In situ upgrading of oil shale by Steamfrac in multistage transverse fractured horizontal well system

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In this article

ABSTRACT

We conduct numerical simulations of kerogen pyrolysis by the in situ upgrading process of Steamfrac, which entails the steam or hot-water injection into multistage transverse fractured horizontal well systems, by using a fully functional simulator developed to describe the in situ upgrading process. We first conduct simulation cases of a huff-n-puff method to analyze the sensitivity of temperature distribution of the reservoir to the positions of horizontal wells. Then, we conduct continuous hot-water injection and simultaneous fluid production cases, and analyze the productivity by applying two different irreducible saturations of aqueous phase in the rock matrix.

KEYWORDS: Hot water injection, hydraulic fracture, kerogen, in-situ upgrading, oil shale

Introduction

Oil shale should be heated up to a very high temperature of 610°F for the decomposition of kerogen into the products including hydrocarbons. There are two approaches of thermal processes for the kerogen decomposition—mining followed by surface pyrolysis and in situ upgrading process. Here we study the in situ upgrading process, which is applicable to the majority of oil shales regardless of the formation depths.

Steamfrac method implements the oil shale in situ upgrading by steam or hot water flowing in the vertical hydraulic fractures of multistage transverse fractured horizontal well system (Thoram and Ehlig-Economides, 2011Thoram, S., and Ehlig-Economides, C. A. 2011. Heat transfer applications for the stimulated reservoir volume (Srv). *SPE Annual Technical Conference and Exhibition*, Denver, CO, tober 30–November 2. [Google Scholar]). The injected water component of objective temperature between 610 and 650°F usually exists as liquid hot water (aqueous phase) in the reservoir due to the high pressure of reservoir systems. In this study, we conduct the two sets of simulation cases of the Steamfrac method by using the simulator developed to describe the kerogen pyrolysis in oil shale reservoir systems (Lee, Moridis, and Ehlig-Economides, 2015Lee, K., Moridis, G. J., and Ehlig-Economides, C. A. 2015. A comprehensive simulation model of kerogen pyrolysis for the in-situ upgrading of oil shales. *SPE Reservoir Simulation Symposium*, Houston, TX, February 23–25. [Google Scholar]). In the first set of cases, we apply the huff-n-puff method and analyze the heating patterns by using three different positions of horizontal wells. In the second set of cases, we perform two simulation cases with different irreducible saturations of aqueous phase by using the well pattern showing the most efficient heating, which is found from the first set of cases. Because the injected water component exists as liquid hot water in our reservoir system, the irreducible saturation of aqueous phase is expected to significantly affect the flow behavior and the productivity.

Methodology

The kerogen pyrolysis simulator describes the non-isothermal multiphase–multicomponent systems involving multiple chemical reactions of kerogen and

hydrocarbons decomposition. In the simulations, the system changes are computed based on the coupled flow of fluid and heat.

Properties of the oil shale reservoir system

Oil shale formations contain sodium carbonate minerals mixed with kerogen, and natural fractures can occur in this kind of calcareous shales (Dyni, 2006Dyni, J. R. 2006. *Geology and resources of some world oil-shale deposits*. US Department of The Interior, US Geological Survey. [Google Scholar]). We apply multiple interacting continua method to describe the naturally fractured media (Pruess, 1985Pruess, K. 1985. A practical method for modeling fluid and heat flow in fractured porous media. *Soc. Pet. Eng. J*. 25:14–26.[Crossref], [Web of Science ®], [Google Scholar]). The presence of a natural fracture system enables the continuous water injection and simultaneous fluid production, despite the low porosity and permeability of the formation. The Reservoir properties and the initial conditions of our simulation cases are listed in Table 1.

Table 1. Reservoir properties and initial conditions.

