The Pennsylvania State University
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Mathematical Simulation of Conduction Heating in Oil Shale

A Thesis in

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by

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CHAPTER I

INTRODUCTION

Conduction heating is an important mechanism to be considered in thermal oil recovery techniques. However, conduction heating is most applicable to systems containing immobile bitumen such as tar sands and oil shale deposits, and reservoirs with low permeability containing highly viscous oil.

Several investigators have developed mathematical models representing conduction heating and have shown their applications in in situ recovery from oil shale.

H. A. Lesser, G. H. Bruce and H. L. Stone (1966) proposed a mathematical model that represents the conduction heating of formation with limited permeability by condensing gases and illustrated the application of the model in predicting in situ heating of oil shale using superheated steam as injected fluid. The heating is accomplished by inducing horizontal fractures to produce communication between the injection and production wells. In this way heat is conducted into the formation and once the pyrolysis temperature is reached the kerogen is transformed to liquids and gases which are recovered together with the injected fluid.

In this process, an analysis of the heat conduction mechanism can be used to determine the time required to heat all of the formation to a desired temperature. Also, the distribution of temperature can be obtained for any injection time and the area or volume of the formation heated to certain temperatures can be calculated for any period of time. Therefore, based upon laboratory experiments, the oil shale recovery can be estimated if it is know how much kerogen pyrolyzes below each temperature.

It is the objective of the present work to develop the mathematical model presented by Lesser, Bruce and Stone and then apply it to conduct a more extensive study of the parameters involved in an oil recovery process for oil shale using steam as the injected fluid. Finally, based on the above results, the possibility of using the model in determining optimal parameters is illustrated.

CHAPTER II

REVIEW OF THE LITERATURE

Thermal processes used for secondary or tertiary oil recovery have been studied with models that consider the heat conduction mechanism disregarding the flow of fluids through the reservoir rocks.

Considering the heat conduction to be the only factor affecting the thermal processes imposes a limitation on the application of the models. However, these models will provide insight on the cases studied by helping to explore the trend of the results when parameters are varied. Temperature history, heat losses, heated area as a function of time, together with relevant laboratory experiments and temperature - properties relationships, are the basic information necessary to estimate oil recovery and to explore economic parameters in thermal processes.

Many authors have studied hot fluid injection, and forward and reverse combustion, and several of them have proposed mathematical models based only on conduction heat transfer mechanism.

H. A. Lauwerier (1955) made a mathematical model for the injection of hot water into an oil bearing layer. Constant injection rate, convection within the sand and conduction into the surrounding formation were considered. Two-dimensional Laplace transformation with respect to the distance and the time variables were used for solving the partial differential equations representing the problem.

Later, Marx and Langenheim (1959) described a method for estimating thermal invasion rates, cummulative heated area and theoretical economic limits for sustained steam injection at a constant rate into an idealized oil reservoir. Basically, their model considers heat conduction to the adjacent formations, and allows for a heated area for any geometry. H. J. Ramey (1959) extended the treatment of Marx and Langenheim to include the case of steam injection at a varying rate. S. M. Farouq Ali (1970) developed a more general model of reservoir heating due to Marx and Langenheim with the extension suggested by Ramey.

B. T. Willman et al. (1961) presented another analytical solution of the steam injection process comparable to the Marx and Langenheim solution. L. A. Wilson and P. J. Root (1966) proposed a numerical solution for reservoir heating by steam injection. In their model, radial and vertical heat conduction, both within and outside the reservoir were considered.

A. G. Spillete and R. L. Nielsen (1968) presented a two-dimensional numerical model of hot water injection process considering fluid flow and heat transfer.

N. D. Shutler (1969) published a numerical technique to solve the linear three-phase fluid flow problem in a steamflood process, considering heat conduction in two dimensions.

More recently, A. Satter and D. R. Parrish (1971) presented a numerical solution of the steam heating problem considering convection and conduction within the reservoir and conduction in the adjacent formations. Their model treat a two-dimensional cylindrical system and also simulates steam condensation.

L. C. Vogel and R. F. Frueger (1955) studied a case with a moving cylindrical heat source of constant temperature and conduction in the radial direction. H. J. Ramey (1959), treated the same problem but included conduction in the vertical direction.

H. R. Bailey and B. K. Larkin (1959) solved a more general problem and included initial well heating, vertical heat losses and arbitrary frontal velocities.

In all of the preceding models which consider a moving cylindrical heat source, conduction was assumed to be the only means of heat transfer.

Later on, H. R. Bailey and B. K. Larkin (1960) included the effects of convection in linear and radial system in their previous studies but vertical heat losses were neglected in the radial case. F. F. Selig and E. J. Couch (1961) treating the same problem used a cylindrical model to compare the case where no heat loss from the reservoir is considered with another case in which a constant temperature between the reservoir and its bounding formation is assumed.

G. W. Thomas (1963), presented a more general case. He assumed a permeable bounding formation, so that the convection effect is not restricted to the reservoir itself. Chieh Chu (1963), presented a more general cylindrical model in two dimensions. Combustion, convection and conduction were assumed inside the reservoir, but only conduction was considered in the adjacent formations.

All of the mathematical models briefly described in the preceding paragraphs, consider heat conduction as being an important mechanism of heat transfer in hot fluid injection and in forward and reverse combustion thermal oil recovery processes. However, heat conduction is even of greater importance in systems containing immobile bitumen such as tar sands and oil shale deposits, and in reservoirs with low permeability where such a heat transfer mechanism could have more significance in the entire process.

A great deal of work has been done on both the theoretical and quantitative aspects of conduction heating as a process, and many field tests [C. F. Gates and H. J. Ramey (1958),and D. R. Parrish et al. (1962), among others] indicate that this process may have considerable importance as indicated above.

G. W. Thomas (1964), presented a mathematical model of underground conduction heating in a system of limited permeability and applied the model to solve analitically a radial problem in the conduction heating process in oil shale. He considers the injection of a non-condensing gas through wells interconnected by a single horizontal fracture, and approximates the temperature profile in the fracture by a step function. The model also allows for arbitrary variations of the thermal conductivity with temperature.

A. G. Spillette (1968) presented a numerical technique to solve the energy balance equation to remove the limitations present in analytical procedures such as homogeneites and constant parameters, when considering heat transfer mechanisms in a process of hot fluid injection into an oil reservoir.

In 1966, a field test (14) of an in situ shale oil recovery process using hot natural gas as the injected fluid was reported. This system is adequate to be studied using a heat conduction model.

H. A. Lesser, G. H. Bruce and H. L. Stone (1966) formulated a mathematical model that represents the conduction heating of a rock formation of limited permeability. They illustrated the application of the model in predicting in situ heating of oil shale using superheated steam as the injected fluid. Horizontal and equally spaced fractures with constant thicknesses were assumed to connect injection and production wells. A numerical procedure was used to obtain temperature histories for both the fracture and the formation. This model is described in detail in Chapter IV.

A. L. Barnes and A. M. Rowe (1968) made a heat transfer study of in situ retorting of oil shale by hot gas injection through wells interconnected by single vertical fracture of finite height. The Alternating Direction Implicit Procedure (ADIP) was used to solve the conduction heating equation in the oil shale and an explicit method was employed to solve the convection equation for the fracture. The study was conducted to investigate the effect of the injected gas temperature, injection rate, system geometry, cyclic injection, and the efficiency of retorting.

CHAPTER III

STATEMENT OF THE PROBLEM

The objective of this study is to develop the mathematical model proposed by Lesser, Bruce and Stone for conduction heating in oil shale using steam as the injected fluid, and then apply it to conduct a more extensive study of the parameters, to obtain their effect on the heating process.

These effects are measured by obtaining the fraction of the formation heated to 800°F as a function of time, for a series of twelve different cases considered, and analyzing the tendency of the results when the parameters are varied one at a time in one or the other direction. Temperature distributions for both the fracture and the formation are presented for all cases. A temperature of 800°F was selected for the calculation of the formation heated because at this temperature pyrolysis of kerogen is almost complete in most of the reported cases.

In order to conduct the present study, eight parameters are selected for investigation: horizontal and vertical diffusivities, injection rate, steam pressure, fracture length and thickness, distance to the boundaries, and injection temperature.

One of the sample cases presented by Lesser et al. is selected as a base case, since it represents a typical oil shale formation. The results of this case are employed for comparison purposes when analyzing results of other cases. This base case also enables us to compare the results obtained in this study with those presented by Lesser et al.

Finally, based on the above results, the model is run for a set of parameters which are found to accelerate the heating process to illustrate the possibility of using the model to establish optimal parameter values.

In order to determine the influence of the parameters involved in the conduction heating process, the present study was conducted considering the following cases:

Base case: Used for comparison purposes.

Cases 1 and 2: Influence of injection rate of steam.

Case 3: Influence of fracture length.

Cases 4 and 5: Influence of fracture thickness.

Case 6: Influence of steam pressure.

Case 7: Influence of injection temperature.

Cases 8 and 9: Influence of the distance to the boundaries.

Case 10: Influence of horizontal and vertical thermal diffusivities.

Optimal case: Illustrates the possibility of the model application in determining optimal parameter values.

Table 1 summarizes the cases considered in the present study, and Table 2 presents the parameters which are held constant.

Table 1.

Values of Varied Parameters

Case	a_x sq.ft/hr	a_y sq.ft/hr	h ft.	$(\rho v)_{inj}$ lb/sq.ft/hr	T_{inj} °F	P psia.	L ft.	δ ft.
Base	0.015	0.010	20	1000	1000	1000	500	0.02
1	0.015	0.010	20	3000	1000	1000	500	0.02
2	0.015	0.010	20	2000	1000	1000	500	0.02
3	0.015	0.010	20	1000	1000	1000	200	0.02
4	0.015	0.010	20	1000	1000	1000	500	0.03
5	0.015	0.010	20	1000	1000	1000	500	0.01
6	0.015	0.010	20	1000	1000	2000	500	0.02
7	0.015	0.010	20	1000	1500	1000	500	0.02
8	0.015	0.010	40	1000	1000	1000	500	0.02
9	0.015	0.010	10	1000	1000	1000	500	0.02
10	0.030	0.020	20	1000	1000	1000	500	0.02
Opt.	0.030	0.020	20	3000	1000	2000	500	0.03

Table 2

Values of Constant Parameters

To	$= 100°F$
$(\rho C)_f$	$= 41.2$ Btu/cu.ft°F
ε	$= 0.25$
Δx	$= 10$ ft.

CHAPTER IV

DESCRIPTION OF LESSER, BRUCE AND STONE'S MODEL FOR A PROCESS OF OIL RECOVERY FROM OIL SHALE

General

In this chapter the mathematical model proposed by Lesser, Bruce and Stone is summarized. Scope and possible applications are pointed out. Assumptions, mathematical description, and solution method are presented for a case of oil recovery from oil shale using superheated steam as the injected fluid.

Scope and Possible Applications of the Model

The model in reference solves the conduction heating problem in a formation of limited permeability when condensing gases are injected at high temperatures into the formation.

However, this model can be used not only in recovery of oil shale where permeability is zero, but it could also be applied to systems containing immobile bitumen such as tar sands and reservoirs with low permeability containing highly viscous oil. In all of these systems, conduction heating plays a very important role in the recovery of oil; therefore the solution of the above mentioned heat transfer problem is a powerful tool to determine the performance and feasibility of the thermal recovery process considered.

Application of the Model in the Recovery of Oil from Oil Shale

Bruce, Lesser and Stone illustrated the application of their mathematical model for oil recovery from oil shale.

The process is implemented creating artificial fractures to communicate between injection and production wells. Figure 1 shows a cross-sectional picture of the fracture and adjacent formation.

Superheated steam is injected at one end of the fracture and heat is conducted into the formation, increasing its temperature. Once the formation reaches the pyrolysis temperature, oil and gas products flow into the fracture and are then produced at the other end of the fracture with the injection fluid.

Assumptions

The following assumptions are made:

1. Linear flow of steam through horizontal fracture.
2. Constant thickness and spacing of the fractures.
3. Vertical temperature variations are ignored.
4. Horizontal pressure changes and horizontal heat conduction in the fracture are neglected.
5. Endothermic reactions are not considered.
6. Presence of oil and gas in the fracture and the formation is ignored.
7. Thermal diffusivities in x- and y-direction are different but constant.
8. Formation is assumed to have no permeability except for fracture permeability.

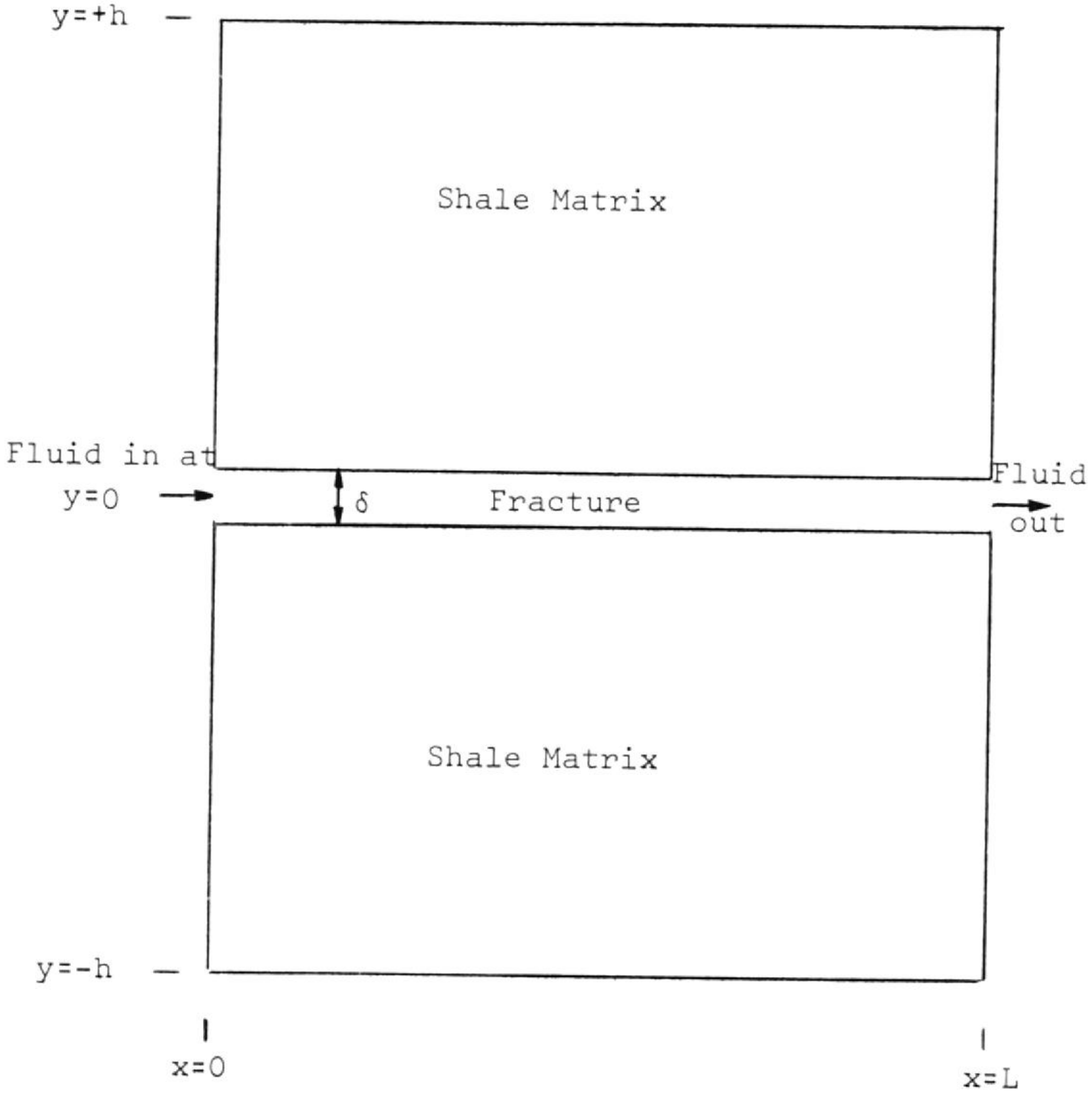

Figure 1. Cross-section of a typical fracture and adjacent formation.

9. Initial formation and fracture temperatures are equal and constant.
10. Heat is distributed equally above and below the fracture.
11. No heat flow boundary conditions are established at the reflection boundaries above and below the fracture
12. No heat transfer between either production or injection wells and the formation is considered.
13. Constant density-heat capacity product for the formation.

Mathematical Description of the Model

Under the above assumptions, the mathematical equations which describe the process are:

1. Equations (4.1) and (4.2) which describe the temperature history of the rock matrix and the appropriate initial and boundary conditions, respectively:

$$\frac{\partial T}{\partial t} = \frac{\partial}{\partial x} a_x(T) \frac{\partial T}{\partial x} + \frac{\partial}{\partial y} a_y(T) \frac{\partial T}{\partial y} \tag{4.1}$$

At $t = o$, $T = To$, for $o<x\leq L$ and $o\leq y\leq h$

At $x = o$, $\frac{\partial T}{\partial x} = o$, for $o<y\leq h$ and $t\geq o$

At $x = L$, $\frac{\partial T}{\partial x} = o$, for $o<y\leq h$ and $t\geq o$

At $y = o$, $2(\rho C)_f \left[a_y(T)\frac{\partial T}{\partial y}\right] = -Q$, for $o\leq x\leq L$ and $t\geq o$

At $y = o$, T = fracture temperature, for $o\leq x\leq L$ and $t\geq o$

At $y = \pm h$, $\frac{\partial T}{\partial y} = o$, for $o\leq x\leq L$ and $t\geq o$ (4.2)

2. Equations (4.3) and (4.4) which represent the flow of fluid in the fracture. The former is the continuity equation, the latter the energy balance equation. Equation (4.5) represents the initial and boundary conditions for the fracture:

$$\frac{\partial \rho}{\partial t} + \frac{\partial \rho v}{\partial x} = o \qquad (4.3)$$

$$\frac{\partial \rho H}{\partial t} + \frac{\partial \rho v H}{\partial x} = - \frac{Q}{\delta} \qquad (4.4)$$

$$\begin{aligned}
&\text{At } t = o,\ \rho=\rho(To,So),\ \text{for } o\leq x\leq L \\
&\text{At } t = o,\ H = H(To,So),\ \text{for } o\leq x\leq L \\
&\text{At } x = o,\ \rho=\rho(T_{inj},\ S_{inj}),\ \text{for } t>o \\
&\text{At } x = o,\ H = H(T_{inj},\ S_{inj}),\ \text{for } t>o \\
&\text{At } x = o,\ v = v_{inj},\ \text{for } t>o
\end{aligned} \qquad (4.5)$$

3. Equation (4.6) and (4.7): functional relationship between density and specific enthalphy of the fluid, and temperature and vapor quality:

$$\rho = \rho(T,S) \qquad (4.6)$$

$$H = H(T,S) \qquad (4.7)$$

Solution Method

The numerical method presented by Lesser, Bruce and Stone, solves simultaneously Equation (4.1) through (4.7) using finite difference approximations.

Equation (4.1) is approximated by Equation (4.8):

$$\frac{\Delta_k T^n_{i,j}}{\Delta t_n} = (a_x)^n_{i+\frac{1}{2},j} \frac{\Delta_i T^n_{i,j}}{(\Delta x)^2} - (a_x)^n_{i-\frac{1}{2},j} \frac{\Delta_i T^n_{i-1,j}}{(\Delta x)^2}$$

$$+ \frac{2}{\Delta y_j + \Delta y_{j-1}} \{[\varepsilon (a_y)^n_{i,j+\frac{1}{2}} \frac{\Delta_j T^n_{i,j}}{\Delta y_j} +$$

$$(1-\varepsilon)\ (a_y)^{n+1}_{i,j+\frac{1}{2}} \frac{\Delta_j T^{n+1}_{i,j}}{\Delta y_j}] - [\varepsilon (a_y)^n_{i,j-\frac{1}{2}} \frac{\Delta_j T^n_{i,j-1}}{\Delta y_{j-1}}$$

$$+ (1-\varepsilon)(a_y)^{n+1}_{i,j-\frac{1}{2}} \frac{\Delta_j T^{n+1}_{i,j-1}}{\Delta y_{j-1}}] \qquad (4.8)$$

Equations (4.3) and (4.4) are approximated by Equations (4.9) and (4.10) as follows:

$$\frac{\Delta_n \rho^n_i}{\Delta t_n} + \varepsilon \frac{\Delta_i (\rho v)^n_{i-1}}{\Delta x} + (1-\varepsilon) \frac{\Delta_i (\rho v)^{n+1}_{i-1}}{\Delta x} = 0 \qquad (4.9)$$

$$\frac{\Delta_n (\rho H)^n_i}{\Delta t_n} + \varepsilon \frac{\Delta_i (\rho v H)^n_{i-1}}{\Delta x} + (1-\varepsilon) \frac{\Delta_i (\rho v H)^{n+1}_{i-1}}{\Delta x}$$

$$= - \frac{\varepsilon}{\delta} Q^n_i - \frac{1-\varepsilon}{\delta} Q^{n+1}_i \qquad (4.10)$$

To obtain the density and enthalpy functions [Equations (4.6) and (4.7)], second degree polynomials were fitted by the method of least squares to data from Keenan and Keyes(1936).

