

Geothermal Energy Production from Oil/Gas Wells and Application for Building Cooling

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ABSTRACT

One significant source of low-temperature geothermal energy is the coproduced hot water from oil/gas field production. In the United States, daily oil production has reached above 8 million barrels per day in recent years. Considering various conditions of wells, 5-10 times this volume of water can be coproduced with a temperature in the range of 120 to 300°F. Like other geothermal resources, such energy source is under-utilized due to its typically long distance from consumption sites. Many oil/gas fields, however, are relatively close (less than 10 miles) to population centers. For instance, some petroleum fields in Pennsylvania are only a few miles away from the towns in the Pittsburgh area and some fields in Texas are quite close to Houston. In this paper, we evaluate geothermal potential from oil/gas wells by conducting numerical simulation and analysis of a fractured oil well in the Hastings West field, Texas. The results suggest that hot water can be continuously coproduced from oil wells at a sufficient rate (about 4000 gallons/day from one well) for more than 100 years. Viable use of such geothermal source requires economical transportation of energy to consumers. The recently proposed two-step geothermal absorption (TSGA) system provides a promising energy transport technology that allows large-scale use of geothermal energy from thousands of oil/gas wells.

1. Introduction

Geothermal energy has been mainly used for power generation using high-temperature hydrothermal resources or enhanced geothermal systems. Many low-temperature (below 300°F /150°C) geothermal resources, however, are also available but rarely used. For example, it is estimated that 25 billion barrels of geothermal fluids (mostly water and some dissolved solids) at 176°F to 302°F (80°C to 150°C) are coproduced annually from oil/gas wells in the United States (DOE 2015). The heat contained in coproduced geothermal fluids (also called “coproduced water”) is typically wasted because the fluids are reinjected into the ground or discharged on the surface without any heat extraction.

Hot water from low-temperature geothermal reservoirs can be used to provide heat for industrial processes, agriculture, or buildings. Such applications are usually called “direct use.” In typical direct-use applications, a well is drilled into a geothermal reservoir and a pumping system is used to extract a stream of hot water from the well. The hot water then delivers heat through a heat exchanger for its intended use. The cooled water can be injected back underground or disposed of on the surface.

Low-temperature geothermal energy can also be used to provide space cooling and refrigeration through absorption or adsorption cooling technologies (Holdmann 2005, Lech 2009, Luo et al. 2010, Kreuter 2012, Wang et al. 2013). Kreuter (2012) studied the required temperatures of energy sources and common cooling agents for the absorption and adsorption chillers. Lech (2009) analyzed the technical and economic feasibility of various cooling/heating systems for a commercial building based on computer simulations. Wang et al. (2013) presented a techno-economical study for a

conceptual design of a large-scale geothermal absorption air-conditioning system, which is proposed to provide base-load cooling to the main campus of the University of Western Australia. The European Geothermal Energy Council (EGEC 2005) projected good future development in the use of geothermal energy for cooling purposes, especially in the warmer regions of Europe, and concluded that “like low-temperature geothermal power production, geothermal absorption cooling is restricted to areas with geothermal resources of about 212°F (100°C) and above.”

In this work, we studied the potential of geothermal heat from a hydraulically fractured shale oil well in the Hastings West field, which is about eighteen miles south of Houston, Texas. Cold water is injected into the fractured well to extract the heat from rocks and connate fluids in the field and hot water alone with oil is produced from the production well. We simulate the production process by running reservoir simulation with a numerical model for the fractured field. The micro-seismic data (collected during the fracturing processes) is used to construct the fracture network in the model. Computer simulations with the reservoir model compute the dynamics of saturations of fluids and gas in the field and estimate the oil and hot water production rates through the production time. We use a heat transfer model to compute heat loss when the hot fluids flow through the bottom of a production well to the surface. The hot water is separated from oil/gas on the surface and can be used for thermal applications.

A case study for utilizing the coproduced hot water from an oil field in Houston, TX to provide space cooling to a large office through an innovative two step geothermal absorption (TSGA) system is also presented in this paper. This case study indicates that the simple payback of the TSGA system is 10.7 years for a 10-mile distance between the oil field and the building.

2. Geothermal Energy From Oil/Gas Wells

USA Energy Information Administration (2015) reported that there are more than 27 million oil/gas wells drilled in the USA. While many of these wells are relatively shallow and with low bottom hole temperatures, there are still hundreds of thousands of deep wells with temperatures in the range of 120-300°F, and at least two million oil/gas wells in the USA have been hydraulically fractured (fractracker.org). The depths of fractured wells are typically in the range of 6,000-13,000 feet. Based on the typical temperature gradient in the crust of the earth (1°/70ft), the hot rocks at the bottom of wellbores are usually at 120-250°F.

