniques rely on heat transfer by injected or in situ partial burning of hydrocarbons. They require large capital investments, and applications are restricted by factors such as the target formation’s depth and thickness and other logistics.

Another family of thermal EOR utilizes electric current to directly heat a formation. This group includes resistive, radiofrequency, and inductive heating. Their impact on incremental recovery is not as significant as that of traditional methods, but they provide a means of enhancing productivity in situations where capital investments are unattainable or technical implementation of typical thermal EOR is impractical (e.g., offshore wells). Resistive heating employs a potential difference between two wells that occurs when one is acting as an electrode and the other, a cathode, with some water injected to improve heat conduction. A formation enclosed by two adjacent wells is subject to increases in temperature, and hence oil production can be enhanced.10 A similar principle can be applied when a downhole electrical heater is placed to heat hydrocarbons in close proximity to a well; compared with the steam-assisted gravity drainage (SAGD) process, this has shown some reasonable efficiency with a lower water-to-oil production ratio.11−14 Reservoir models and simulation studies have established the feasibility of downhole electrical heating.15,16 Laboratory work has also been conducted to experimentally study resistive heating.17 The radiofrequency heating approach involves converting electromagnetic waves into thermal energy in reservoirs assisted by organic solvent injection. This approach has the advantage of reducing water injection and carbon dioxide emissions. Downhole equipment design and high pressure/high temperature conditions are some of the limitations.18−23

Downhole electric heating accomplished by increasing the temperature of a permanently installed element can enhance...
hydrocarbon flow from the reservoir to the wellbore. Moreover, heated hydrocarbons have shown improved outflow performance from the wellbore to the surface, as both viscosity and density are reduced at elevated temperatures. The objective of the present research is to study the recovery enhancement obtained through continuous downhole heating of heavy and extra heavy oils by combining energy and mass balance simulations within the reservoir and from the wellbore to the surface.

## ELEMENT DESIGN

Subsurface heating of reservoir hydrocarbons for enhanced production can be achieved through an injected hot fluid (i.e., steam), focused electromagnetic radiations, or in situ conversion process ICP where the resistive element is supplied with electric current to raise its temperature. The element is in direct contact with the formation, and hence the fluids stored in the pores are subject to thermal gradient. Renewable energy can be utilized as the source of electric current for the sustainable and environmentally friendly process. Desired downhole temperature of the heating element can be used to quantify the required energy, which, in turn, can be translated into the surface design of the renewable system (i.e., number of windmills or surface area of solar panels). For modeling the conversion of solar radiation into electric current, several approaches are discussed in the literature. In general, the photovoltaic cell (PV) is used, which can be presented as shown in Figure 1. The heating element should be perforated to allow the fluid to flow from the reservoir to the wellbore. It also should be made of a material that can withstand harsh conditions (i.e., high pressure and temperature).

## MATHEMATICAL MODELS

The model assumed a section of homogenous and isotropic reservoir that contained a single-phase high viscosity oil. A vertical wellbore was placed in the formation and a perforated heating element was positioned around the pay zone. The upper section of the wellbore contained a cemented casing, as shown in Figure 2. It was assumed that the reservoir rock and fluids’ thermal properties (e.g., heat capacity and thermal conductivity) were constants. Also, the oil could flow at initial reservoir conditions; nevertheless, the heated element was applied to improve productivity. The mathematical formulas for the mass and heat transfer model for the wellbore and reservoir system are discussed below.

**Wellbore Model.** A wellbore model was used to investigate the impact of placing a permanent downhole heat source on the bottomhole pressure required to support a certain flow rate for a given flowing surface tubing pressure. The model solved for the velocity, fluid properties, temperature, and pressure profiles along the wellbore’s length.

---

**Figure 1.** Solar cell model to convert solar radiations into electric current that feeds the heating element.

**Figure 2.** Schematic of the heating element’s placement within the wellbore/reservoir system.

The velocity profile was obtained from the mass balance over a section of the wellbore, as shown in Figure 2. The wellbore continuity equation is written as

\[
\frac{\partial \rho_v}{\partial t} + \frac{\partial (\rho_v v_z)}{\partial z} = 0
\]

where \(\rho_v\) is the fluid density, \(R_w\) is the inner casing or tubing radius, \(t\) is time, \(\gamma\) is the wellbore open ratio, \(v_z\) is the produced fluids velocity, and \(z\) is the direction along the wellbore length.