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As kerogen decomposes into the fluid and solid products, volume of the pore space for the fluid flow changes. We compute the fluid phase permeability by applying the Parker's method and the original porous model, which accounts for the fluid relative permeability as changing by the amount of solid phase in the pore (Moridis, 2014Moridis, G. J. 2014. TOUGH+ HYDRATE v1. 2 User's Manual: A code for the simulation of system behavior in hydrate-bearing geologic media. [Google Scholar]; Parker, Lenhard, and Kuppusamy, 1987Parker, J. C., Lenhard, R. J., and Kuppusamy, T. 1987. A parametric model for constitutive properties governing multiphase flow in porous media. *Water Resour. Res*. 23:618–624.[Crossref], [Web of Science ®], [Google Scholar]). The mechanical effect of the changes of pressure and temperature on the media porosity is applied in the simulation by using the following equation:

$$\phi = \phi_{ref} \exp\left[C_\phi (P - P_{ref}) + \alpha_T (T - T_{ref})\right] \quad (1)$$

where ϕ is the media porosity including fluids and solid phases; ϕ_{ref} is the reference porosity at the reference pressure (P_{ref}) and the reference temperature (T_{ref}); C_ϕ is the pore compressibility; α_r is the pore thermal expansivity; P is the system pressure; and T is the system temperature.

Chemical reactions of the in situ upgrading process

The kinetic reactions of kerogen pyrolysis and corresponding reaction parameters are listed in Table 2(Wellington et al., 2005Wellington, S. L., Berchenko, I. E., De

Rouffignac, E. P., Fowler, T. D., Karanikas, J. M., Ryan, R. C., Shahin Jr, G. T., Stegemeier, G. L., Vinegar, H. J., and Zhang, E. 2005. *In situ thermal processing of an oil shale formation to produce a condensate*. Google Patents. [Google Scholar]). KER, PRCH, and CHAR indicate kerogen, prechar, and char, respectively. Prechar and char are the solid carbons generated from the reactions. We describe the heavy oil, light oil, and hydrocarbon gas as the integrated components with carbon number 22, 11, and 2, respectively.

Table 2. Chemical reactions and reaction parameters of the in situ upgrading process (Wellington et al., 2005Wellington, S. L., Berchenko, I. E., De Rouffignac, E. P., Fowler, T. D., Karanikas, J. M., Ryan, R. C., Shahin Jr, G. T., Stegemeier, G. L., Vinegar, H. J., and Zhang, E. 2005. *In situ thermal processing of an oil shale formation to produce a condensate*. Google Patents. [Google Scholar]).
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First reaction is the kerogen decomposition into water, heavy oil, light oil, hydrocarbon gas, hydrogen, carbon dioxide, and prechar. Second to fifth reactions are the cracking of the oil components. In these reactions, heavy oil and light oil components in the gaseous phase and the liquid organic phase crack into the lighter hydrocarbons and solid products. Sixth reaction is the coking of hydrocarbon gas into hydrogen and char. We can compute an activation temperature for each reaction by using the reaction parameters. The activation temperatures for the six reactions are 554, 626, 626, 626, 626, and 680 °F, respectively.

Governing equations

The numerical simulator we use in the simulation cases accurately accounts for the coupled flow of fluid and heat in porous and fractured media, chemical reactions, changes of the properties of phases and bulk oil shale rock, and phase equilibrium and phase transition thermodynamics. The governing equations, which are described by mass balance and energy balance equations, are defined as the integral form as follows:

$$\frac{d}{dt}\int_{V_n} M^{\kappa(\theta)} dV_n = \int_{r_n} \mathrm{F}^{\kappa(\theta)} \cdot \vec{n} d\tilde{A} + \int_{V_n} q^{\kappa(\theta)} dV_n \quad (2)$$

where V_n and Γ_n are the volume and the surface area of grid block *n*, respectively. $M^{\kappa(\theta)}$, $F^{\kappa(\theta)}$, and $q^{\kappa(\theta)}$ are the accumulation term, flux term, and source/sink term of component κ and heat, respectively.

The system includes 4 phases and 10 components, which are resulted from the kinetic reactions we are considering. Aqueous, liquid organic, gaseous, and solid phases contain heavy oil (IC_{22}), light oil (IC_{11}), hydrocarbon gas (IC_2), water (H_2O), hydrogen (H_2), carbon dioxide(CO_2), nitrogen(N_2), kerogen, prechar, and char components.