The geothermal energy potential from oil/gas wells can be roughly estimated based on existing well data (national geothermal data system, NGDS). In Texas, for instance, hundreds of thousands of petroleum wells have been drilled in the past decades. Figure 1 shows the borehole temperatures of 13,539 oil/gas wells in Texas as recorded in an NGDS dataset (NGDS 2015). Based on the dataset, about 31% of these wells (4,183 of 13,539 wells) have borehole temperatures higher than 200°F. Note that there are many more wells drilled in Texas than reported in NGDS and many more wells recently drilled in Texas are deeper, fractured horizontal wells with higher borehole temperatures.

Oil wells produce large volumes of hot water, particularly in their late stage of production. The average water-oil ratio (WOR) of oil fields in Texas is estimated around 14 to 21 (Welch and Rychel 2004), which means for each barrel of crude oil production, 14-21 barrels of hot water is produced from an oil well. Although temperature data is not available at high enough resolution to support an accurate calculation of heat content, the magnitude can be illustrated as follows. If we assume that the average coproduced fluid temperature is 226°F, then 4,000 bbl hot water produced from an average oil well each day represents about 100 MBTU/day thermal energy (assuming a 70°F temperature difference). Applying this set of assumptions to oil production in the entire US (8 million barrels per day), coproduced fluid would contain 0.7 Quads/year, 2.5% of the primary energy derived from natural gas in the US in 2015.

3. A Case Study of Geothermal Production From an Oil Well

To evaluate the geothermal heat production potential of the oil/gas wells, a simulation study was performed with a numerical model of a hydraulically fractured oil well in the Hastings West oil field. The Hastings oilfield is located eighteen miles south of Houston, TX. The field is approximately five miles long and four miles wide. It was discovered on

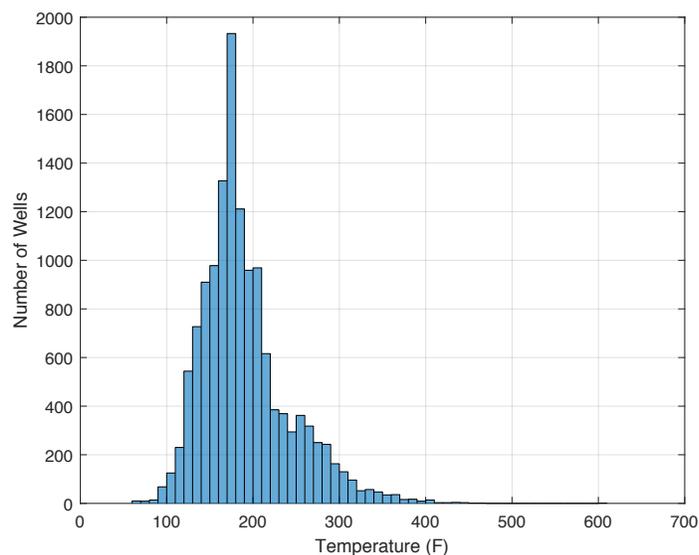


Figure 1. Texas oil/gas well borehole temperatures (National Geothermal Data Systems).

Figure 2. Monthly oil and water productions from three wells in Hastings West field.

December 23, 1934 and was divided into Hastings East and Hastings West in 1958. The Hastings field is in an advanced (late) stage of primary depletion and enhanced oil recovery systems are needed to further produce oil from the wells. According to the oil/gas well data shown in NREL’s geothermal prospector, the wells in the vicinity of the Hastings oil field have bottom hole temperature (BHT) of above 212°F (100°C). Figure 2 shows that the WOR ratio for the three wells in Hastings West field is greater than 10 during the measurement time period of years 2002-2010. Conservatively assuming the WOR