The first term in the continuity equation accounts for the fluid density change, the second indicates the fluid convection from the reservoir to the wellbore, and the last is the fluid convection inside the wellbore. After obtaining the velocity profile, the temperature profile was obtained by solving the thermal energy balance equation, which is written as

\[
\hat{C}_p \hat{C}_p \left( \frac{\partial T_{wb}}{\partial t} + \frac{\partial v_z T_{wb}}{\partial z} + 2 \frac{\gamma}{R_w} v_{L,p} (T_{wb} - T_{i|b}) \right) = \frac{2 (1 - \gamma) U}{R_w} (T_{i|b} - T_{wb})
\]

where \(\hat{C}_p\) is the fluid’s specific heat capacity, \(T_{wb}\) is the wellbore temperature, \(U\) is the overall heat transfer coefficient between the wellbore and formation in the nonheated section, and \(T_{i|b}\) is the temperature at the wellbore/formation boundary. The overall heat transfer coefficient was estimated through the Hasan and Kabir approach. The first term in the thermal energy balance equation represents the heat accumulation, the second is the heat convection along the wellbore’s length, the third denotes heat convection from the formation’s produced fluids, and the last represents the heat conducted from the formation. The final term in the above equation was modified for the heated section of the wellbore where the element was placed (see Figure 2).

The equation is written as

\[
\hat{C}_p \hat{C}_p \left( \frac{\partial T_{wb}}{\partial t} + \frac{\partial v_z T_{wb}}{\partial z} + 2 \frac{\gamma}{R_w} v_{L,p} (T_{wb} - T_{i|b}) \right) = \frac{2 (1 - \gamma) h}{R_w} (T_e - T_{wb})
\]

where \(h\) is the heat transfer coefficient and \(T_e\) is the heated element temperature.

Solving the above equation required knowledge of the formation temperatures. An iterative procedure was used to solve the complete system. Geothermal temperature was
employed to initialize the model (i.e., the initial condition), and the fluid temperature leaving the reservoir served as the boundary condition for the wellbore model. The wellbore temperature model was then coupled with the radial reservoir temperature conduction model, which is written as

$$\rho \overline{C_p} \frac{\partial T_r}{\partial t} = \frac{1}{r} \frac{\partial}{\partial r} \left( r \overline{C_p} \frac{\partial T_r}{\partial r} \right) + \frac{\partial^2 T_r}{\partial z^2} \quad (4)$$

where

$$\overline{\rho C_p} = \rho_0 \overline{C_p} + \rho_0 \overline{C_p} \phi (1 - \phi) \quad (5)$$

$$\overline{C_p} = \overline{\phi \rho C_p} \quad (6)$$

And $T_r$ is reservoir temperature, $\overline{\rho C_p}$ is the effective average reservoir rock and fluid property, $\overline{C_p}$ is the effective average thermal conductivity, $r$ is the radial direction away from the wellbore, $\phi$ is the formation porosity, and the subscripts $f$ and $r$ represent fluid and rock, respectively. The reservoir and wellbore (i.e., inner boundary conditions) were coupled through the following boundary condition

$$\left. \frac{\partial T_r}{\partial r} \right|_{t=T_{eb}} = U(T_{eb} - T_{wb}) \quad (7)$$

where the first term represents the heat condition at the reservoir/wellbore boundary and the second is the heat flux from the wellbore. Convergence of the two models was declared when the difference between the heat fluxes of the wellbore and reservoir models at the boundary was small. The initial reservoir temperature was used as the outer boundary condition. The pressure along the wellbore was obtained by solving the momentum balance, written as

$$\frac{\partial p_{wb}}{\partial z} = -\frac{f_m \rho_0}{4R_w} \left( \frac{\partial (\rho_0 v_z)}{\partial z} \right) - \rho g \sin \theta \quad (8)$$

where $p_{wb}$ is the wellbore pressure, $f_m$ is the Moody friction factor, $g$ is the gravitational acceleration, and $\theta$ is the inclination of the wellbore. The Moody friction factor for laminar flow ($N_{Re} < 2000$) is

$$f_m = \frac{64}{N_{Re}} \quad (9)$$

where $N_{Re}$ is the Reynold number, which is defined as

$$N_{Re} = \frac{\rho_0 d v_z}{\mu} \quad (10)$$

where $\mu$ is the fluid viscosity and $d$ is the inner casing or tubing diameter. For unstable and turbulent flow ($N_{Re} \geq 2000$), Jain and Swamee’s method was used to calculate the friction factor, as follows

$$f_m = 4 \left[ 2.28 - 4 \log \left( \frac{0.0023}{d} + \frac{21.25}{N_{Re}^{0.8}} \right) \right]^{-2} \quad (11)$$

**Reservoir Model.** A reservoir model was implemented to investigate the impact of the heat source on improving the reservoir fluids’ mobility and eventual productivity. The model consisted of the diffusivity equation to solve for the pressure profile and energy balance to obtain the reservoir’s temperature profile.