A grid designed to permit unequal grid spacing in y-direction is used. Small time steps are initially employed in the process and they are allowed to increase with decreasing temperature gradients. A constant grid spacing in the x-direction is considered. The difference equations are formulated in such a way that they can be solved for a single column grid-points at a time. This is accomplished by performing the forward and then, the backward solution of the Gaussian elimination technique. As a result temperature distribution in the formation and fracture as well as enthalpy, velocity, quality, and density of the fracture fluid are calculated.

The solution method was obtained using an IBM 370/165 model computer. A program was written in FORTRAN IV language.

A flow chart for the computational procedure is presented in Figure 2.

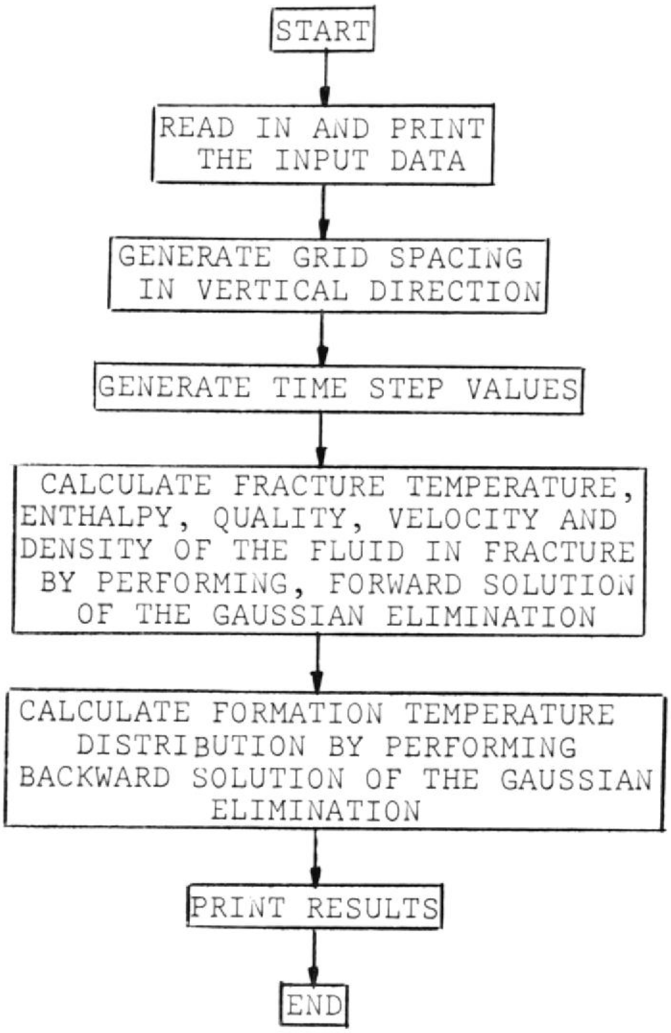

Figure 2. Flow Chart for the Computational Procedure.

CHAPTER V

DISCUSSION OF THE RESULTS

General

The model of Lesser, Bruce, and Stone was developed and used in the present work to conduct a more extensive study of the parameters involved in the heat conduction mechanism when applied in the in situ heating of oil shale described in Chapter IV. Based on the results, the model was run for a set of parameters which are found to accelerate the heating process to illustrate the possibility of using it to establish optimal parameter values.

This chapter outlines the results for all cases considered. A base case is established for comparison purposes, ten more cases are considered to obtain the influence of the parameters in the heating process, and a last case shows the possibility of using the model for establishing optimal parameter values.

Temperature histories for both fracture and formation are obtained and plotted for different injection times. Also, curves representing the fraction of formation heated to 800°F or higher as a function of time are presented.

Based on laboratory experiments, these results can be used to determine the oil recovery from oil shale in the process considered here. Furthermore, economical feasibility of a project may be explored.

Base Case. Basis of Comparison

A sample case presented by Lesser et al. is selected as a base case since it represents a typical oil shale formation. The results obtained for this case are used as a comparison basis when other cases are studied, since parameters are varied one at a time, leaving the others as in the base case.

Also, the model is tested, comparing the results obtained in this base case with those presented by Lesser et al.

Figure 3 shows the fraction of formation heated to 800°F and 600°F, respectively. More than 10 years are required to heat all the formations to 800°F or higher. Figures 4 through 8 present formation isotherms for injections times of 0.568, 2.815, 5.691, 7.948 and 9.828 years. Figure 9 shows the temperature distribution in the fracture for some injection times. As can be observed, an appreciable length of the fracture remains at 544.61°F (saturation temperature) for a long period of time. Eighty per cent of the fracture length is still at that temperature after a period of 2.815 years. This result is due to the fact that 200 and 400°F isotherms are fairly flat over a wide region (Figure 4).

Results presented for this case agree with those presented by Lesser et al.

Cases 1 and 2. Influence of Injection Rate of Steam

Injection rates of 2000 and 3000 lb/sq.ft-hr are

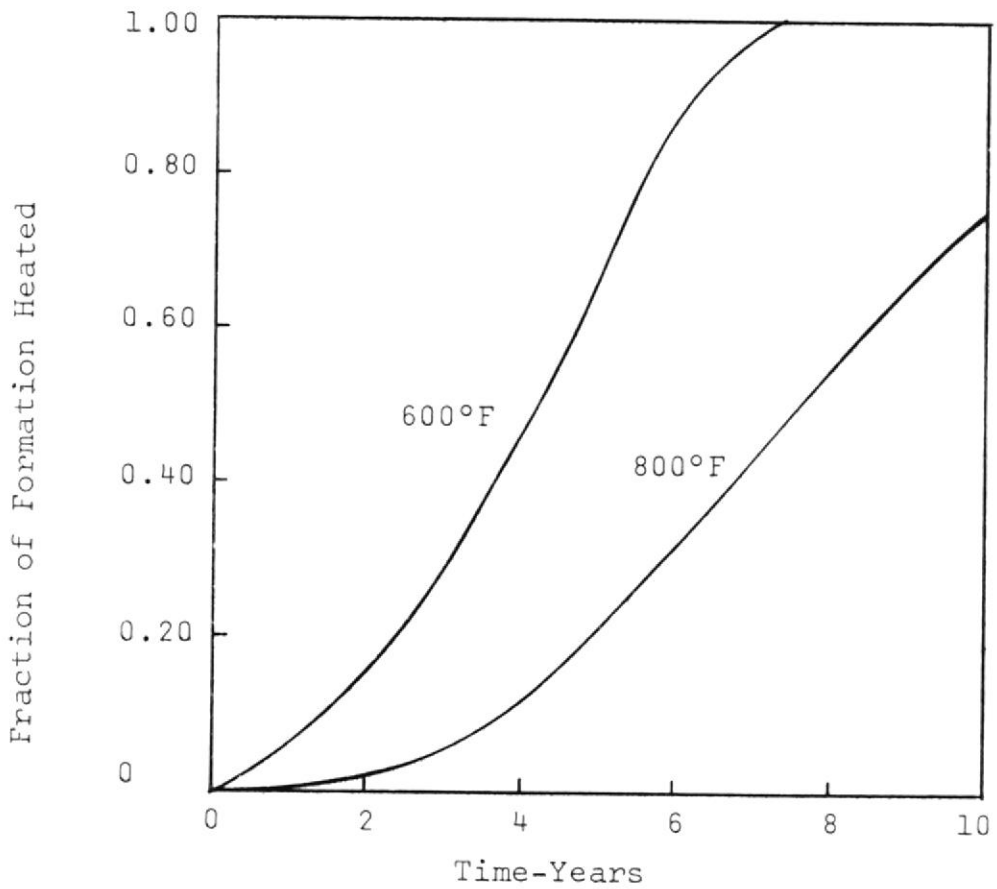

Figure 3. Fraction of Formation Heated to Specified Temperature for Base Case.

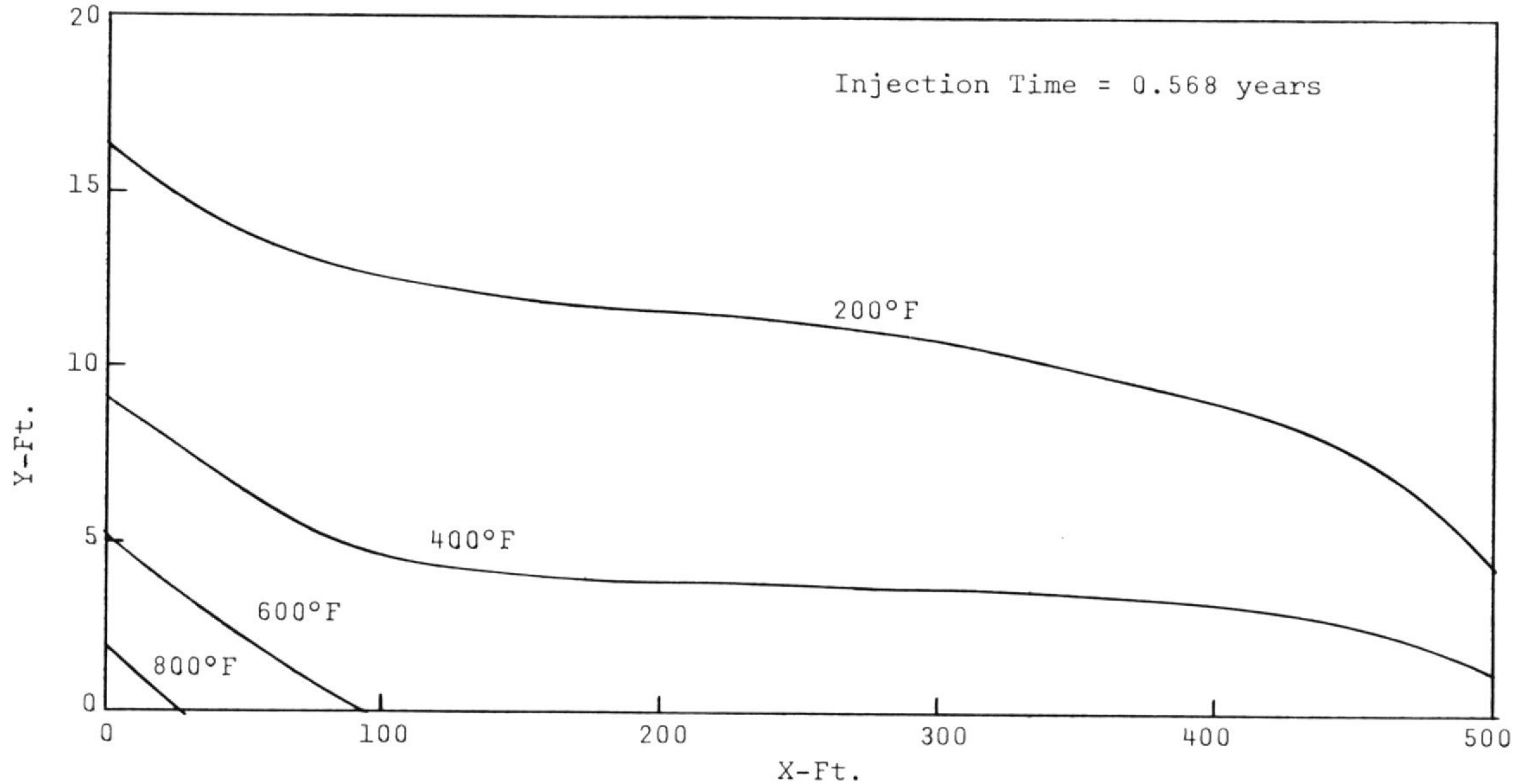

Figure 4. Formation Isotherms for Base Case.

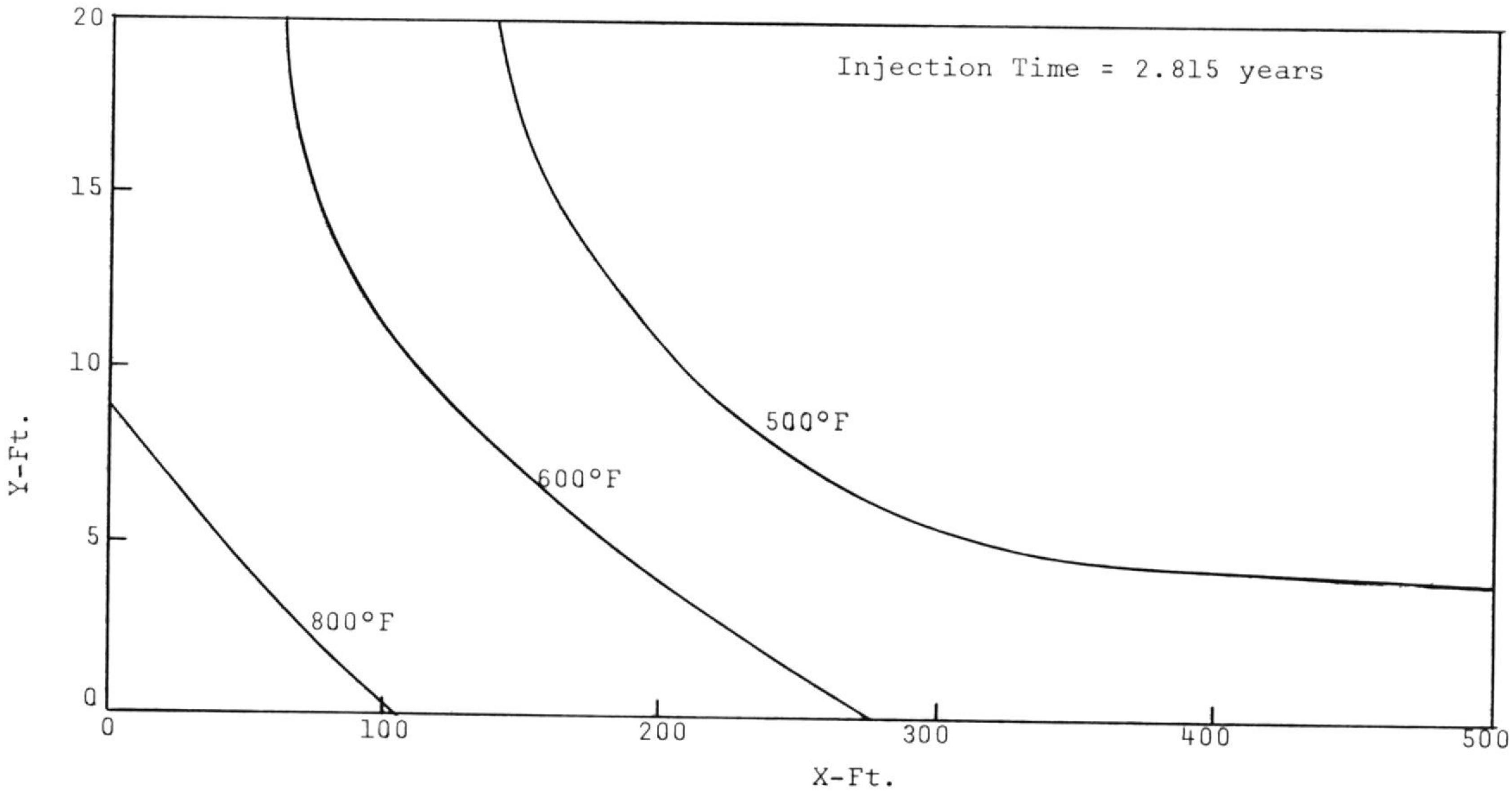

Figure 5. Formation Isotherms for Base Case.

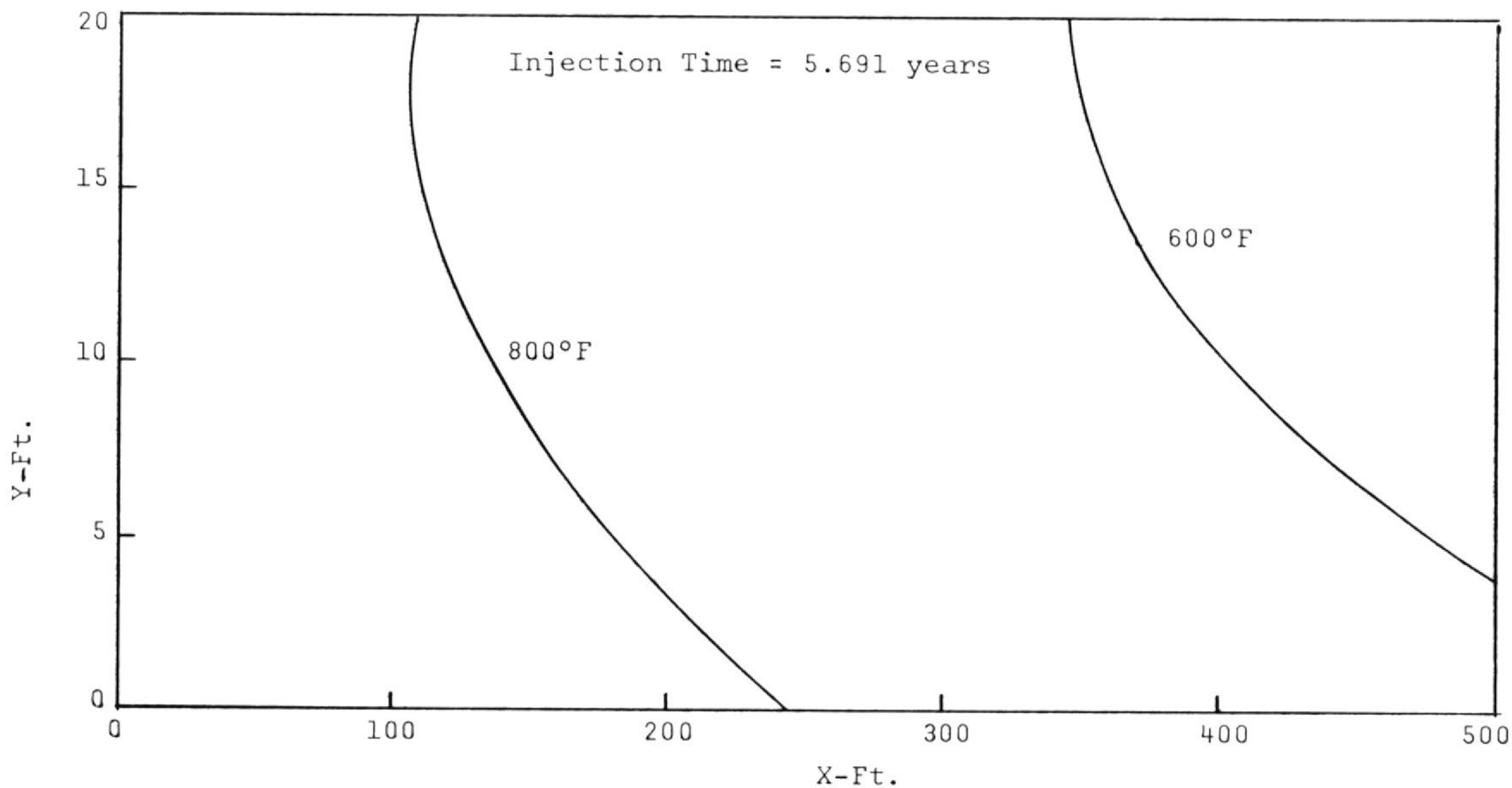

Figure 6. Formation Isotherms for Base Case.