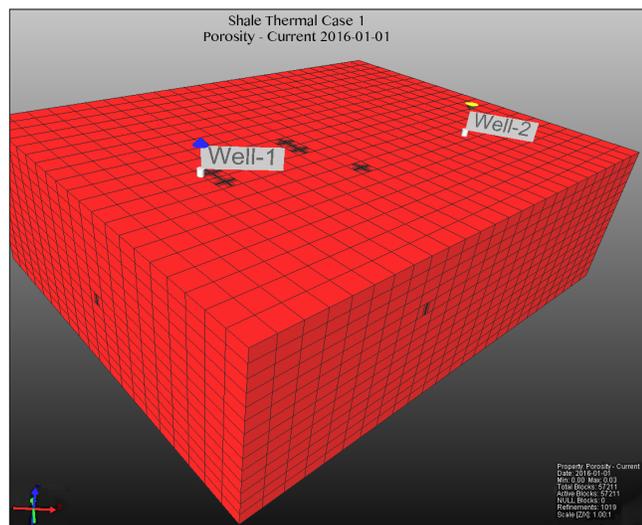
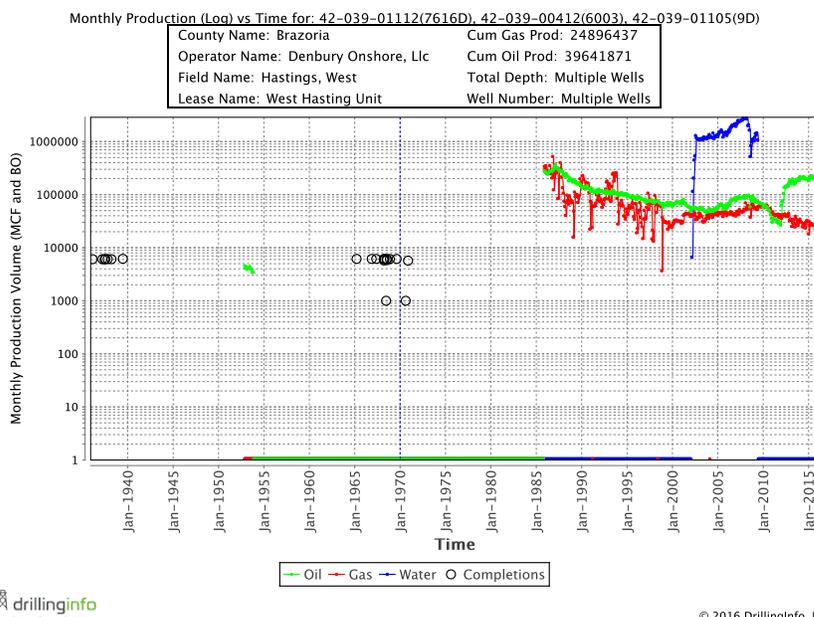


Figure 3. A 3D discrete reservoir model for part of the Hasting West field.

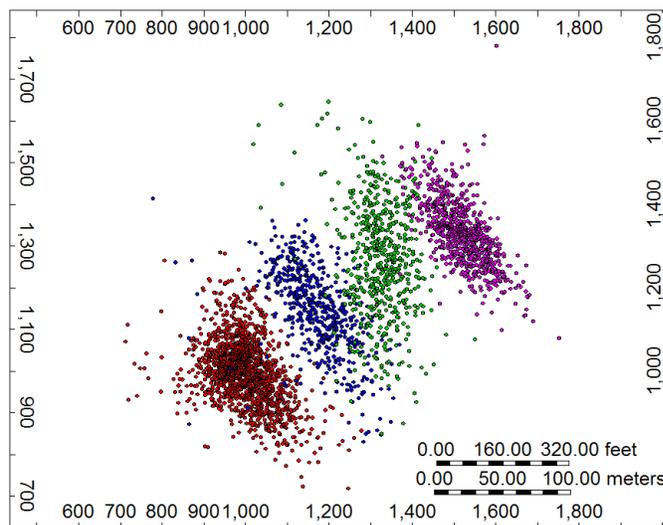


Figure 4. Micro-seismic events from hydraulic fracturing processes.

of the oil wells in the Hastings field is 10, then combining both west and east fields the total annual co-produced water production is 25,585,770 bbl/year.

3.1 Modeling a Fractured Oil Field

The considered well stimulated a reservoir area of about 1500x1000x500 (ft^3). The well was drilled at a depth of 9,860 feet below the surface. The temperature at the bottom of the well is 226°F. We assume the considered reservoir has the same 226°F temperature throughout the field. In reality, there is a vertical temperature gradient in the field. However, since major heat transfer occurs at the fractures close to the wellbore, the error resulting from the assumption of uniform temperature in the field is thought to be negligible.

The field has been numerically modeled and simulated with a discrete reservoir model of 26x20x14 blocks (Figure 3), with each block of the same size. To develop thermal energy from this hydraulically fractured shale field, we use two wells: Well-2 is used to inject cold water (50°F) and well-1 is used to produce hot water to the surface.