Since both fluids’ viscosity and density are functions of the temperature (which varies due to the heat source), the following diffusivity equation, which assumes variable fluid properties, was solved

$$\frac{1}{r} \frac{\partial}{\partial r} \left( r \rho \frac{\partial p}{\partial r} \right) = \frac{\partial (\rho \phi \mu)}{\partial t} \quad (12)$$

where $p$ is the reservoir pressure and $k$ is the permeability. To solve the partial differential equation, the pressure was equated to the initial reservoir pressure before production began. A constant flow rate was assumed at the inner boundary condition, generating a Neumann boundary

$$(\nabla p)_{wellbore} = -\frac{q_{sc} B_o \mu}{2 \pi r \Delta h_{pay}} \quad (13)$$

where $q_{sc}$ is the production rate at standard conditions, $B_o$ is the oil formation volume factor, $r_w$ is the wellbore radius, and $h_{pay}$ is the pay zone thickness. No flow outer boundary condition at the reservoir perimeter was implemented, which is written as

$$n \cdot \nabla p = 0 \quad (14)$$

where $n$ is the normal vector to the boundary.

The temperature profile could be solved after obtaining the pressure and velocity distributions. This was done by solving the energy balance equation, assuming 1D radial heat transfer:

$$\frac{\rho \overline{C_p}}{r} \frac{\partial T_r}{\partial t} - \rho \beta_r T_r \frac{\partial p}{\partial t} + \rho_0 \overline{C_p} \mu \frac{\partial T_r}{\partial r} = \frac{1}{r} \frac{\partial}{\partial r} \left( \overline{\phi \rho \overline{C_p} \mu} \frac{\partial T_r}{\partial r} \right) + (\beta_r - 1) \mu \frac{\partial p}{\partial r} \quad (15)$$

where $\beta_r$ is the thermal expansion factor. The first two terms of the above equation represent heat accumulation, the third represents heat convection, the fourth indicates heat conduction, and the last one is the effect of fluid expansion. Since heavy oil is incompressible fluid, the expansion terms (i.e., second and last term) can be neglected. The differential equation was solved by applying initial and boundary conditions. Initially, the temperature everywhere was considered to be equal to the reservoir temperature. For the outer boundary, the temperature was assumed to be constant at the reservoir temperature. The inner boundary condition could be specified as

$$\left. \frac{\partial T_r}{\partial r} \right|_{r=0} = U_1 (T_e - T_{eb}) \quad (16)$$

where $w$ stands for the wellbore and $U_1$ is the overall heat transfer coefficient in the heated section.

**Heavy Oil Fluid Properties.** Different correlations were developed for the heavy oil fluid density and viscosity, which varies based on the reservoir type. In this work, the heavy oil viscosity was estimated using Beggs and Robinson’s method.28 This method was used to estimate the viscosity of dead and live oil at different temperatures and American petroleum institute (API) gravity. In the context of this work, the dissolved gas ratio was assumed to be negligible ($R_d = 0$) and low API gravity was used to represent heavy oil. The density was projected using the Aloffair et al.’s approach.29 The method assumes dead oil density, which is also a function of temperature and API gravity.

**Comparison with Analytical Solutions.** This section discusses the accuracy of the model’s numerical approach; however, it was not compared against field data. The integrated heat and mass transfer numerical model was validated against...
Analytical solutions were used to evaluate the numerical model accuracy, assuming a steady-state condition. It was assumed that the initial temperature in the wellbore was equal to the geothermal one. The wellbore analytical solution was obtained by integrating the wellbore ordinary differential equation (see eq 2). The wellbore temperature analytical solution can be formulated as

\[ T_{wb} = e^{-\varepsilon (ab + acz - c)} a^2 + T_{is} - \frac{ab - c}{a^2} \]  

(17)

where

\[ a = \frac{2U}{\rho_f C_{pf} v_f R_w}, \quad b = \frac{2U t}{\rho_r C_{pr} v_r R_w}, \quad c = \frac{2U g_0}{\rho_f C_{pf} v_f R_w} \]  

(18)

and where, \( g_0 \) is the geothermal temperature, \( T_{is} \) is the ambient temperature, and \( T_{in} \) is the injected fluid temperature at the surface. The long-term transient numerical solution matched the analytical one perfectly, as Figure 3a indicates.

A transient temperature solution for a reservoir was provided by Whitsitt and Dysart. The solution assumes linear heat transfer where the reservoir is exposed to a colder fluid injection. The solution assumed that heat transfer occurs only through the rock; nevertheless, a correction for the assumption was applied such that the transfer occurs through both the formation’s rock and fluids. Thus, it was modified using the effective thermal properties. The modified analytical solution can be shown as

\[ T_r = T_R - \frac{T_R - T_{in}}{2} e^{-[\beta r (2/\sqrt{t} - \varepsilon + 1/\beta)]} + e^{-[\beta r (2/\sqrt{t} - \varepsilon + 1/\beta)]} \]  

(19)

where

\[ \varepsilon = \frac{1}{2} \frac{C_{pf} v_f}{C_{pr} v_r}, \quad \beta = \sqrt{\frac{\rho_c}{\rho_r}} \]  

(20)

and where \( T_R \) is the initial reservoir temperature, \( T_{in} \) is the injected cold fluid temperature to the reservoir, and \( v_r \) is the velocity of cold fluid. Figure 3b shows that there is a perfect match between the numerical and analytical reservoir temperature solutions.