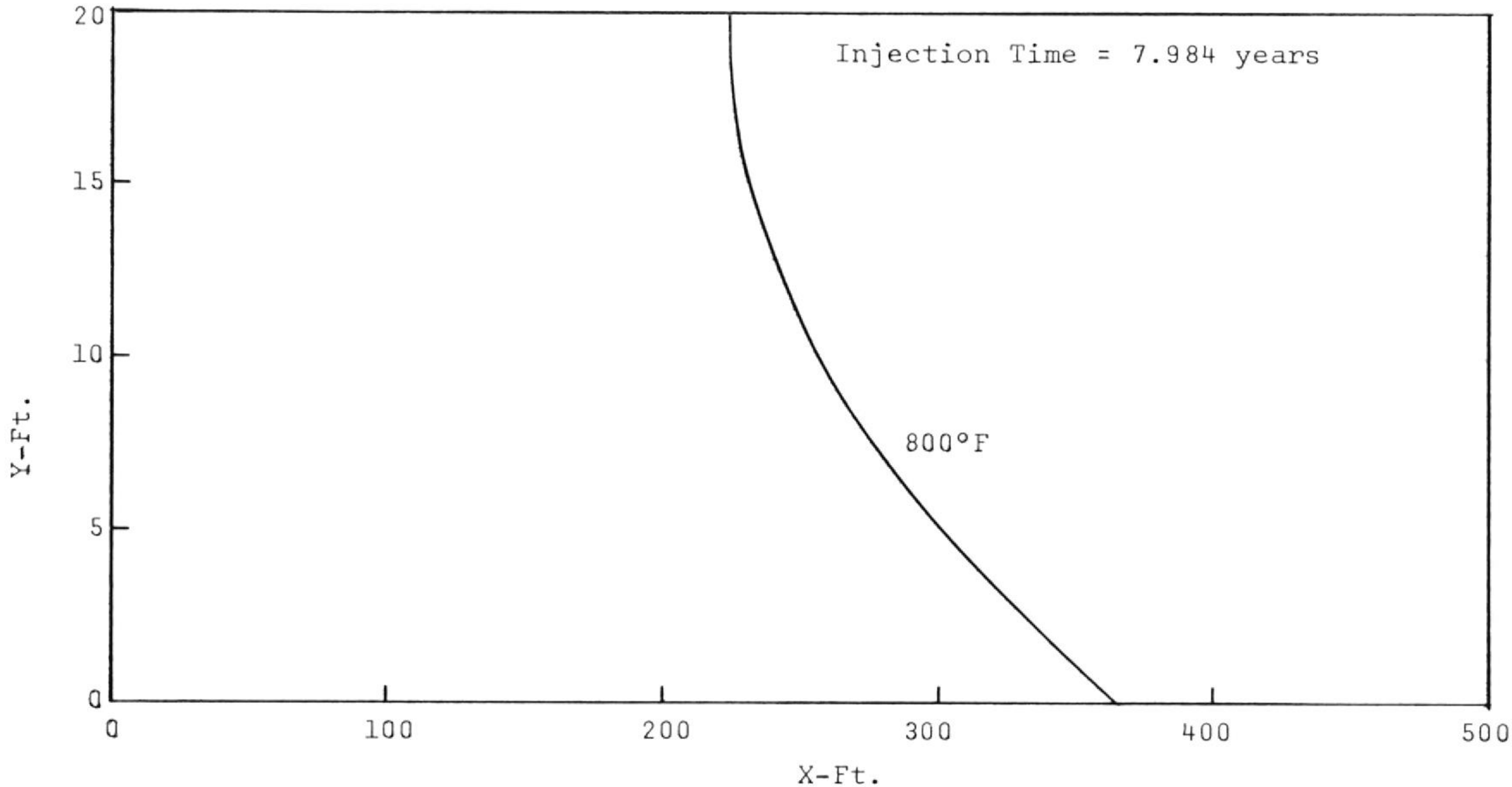

Figure 7. Formation Isotherms for Base Case.

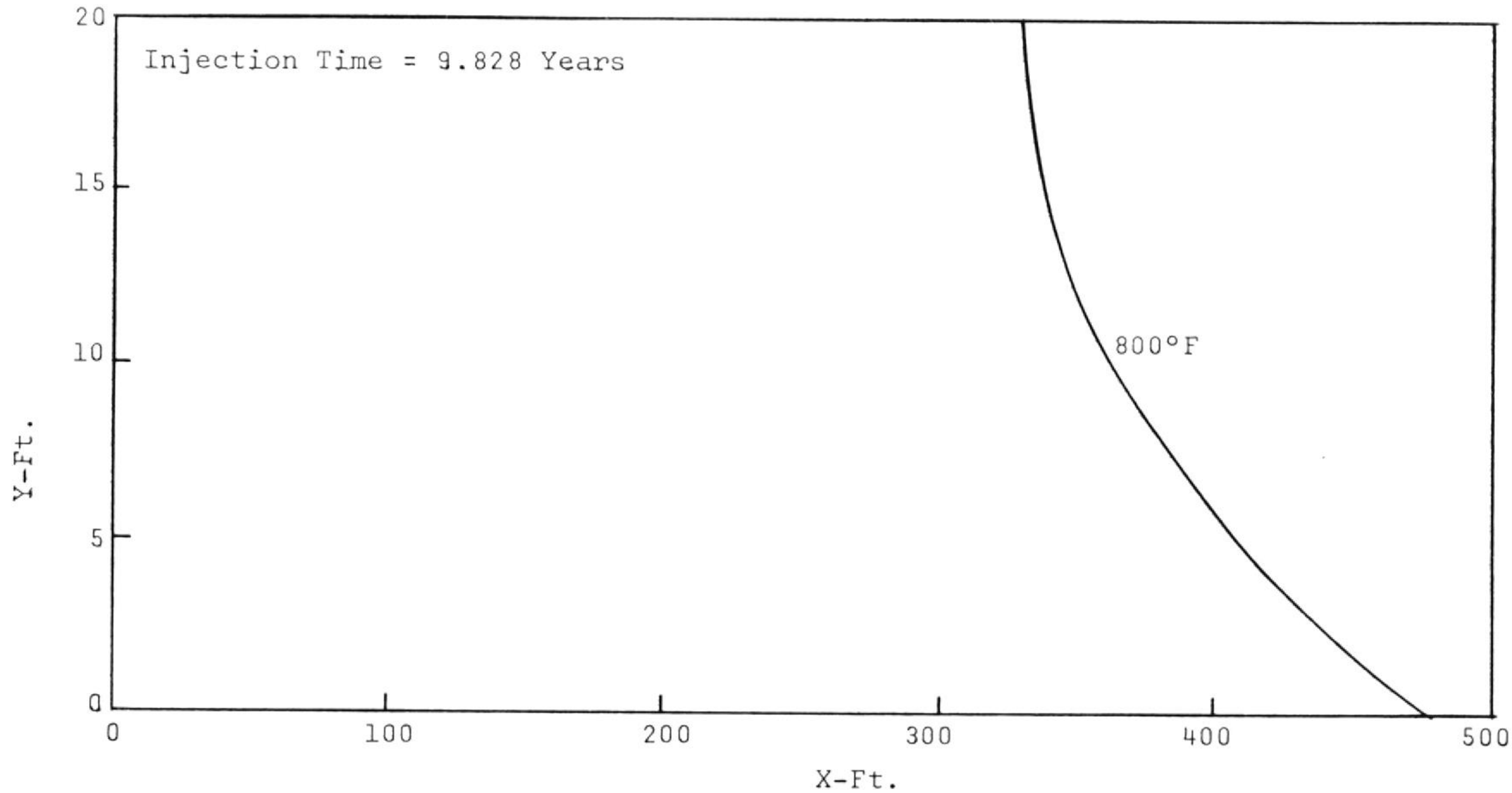

Figure 8. Formation Isotherms for Base Case.

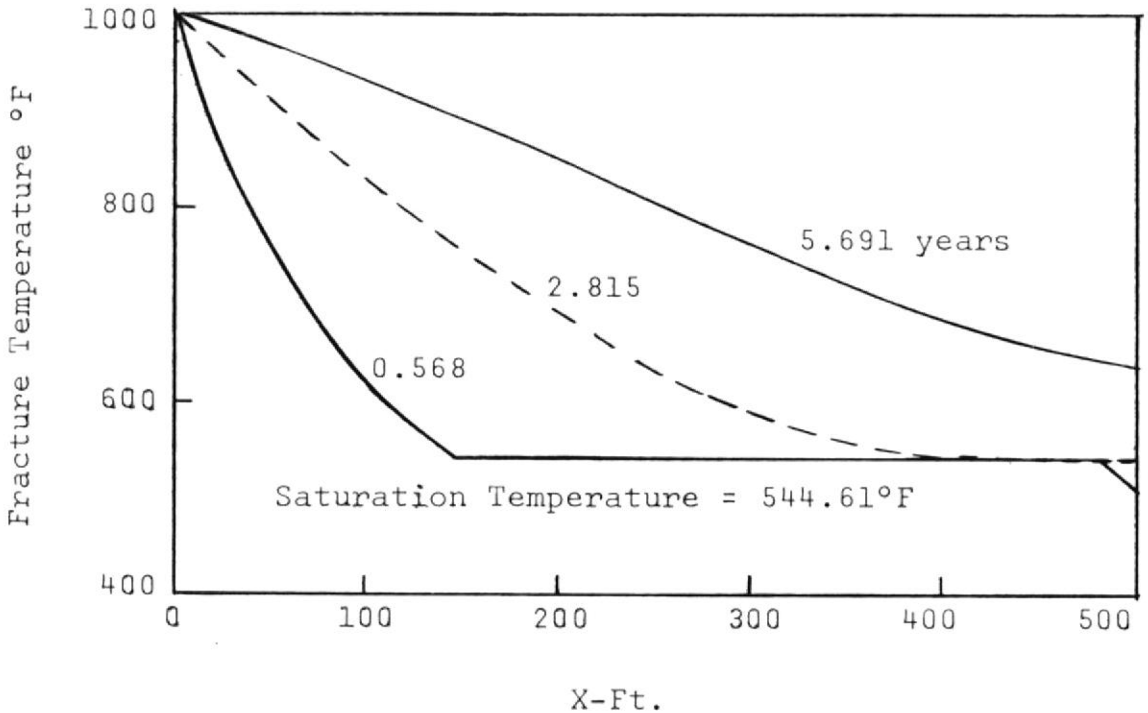

Figure 9. Temperature Distribution in the Fracture for Base Case.

considered in these two cases. It is assumed that these injection rates are possible in practice.

Figure 10 shows results for injection rates of 1000 (base case), 2000 (case 2), and 3000 lb/sq.ft-hr(case 1).

As can be observed the fraction of formation heated increases more rapidly when the injection rate is raised from 1000 to 2000 lb/sq.ft-hr than when it is increased from 2000 to 3000 lb/sq.ft-hr. This is because in the latter case a larger amount of heat is produced at the production well since high temperature isotherms breakthrough in a shorter period of time.

All of the formation is heated to 800°F in 6.3 and 8.2 years for injection rates of 2000 and 3000 lb/sq.ft-hr respectively. For these same values of injection rates and for a period of 5 years, 49 and 65 per cent of the formation is heated to the above specified temperature, and only 0.81 and 1.18 per cent for an injection time of 0.568 years. On the other hand with an injection rate of 1000 lb/sq.ft-hr (base case), 76 per cent of the formation is heated to 800°F or higher in 10 years, while only 21.5 and 0.275 per cent of the formation is heated to the same temperature in 5 and 0.568 years, respectively.

Figure 11 through 20 show formation isotherms for the values of injection rates considered. As the velocity of the steam increases the isotherm lines moves more rapidly in the x-direction but its penetration in y-direction is too slow.

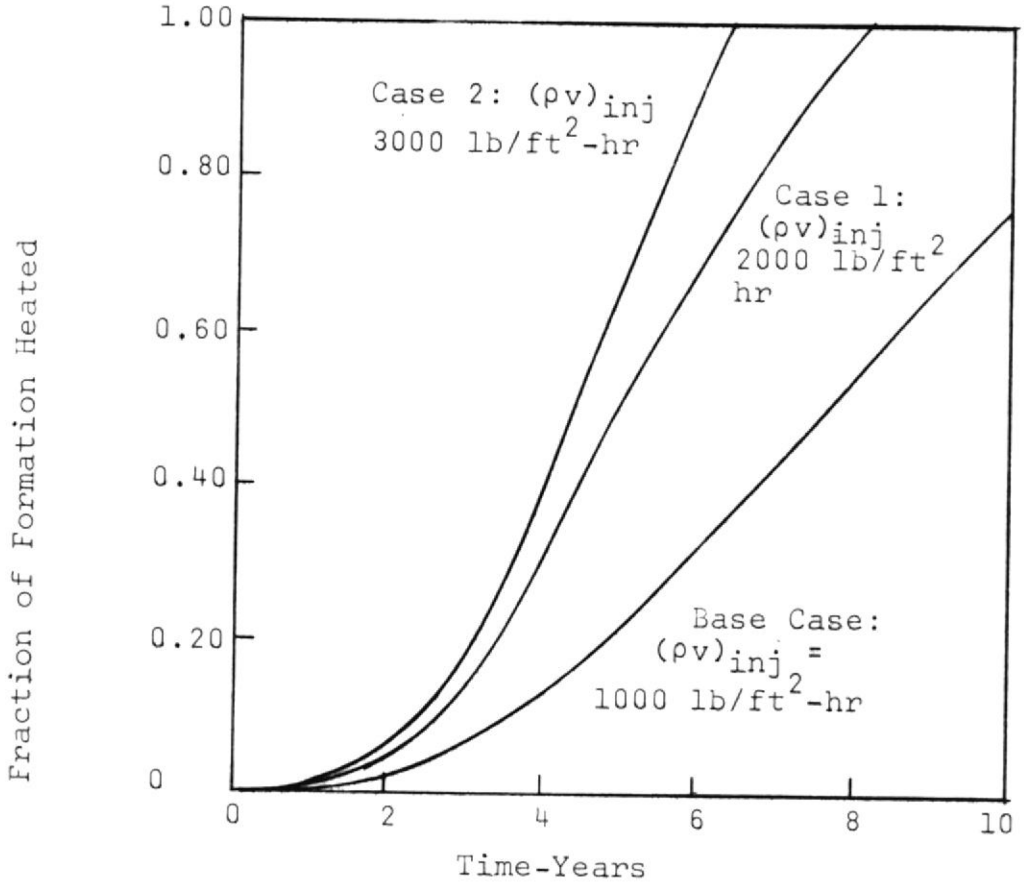

Figure 10. Fraction of Formation Heated to 800°F or Higher for Cases 1 and 2.

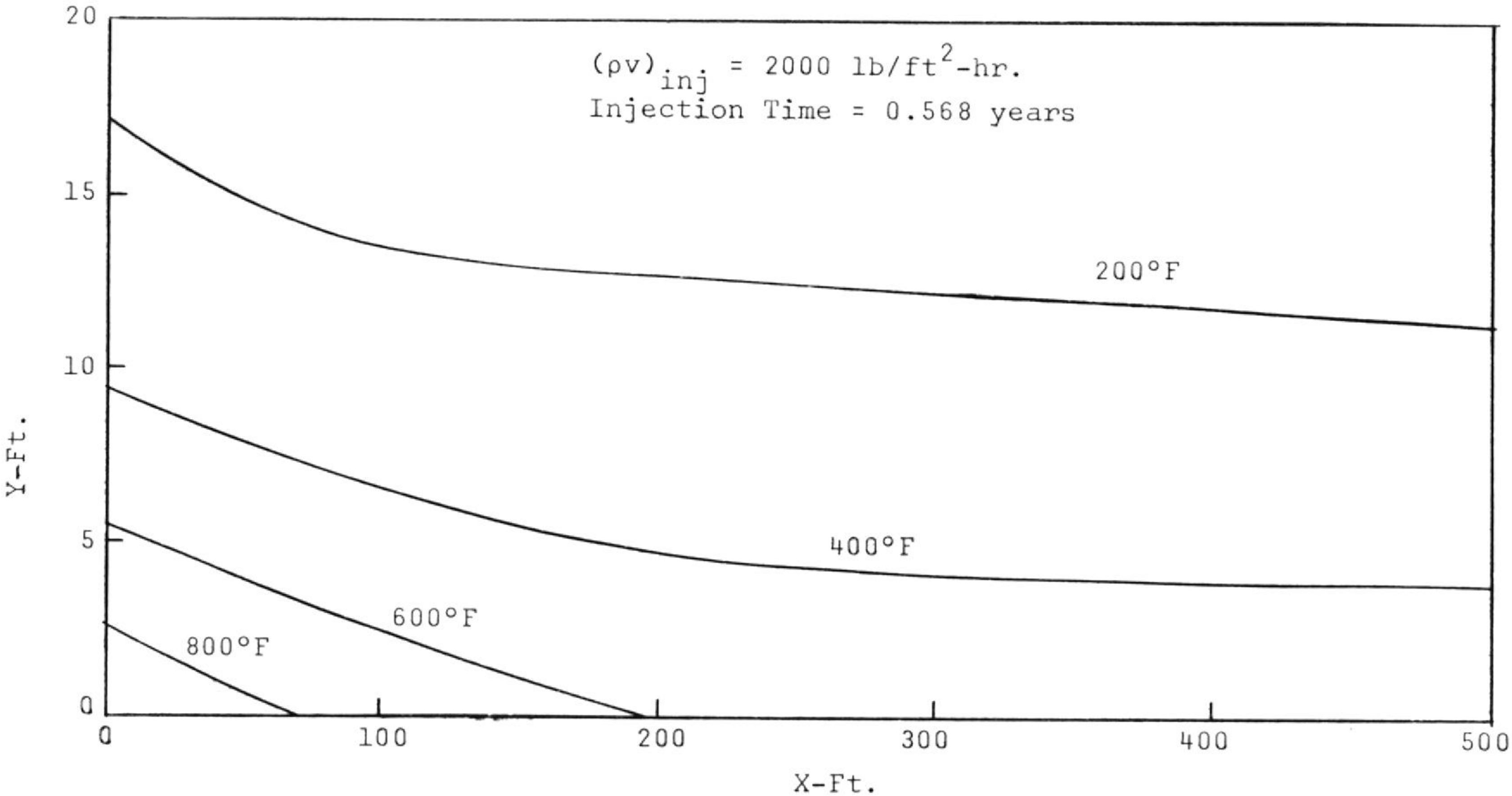

Figure 11. Formation Isotherms for Case 1.

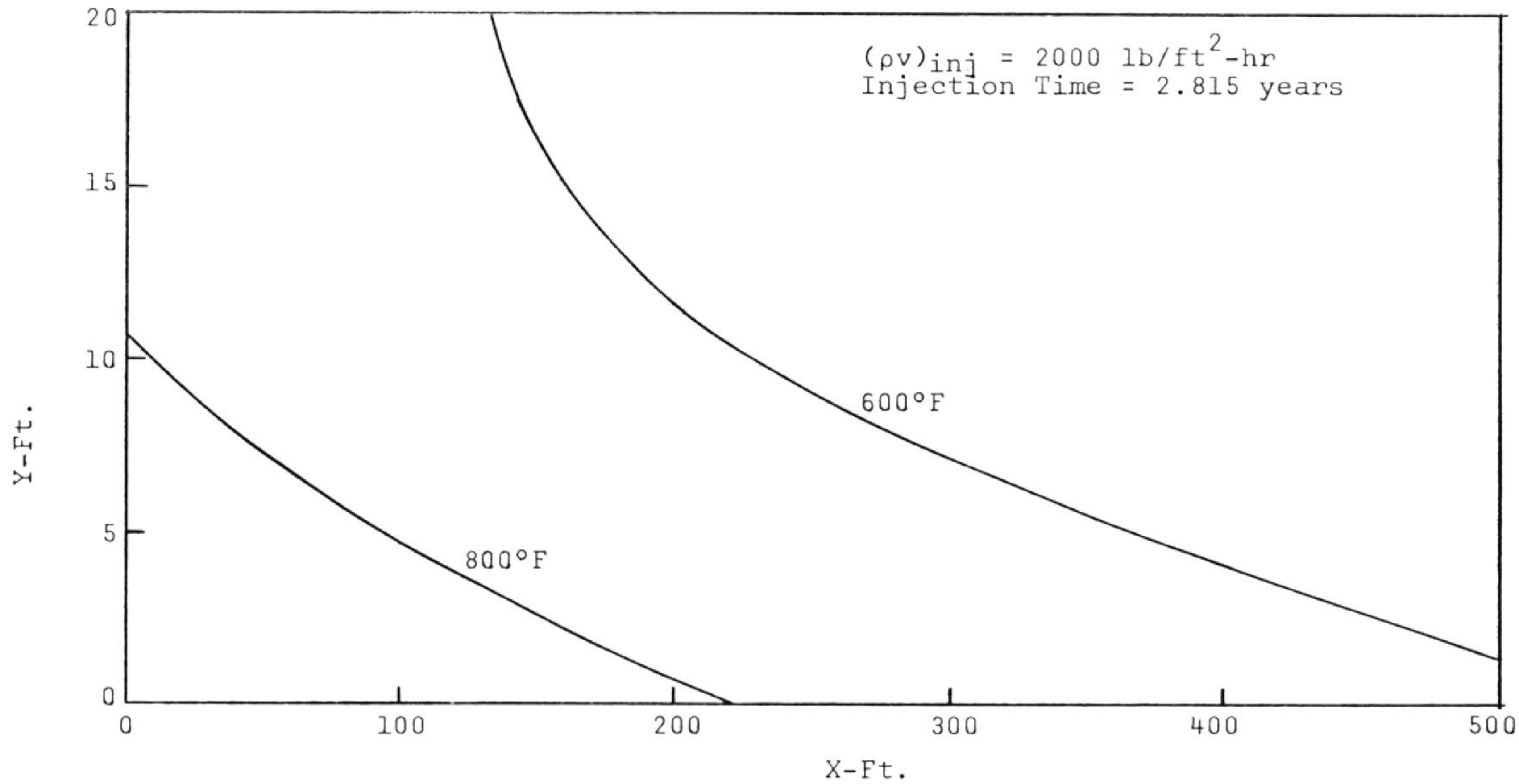

Figure 12. Formation Isotherms for Case 1.