To evaluate thermal production from this field, we need to accurately simulate the fluids (water, oil, and gas) flow in the field. The injected water flows through the field fractures to extract heat from connate fluids and hot rocks. It is important to have a valid model to represent the fracture network hydraulically induced within the field. We use micro-seismic data to predict and model the stimulated fracture network. Figure 4 shows a number of micro-seismic events occurred during

Figure 5. Fracture network model based on micro-seismic data.

the hydraulic fracturing procedure (4-dimensional micro-seismic data projected to a 2D plane). Different colored groups of dots represent the events associated with four different stages of fracturing. Each of the micro-seismic events suggests that either a new fracture is created or an existing fracture gets expanded longer or wider. Based on the seismic data analysis, the complex fracture network generated by the four-stage hydraulic fracturing process is shown in Figure 5.

3.2 Simulation of Geothermal Production From the Fractured Oil Field

In order to evaluate the potential of the fractured oil field in producing hot water and the impact of hot water production on the field temperature over a long term, a geothermal reservoir simulation was carried out. The flows of fluid and heat are modeled based on two sets of partial differential equations (PDEs): the mass balance and energy balance equations (Faust, et al. 1979). The mass balance combined with the Darcy's law provides the following mass balance flow PDEs:

$$\nabla \left[k k_{r\alpha} y_{i,\alpha} \frac{\rho_\alpha}{\eta_\alpha} (\nabla P_\alpha - \rho_\alpha g \nabla z) \right] = \frac{\partial}{\partial t} (\phi \rho_\alpha S_\alpha y_{i,\alpha}) + q_{i,\alpha} \quad (1)$$

$$i \in \{water, oil, gas\},$$

where three components i water, oil, and gas are considered in the field. The notation for the properties of rock and fluids includes: the rock permeability k , the relative permeability $k_{r\alpha}$ for phase α , component density ρ_α in phase α , the fluid viscosity η_α , the gravity factor g , phase pressure ρ_α , z is the vertical flow distance, ∇ represents the differential operator, ϕ is the rock porosity, S_α is the saturation of phase α , $y_{i,\alpha}$ is the proportion of component i in phase α , and $q_{i,\alpha}$ is the source term of component i in phase α for the control volume. Note that the pressure ρ_α and the fluid saturation S_α are unknown variables for PDEs.

To evaluate heat extraction by the produced water, a set of heat/energy balance equations for multiple phase flow in the porous reservoir is formulated as follows.

$$\sum_\alpha \left(\frac{\partial (\phi \rho_\alpha S_\alpha H_\alpha)}{\partial t} + \nabla \cdot (\rho_\alpha S_\alpha H_\alpha u_\alpha) \right) + \frac{\partial (1-\phi) \rho_r H_r T}{\partial t} - \nabla \cdot (k_T \nabla T) = 0 \quad (2)$$

where H_α is the specific heat capacity of phase α , u_α is the flow rate of phase α , ρ_r is the rock density, H_r is the specific heat capacity of rock, and T is the temperature. Reservoir simulators solve both (1) and (2) PDEs for production quantities and the amount of heat extracted from the field in the course of production.

Since the simulated well has produced oil for many years and it is at the late stage of primary depletion, it is assumed that there is little oil remaining and the well mainly produces hot water. To extract thermal energy from the field, cold water (50°F) is injected into well-2 and hot water (226°F) is produced from well-1. The simulated injection well has a maximum 2200 psi pressure at the bottom of the well. The production well has a hot water flow rate of 4,000 bbl/day. It is assumed that the well will be operated continuously for 100 years.

The field's temperature changes through the production time. In particular, the temperature around the injection well is reduced first and the most as the cold water is injected into this perforated well. The injected water then slowly flows through the fractures within the reservoir. During the transport time from the injection well to the production well, the water is heated up to the 226°F field temperature. Figure 6 shows the simulated field temperatures of the blocks affected by the water flow through the fractures after 100 years of production. Figure 7 presents a horizontal-section top view of the