Simulation cases and results

Simulation cases of the huff-n-puff method

Three cases of the huff-n-puff methods are simulated to find the positions of the horizontal wells that heat the formation most effectively. The concept of each case is provided in Figure 1, and the positions of the horizontal wells on hydraulic fracture plane are shown in Figure 2. In the first case, one horizontal well, which was used to make the hydraulic fractures, is used for both injection and production. In this case, hot water of T = 650°F is injected into the well for one day; injected hot water is soaked into the formation for another one day after the injection; fluid is produced from the well for next one day. This three-day cycle of injection, soaking, and production is repeated until t = 300 days. The rate of injection and production is 3,175 lbm/h in one hydraulic fracture unit.

Figure 1. Three concepts of the huff-n-puff cases.

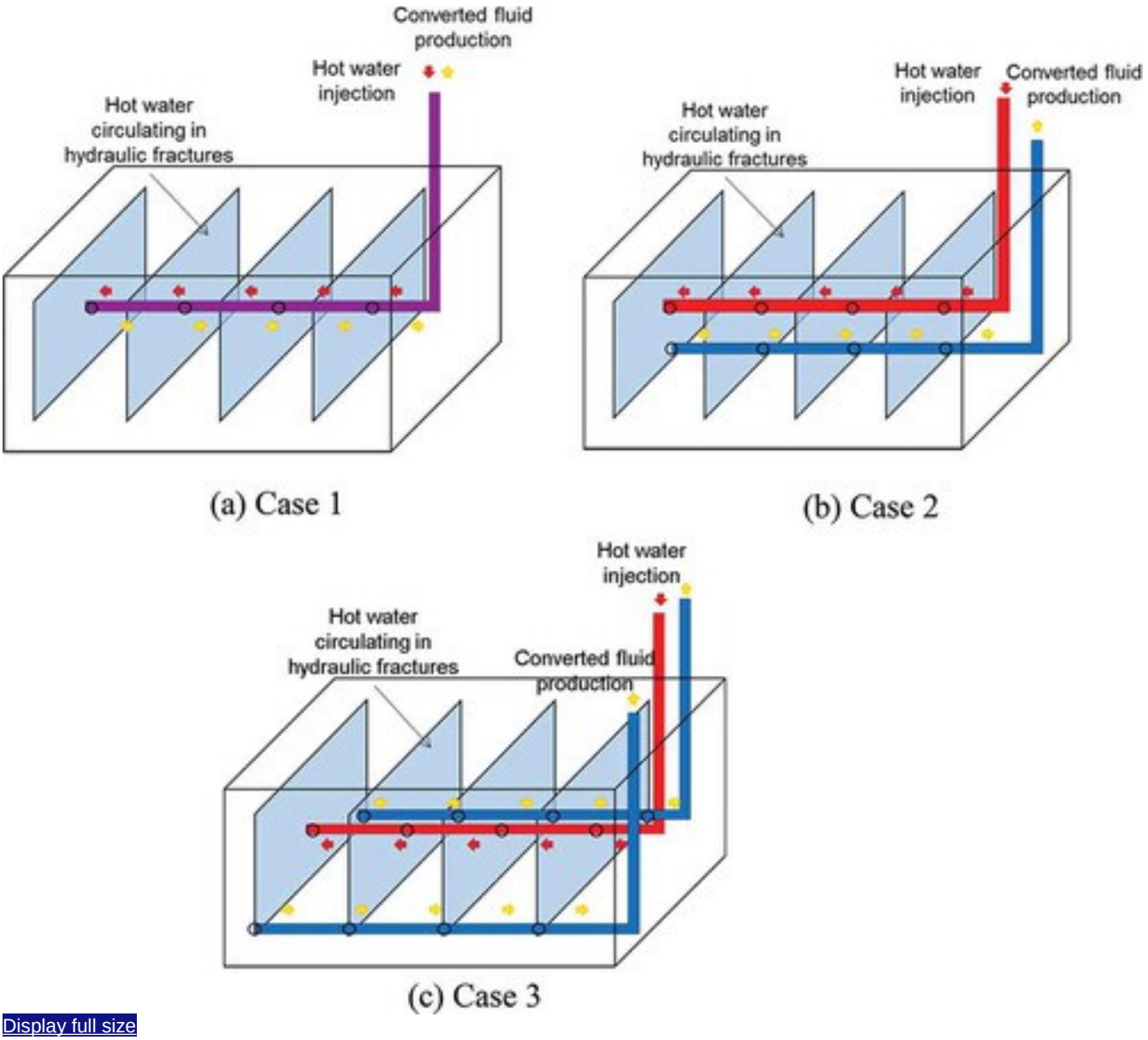

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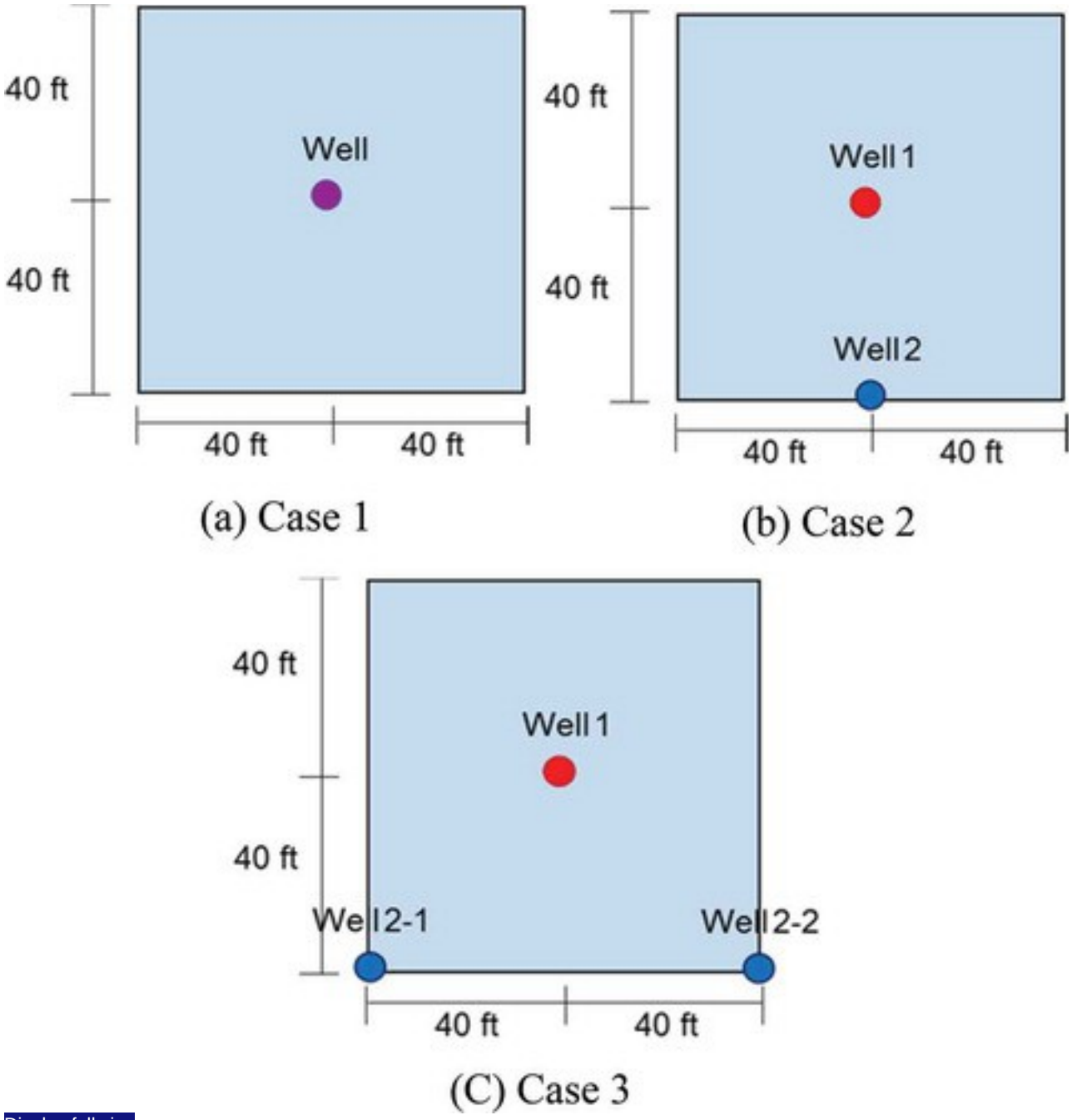
Figure 2. Well positions on the hydraulic fracture plane in the huff-n-puff cases.