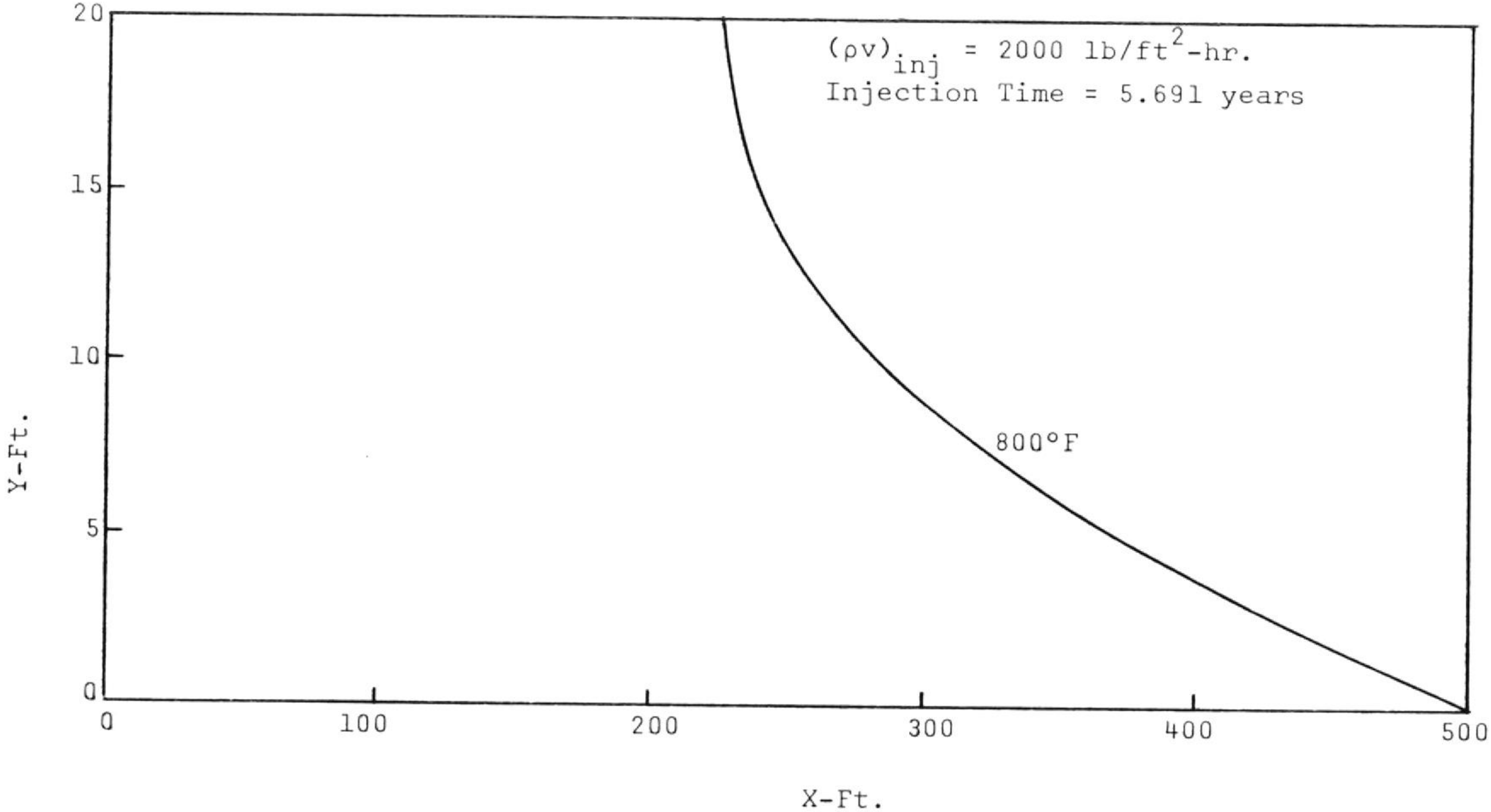

Figure 13. Formation Isotherms for Case 1.

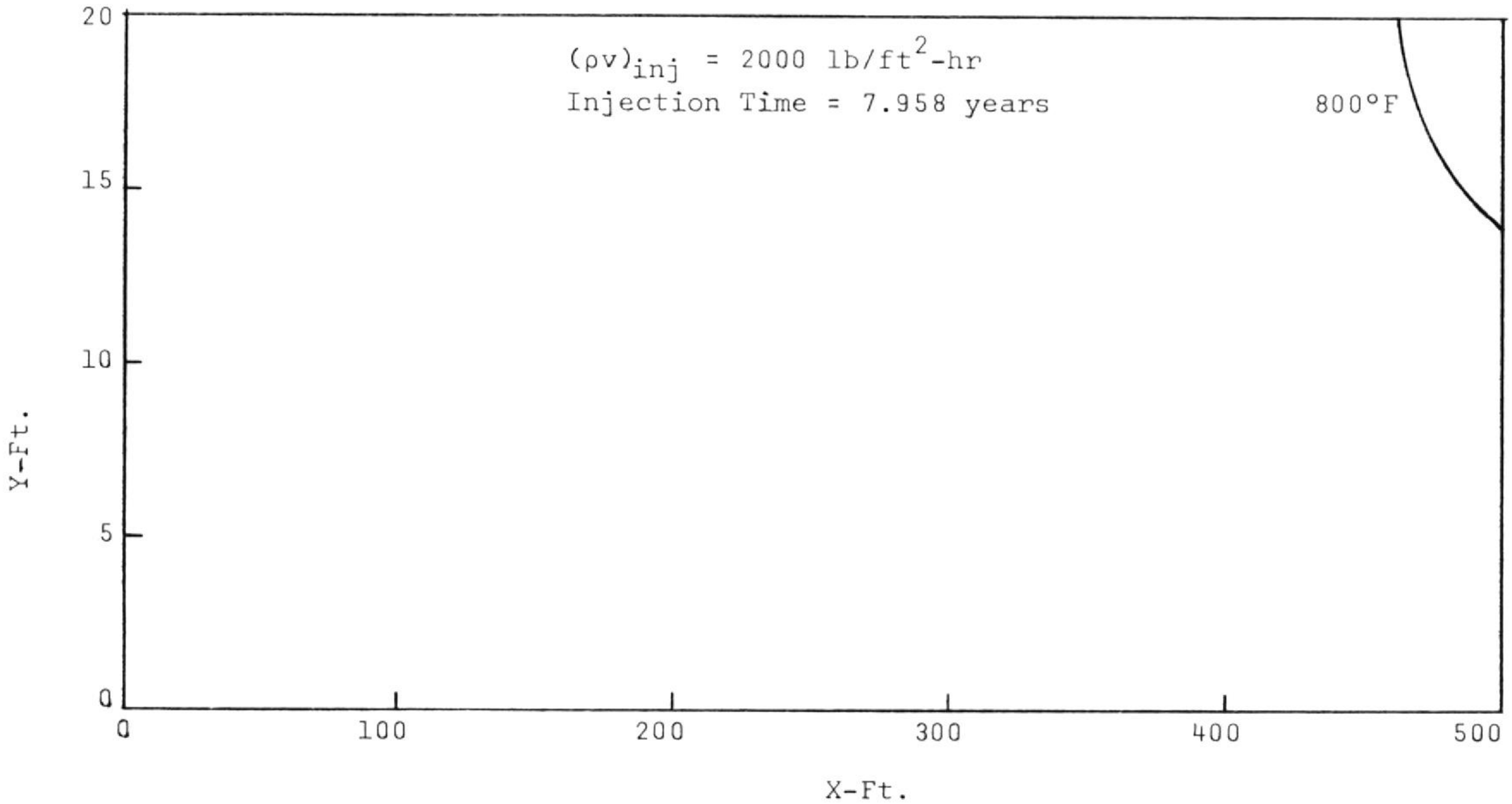

Figure 14. Formation Isotherms for Case 1.

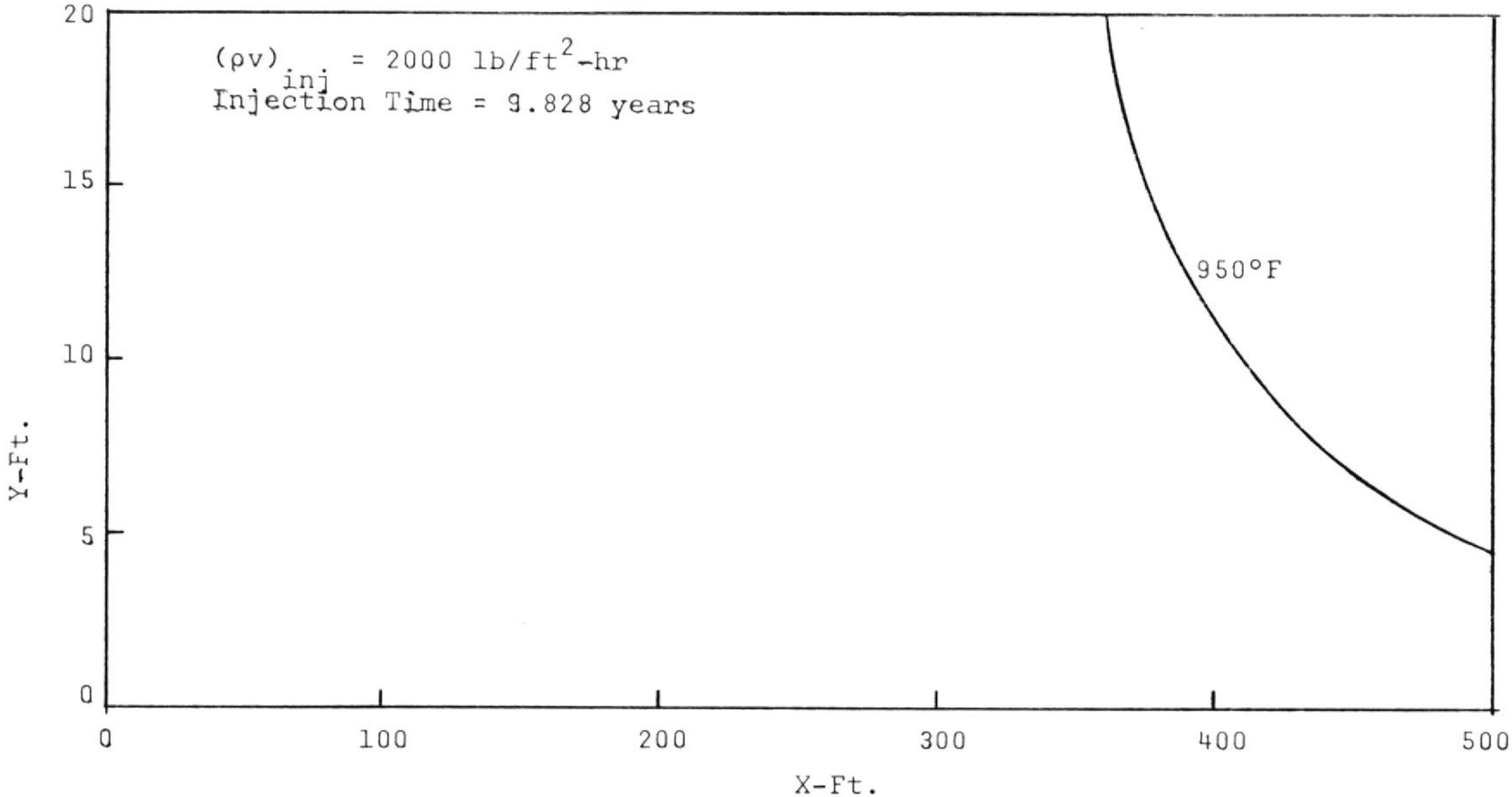

Figure 15. Formation Isotherms for Case 1.

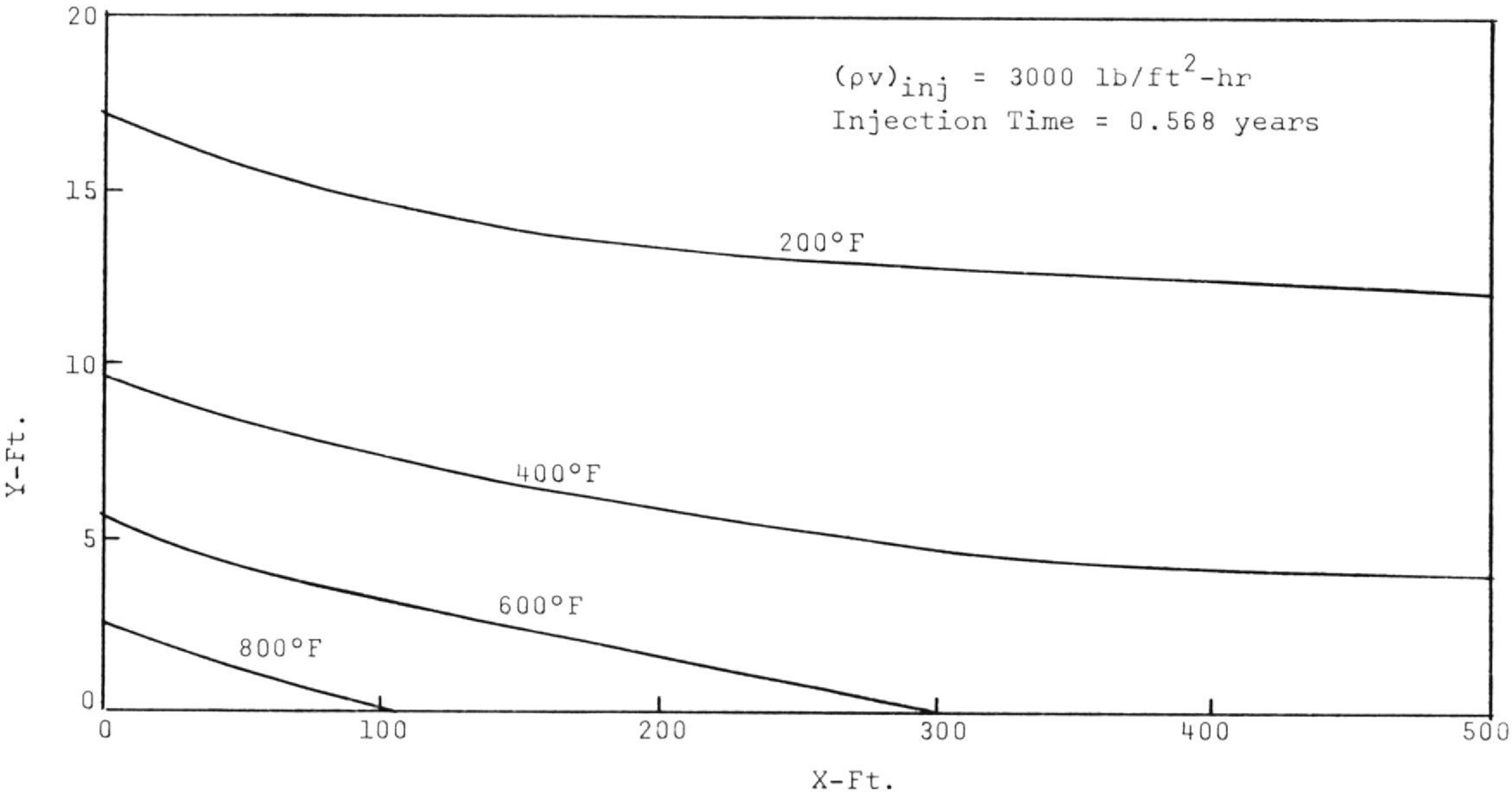

Figure 16. Formation Isotherms for Case 2.

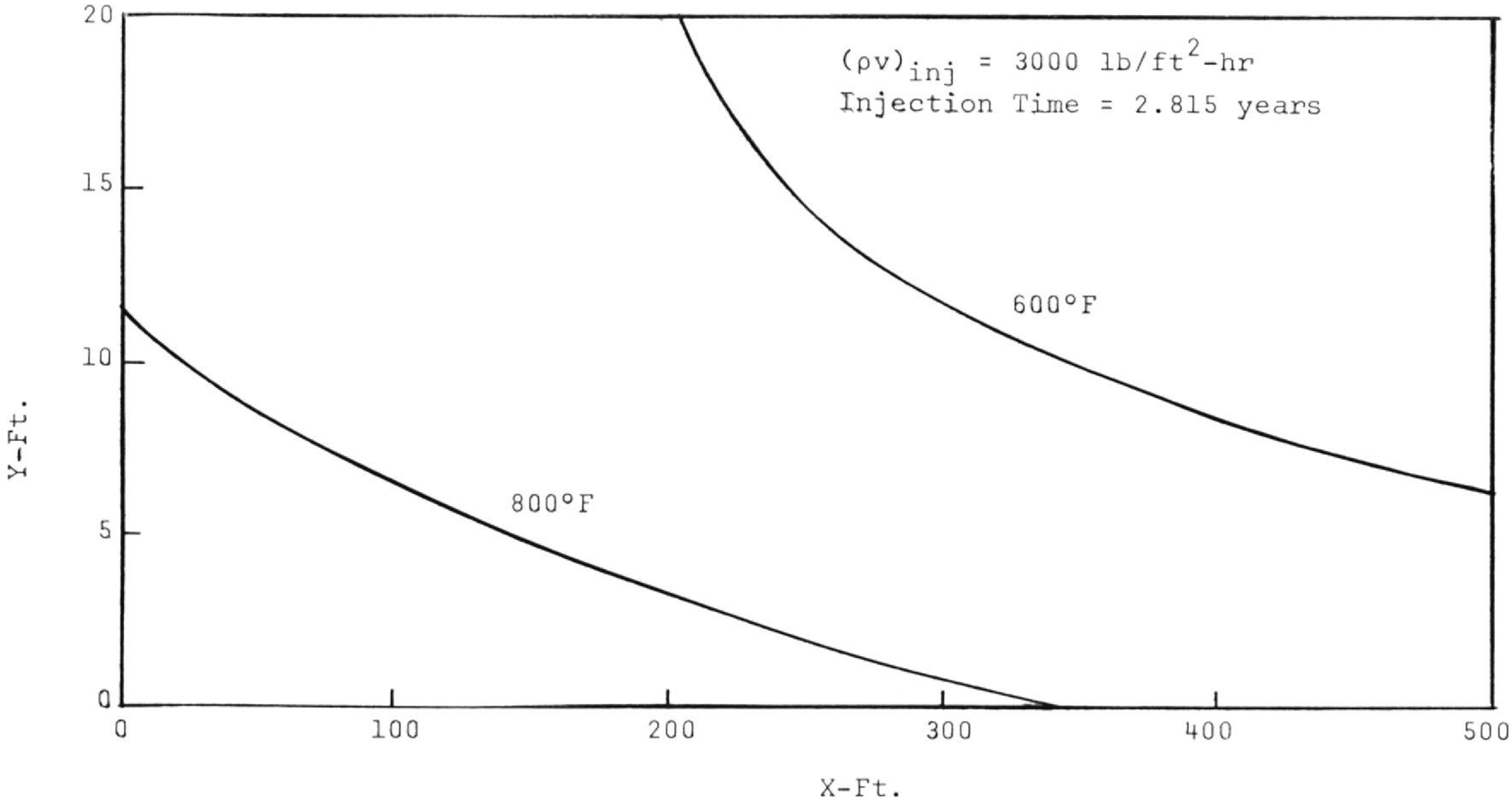

Figure 17. Formation Isotherms for Case 2.

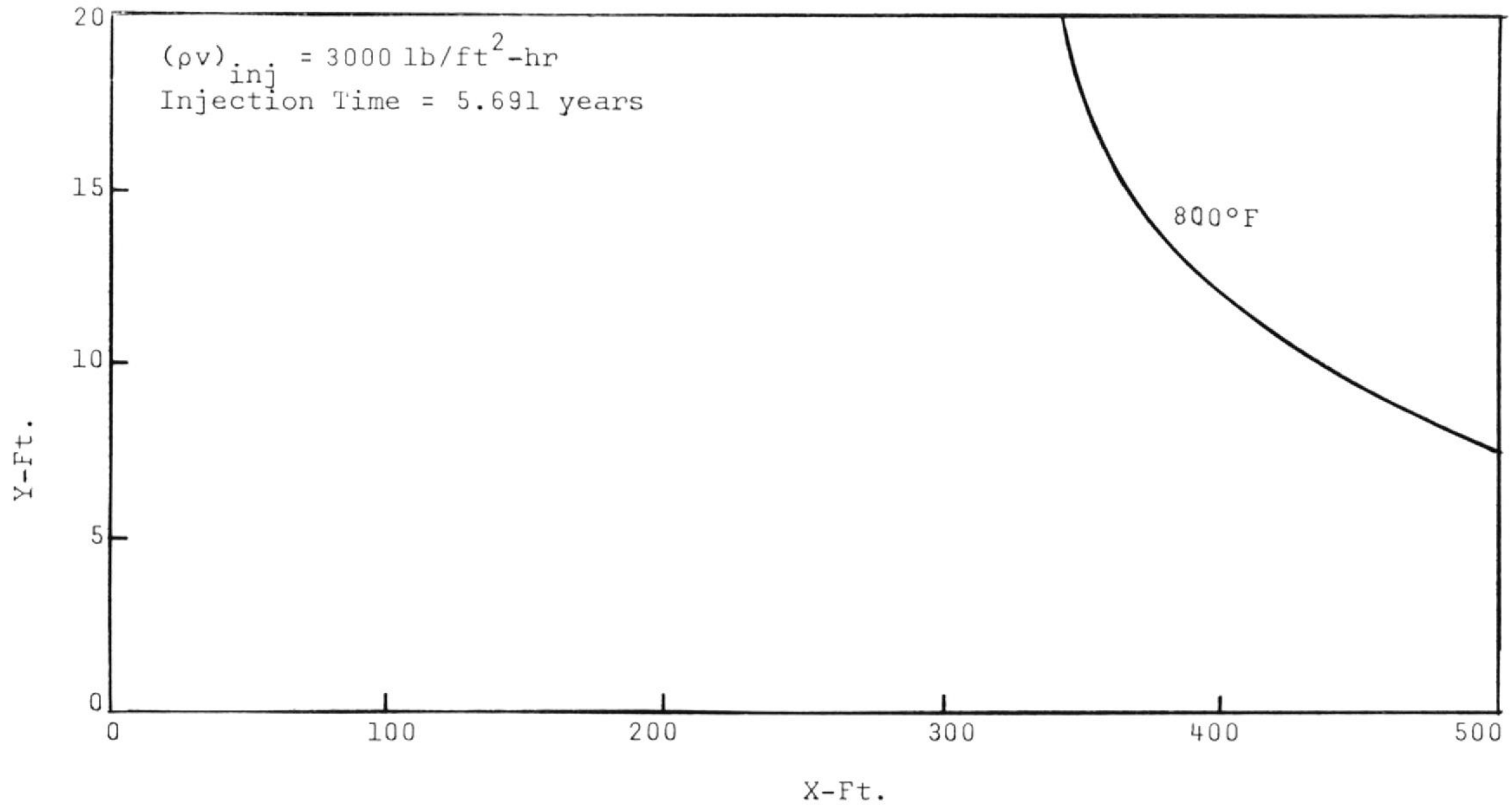

Figure 18. Formation Isotherms for Case 2.