Solution Methodology. Figure 4 shows the flow of the model, starting with reading the input data. Then, the reservoir model is applied by solving the reservoir’s fluid properties, pressure, and temperature until convergence. Convergence is declared when the change between two consecutive pressure and temperature profiles is negligible. The reservoir model provides the temperature of the reservoir fluids entering the wellbore. Then, the wellbore model is applied by solving the wellbore’s fluid properties, velocity, temperature, and pressure until convergence. This is done at each time step until reaching the final production time.

## RESULTS AND DISCUSSION

The introduction of a heating element can improve reservoir fluid mobility, as well as assist with fluid lifting in the wellbore. Hence, this study focused on the temperature and pressure responses of the reservoir/wellbore system before and after placement of the element. The wellbore, formation, and fluid properties used in this research are shown in Table 1.

### Reservoir.

The reservoir temperature evolved because of heat conduction, which acted against the flow direction. Typical pressure and temperature profiles of a reservoir under production after placement of a heating element are shown in Figure 5. In this case, the simulation was for a 50 STB/day production rate and element temperature of 536 °F. A moderate element temperature was selected because coke precipitates when heavy crude oil encounters the element at high temperatures. Only a small section of the reservoir is shown, as the temperature propagation was limited to the near-wellbore region (see Figure 5b). The temperature profile presented was at a steady state, while the pressure was at a pseudo-steady state. As production continued, the pressure profile kept changing; however, no change was observed with regard to temperature. It is of note that the temperature reaches a steady-state condition within 1 or 2 days under normal production rates (i.e., 50–200 STB/day). Nevertheless, it could take years to reach a steady

### Input Data for the Integrated Heat and Mass Transfer Model

| input data                     | SI unit | field unit |
|-------------------------------|---------|------------|
| wellbore radius, \( r_w \)    | 0.104 m | 0.34 ft    |
| inner casing radius, \( R_c \)| 0.0628 m| 2.475 in.  |
| overall heat transfer coefficient, \( U \)| 0.1 KJ/(s m² °C) | 0.00488 Btu/(h ft² °F) |
| heat transfer coefficient, \( h \) | \( 6.0 \times 10^{-3} \) KJ/(s m² °C) | \( 2.9 \times 10^{-3} \) Btu/(h ft² °F) |
| ambient temperature, \( T_b \) | 25 °C | 77 °F |
| flow surface pressure, \( P_s \) | 0.69 MPa | 100 psi |
| wellbore length, \( L \) | 1220 m | 4000 ft |

### Reservoir/Formation Properties

| property                      | value                |
|-------------------------------|----------------------|
| reservoir initial pressure, \( P_R \) | 34.5 MPa (5000 psi) |
| API gravity                   | 10                   |
| reservoir temperature, \( T_R \) | 80 °C (176 °F) |
| formation rock density, \( \rho_{rock} \) | 2700 kg/m³ (168.48 lbm/ft³) |
| formation specific heat capacity, \( c_p \) | 0.879 KJ/(kg °C) (0.2099 Btu/(lbf °F)) |
| formation thermal conductivity, \( k \) | 1.57 \( \times 10^{-5} \) KJ/(s m °C) (0.907 Btu/(h ft °F)) |
| reservoir permeability, \( k_r \) | 4.93 \( \times 10^{-14} \) m² (50 mD) |
| pay zone thickness, \( h_{pay} \) | 30 m (98.4 ft) |
| drainage radius, \( s \) | 30 m (98.4 ft) |
| formation porosity, \( \phi_f \) | 0.1 |
| initial water saturation, \( \phi_w \) | 0.1 |

### General Reservoir Fluid Properties

| property                      | value                |
|-------------------------------|----------------------|
| heat capacity, \( c_{phenol} \) | 2.2 KJ/(kg °C) (0.524 Btu/(lbf °F)) |
| thermal conductivity, \( k_i \) | 1.2 \( \times 10^{-11} \) KJ/(s m °C) (0.907 Btu/(h ft °F)) |
| viscosity at room temperature, \( \mu \) | 15.5 Pa s (2100 cp) |
state under a shut-in condition depending on the reservoir size and thermal properties.

