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An Integrated Model to Compare Net Electricity Generation for CO₂- and Water-Based Geothermal Systems

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Keywords

Wellbore flow, reservoir simulation, power cycle, fluid flow, CO₂, modeling

ABSTRACT

Utilization of supercritical CO_2 as a geothermal fluid instead of water has been proposed by Brown¹ and its advantages have been discussed by him and researchers^{4,5}. This work assesses the net electricity which could be generated by using supercritical CO_2 as a geothermal working fluid and compares it with water under same reservoir conditions of temperature and pressure. This procedure provides a method of direct comparison of water and CO_2 as geothermal working fluids, in terms of net electricity generation over time.

An integrated three-part model has been developed to determine net electricity generation for CO_{2^-} and water-based geothermal reservoirs. This model consists of a wellbore model, reservoir simulation and surface plant simulation. To determine the bottomhole pressure and temperature of the geothermal fluid (either water or CO_2) in the injection well, a wellbore model was developed using fluid-phase thermodynamic equations of state, fluid dynamics, and heat transfer models. A computer program was developed that solves for the temperature and pressure of the working fluid (either water or CO_2) down the wellbore by simultaneously solving for the fluid thermophysical properties, heat transfer, and frictional losses.

For the reservoir simulation TOUGH2 has been used to model the temperature and pressure characteristics of the working fluid in the reservoir. The EOS1 module of TOUGH2 has been used for the water system and the EOS2 module of the TOUGH2 code has been employed for the CO_2 case.

The surface plant is simulated using CHEMCAD, a chemical process simulator, to determine the net electricity generated. A binary organic Rankine cycle is simulated. The calculated net electricity generated for the optimized water and CO_2 systems are compared over the working time of the reservoir.

Introduction

There is enough heat in the crust of the earth to satisfy a large part of the world's probable energy needs for a very long time. This heat could be tapped by Enhanced Geothermal Systems (EGS) which aims to extract the heat beneath the earth crust by injecting a fluid through a wellbore, which flows through a hot artificially fractured reservoir and then is forced out from the production well, thus heat is carried to the surface of the earth from beneath the surface. Conventional geothermal power plants are based on extracting the heat from the existing geothermal reservoirs having naturally occurring porosity, permeability which allows the flow of water through them. However, there is vast majority of hot dry rocks that could be found in western U.S.² which are assessable through current drilling practice. The heat from these hot dry rocks could be tapped by enhancing the permeability of the rock through hydraulic stimulation and thereafter allowing the fluid to flow through them. One of the most common options is to use water as a heat transfer fluid. However, some of the researchers like Brown¹, Pruess³ etc. have considered and studied the use of CO_2 as a heat transfer fluid.

Properties that motivate the use of CO_2 as a geothermal fluid emphasized are:

- 1. The density of cold CO_2 and that of hot CO_2 obtained from production well have large differences, which could provide a significant buoyant force⁴ and thus circulation power consumption would be less and more net electricity could be generated.
- 2. CO₂ is a poor solvent may not dissolve minerals from reservoir thus reducing scaling problems caused by silica dissolution⁴. Conversely water is a powerful solvent, makes difficult to operate EGS reservoir in a stable manner.
- 3. At the elevated temperature of reservoir, CO_2 -mineral reactions may provide an additional advantage for the sequestration of CO_2^{5} .

This work primarily concerns the comparison of CO_2 and water as a geothermal fluid in terms of net electricity generation over a period of time. The aim of the comparison is to understand under identical set of reservoir conditions which choice is better if one fluid has to be picked over other. A comparison is being made using the same flow rate of both the fluids operating under same surface power cycles and same reservoir conditions compared to work by Pruess et al³ that compared those under constant delta P.

Any geothermal power plant comprises of three components: the wellbore (injection/production), the geothermal reservoir (from which heat is extracted), and the surface plant (where heat extracted is transformed into electricity for human use). These three components need to be studied separately yet need to be coupled to understand the overall impact on net electricity generation.

In this work, to determine the temperature and pressure profiles of two fluids (water/CO₂) a wellbore model has been developed. TOUGH2, a numerical simulator has been employed for reservoir simulations using the EOS1 module of TOUGH2 for simulating flow of water and EOS2 for CO₂. Finally to determine net electricity generation the chemical process simulation software, Chemcad, has been used for surface plant calculations.