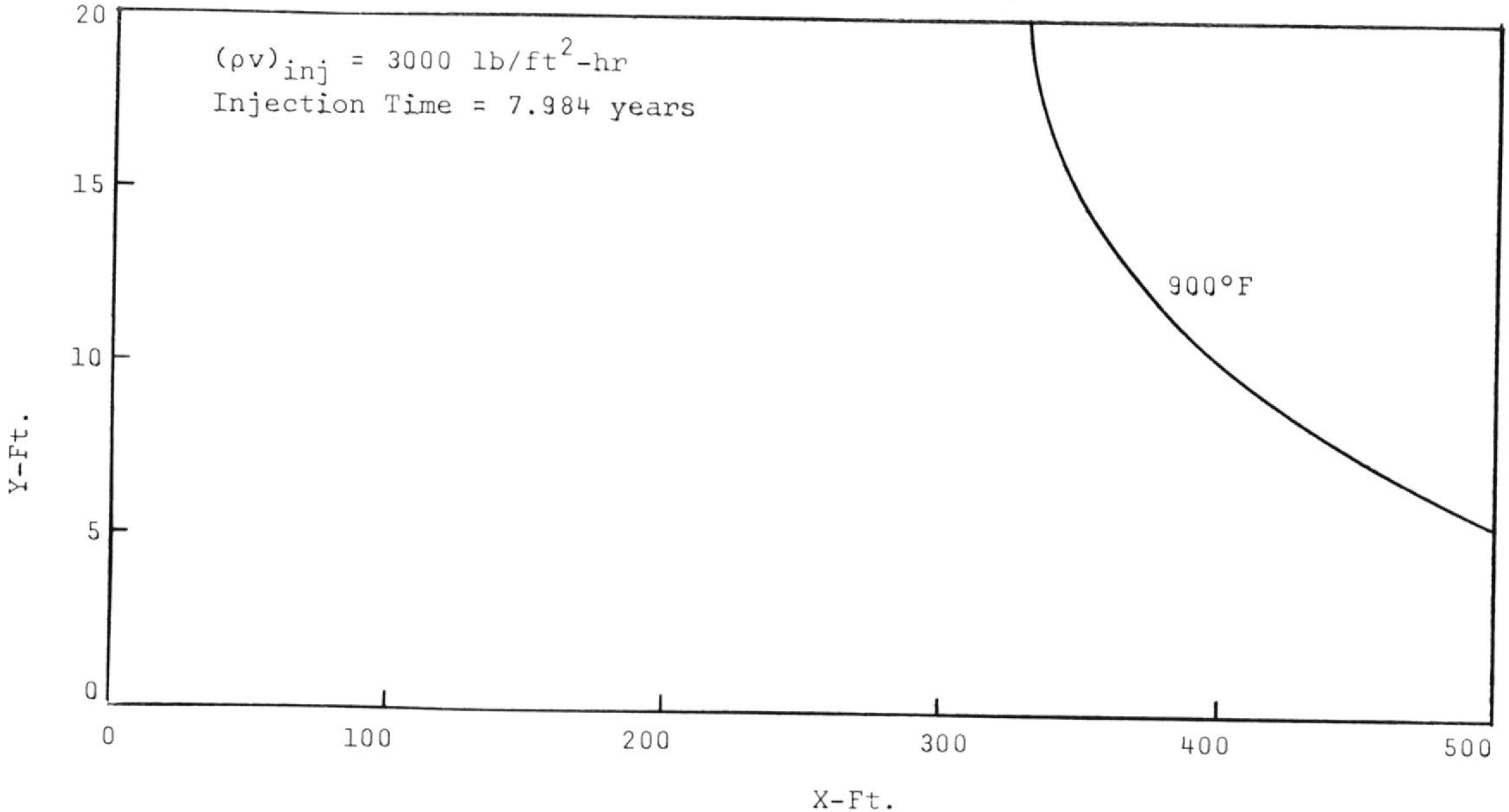

Figure 19. Formation Isotherms for Case 2.

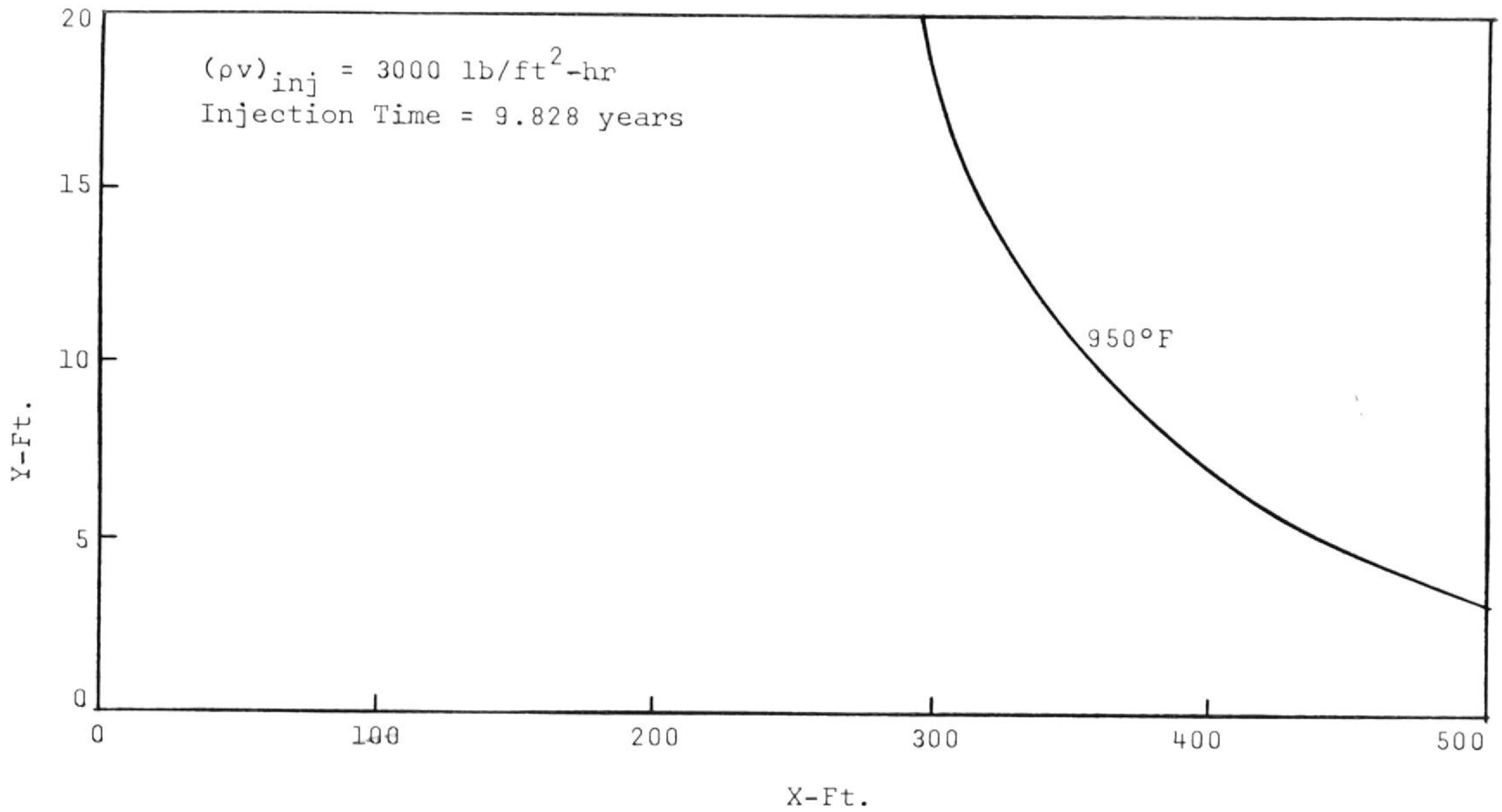

Figure 20. Formation Isotherms for Case 2.

From the above results it is observed that a shorter period of time is required to heat all the formation when the injection rate is increased. However, a large amount of heat is produced at the production well. In order to increase the heating efficiency (defined as heat utilized divided by heat injected), this produced heat could be reused for the heating process. In this way process efficiency could be improved.

Case 3. Influence of Fracture Length

The effect of the fracture length on the fraction of formation heated is shown in Figure 21, where curves for lengths of 200 ft. (case 3) and 500 ft. (base case) are presented.

As can be observed, when fracture length is reduced, the temperature at the end of the fracture increases fast and heating efficiency decreases, however, less time is required to achieve the desired amount of heating and a notable improvement in formation heating rate results. However, since the area considered for heating is smaller, the amount of fluids recovered also decreases.

Based on these results, the number and spacing of wells required to heat all the formation in a desired time, could be devised. Here again, it is the economic analysis and the characteristics of a particular case considered which finally decide these factors.

Figure 21 shows the enourmous improvement in formation heating rate when the fracture length is reduced from

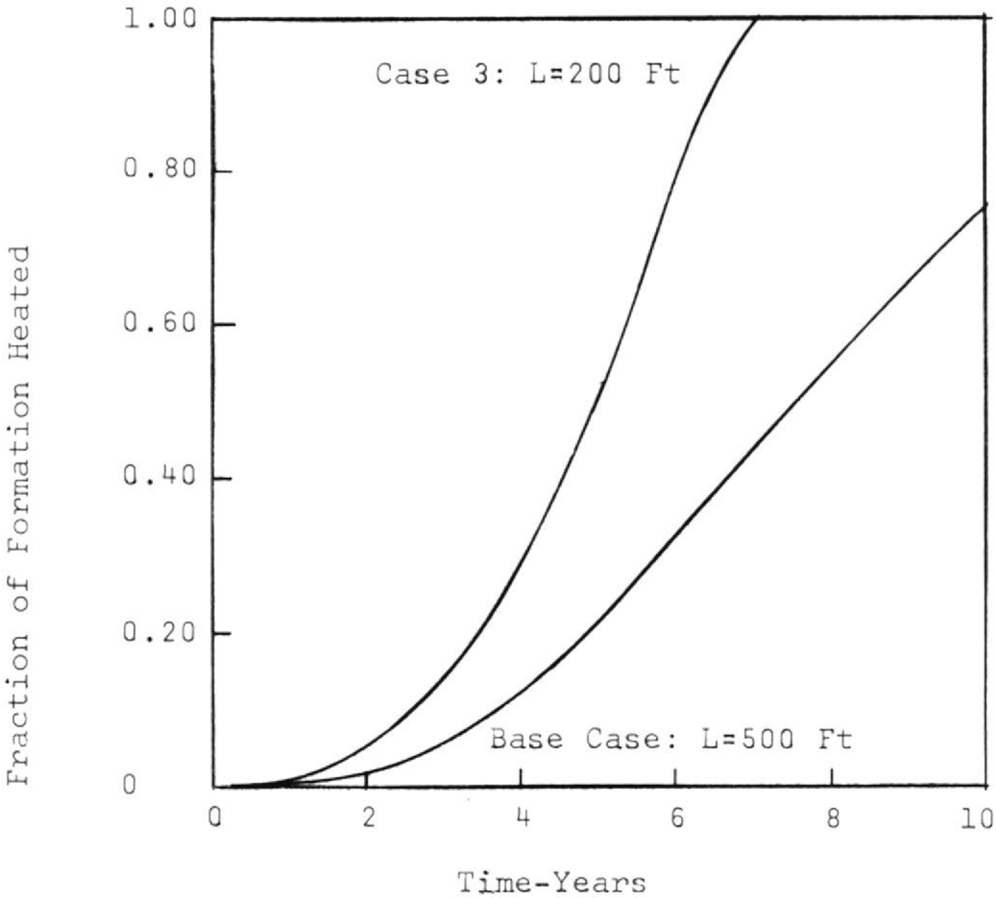

Figure 21. Fraction of Formation Heated to 800°F or Higher for Base Case.

500 ft. (base case) to 200 ft. (case 3). In the base case more than 10 years are required to heat all the formation to 800°F or higher while only 6.8 years are needed in case 3).

Figure 22 shows the fraction of the formation heated to 600, 800, and 900°F for case 3. Notice that the entire formation is heated to 900°F or higher in 10 years.

Figures 23 through 27 show formation isotherms for injection times of 0.568, 2.815, 5.691, 7.948, and 9.828 years for case 3.

Cases 4 and 5. Influence of Fracture Thickness

A considerable increase in the area heated is observed when fracture thickness is increased. This is a consequence of the energy balance equation for the fracture [Equation (4.4)], since the amount of heat conducted into the formation increases proportionately with fracture thickness. Cases 4 and 5 represent fracture thicknesses of 0.03 and 0.01 feet, respectively.

Figure 28 shows results for these two cases compared with those corresponding to the base case.

As can be observed, the curve for the base case is closer to the curve for case 4 than to that for case 5. This also shows that the heating efficiency decreases after high value isotherms reach the end of the fracture. In fact, when fracture thickness is increased the fracture temperature also increases in a shorter time and a greater amount of heat is produced sooner.

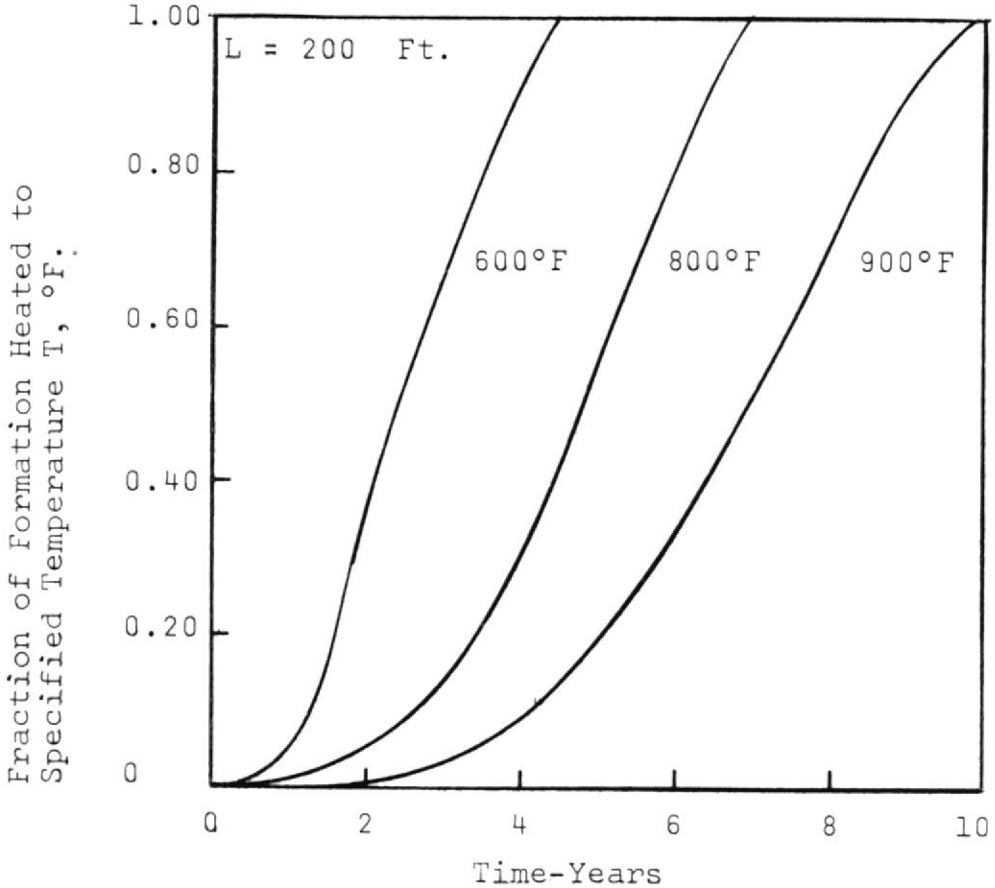

Figure 22. Fraction of Formation Heated for Case 3.

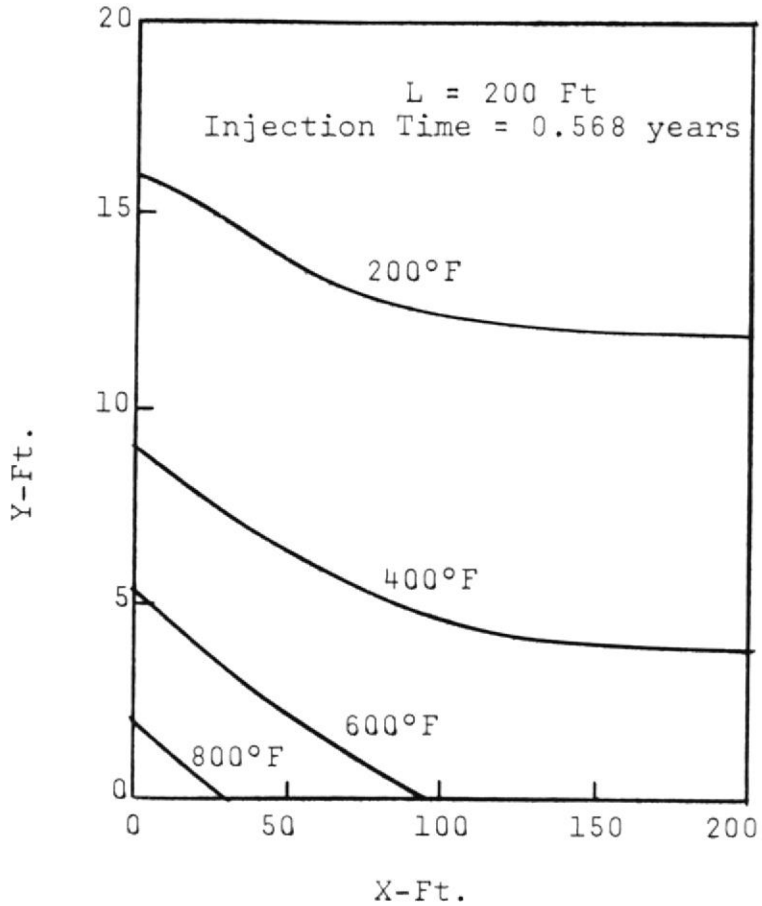

Figure 23. Formation Isotherms for Case 3.

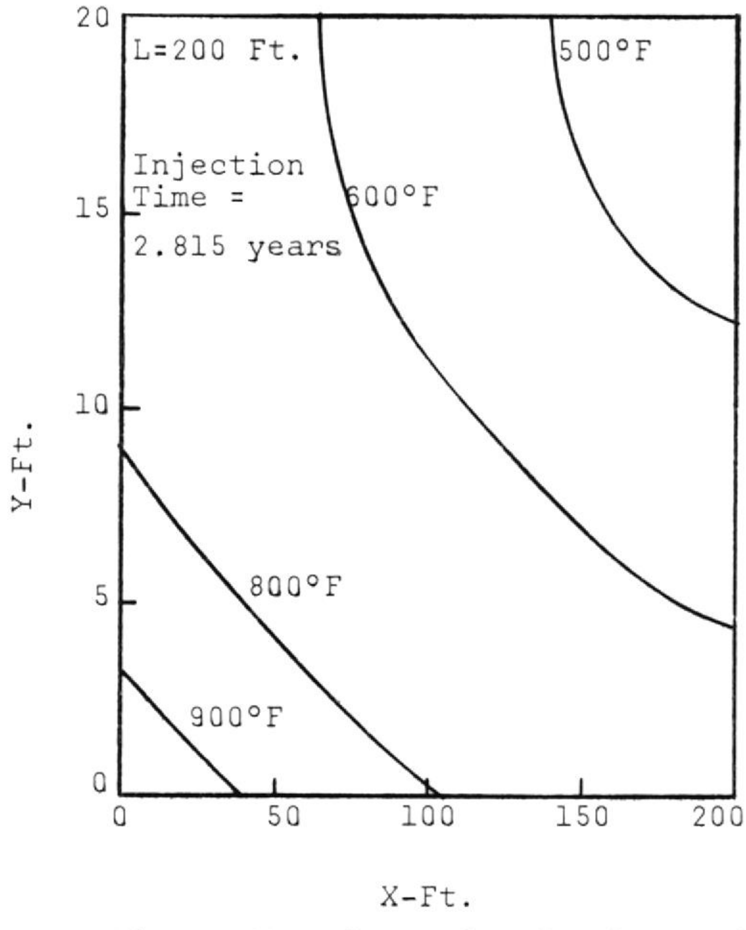

Figure 24. Formation Isotherms for Case 3.