Heat propagation from the heating element was a strong function of the production rate. In all cases presented in Figure 6a, no heat propagation was observed beyond 10−15 ft from the wellbore. It is also of note that the higher the flow rate, the lower are the heat propagation and temperature magnitudes; this was the result of the convection-dominated heat transfer. It is interesting that the reservoir fluids entering the wellbore did not reach the element temperature of 536 °F. When the production rate was 1000 STB/day, no gain in reservoir fluid temperature was observed; hence, heating elements are not applicable for such high production rates. This production was assumed to be generated from a 100 ft thick pay zone. If 1000 STB/day was produced from a 1000 ft pay zone, as could occur in a horizontal wellbore, the temperature profile might behave similar to that of the 100 STB/day case. Figure 6b shows the corresponding viscosity profiles at different production rates. Although the viscosity is moderate at reservoir conditions, it is estimated to be 2100 cp at room temperature using Beggs and Robinson’s approach. It is of note that the lower the production rate, the better is the mobility achieved, due to the greater reduction in viscosity.

Heating element viability was assessed by studying the reservoir productivity index at a pseudo-steady state, $J$, defined as

$$ J = \frac{q}{\bar{P} - P_{wf}} $$

(21)

where $q$ is the production rate, $\bar{P}$ is the average reservoir pressure, and $P_{wf}$ is the bottomhole flowing pressure. Figure 7 shows the pseudo-steady state productivity index as a function of
When no heating was considered (176 °F), the productivity index did not change with an increase in the production rate. Once the element was placed, the productivity index declined with an increase in the production rate because the heat did not propagate as efficiently inside the reservoir. Notice that the improvement in the productivity index could be as large as 42% at 50 STB/day, as low as 8% at 200 STB/day, and diminished to zero at 1000 STB/day.

For reservoirs that may not produce naturally due to the fluid's high viscosity, cycles of shut in and production may be viable. Theoretically speaking, heat propagation can reach to the drainage area’s boundary through heat conduction if enough time is given, assuming no flow condition. Figure 8a shows the final temperature profile after 80 days of shut in, where heat propagation reached more than 30 ft. Figure 8b shows the temperature evolution at different locations inside the reservoir during those 80 days. It is of note that the closer the reservoir location to the heating element, the faster and sharper is the increase in the temperature profile. For instance, heating at a 3 ft radius from the wellbore was efficient during the first 10 days but the subsequent increase in temperature was much slower. Figure 9 shows 80 days of production after a similar period of shut in, and a second case in which no shut-in period preceded production. The productivity of the former scenario was almost 4 times greater than that of the latter at the initial time; however, productivity declined to reach that of the second case after 80 days of production, as the temperature dropped to the initial geothermal value. In both cases, the element temperature was assumed to be around 536 °F and the production rate was 200 STB/day. The case presented below may not be ideal for cyclic production if the reservoir flows naturally. Nevertheless, it might
be suitable for extra heavy reservoirs that require heat to flow. It is of note that cyclic periods can be optimized to reach maximum recovery.

Wellbore. The heating element not only improved reservoir fluid mobility but also assisted with fluid lifting in the wellbore. The model assumed that the initial formation temperature was equal to the geothermal temperature (see Figure 10a). Figure 10b shows the formation temperature adjacent to the wellbore after 10 days of production at 50 STB/day. Most of the temperature increase occurred within a 1 ft radius around the wellbore; however, the heat flux reached much longer distances due to the no convection condition above the productive zone. It is of note that the temperature contour range and colors in Figure 10a,b are different. This is due to the high element temperature of 536 °F, as compared with the 176 °F initial reservoir temperature. Also, it was assumed that the 4000 ft represented the section above the heated pay zone.
The temperature profile in the wellbore also depended on the production rate. Figure 11 is a continuation of Figure 6a, where the temperature was investigated in the wellbore. Notice that the temperatures at 4000 ft in Figure 11 are not similar to those at the downhole production location in Figure 6a (i.e., zero). The reason is that the fluids produced from the reservoir were heated again by the element when they flowed vertically in the 100 ft heated section. For instance, at 50 STB/day, the fluids produced from the reservoir were at 390 °F (see Figure 6a) and were heated to 510 °F during the vertical flow around the pay zone (see Figure 11). Note that the heating element temperature was assumed to be constant at 536 °F. As seen in Figure 11, the fluids were heated to higher temperatures at lower flow rates; nevertheless, they tended to lose heat to the adjacent formation at a faster rate when flowing to the surface. For the 1000 STB/day case, the fluids did not increase in temperature as they left the reservoir but rather were heated to 234 °F within the wellbore. Hence, the heating element may not have improved the reservoir fluid’s mobility but did still improve the outflow performance by reducing density and viscosity. It is advisable to have insulated tubing, especially at low production rates, to keep the heat within the wellbore.

The impact of the heating element on the wellbore temperature and fluid properties is shown in Figure 12. It was assumed in this simulation that the heating element temperature was 536 °F and the production rate was 200 STB/day. Figure 12a shows the shift in wellbore temperature due to the heating element. Figure 12b,c shows the reduction in fluid density and viscosity attributable to the temperature increase. The reduction in fluid viscosity decreased the pressure drop in the wellbore due to frictional losses, while the reduction in fluid density diminished the pressure drop due to the weight of the oil column. This resulted in a lower bottomhole pressure at a steady state condition for a given production rate.