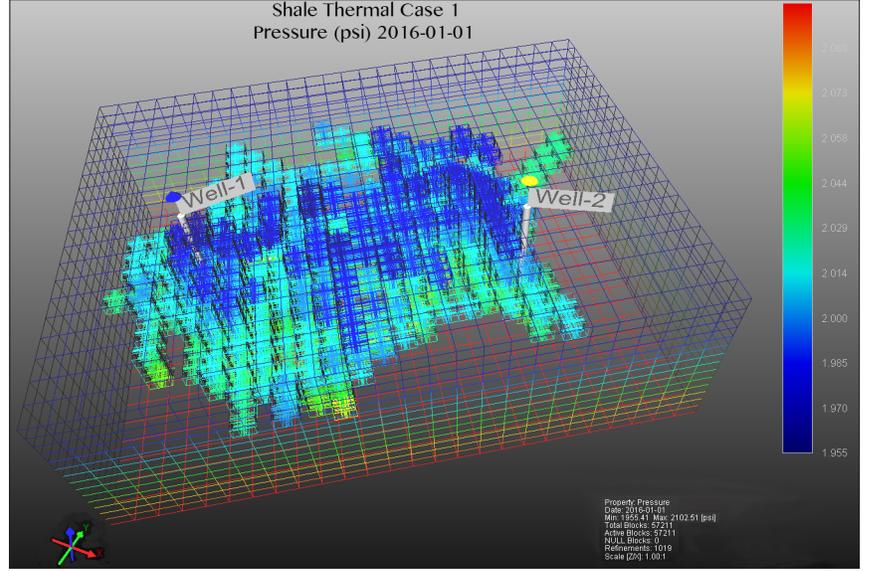
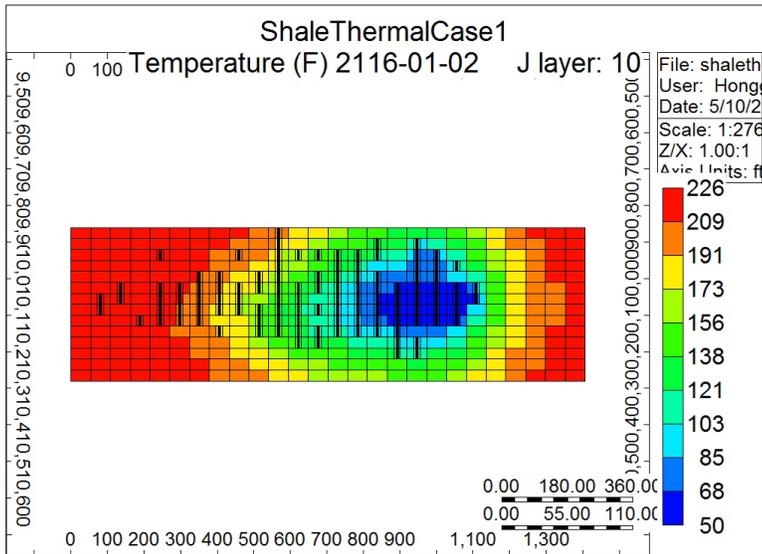
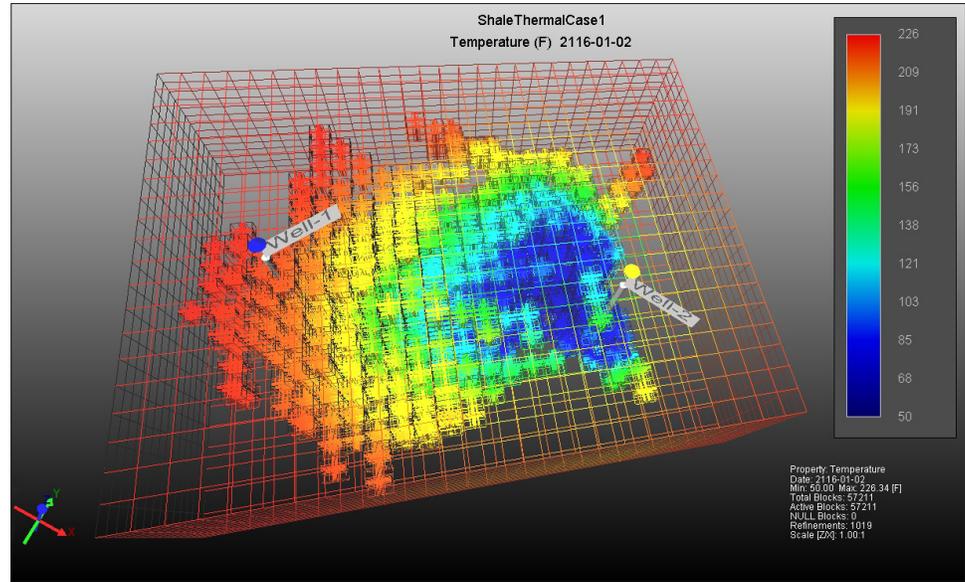


Figure 6. Field temperatures after 100 years of geothermal production.

temperature field at the middle pane of the reservoir after 100 years of production. The results show that the field can still produce 226°F hot water (at well bottom) after 100 years of continuous operation. As shown in Figure 8, almost all the fluids originally in the fractures have been swept by the injected water.