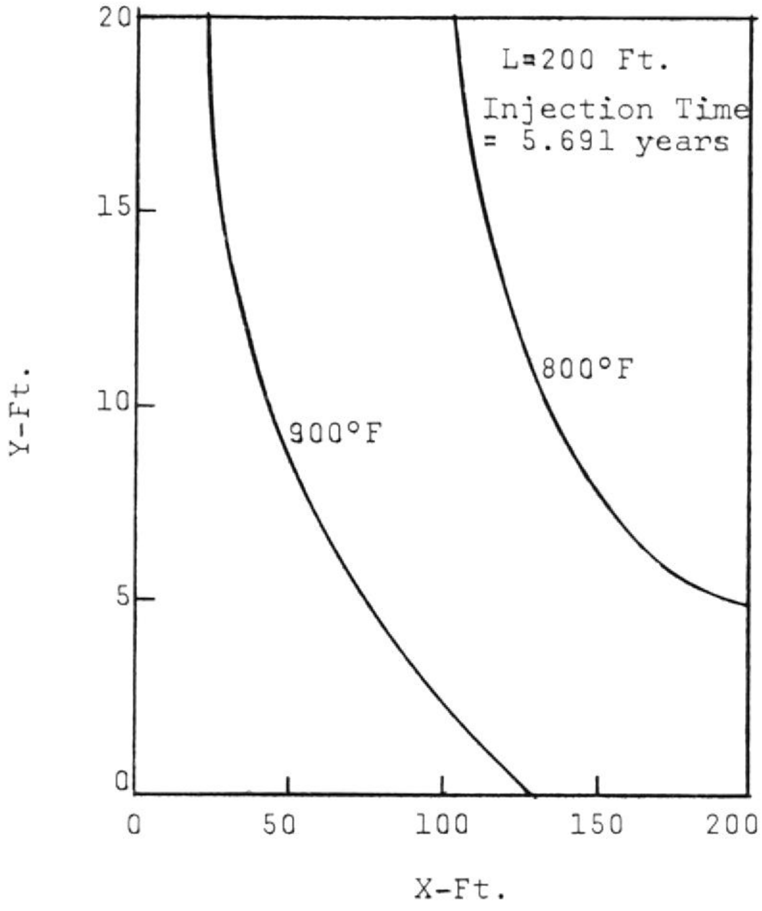

Figure 25. Formation Isotherms for Case 3.

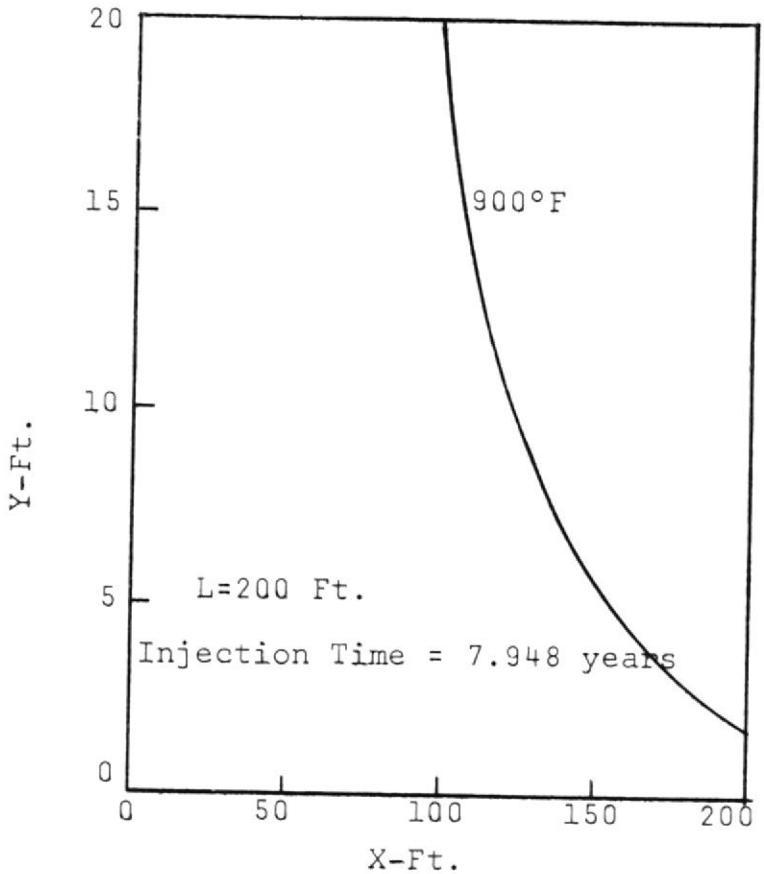

Figure 26. Formation Isotherms for Case 3.

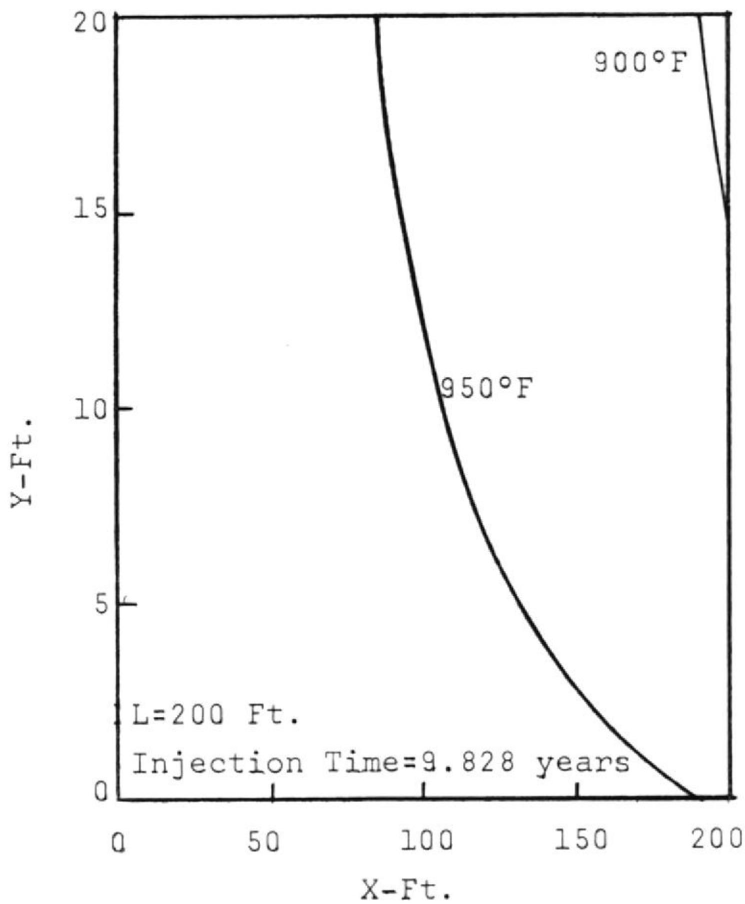

Figure 27. Formation Isotherms for Case 3.

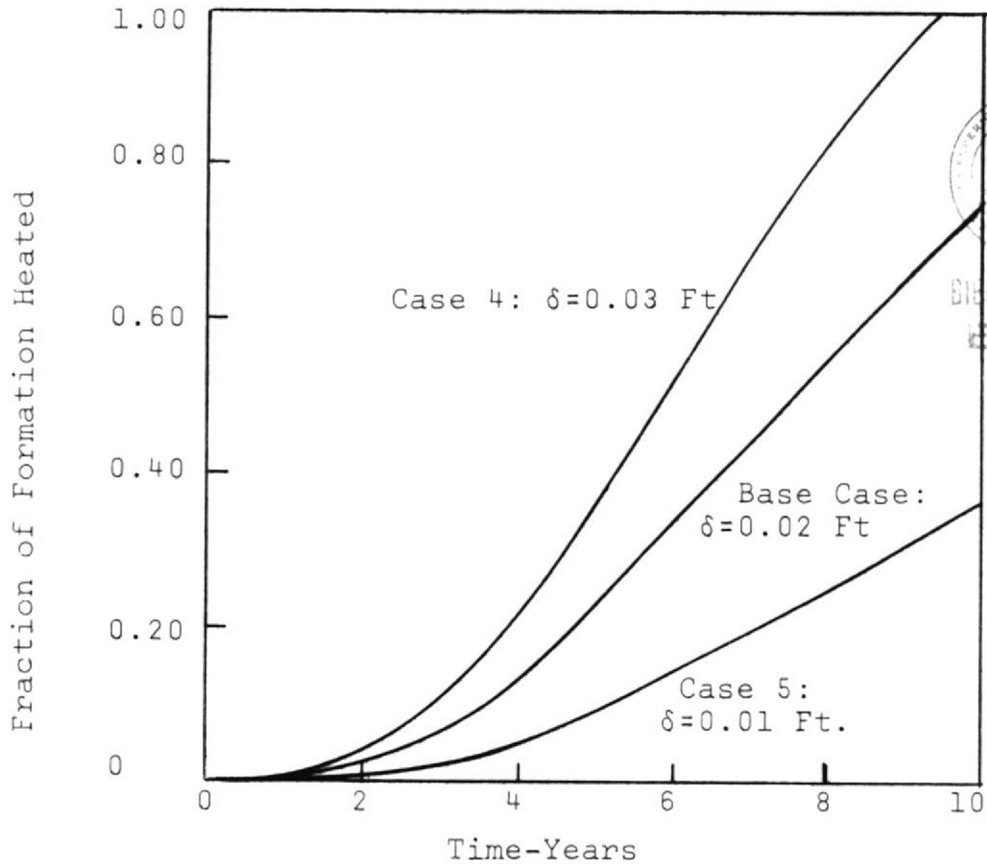

Figure 28. Fraction of Formation Heated to 800°F or Higher for Cases 4 and 5.

As can be observed in Figure 28, in case 4, the entire formation is heated to 800°F or higher in 9.4 years compared with 70 and 33 per cent corresponding to the base case and case 5 respectively, for the same period of time.

Figure 29 shows fraction of the formation heated to 600°F and 800°F as a function of time for case 5. Same kind of results are presented in Figure 30 for case 4 but for temperatures of 600, 700, and 800°F.

Figure 31 through 40 show thermal isotherms for cases 4 and 5, and injection times of 0.568, 2.815, 5.691, 7.948, and 9.828 years.

Figure 41 shows temperature distribution in the fracture for case 5, for different injection times. As can be observed, with a reduction in the fracture thickness a considerable length of the fracture remains at the saturation temperature for a longer period of time. For the 2.815 years period, for example, 72 per cent of the fracture length is still at that temperature, and 20 per cent for an injection time of 5.691 years. As a result, longer time is required to heat all the formation to a certain temperature, but on the other hand, better heat utilization is obtained. Since large amounts of heat are not produced at the production well.

Case 6. Influence of the Steam Pressure.

Figure 42 shows the results when injection pressure is varied. Curves are plotted for values of 2000 psia (Case 6) and 1000 psia (Base Case). Comparison of these

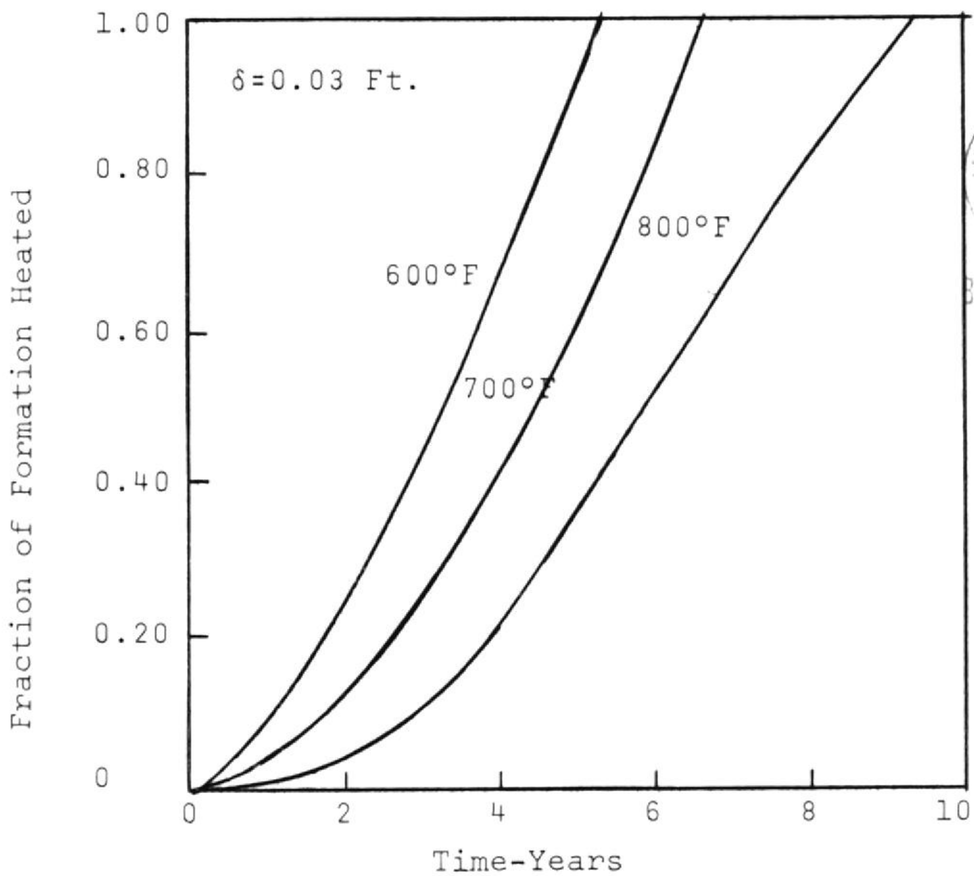

Figure 30. Fraction of Formation Heated to Specified Temperature for Case 4.

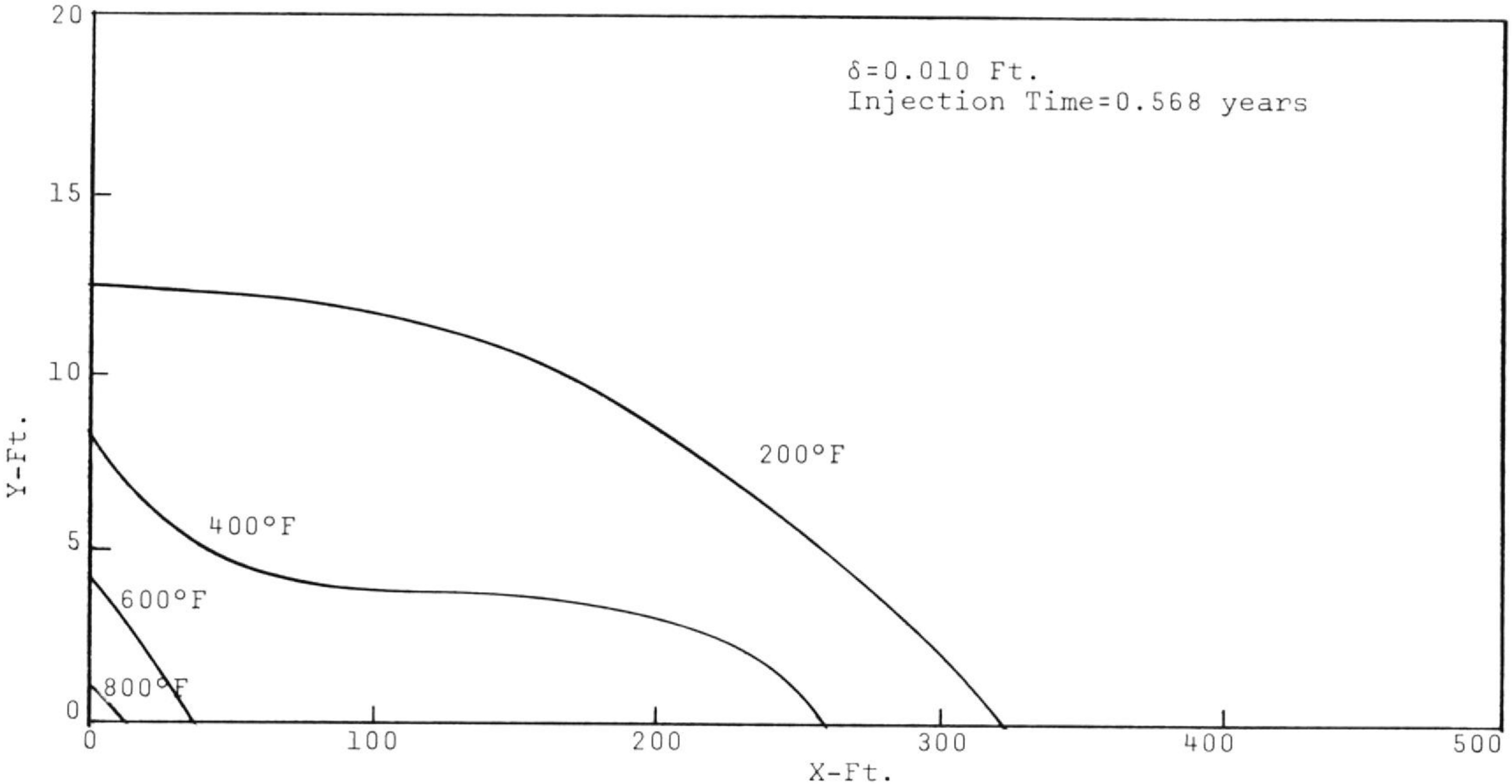

Figure 31. Formation Isotherms for Case 5.

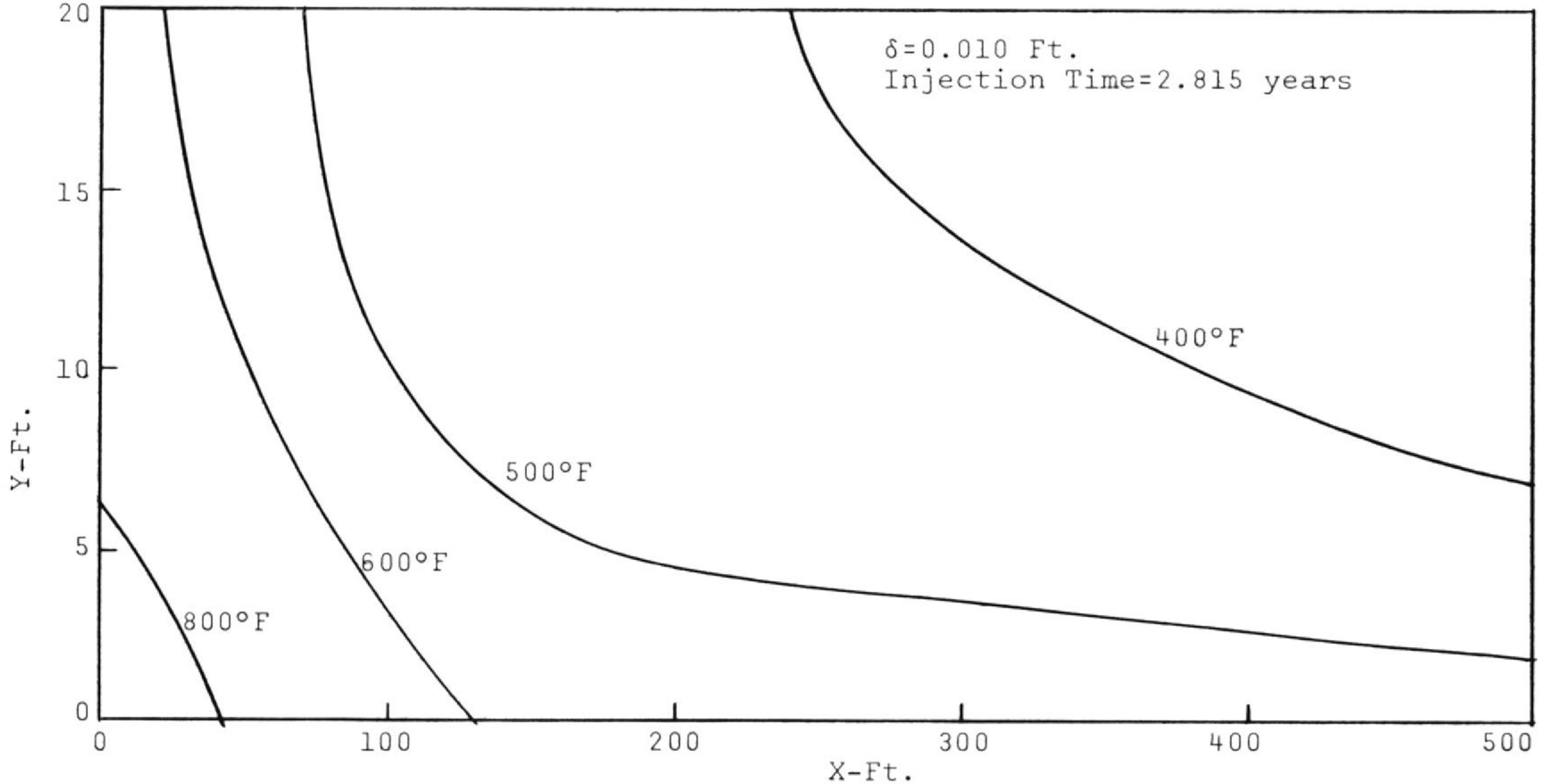

Figure 32. Formation Isotherms for Case 5.