Figure 13 shows the outflow performance relationship (OPR) at different element temperatures. The OPR associates the production rate with the flowing bottomhole pressure in the wellbore. The general trend was a lower flowing bottomhole pressure as the element temperature increased (see Figure 13). The blue curve in Figure 13a represents the original case with no heating element. Initially, as the production rate increased, the bottomhole pressure dropped because the average wellbore fluid temperature was higher. For instance, at 100 STB/day, the fluid’s average temperature in the wellbore was higher than at 50 STB/day (see Figure 11). However, at higher flow rates, the

![Figure 11. Wellbore temperature profiles at different flow rates after 10 days.](image)

![Figure 12. Two hundred STB/day after 10 days of heating: (a) temperature profiles before and after placing the heating element, (b) viscosity profiles before and after placing the heating element, and (c) density profiles before and after placing the heating element.](image)
pressure increased again as the heating element became less efficient and frictional losses increased. The flow rate range (see Figure 13) did not exceed 260 STB/day as heating became less efficient; hence, a sharp increase in bottomhole pressure was likely at higher rates. It was noted that the heating element was more efficient at improving oil lifting when the wellbore was longer. For instance, the heating element could reduce the bottomhole pressure by 120 psi when production was 150 STB/day (see Figure 13a) for the 4000 ft wellbore. For the 8000 ft case, a reduction of around 200 psi was achieved (see Figure 13b), indicating better lift performance. Also, placing the heating element within a smaller diameter wellbore resulted in better wellbore performance, as compared to wellbores of a larger diameter. The reason is that the temperature increase due to the heating element significantly reduced the frictional losses, which tend to be more severe in smaller diameter wellbores. Also, the lower the API gravity, the more efficient the heating element in reducing the flowing bottomhole pressure.

Placing the heating element provided a synergic effect in terms of improving the reservoir fluid mobility and assisting with fluid lifting in the wellbore. This was investigated by studying the reservoir inflow performance relationship (IPR) and wellbore OPR. Figure 14 shows the OPR as a dotted line before (OPR1) and after (OPR2) heating, as well as the IPR in a solid line before (IPR1) and after (IPR2) heating. The black arrow indicates the IPR/OPR intersection before heating; the red line is after heating. The intersection represents the actual reservoir/wellbore system’s performance. Figure 14a shows that the production increased from 80–96 STB/day, representing a 20% productivity improvement attributable to the heating element. Figure 14b shows that the production rate increased from 162–180 STB/day, representing only a 10% increase in production. Notice that even though the production was higher for the shorter wellbore at a given flowing surface pressure, the increase in production was lower. In fact, the longer the wellbore, the more viable the placement of a heating element. Notice that if the vertical left performance in the wellbore is ignored, only half of the production increase will be observed.

Finally, it is important to estimate the amount of energy required to keep the heating element temperature constant during production. The energy required at a steady state condition was calculated using the following formula

\[ \dot{E} = \dot{C}_{fe} m \Delta T \]
where $\dot{E}$ is the required energy, $\dot{m}$ is the mass flow rate, and $\Delta T$ is the difference between the temperature of the fluids leaving the heated section of the wellbore and the initial fluid temperature in the reservoir. As discussed, fluids were heated in the reservoir as they flowed to the wellbore and again as they vertically flowed within the heated wellbore section. Assuming a heating element temperature of 536 °F, Figure 15 shows the temperature of the fluid leaving the reservoir, as well as leaving the heated wellbore section. Also, the figure indicates the energy needed to keep the element temperature constant, which increases with the increase in the production rate. This is logical, since more energy is needed to keep a material’s temperature constant when colder fluid is flowing against it. When the production rate was 200 STB/day, 84 kW was needed to heat the fluids. However, the energy requirement could be as much as 10 times greater for a horizontal wellbore. Even though the heating element approach is not as effective as SAGD, it requires much lower capital and operational investments. For instance, SAGD requires on average between 15 and 30 MW of energy, which is at least 20 times the energy required for a heated element in a 1000 ft horizontal section.

Downhole energy requirements are dependent on the desired downhole temperature, pay zone thickness, production rate, and thermal properties of the reservoir. That energy is used as an input parameter to design the solar panels when renewable energy sources are considered. Here, we consider a case of fixed element temperature, variable production rate (see Figure 16). Notice that the required surface area of the solar panels depends strongly on the production rate as more energy is consumed to sustain the element temperature.

**CONCLUSIONS**

A numerical study was conducted on the impact of placing a heating element around the pay zone of a heavy oil reservoir. It was determined that heat propagation in the reservoir did not exceed 10–15 ft, and was inversely related to the production rate. In the cases studied, the heating element did not improve the productivity index of the reservoir when production was around 1000 STB/day; however, the productivity index improved by more than 40% when the production rate was 50 STB/day. Nevertheless, heat propagation in a reservoir can reach longer distances if the production stops for extended periods of time.