The hot water will lose some heat when it flows from the bottom of the production well to the surface. We use the following model (Kolo, et al. 2014) to estimate the temperature of the produced water at the surface.



$$T_f(d,u) = T_{bh} - ad + aA \left(1 - e^{-\frac{d}{A}} \right) \quad (3)$$

where u is the production rate, T_{bh} is the wellbore temperature at the bottom, α is the temperature gradient in the field, and d is the distance at the measurement point from the well bottom, and A is a time function (Ramey 1962) defined as follows.

$$A = \frac{uc \left[k + rUf(t) \right]}{2\pi rUk},$$

where c is the heat capacity of water, k is the thermal conductivity of rock, r is the casing radius of well, and U is the overall heat transfer coefficient between the fluid in tubing and the formation outside of casing. The coefficient U can be calculated as below.

$$\frac{1}{U} = r \left(R_f + R_c + R_{cem} \right),$$

where R_f , R_c , R_{cem} are the thermal resistance of fluids, casing, and cement in the simulated well. The time transient heat conduction time function can be estimated as (Kolo, et al., 2014):

$$f(t) = \ln \left(e^{-0.2t} + (1.5 - 0.3719e^{-t}) \sqrt{t} \right)$$

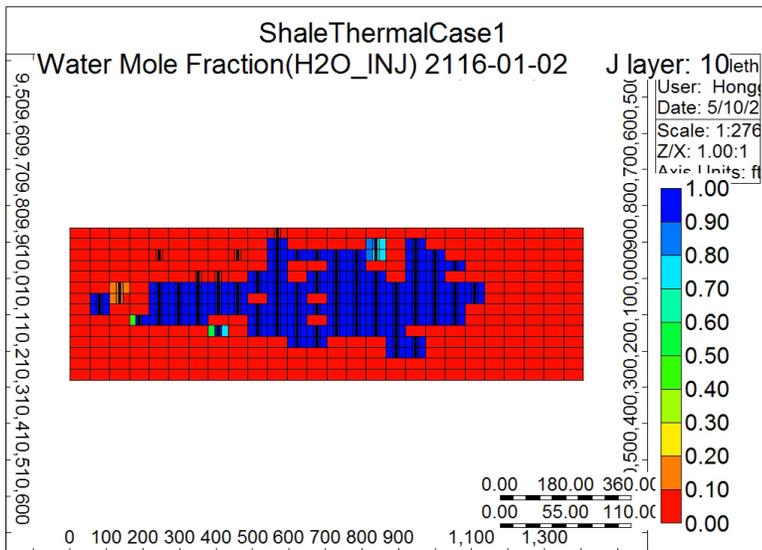


Figure 7. Temperature distribution in the field after 100 years (horizontal-section top view).

Figure 8. Injection water distributed in the field after 100 years (horizontal-section top view).

In our case study, the production well-1 has the casing size 7 inches diameter (6.366in inside diameter). The well is 9,860 feet deep and the bottom hole temperature is 226°F. We use the geothermal gradient $a = 0.0083^\circ F / ft$ and assume the surface temperature is 58°F. Based on Equation (3), Figure 9 plots the temperature loss when the water flows from wellbore bottom to wellhead (surface). Therefore, for this case, the produced hot water has a temperature around 212°F on the surface.

Based on this simulation study, we conclude that the hydraulically fractured wells in Hastings West field can be used to produce large amounts of hot water for at least 100 years. In the above simulations, it is assumed that 50°F cold water is injected into the field. However, if the produced hot water is re-injected into the field after transferring heat through a heat exchanger, the water injection temperature will be much higher than 50°F. In this case, a much longer production time could be expected before the field temperature drops. As the following analysis demonstrates, with TSGA, these hot water can be efficiently and economically used for cooling large buildings.

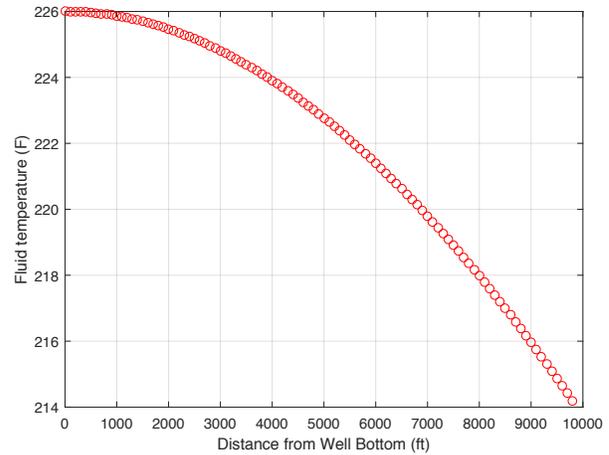


Figure 9. Heat loss of hot water from wellbore bottom to surface.