Wellbore Model

Geothermal fluids either CO₂ or water are being injected into the reservoir through injection wells and the heated fluid are being taken out from the reservoir through production wells. As the fluid travels through the wellbore it either loses enthalpy to or gains enthalpy from the wellbore formation and the rate of loss or gain of enthalpy is a function of time and depth. Therefore geothermal wells should be considered nonisothermal. It is important to know the bottom-hole pressure and temperature in the case of an injection well (to know the enthalpy of the injected fluid to the reservoir) and the wellhead pressure and temperature for the production well. It is the temperature and pressure of the fluid obtained at the wellhead of the production well that determines the amount of electricity that could be generated from the geothermal fluid. Figure 1 shows the basic well configuration used for the modeling. Although the model is developed for any depth and any radius but in this work reservoir is considered to be at a



Figure 1. Basic wellbore configuration (1a) Tube diameter variation with depth (1b) Different layers of materials in the radial direction.

depth of 3 km. Direction of fluid flow in the well could be either upwards or downwards.

Basic Flow Equations

We shall now discuss the basic equations used and the methodology in determining the temperature and pressure distribution of the geothermal fluid along the well. The assumptions which are incorporated in the development of this model are:

- 1. As the diameter of the wellbore is very small when compared to its length, no variation of temperature, pressure and fluid velocity in the radial direction of well is assumed. All properties changes along vertical direction only.
- 2. For designing flow of CO₂ in the well, the well is taken to be completely dry with respect to water.
- 3. The geothermal gradient of the earth (which is defined as the rate of change of temperature with depth) is taken to be constant in this work. However, the code could easily be modified to give geothermal gradient variation with depth.
- 4. The acceleration term of the pressure gradient is neglected. This can be a reasonable assumption, considering that velocity of the fluid doesn't change as fast as the pressure changes with depth. Velocity is a function of density and density is a function of pressure and temperature. As geothermal fluid goes down the wellbore, its pressure increases and hence density tends to increase but due to thermal gradient of earth, temperature also increase which causes the density to decrease and hence the net effect on density and velocity is not that large as in the case of pressure. So, change in velocity is sluggish in comparison to change in pressure. Thus, velocity gradient and hence acceleration term can be neglected in comparison with pressure gradient. It can be justified when the velocity profile is obtained based on this assumption. Based on the similar argument, acceleration term can be dropped when the fluid is ascending the production wellbore.
- 5. Vertical heat diffusion is neglected as a first effort of model development. It can also be a reasonable assumption because velocity of the fluid is high and convective heat transfer dominates the diffusive heat transfer.

The equation for the pressure drop in a well is given by:

$$\frac{dp}{dz} + \rho v \frac{dv}{dz} + \rho g + f \frac{\rho v^2}{2d} = 0 \tag{1}$$

where,

 $p = \text{pressure}, \text{N/m}^2$

- z = distance in vertical direction from the wellhead, m
- ρ = density of fluid, kg/m³
- v = velocity in z direction, m/s
- g = acceleration due to gravity, m/s²

f = Moody friction factor

d = wellbore diameter, m

All units are taken in SI system.

In Equation (1) the $\rho v \frac{dv}{dz}$ term represents the acceleration term, *pg* represents the gravitational term and $f \frac{\rho v^2}{2d}$ represents the frictional term of the pressure gradient along the well.

Neglecting the acceleration term of the pressure gradient as discussed above, one is left with

$$\frac{dp}{dz} + \rho g + f \frac{\rho v^2}{2d} = 0 \tag{2}$$

The friction factor, f, can be calculated as¹¹

$$f = \left[-2\log\left\{\frac{\epsilon/d}{3.7065} - \frac{5.0452}{Re}\right]^{-2} \log\left(\frac{(\epsilon/d)^{1.1098}}{2.8257} + \left(\frac{7.149}{Re}\right)^{0.8981}\right)\right]^{-2}$$
(3)