**Figure 15.** Temperature increase due to the heating element and energy requirements.

The heating element can also provide a means of improving the vertical lift performance in the wellbore by reducing fluid viscosity and density. The cases studied showed that the heating element was more efficient when the production rate was between 150 and 200 STB/day, as the average wellbore temperature was higher. This resulted in around 200 psi less flowing bottomhole pressure needed to achieve a certain production rate. The energy required for the 200 STB/day production rate did not exceed 84 kW, which is considered moderate.

**AUTHOR INFORMATION**

**Corresponding Authors**
*E-mail: mjawad@kfupm.edu.sa. (M.S.A.).*  
*E-mail: safnan@kfupm.edu.sa. (S.A.).*

**ORCID**

Murtada Saleh Aljawad: 0000-0002-3540-6807  
Saad Alafnan: 0000-0001-9124-8340

**Notes**

The authors declare no competing financial interest.

**NOMENCLATURE**

$B_w$ oil formation volume factor, reservoir bbl/ STB  
$C$ fluid’s specific heat capacity, Btu/(lbm °F)  
$d$ inner casing or tubing diameter, in.  
$E$ energy required, kW  
$f_m$ Moody friction factor, unitless  
$g$ gravitational acceleration, m/s²  
$h$ heat transfer coefficient, ft  
$h_{pay}$ pay zone thickness, ft  
$I$ productivity index, STB/day/psi  
$k$ permeability, md  
$k_c$ effective average thermal conductivity, Btu/(h ft °F)  
$m$ mass flow rate, lbm/min  
$p$ reservoir pressure, psi  
$\bar{p}$ average reservoir pressure, psi  
$P_{wb}$ wellbore pressure, psi  
$P_{fh}$ bottomhole flowing pressure, psi  
$q_{sc}$ production rate at standard conditions, STB/day  
$r$ radial direction away from the wellbore, ft  
$R_t$ inner casing or tubing radius, inch  
$r_w$ wellbore radius, in.  
$t$ time, s  
$T_e$ heated element temperature, °F  
$T_{wb}$ wellbore temperature, °F  
$U$ overall heat transfer coefficient between, Btu/(h ft² °F)  
$\nu_{in}$ produced fluids velocity, ft/min

**Figure 16.** Surface area of a photovoltaic cell needed for the element temperature of 572 °F as a function of the production rate.
direction along the wellbore length, ft
ΔT fluids temperature increase, °F
φ formation porosity, unitless
θ inclination of the wellbore, degree
ρf fluid density, lbm/ft³
γ wellbore open ratio, unitless
μ fluid viscosity, cp