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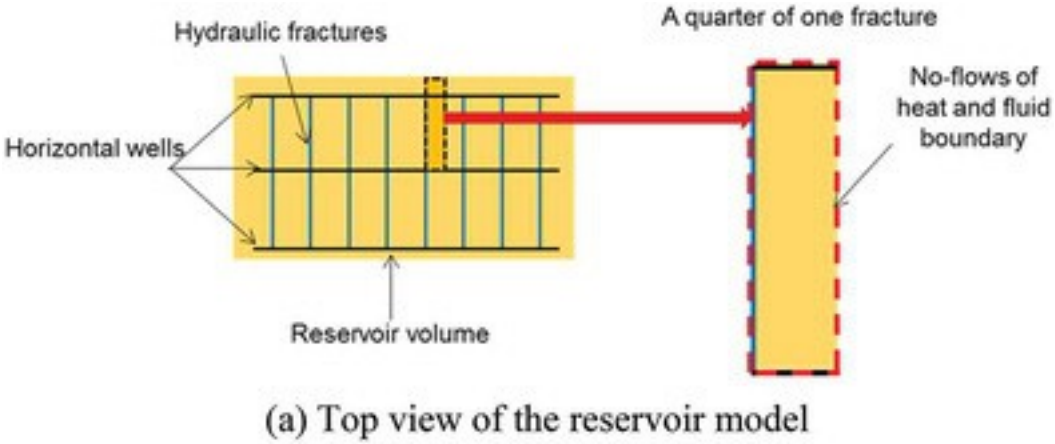
In the second case, an additional horizontal well drilled at the bottom center of the reservoir is used. In this case, hot water is injected into well 1 at the reservoir center for 1 day; injected hot water is soaked into the formation for another 1 day after the injection; fluid is produced from well 2 at the reservoir bottom for next one day. The injection and production wells are switched every 30 days.

In the third case, two horizontal wells drilled at the bottom edges of the reservoir are used additionally. Hot water is injected into well 1 at the reservoir center for 1 day; injected hot water is soaked into the formation for another 1 day after the injection; fluid

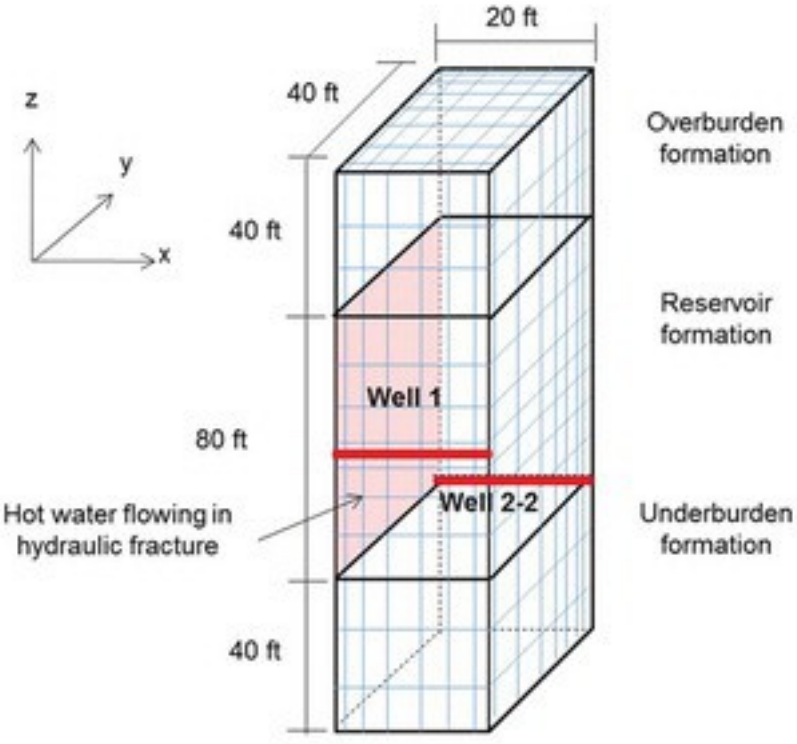
is produced from well 2-1 and well 2-2 at the reservoir bottom for next 1 day. The injection and production wells are switched every 30 days as the second case.