Where,

 ϵ = Pipe roughness factor

Re = Reynolds number

$$Re = \frac{d\nu\rho}{\mu} \tag{4}$$

Temperature Calculations

The variation of the formation temperature along the radial direction as a function of temperature can be given by diffusivity equation:

$$\frac{\partial^2 T_e}{\partial r^2} + \frac{1}{r} \frac{\partial T_e}{\partial r} = \frac{C_e \rho_e}{K_e} \frac{\partial T_e}{\partial t}$$
(5)

where,

 T_e = Temperature of earth (°C) at time t

r = Distance from center of well, m

 K_e = Thermal conductivity of earth, W/m/K

 C_{ρ} = Specific heat of earth, J/kg

 ρ_e = Density of earth, kg/m³

Hasan and Kabir⁶ solved the above diffusivity equation using Laplace transform method involving dimensionless variable and concluded the following solution:

$$T_D = \ln \left[e^{-0.2t_D} + (5)$$

where,

 T_D = Dimensionless temperature which is defined as

$$T_D \equiv -\frac{2\pi K_e}{Q} \left(T_{wb} - T_{ei} \right) \tag{7}$$

 t_D = Dimensionless time

$$t_D = \frac{\alpha t}{r_{wb}^2} \tag{8}$$

where,

 R_{wb} = Outer radius of cement, m

 T_{wb} = temperature at R_{wb} , °C

$$T_{ei}$$
 = Initial temperature of the earth as a function of depth, °C

$$A = 1$$
 hermal diffusivity, $a = \frac{1}{\rho_e C_e}$

 T_{ei} is a function of depth and geothermal gradient and can be defined as

$$T_{ei} = T_{eibh} - (L - Z)g_G \tag{9}$$

where,

L = Length of the well, m

 T_{eibh} = Bottomhole temperature of the production well, °C

 g_G = Geothermal gradient, °C/km

 T_{ei} can also be defined on the basis of wellhead temperature in the injection well and geothermal gradient.

To relate the dimensionless temperature (T_D) to the temperature of fluid (T_F) energy balance is carried out as depicted in Figure 2, heat transfers takes place from the earth which is at higher temperature to the cold fluid in the tube of the injection well and vice versa for production well. All resistances to heat transfer across the well, i.e., resistance offered by cement, annulus fluid (air), insulation and tube thickness can be assumed in series.



Figure 2. Energy balance on fluid.

Consider an elemental fluid at a depth of z and of control volume Adz, if A is the cross section area. Assuming flow rate of fluid to be W kg/s and the specific enthalpy of fluid to be H kJ/kg.

Conserving energy on the control volume gives:

$$(WH)_{Z+dz} + Wg(Z+dz) + \left(\frac{WV^2}{2}\right)_{Z+dZ}$$
(10)
+ $Qdz = (WH)_Z + wg(Z) + \left(\frac{WV^2}{2}\right)_Z$

Equation (10), the sign of Q changes if the heat is transferred from the fluid to the formation which is the case of injection well. Rearranging Equation (10) gives

$$\frac{dH}{dZ} + g + V\frac{dV}{dZ} = \pm \frac{Q}{W}$$
(11)

Where a negative sign implies production well and positive sign implies injection well.

Substituting the definition of enthalpy as a function of pressure and temperature, Hasan and Kabir⁶ obtained the following Equation (12).

$$\frac{dT_f}{dz} = C_J \frac{dP}{dz} + \frac{1}{C_P} \left[\mp \frac{Q}{W} - g - V \frac{dV}{dz} \right]$$
(12)

where,

 T_f = Temperature of fluid, °C C_J = Joule- Thompson coefficient, °C/pa C_p = Specific heat of the fluid, J/kg/°C Heat flow per unit length can be defined as

$$Q = 2\pi r_{to} U_{t0} (T_f - T_{wb})$$
(13)

where,

 r_{t0} = Outer radius of tubing, m

 U_{t0} = Overall heat transfer coefficient, J/s-m²-K

For single phase fluid, the Joule Thompson coefficient C_J can be approximated as⁶

$$C_J = \frac{1}{\rho C_P} \tag{14}$$

Since the CO_2 is under supercritical conditions throughout the operation of the geothermal energy generation process, it has been assumed that the Joule Thompson coefficient for CO_2 is also given by Equation (14).