4. Transport of Geothermal Energy Via TSGA

4.1 TSGA System

TSGA system and technologies are proposed by Liu, et. al. (2015). As illustrated in Figure 10, TSGA system decouples the chilled water production and desiccant regeneration of the conventional closed-loop absorption cycle into two steps. The first step is regeneration and takes place near the geothermal resource (i.e., the oil field). A weak solution of lithium bromide (LiBr) and water, or other working fluids, is heated using geothermal heat to drive off the moistures in the solution. The resulting concentrated strong solution is then allowed to cool down to ambient temperature at the geothermal site and is transported to commercial or industrial buildings by tanker trucks (or other means, including trains or ships). The second step is to produce chilled water at the building site, where liquid water is evaporated to cool the chilled water and then the water vapor is absorbed by the strong solution. The diluted weak solution is then transported back to the geothermal site for regeneration. The processes of these two steps repeat for continuous operations of TSGA.

TSGA provides a promising technology that can be used for economical transportation of geothermal energy produced from oil/gas wells to consumers. The following section summaries the results (Liu, et al. 2016) that demonstrate the viable application of geothermal energy from oil/gas wells for providing space cooling in buildings.

4.2 A Case Study of TSGA for Geothermal From Oil Wells

A case study for applying the TSGA system to a large office building in Houston, Texas is conducted to evaluate the economic viability of the application of geothermal energy from oil wells via TSGA. The office building has a total floor space of 498,588 ft² (46,320m²) and it is designed in accordance with the American Society of Heating Refrigerating and Air-Conditioning Engineers (ASHRAE) Standard 90.1-2004 (ASHRAE 2004). Details of this building are described in a technical report by Deru et al. (2011). The baseline cooling system for the large office building includes two water-cooled electric-driven centrifugal vapor compression (VC) chillers with a total capacity of 871 tons (3063 kW_{clg}), a wet cooling tower, a pump to circulate condensing water between the cooling tower and the chiller, and other HVAC components inside the building, such as the distribution system for the chilled water, air-handling-unit, fan coils, or other heat-transfer terminals.

As analyzed by Liu, et al. (2016), a 900 ton (3,165 KW) two-step absorption chiller is used in the TSGA system for cooling the considered building. Under normal operations, this TSGA requires about 28,068 bbl/day hot water produced from oil wells in the Hastings West field. Based on our simulation study (Section 3), we need about 7 similar wells at a rate of 4,000 bbl/day or higher and producing 212°F water.

To evaluate the economic viability of the TSGA system, its initial and operating costs are compared with the conventional baseline system. The initial cost of the baseline system includes the costs for the VC chiller and associated equipment; the initial cost of the TSGA system includes the cost of the LiBr/H₂O solution and holding tanks in addition to the cost of the absorption chiller and the other associated equipment. Initial cost of the major equipment used in the TSGA