The reservoir top view and the simulation model of case 3 are provided in Figure 3. The minimum dividable unit of the reservoir – a quarter of one hydraulic fracture unit – is simulated by using a 3D model. The set of hydraulic fractures has 80 ft height, 80 ft length, and 40 ft spacing. At the six boundaries, the boundary condition of no flows of fluid and heat is applied.

Figure 3. Reservoir top view and simulation model of huff-n-puff case 3.



(a) Top view of the reservoir model



(b) Simulation model geometry

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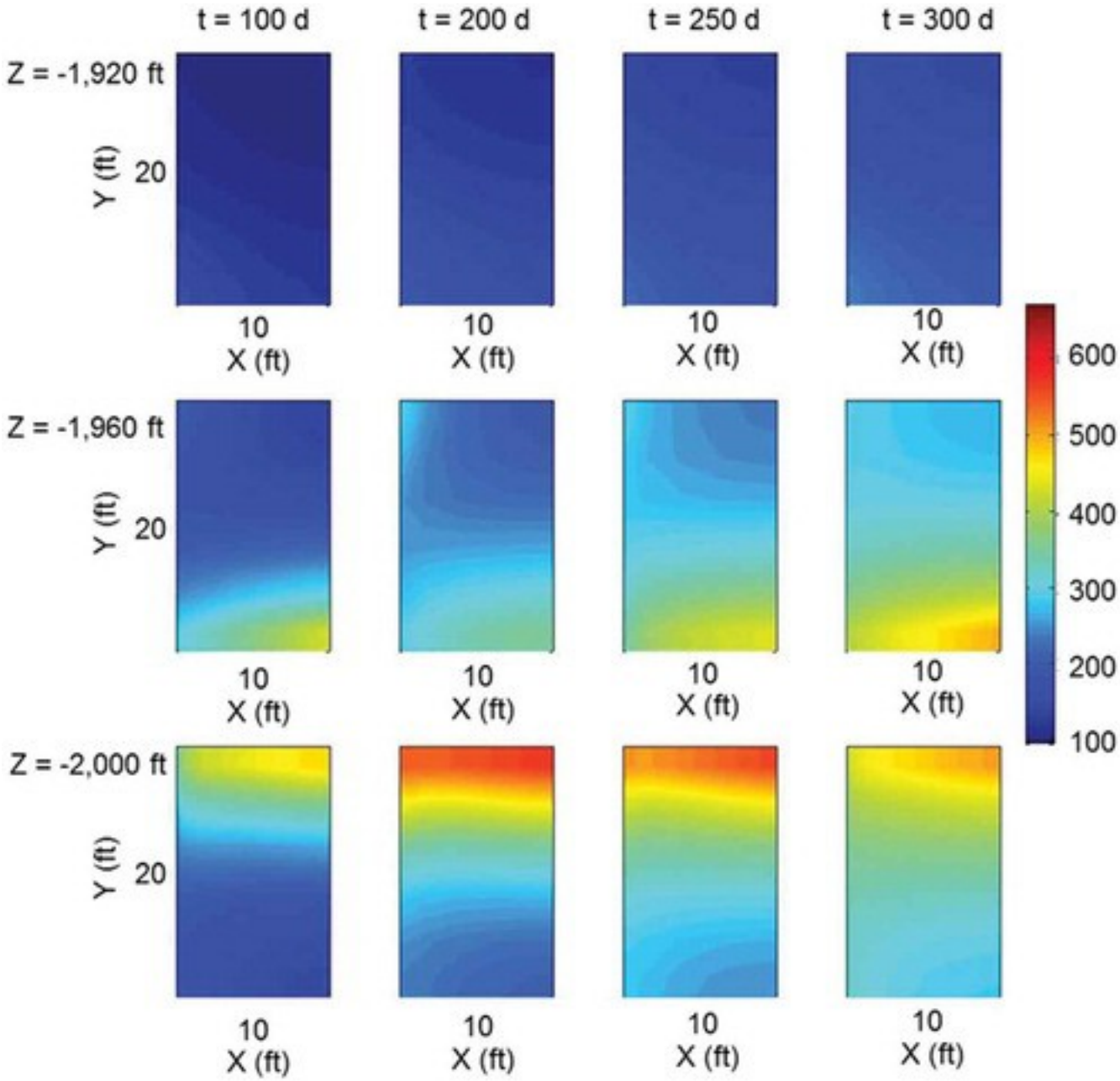
From the simulation runs, case 3 shows the widest heating area among the cases. The temperature profiles of case 3 are provided in Figure 4. From the temperature profiles, the huff-n-puff method is found to need a long time period for kerogen decomposition in the system, even in the most effective case (case 3). It is also expected that the converted hydrocarbons will rise in the soaking period by the gravity, and they will be hardly produced in the subsequent production period.