Combining Equations 7, 9, 12, 13 & 14 and eliminating T_{wb} , a final equation obtained for production well by Hasan and Kabir⁶ used in this model is

$$T_F = T_{eibh} - g_G [(L - Z) - (1 - e^{(Z - L)L_r})/L_R]$$
(15)

Above Equation (15) can be modified for the injection well as follows

$$T_F = T_{eiwh} + g_G[(Z) - (1 - e^{(-Z)L_r})/L_R]$$
(16)

where,

 T_{eiwh} = Temperature at the wellhead of the injection well (°C)

 L_R is called relaxation parameter and is defined by Ramey⁷ as

$$L_{R} = \frac{2\pi}{C_{P}W} \left[\frac{r_{t0}U_{t0}K_{e}}{K_{e} + (r_{t0}U_{t0}T_{D})} \right]$$
(17)

The correlation for overall heat transfer coefficient is obtained from Hasan and Kabir.⁸

Thermophysical properties of water such as density, viscosity, enthalpy, specific heat etc. are calculated using ASME steam table obtained as an Excel Add-In from Bernhard Spang⁹. For CO₂, Altunin¹² correlations are used, calculated using an Excel Add-In developed by our group. A computer program was devel-

Table 1. Specification of input variables.

Well head pressure of the fluid at injection well	8 MPa
Well head temperature of fluid at injection well	35°C
Surface temperature of earth	30°C
Flow rate	15 kg/sec
Geothermal gradient	80°C/km
Well depth	3 km
Inner radius r1	0.5 km
Inner radius r2	0.3 km
Inner radius r3	0.2 km

oped using Microsoft Visual Basic that solves for the temperature and pressure of the working fluid (either water or CO_2) down the wellbore by simultaneously solving for the fluid thermophysical properties, heat transfer, and frictional losses. Input variables were specified for both water and CO_2 as shown in Table 1 although the code can be used for any flow rate, well radius, geothermal gradient, or injection conditions. A very high geothermal gradient of 80° C/km is employed in this study to compare H₂O and CO₂ under commercial conditions². The properties of the earth surrounding the well specified in this work are shown in Table 2.

Table 2. Specification of earth properties.

Thermal conductivity of earth	2.42 W/m•K
Diffusivity of earth	10 ⁻⁶ m ² /sec
Thermal conductivity of cement	1.50 W/m•K
Annulus fluid	Air

Results obtained after running the code for various times are shown in Figure 3a, 3b and 3c.



Figure 3a. Temperature and pressure profiles of CO₂ and water in the injection well after 0.001 years.







Figure 3c. Temperature and pressure profiles of CO_2 and water in the injection well after 30 years.

As shown in the Figure 3 and also expected theoretically, CO_2 gains more temperature from the surrounding formation than water due to the virtue of its low specific heat capacity. On the same basis, it loses more temperature than water in the production well. As time progress temperature of earth adjacent to the injection well (see Figure 1) starts to decrease and thus the rate of heat gained by the fluids (both water and CO_2) from the earth starts to decrease.

The increase in pressure for water is more than that of CO_2 because of higher density of water than supercritical CO_2 . The net gain in pressure decreases over time for both the fluids. The bottom-hole temperature and pressure of the injection well obtained from the wellbore model is subsequently used in the reservoir simulation.

Reservoir Simulation

A five spot pattern is considered for reservoir simulation as shown in Figure 4. Due to the high level of symmetry only 1/8 of the whole reservoir needs to be modeled. As mentioned before, a flow rate of 15 kg/sec is being injected on the basis of 1/8 of the reservoir, thus on the full well basis a flow rate of 120 kg/sec is being injected. All results shown in this work are on the basis of 15 kg/sec.



Figure 4. Five spot pattern reservoir.

Parameters used for reservoir simulation using TOUGH2-MP are shown in Table 3. These are based on the parameters used by Karsten Pruess³.

Table 3.	Parameters	of the	reservoir.
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Thickness	305 m
Grid block dimensions	70.71 m ×70.71 m
Permeability	$60 \times 10^{-15} \text{ m}^2$
Rock Density	2650 kg/m ³
Rock specific heat	1000 J/kg/°C
Rock thermal conductivity	2.1 W/m/°C
Initial reservoir temperature	270°C
Initial reservoir pressure	32 MPa

Results obtained from reservoir simulation are shown in Figure 5. It is assumed that the temperature of the fluid coming out of the production block is same as the production block.

Results showed that more pressure and temperature drop is observed in the reservoir using water as a flowing fluid than CO_2 having exactly same flow rate. Thus, it can be concluded that there is more heat sweep of the reservoir having water as a heat transmission fluid.