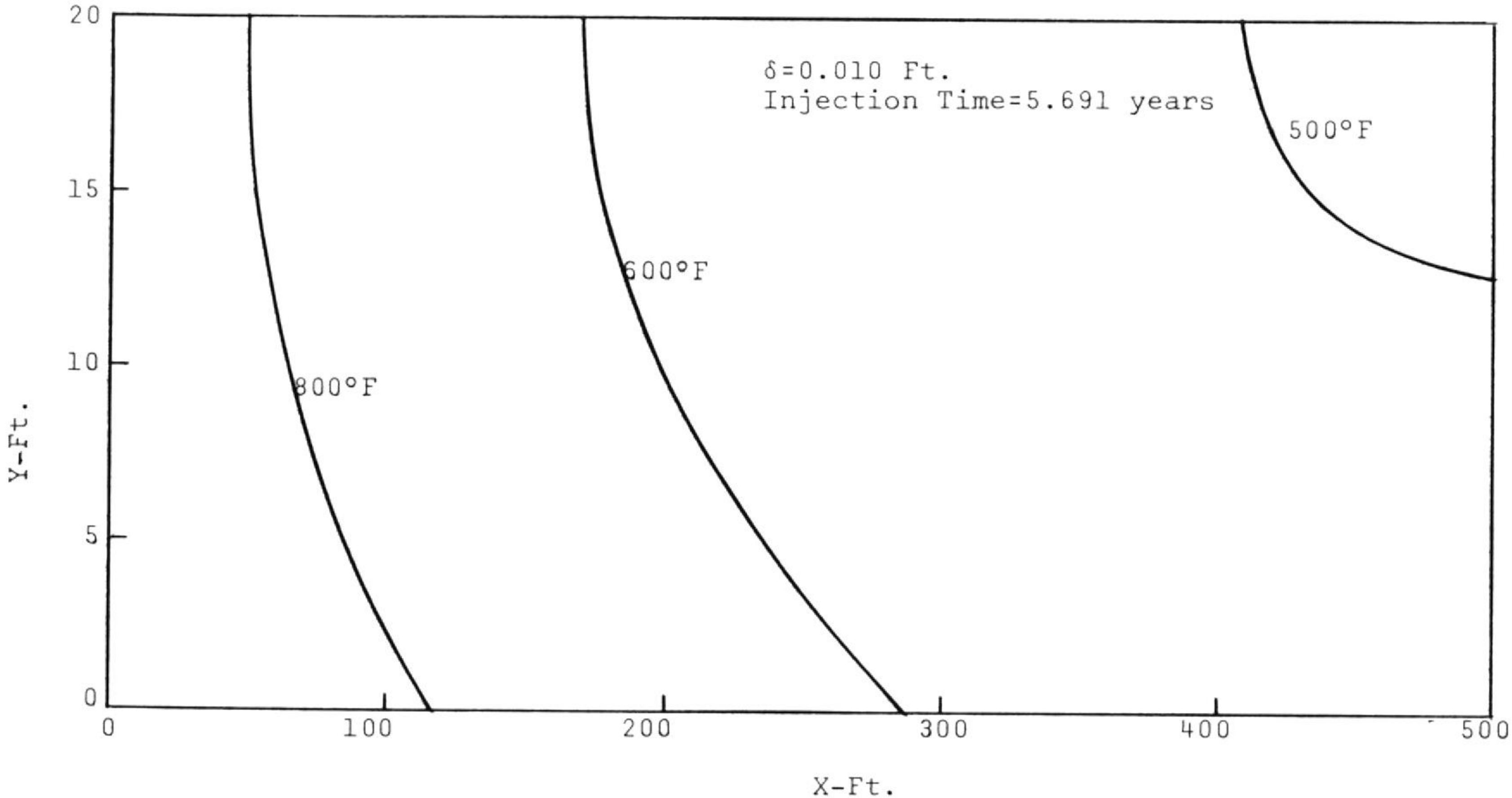

Figure 33. Formation Isotherms for Case 5.

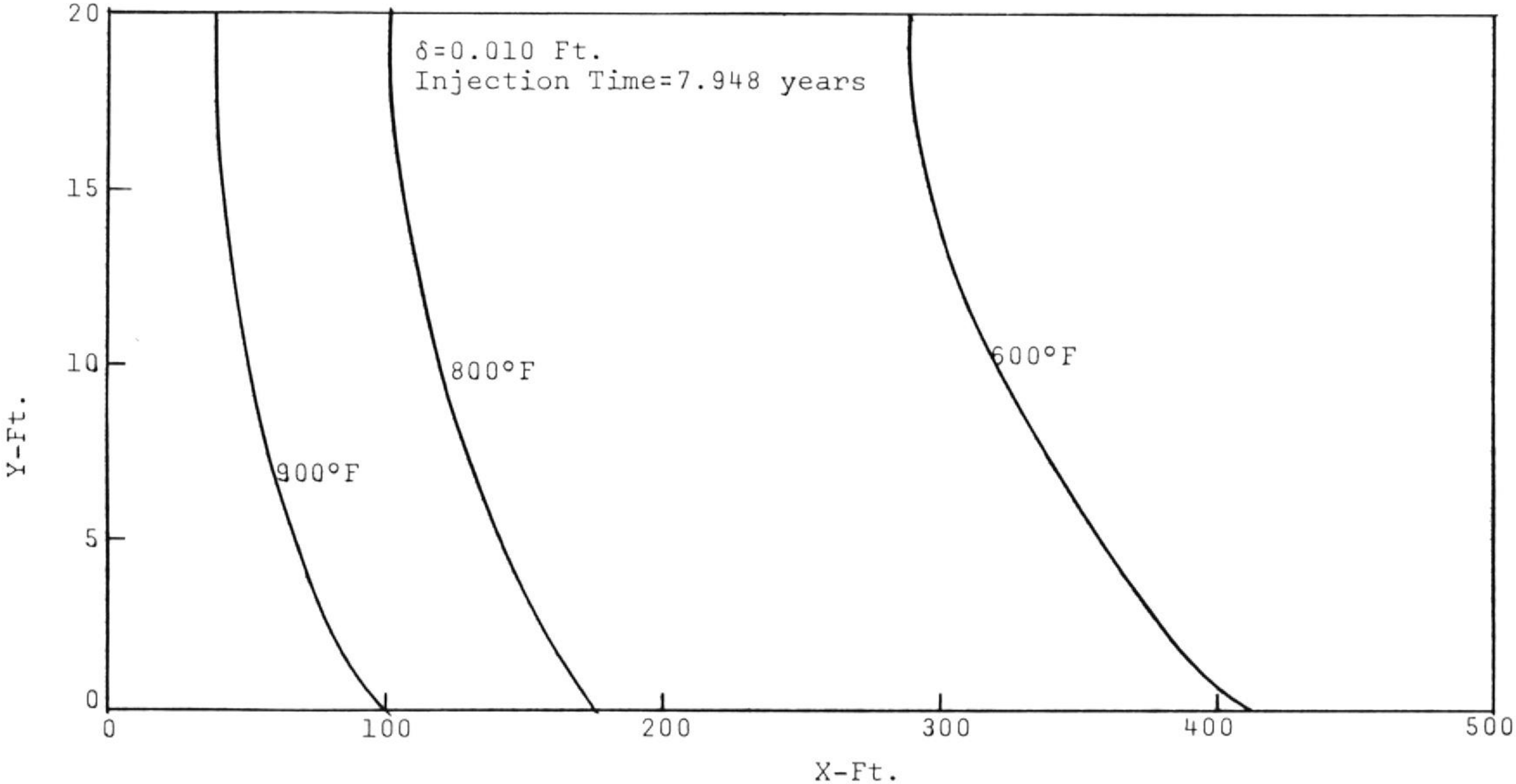

Figure 34. Formation Isotherms for Case 5.

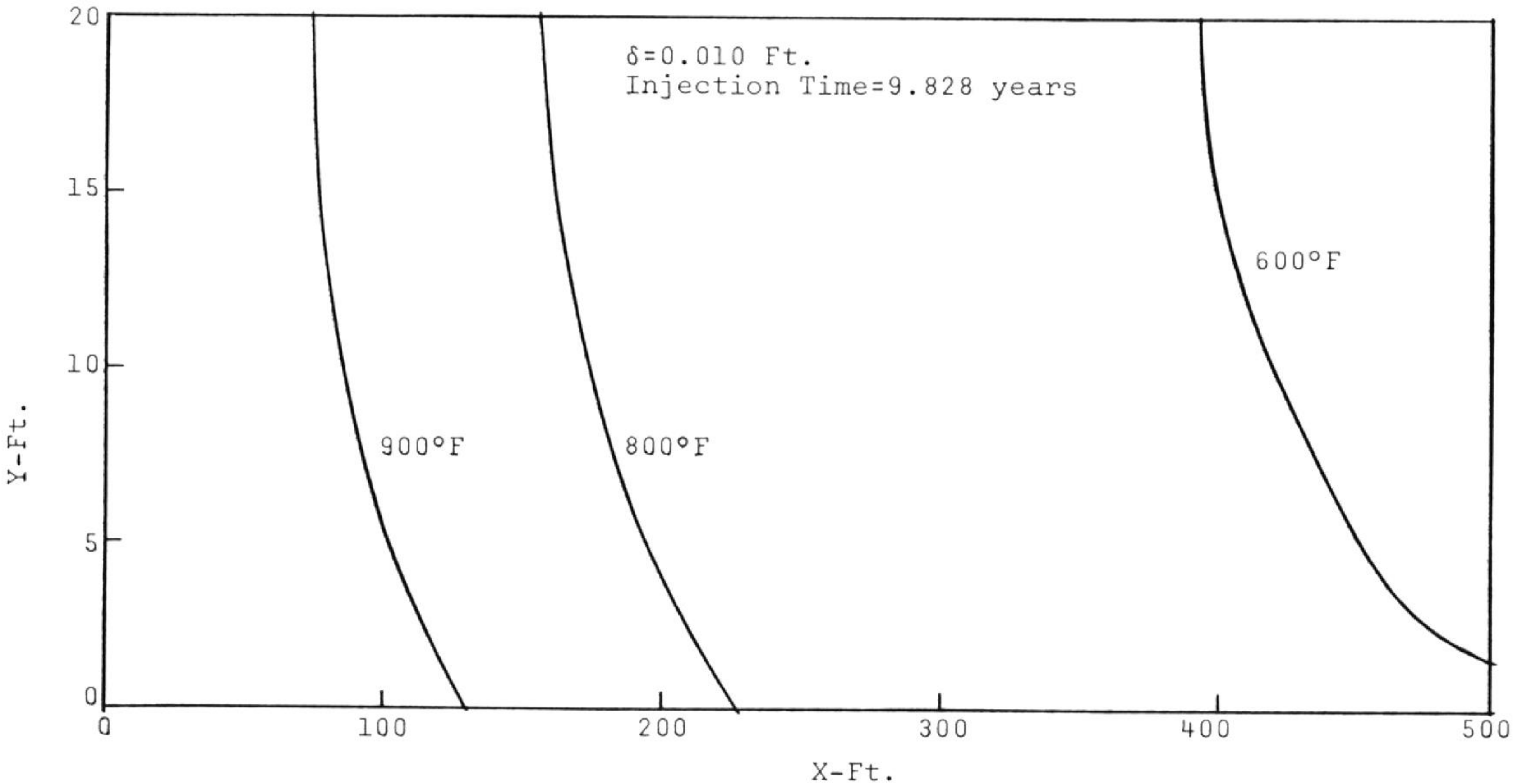

Figure 35. Formation Isotherms for Case 5.

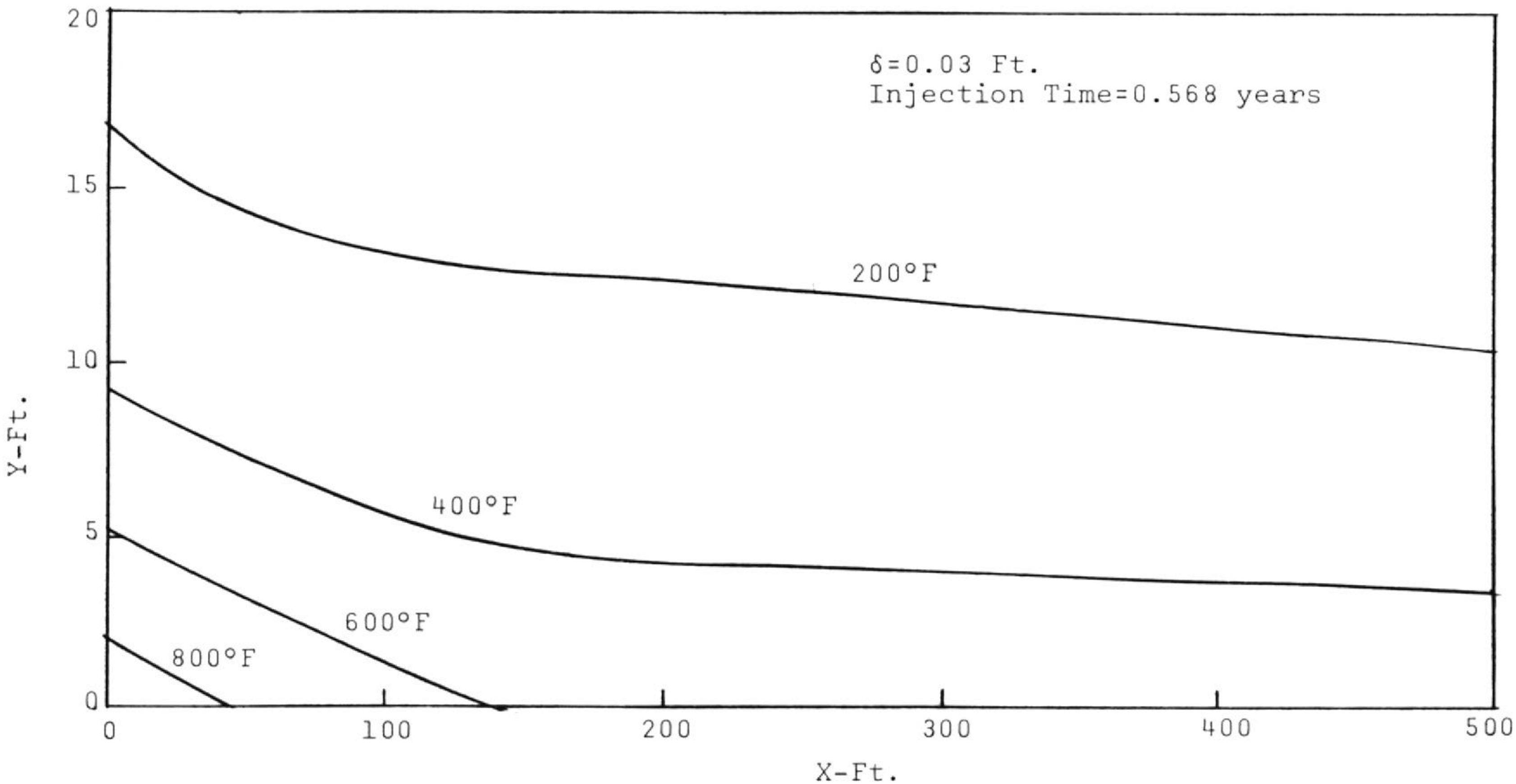

Figure 36. Formation Isotherms for Case 4.

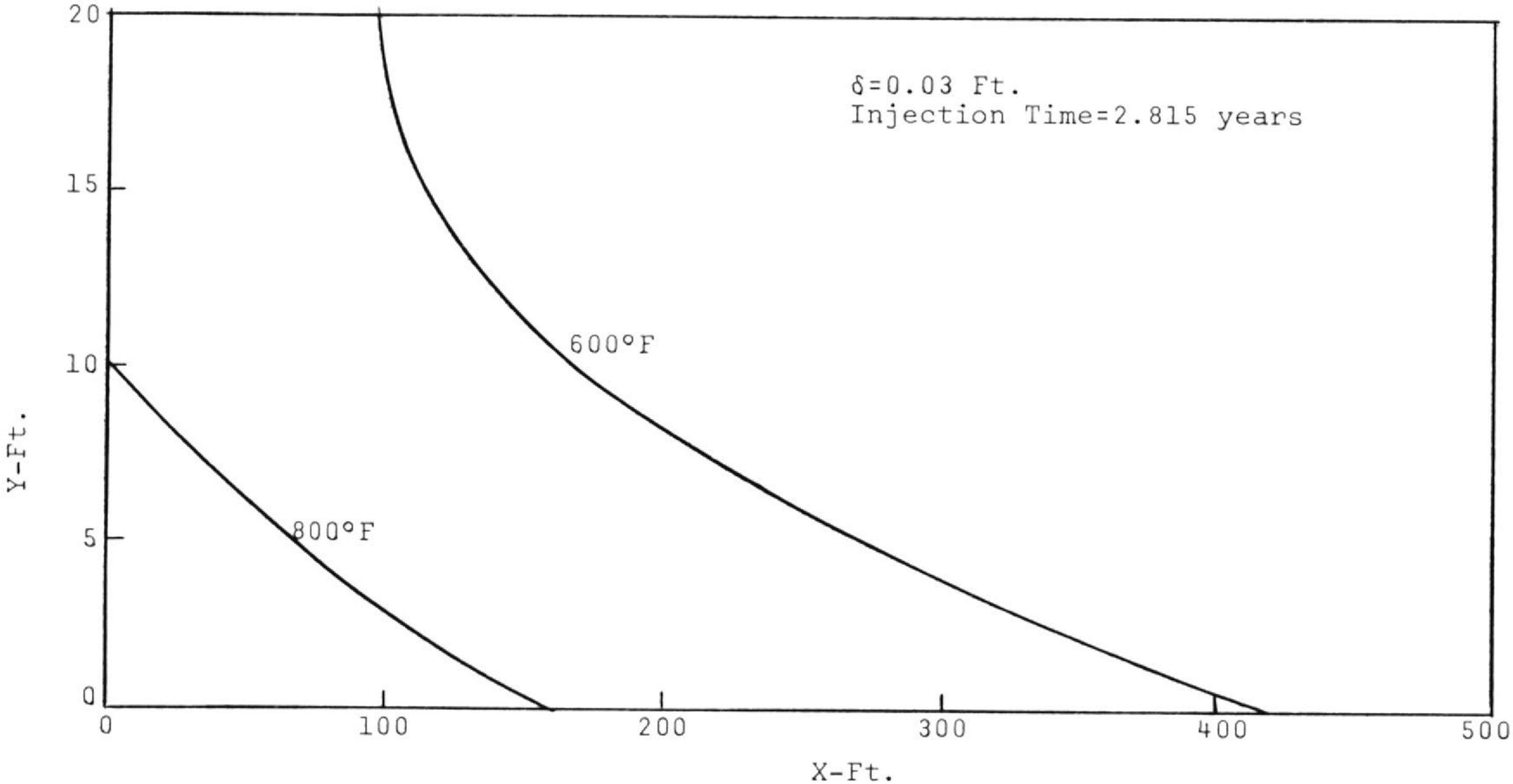

Figure 37. Formation Isotherms for Case 4.