REFERENCES

(1) Kokal, S.; Al-Kaabi, A. World Petroleum Council: Official Publication; World Petroleum Council: Official Publication, 2010; pp 64–69.
(2) Sarapardeh, A.; Kiasari, H. H.; Alizadeh, N.; Mighani, S.; Kamari, A. In Application of Fast-SAGD in Naturally Fractured Heavy Oil Reservoirs: A Case Study, SPE Middle East Oil and Gas Show and Conference; Manama, Bahrain, 2013; pp 10–13.
(3) Hemmati-Sarapardeh, A.; Shokrollahi, A.; Tatar, A.; Gharagheizi, F.; Mohammadi, A. H.; Naseri, A. Reservoir Oil Viscosity Determination Using a Rigorous Approach. Fuel 2014, 116, 39–48.
(4) Bera, A.; Babadagli, T. Status of Electromagnetic Heating for Enhanced Heavy Oil/Bitumen Recovery and Future Prospects: A Review. Appl. Energy 2015, 151, 206–226.
(5) Prats, M. Thermal Recovery; SPE of AIME: New York, 1982; Vol. 7.
(6) Conaway, C. F. The Petroleum Industry: A Nontechnical Guide; PennWell Books: Tulsa, 1999; pp 85–86.
(7) Alvarado, V.; Manrique, E. Enhanced Oil Recovery: An Update Review. Energies 2010, 3, 1529–1575.
(8) Santos, R.; Loh, W.; Bannwart, A.; Trevisan, O. An Overview of Heavy Oil Properties and Its Recovery and Transportation Methods. Braz. J. Chem. Eng. 2014, 31, 571–590.
(9) Ali, S. M.; Bayestehparvin, B. In Electrical Heating―Doing the Same Thing Over and Over Again, SPE Canada Heavy Oil Technical Conference, Society of Petroleum Engineers, 2018.
(10) Yuan, J.-Y.; Isaacs, E. E.; Huang, H.; Vandenhoff, D. G. Wet Electric Heating Process. U.S. Patent US66317612003.
(11) Maggard, J. B.; Wattenbarger, R. A. In Factors Affecting the Efficiency of Electrical Resistance Heating Patterns, Proc., UNITAR/UNDP 5th International Conference on Heavy Oil and Tar Sands; Caracas, Aug 4–9, 1991; pp S19–S30.
(12) Vinsome, K.; McGee, B.C.W.; Vermeulen, F. E.; Chute, F. S. Electrical Heating; Petroleum Society of Canada, 1994.
(13) Faradonbeh, M. R.; Hassanzadeh, H.; Harding, T. Numerical Simulations of Bitumen Recovery Using Solvent and Water Assisted Electrical Heating. Fuel 2016, 186, 68–81.
(14) Bottazzi, F.; Repetto, C.; Tita, E.; Maugeri, G. In Downhole Electrical Heating for Heavy Oil Enhanced Recovery: A Successful Application in Offshore Congo, International Petroleum Technology Conference, 2013.
(15) Rangel-German, E. R.; Schembre, J.; Sandberg, C.; Kovscek, A. R. Electrical-Heating-Assisted Recovery for Heavy Oil. J. Pet. Sci. Eng. 2004, 45, 213–231.
(16) Sierra, R.; Tripathy, B.; Bridges, J. E.; Farouq Ali, S. M. In Promising Progress in Field Application of Reservoir Electrical Heating Methods, Paper SPE 69709 presented at the SPE International Thermal Operations and Heavy Oil Symposium, Porlamar, Margarita Island, Venezuela, 12–14 March, 2001.
(17) Newbold, F. R.; Perkins, T. K. Wellbore Transmission of Electrical Power. J. Can. Pet. Technol. 1978, 17, 39–53, DOI: 10.2118/78-03-03.
(18) Amba, S.; Chilingar, G.; Beesom, C. Use of Direct Electrical Current for Increasing the Flow Rate of Reservoir Fluids During Petroleum Recovery. J. Can. Pet. Technol. 1964, 3, 8–14.
(19) Jha, K. N.; Chakma, A. Heavy Oil Recovery from Thin Pay Zones by Electromagnetic Heating. Energy Sources 1999, 21, 63–73.
(20) Sahni, A.; Kumar, M.; Knapp, R. B. In Electromagnetic Heating Methods for Heavy Oil Reservoirs, SPE/AAPG Western Regional Meeting, Long Beach, CA, June 19–22, 2000; pp 19–22.
(21) Acar, C.; Hascakir, B.; Demiral, B.; Akin, S.; Karaca, H.; Kartal, O. E. In Microwave Heating of Heavy Oil Reservoirs: Effect of Wettability, Proc. 150 Years of the Romanian Petroleum Industry: Tradition and Challenges, Bucharest, Romania, 14–17 October, 2007.
(22) Hascakir, B.; Acar, C.; Akin, S. Microwave-Assisted Heavy Oil Production: An Experimental Approach. Energy Fuels 2009, 23, 603–6039.
(23) Kovaleva, L.; Davletbaev, A.; Babadagli, T.; Stepanova, Z. Effects of Electrical and Radio-Frequency Electromagnetic Heating on the Mass-Transfer Process During Miscible Injection for Heavy-Oil Recovery. Energy Fuels 2011, 25, 482–486.
(24) Alafnan, S.; Aljawad, M.; Alismail, F.; Almajed, A. Enhanced Recovery from Gas Condensate Reservoirs through Renewable Energy Sources. Energy Fuels 2019, 33, 10115.
(25) Villalva, M. G.; Gazoli, J. R.; Filho, E. R. Comprehensive approach to modeling and simulation of photovoltaic arrays. IEEE Trans. Power Electron. 2009, 24, 1198–1208.
(26) Hasan, A. R.; Kabir, C. S. Wellbore Heat-Transfer Modeling and Applications. J. Pet. Sci. Eng. 2012, 86–87, 127–136.
(27) Li, X.; Zhu, D. Temperature Behavior During Multistage Fracture Treatments in Horizontal Wells. SPE Prod. Oper. 2018, 33, 522–538.
(28) Beggs, H. D.; Robinson, J. Estimating the Viscosity of Crude Oil Systems. J. Pet. Technol. 1975, 27, 1140–1141.
(29) Alomair, O.; Jumaa, M.; Alkoriem, A.; Hamed, M. Heavy Oil Viscosity and Density Prediction at Normal and Elevated Temperatures. J. Pet. Explor. Prod. Technol. 2016, 6, 253–263.
(30) Whitsitt, N. F.; Dysart, G. R. In Effect of Temperature on Simulation Design, Paper SPE 2497 presented at the Annual Fall Meeting of the Society of Petroleum Engineers of AIME, Denver, Colorado, Sept 28–Oct 1. SPE-2497-MS, 1969.
(31) Aljawad, M. S. In Identifying Formation Mineralogy Composition in Acid Fracturing From Distributed Temperature Measurements, SPE Reservoir Evaluation & Engineering, 2019.