Figure 4. Profiles of temperature distribution in huff-n-puff case 3.



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Simulation cases of continuous injection and simultaneous production

From the simulation cases of the huff-n-puff method, we expect that the continuous injection and simultaneous production will be more efficient to heat the oil shale formation and will produce converted fluids in a short time. In this simulation example, we use the simulation model of three horizontal wells in Figure 3 and simulate the process of continuous hot-water injection and simultaneous fluid production. Two simulation cases having different irreducible saturations of aqueous phase in the matrix domain are conducted. Cases 1 and 2 have the irreducible saturations of aqueous phase of 0.3 and 0.2, respectively.

In each case, hot water in one hydraulic fracture unit is injected into well 1 at the rate of 3,175 lbm/h, and a fluid is produced by using the constant bottom-hole pressure at well 2-1 and well 2-2. The injection and production wells are switched every 50 days, and the injection and production processes are continued for 2 years.

The results of the simulation cases are provided in Table 3. The numbers represent the values for one hydraulic fracture unit. The total hydrocarbon production is computed by using the conversion factor of 0.1770 BOE/MSCF (barrel of oil equivalent/thousand standard cubic feet per day) of hydrocarbon gas. Case 1 (S_{irA} = 0.3) has more remaining kerogen in place and more hydrocarbon production than case 2 (S_{irA} = 0.2) at the end of the process. This was caused by the aqueous phase that conveyed the most heat into the formation and could flow more easily in case 2.

Table 3. Simulation results of continuous injection and simultaneous production using different irreducible saturations of aqueous phase.

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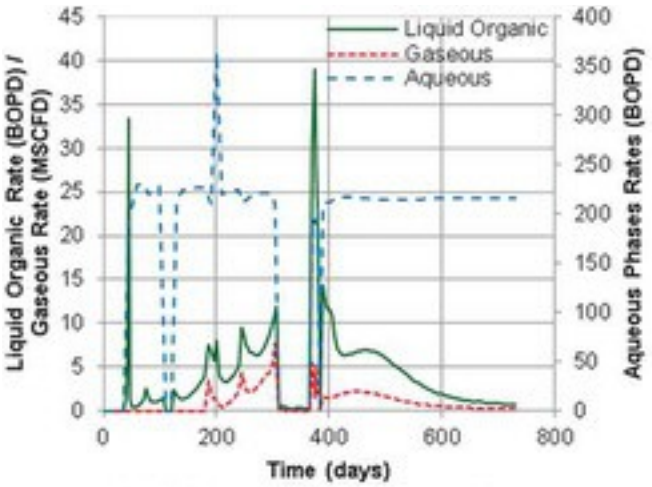
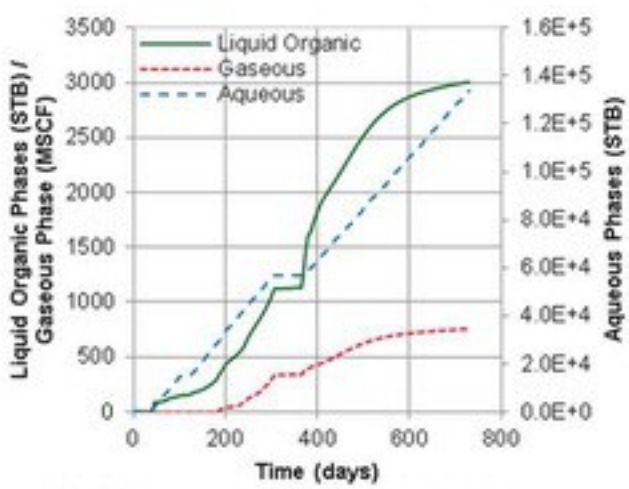
The graphs of the simulation results of case 1 are shown in Figure 5. Figure 5a shows that the production rates of liquid organic phase and gaseous phase fluctuate, as the injection and production wells are switched repeatedly. In Figure 5b, it is found that the cumulative productions of liquid organic phase and gaseous phase reach to the constant values at the end of the process, while the cumulative production of aqueous phase continuously increases through the process. In Figure 5c, it is found that the light oil component has higher mass fraction than the heavy oil component in the produced liquid organic phase. In Figure 5d, it is found that the hydrocarbon gas is dominant in the produced gaseous phase throughout the whole process.