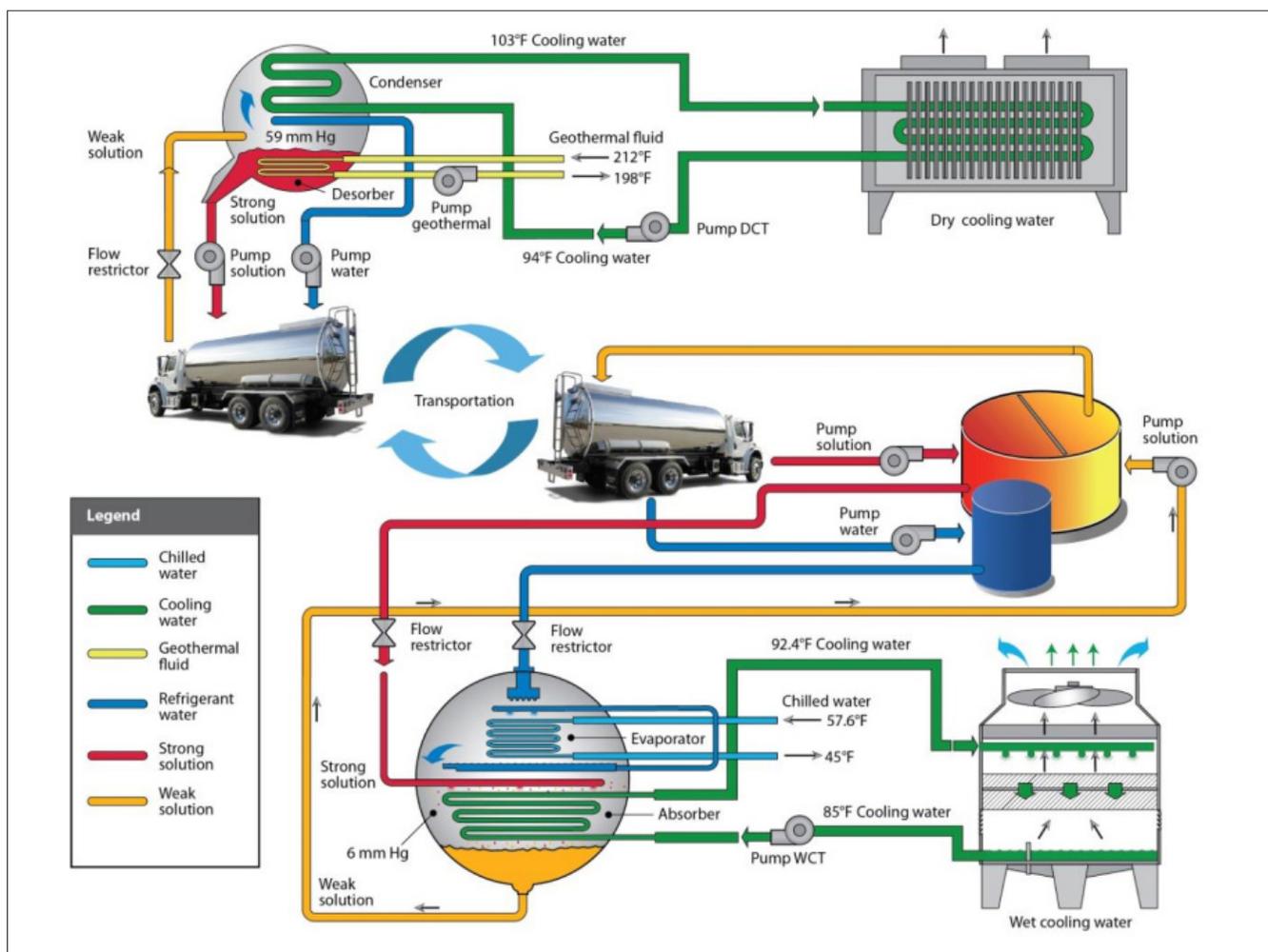


Figure 10. Schematic of the two-step geothermal absorption cooling system (Liu, et al. 2015).

and the baseline system are calculated with RSMears Mechanical Cost Data (Reed Construction 2010), which includes costs of material/equipment, labor, and overhead and profit. The operating cost of the baseline system is the electricity cost for operating the chiller and the associated equipment (i.e., cooling tower and circulation pump). The operating cost of the TSGA system includes the electricity cost for operating the cooling tower and circulation pumps, as well as the cost for transporting LiBr/H₂O solution back and forth between the geothermal site and the building. The operating electricity costs of the two systems are calculated based on the building cooling load, equipment efficiency, and electricity price in Houston area (\$0.102/kWh). The transportation costs involved with the TSGA system is estimated based on an operation schedule of the tanker trucks to keep continuous operation of the TSGA system (Liu et al. 2015) and the national average of the operating costs of trucking (Fender, et al. 2013). Details for calculating the initial cost and the operating cost of the two systems are described in Liu, et al. (2015).

The costs of the baseline and the TSGA system are calculated assuming a 10-mile distance between the geothermal site and the office building. TSGA system has higher initial cost than the baseline system. However, the TSGA system has less operating cost than the baseline system. Overall, TSGA reduces electricity consumption by 72% compared to the baseline system. Given the initial costs and the annual operating costs of the two systems, the payback of the TSGA system is estimated to be 10.7 years.

5. Conclusions

Large amounts of low-temperature geothermal energy can be produced from many existing oil/gas wells. Computer simulations and a case study are performed to demonstrate that such an abundant and sustainable energy source can be used for cooling large buildings via TSGA technology. Considering the zero or low costs of producing hot water from oil wells, such geothermal source with TSGA system is economically viable and can reduce energy costs for long term.

Acknowledgement

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