Figure 5. Temperature (left) and pressure (right) of the production block with time.

It is required to know the temperature and pressure of water and CO_2 at the top of the production well. For this wellbore model is being used. The bottomhole temperature and pressure obtained from reservoir simulation results at the production block served as the input parameter for the wellbore model. Results obtained from wellbore model are shown in Figure 6.



Figure 6. Temperature (left) and pressure (right) at wellhead of the production well with time.

It is important to note that a pump has been placed for water in order to avoid two phase flow in the well as the surface plant is designed for only hot pressurized water and not for wet steam. The role of pump is to increase the pressure of the water from the production block back to 32 MPa. However, amount of work consumed by the pump has been accounted in the net electricity generation calculations.

Surface Plant

The temperature and pressure of the geothermal fluid over time at the wellhead of the production well determines the amount of net electricity generation. A surface plant is designed based on the Rankine cycle to determine electricity production. In this cycle, an organic fluid such as isobutene, iso-pentane, R-32 (refrigerant) etc. takes heat from the geothermal fluid (water or CO₂) and is then get vaporized because of low boiling point. This high-pressure, vaporized organic fluid is then passed through the turbine/generation unit and work (electricity) is obtained. After coming out of the turbine it is then condensed in the condenser and then again pumped back to the heat exchanger (vaporizer) where it gets vaporized and thus the cycle is completed. An extra heat exchanger has been used in the present work in order to extract more heat from the geothermal fluid coming out of the first heat exchanger. The amount of work obtained through this cycle will also depend upon the choice of organic fluid. As mentioned by the Augustine et al.¹⁰, considering the temperature of the geothermal fluid at the wellhead of the production well, the maximum efficiency would be obtained using iso-pentane as the secondary fluid. Hence, iso-pentane is the secondary fluid used



Figure 7. Schematic diagram of power plant for water (Top) and CO_2 (Bottom) as the heat transmission fluid.

in the Rankine cycle. Figure 7 shows the schematic diagram of the surface power plant being simulated.

It is worth noting that an extra turbine could be employed for CO_2 as it coming out of the production well at a higher pressure and would add more to the net electricity generation. The cycle is being operated in such a way that the heat transmission fluid either water/ CO_2 coming out of the cycle nearly equals the injection conditions at the injection well, hence overall cycle is completed. Chemcad 6 has been used to calculate net electricity obtained through the cycle. The overall results are shown in Figure 8. Theoretically, water produces more electricity than CO_2 ,

Figure 8. Net power (MW) and net cumulative electricity (MW-yr) could be generated over time.

but the rate of the decline in net power generation is found to be much more rapid for water than CO_2 as shown in Figure 8.

Although CO_2 has lower pressure drop in the geothermal well and reservoir, but due to its lower heat carrying capacity, less heat is being extracted from the reservoir and thus less power is being produced.

Conclusion

Based on theoretical calculations in this work and other specifications assumed, water is found to produce nearly 70-80% more net power in the initial 10 years of power generation than CO_2 keeping all other parameters exactly same. However, power generation employing water reduces considerably over time giving a disadvantage over CO_2 which seems to produce nearly consistent power generation. After 30 year of plant operation water produces 80% more cumulative electricity than CO_2 .

A important conclusion about CO_2 could be drawn is that it may not require external power circulation as found in this work and the flow of CO_2 through the complete geothermal cycle is possible just on the basis of density difference of cold and hot supercritical CO_2 . So, it could be used as a geothermal fluid in the areas having higher geothermal gradient but facing water scarcity problems.

Loss of water in the reservoir would cost money but loss of CO_2 could be a mean of CO_2 sequestration and hence could earn carbon credits. More frequent fouling in heat exchangers and other units of power plant could be seen employing water because of high minerals dissolved in it, however with CO_2 it might not be the case.

Karsten Pruess³ in his work has shown that approximately 3.7 times flow rate of CO_2 could be achieved over water keeping the pressure drop of the

reservoir to be same and further concluded that CO_2 has more heat extraction rate over water under constant bottom-hole conditions of injection and production well. However, in this study, flow rate of both the fluids are kept same and the more pressure of CO_2 obtained over water (at the production block of the reservoir) is being harnessed at the surface power plant by providing an extra turbine. Further studies are being conducted on the effect of CO_2 flow rates on net electricity production.

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