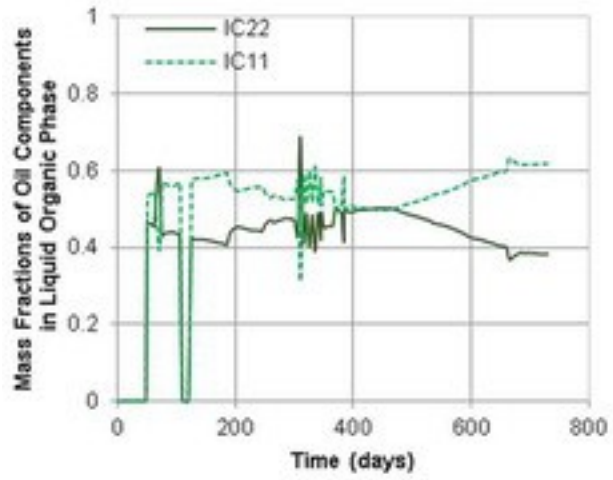
Figure 5. Simulation results of case 1 of continuous injection and simultaneous production.



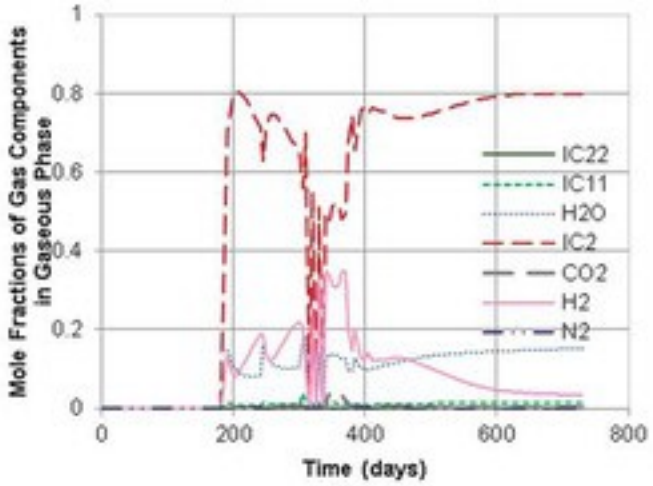
(a) Phases production rates



(b) Phases cumulative productions



(c) Mass fractions of oil components in produced liquid organic phase



(d) Mole fractions of gas components in produced gaseous phase

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Conclusions

In this study, we simulated the diverse cases of the Steamfrac method by using the fully functional simulator developed for the in situ upgrading of oil shales. From the simulation cases of the huff-n-puff method, the case with three horizontal wells was found to be most efficient to convey the heat into the wide area of the reservoir. From the simulation cases of continuous hot-water injection and simultaneous fluid production, it was found that the case of higher irreducible saturation of aqueous phase showed the better performance with higher productivity. The process of continuous injection and simultaneous production allowed fast heating of formation and the timely production of the generated hydrocarbons.

Acknowledgments

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