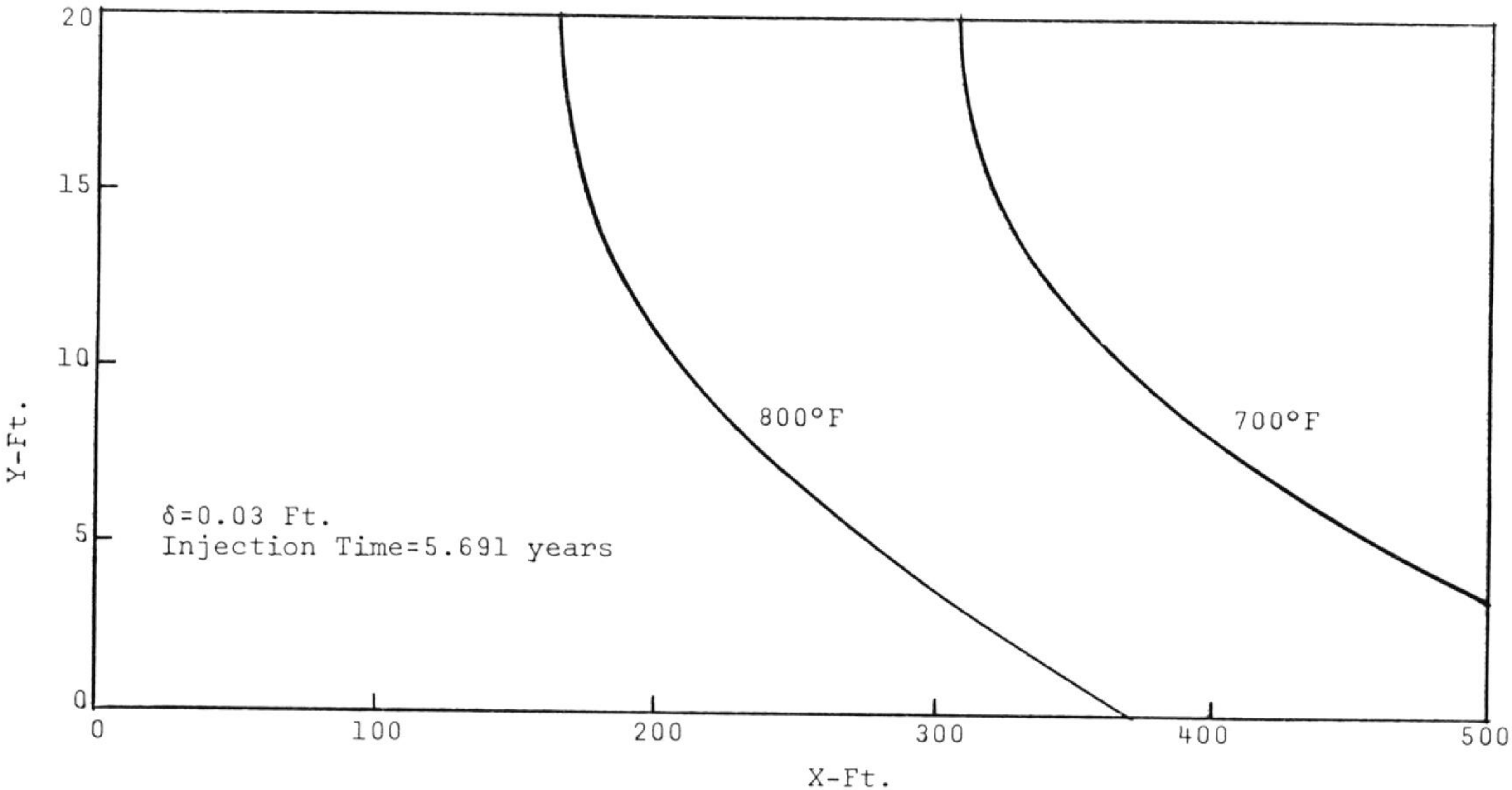

Figure 38. Formation Isotherms for Case 4.

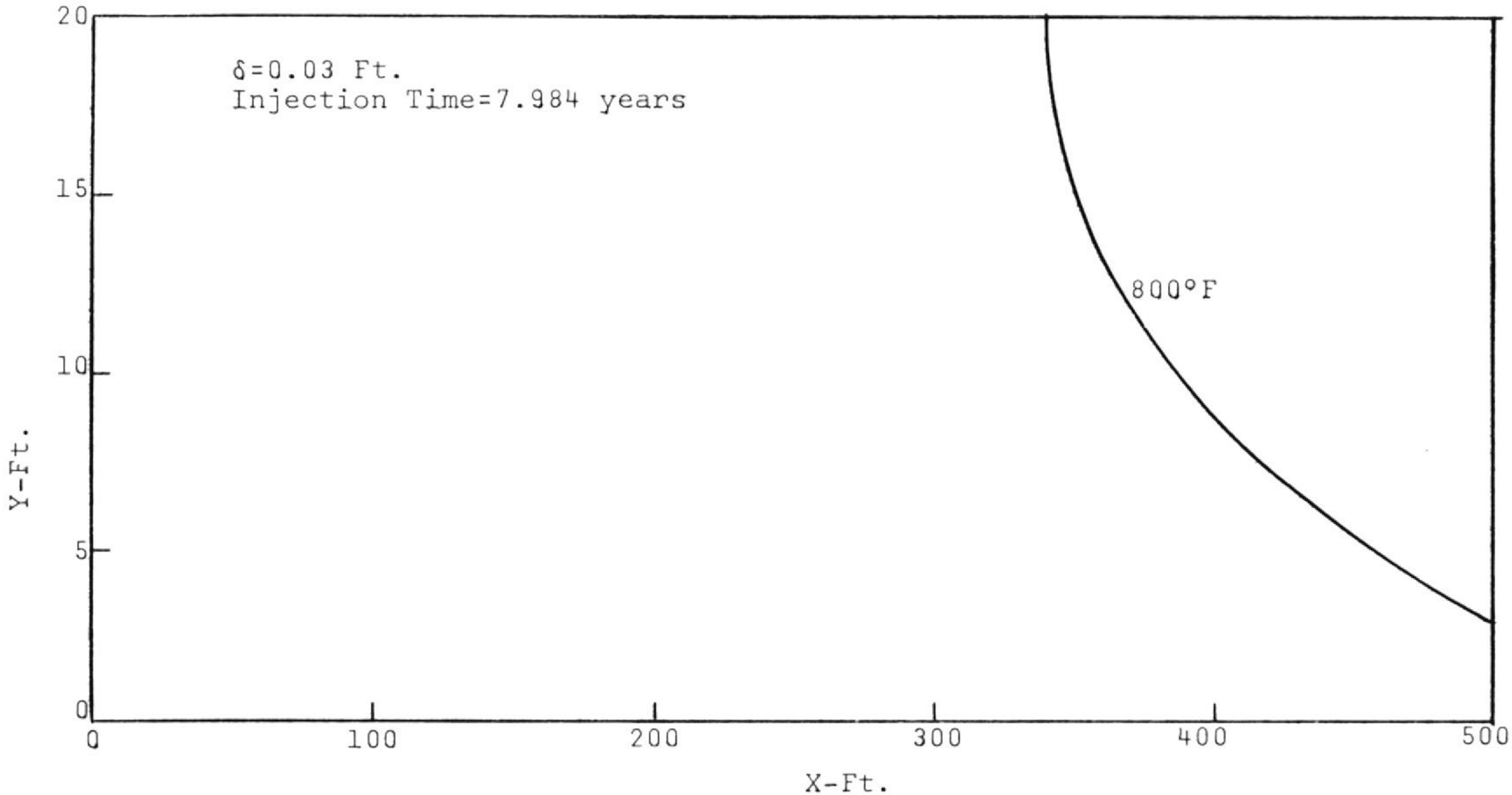

Figure 39. Formation Isotherms for Case 4.

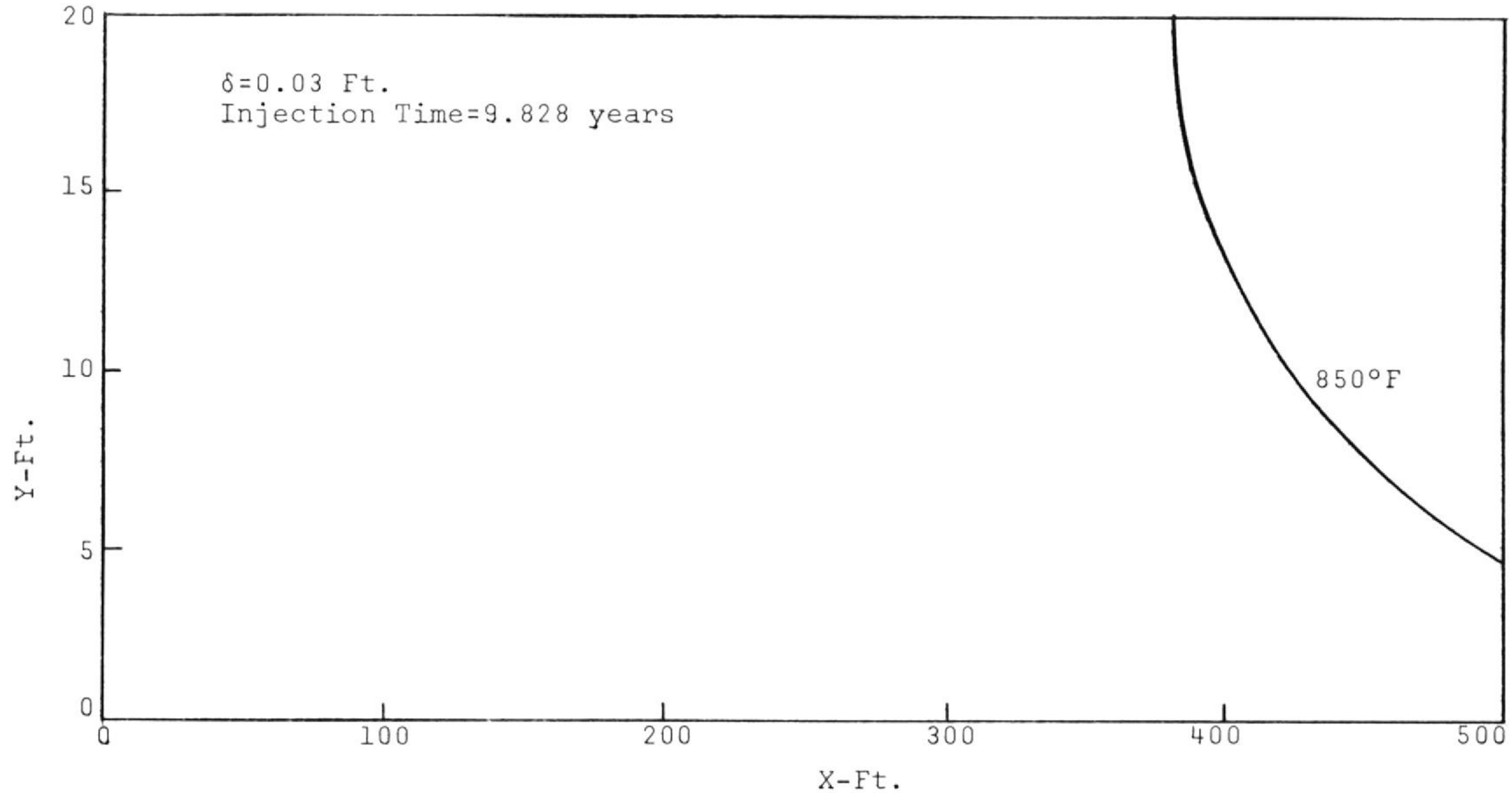

Figure 40. Formation Isotherms for Case 4.

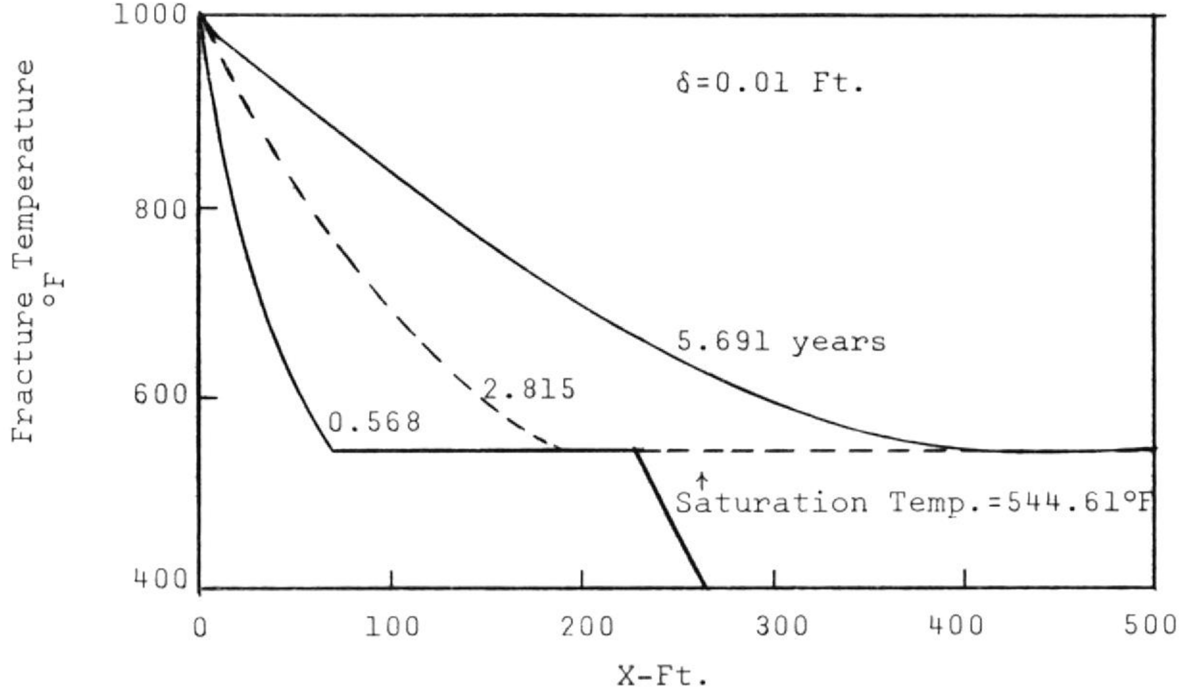

Figure 41. Temperature Distribution in the Fracture for Case 5.

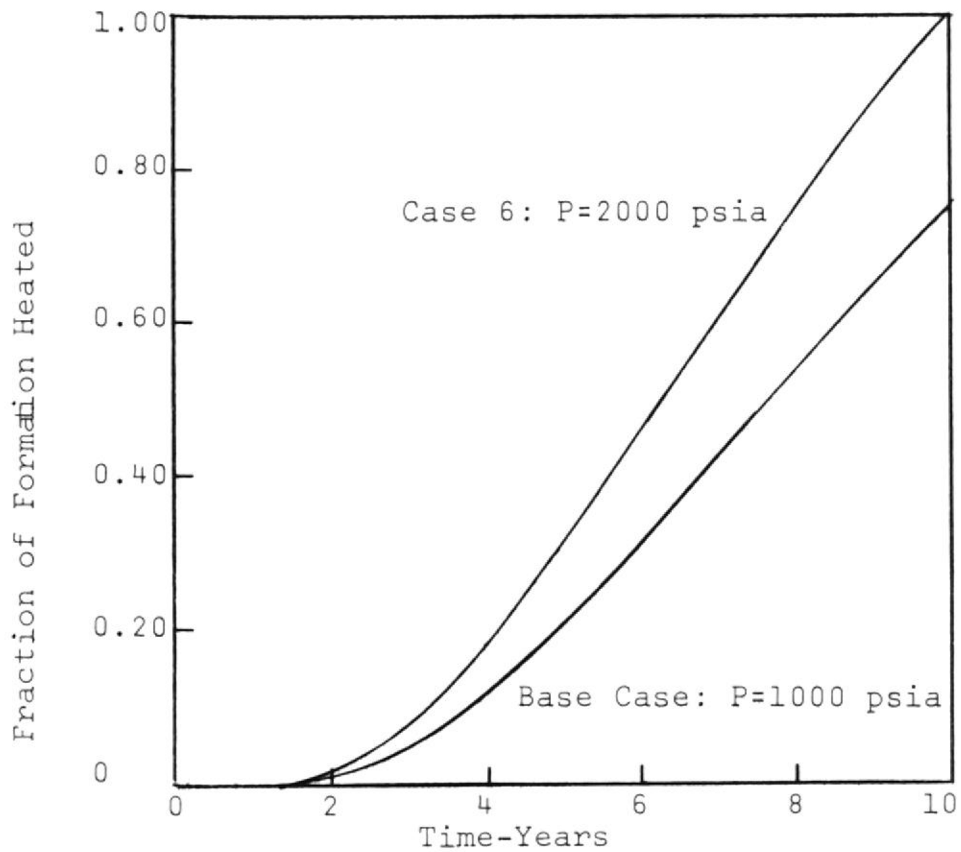

Figure 42. Fraction of Formation Heated to 800°F or Higher for Case 6.

two curves show that the lower heating rate at the lower pressure results in a greater time requirement for formation heating. Pressure changes affect the results because of their effect on the dependencies of the density and specific enthalphy on the temperature and quality of the steam.

Although at higher injection pressures the fraction of formation heated increases, optimal value for the injection pressure will actually be determined by the overburden characteristics and by the additional costs incurred when handling high pressures, compared with the value of the possible additional hydrocarbon recovering.

Figure 42 shows that in case 6 all of the formation is heated to 800°F or higher in 10 years while for this same injection time, only 76 per cent is heated to the same temperature in the base case.

Figures 43 through 47 present thermal isotherms for case 6 and the injection times of 0.568, 2.815, 5.691, 7.948 and 9.828 years.

Case 7. Influence of Injection Temperature

Figure 48 shows curves for the fraction of formation heated to 800°F or higher and injection temperatures of 1500°F (Case 7) and 1000°F (Base Case), and Figure 49 presents the same type of results for Case 7, but for temperatures of 600, 800, 1000, and 1300°F.

As can be observed from Figure 48, 95 per cent of the formation in Case 7 is heated to 800°F or higher in 10 years compared with only 76 per cent in the Base Case.

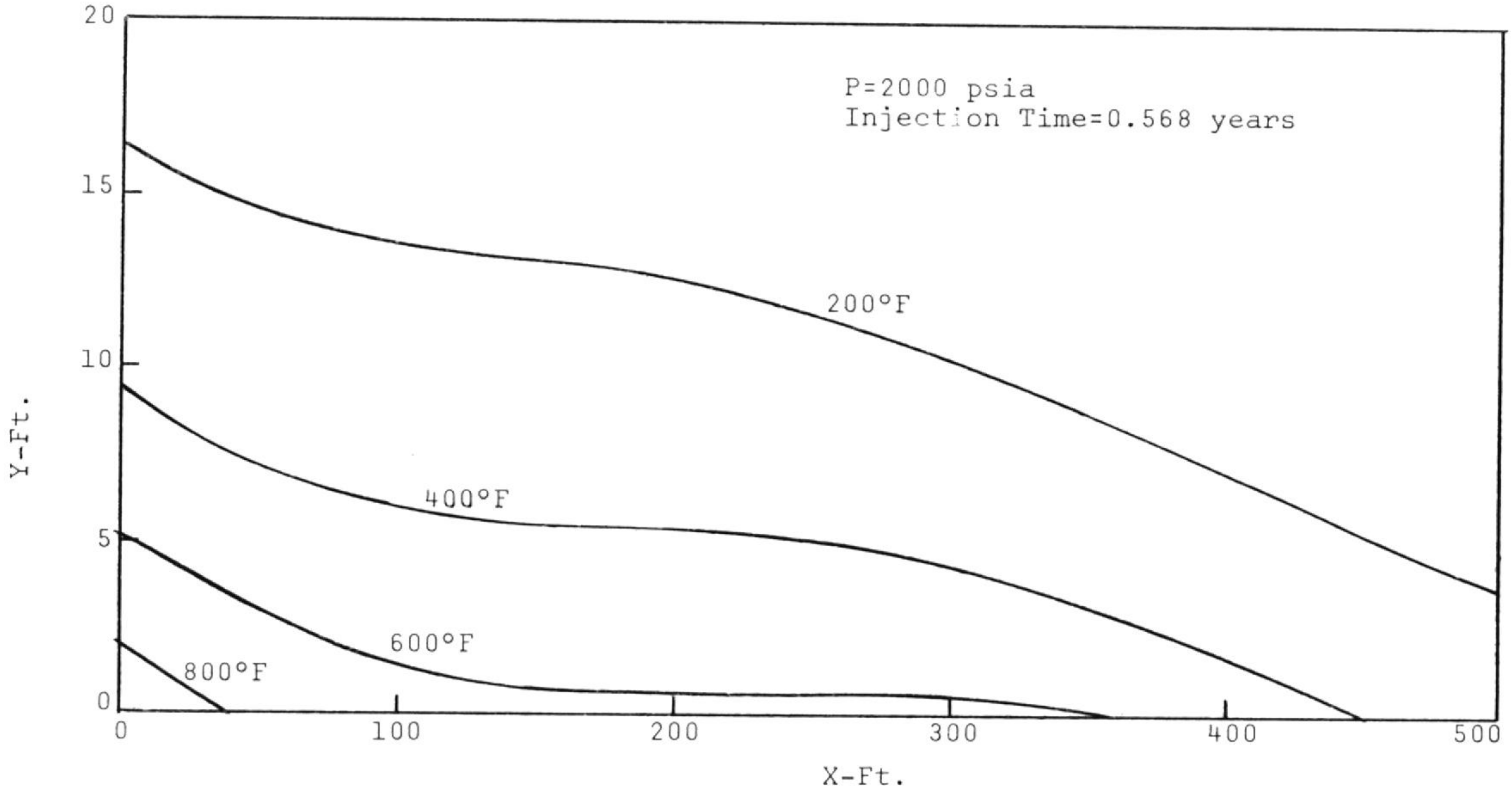

Figure 43. Formation Isotherms for Case 6.

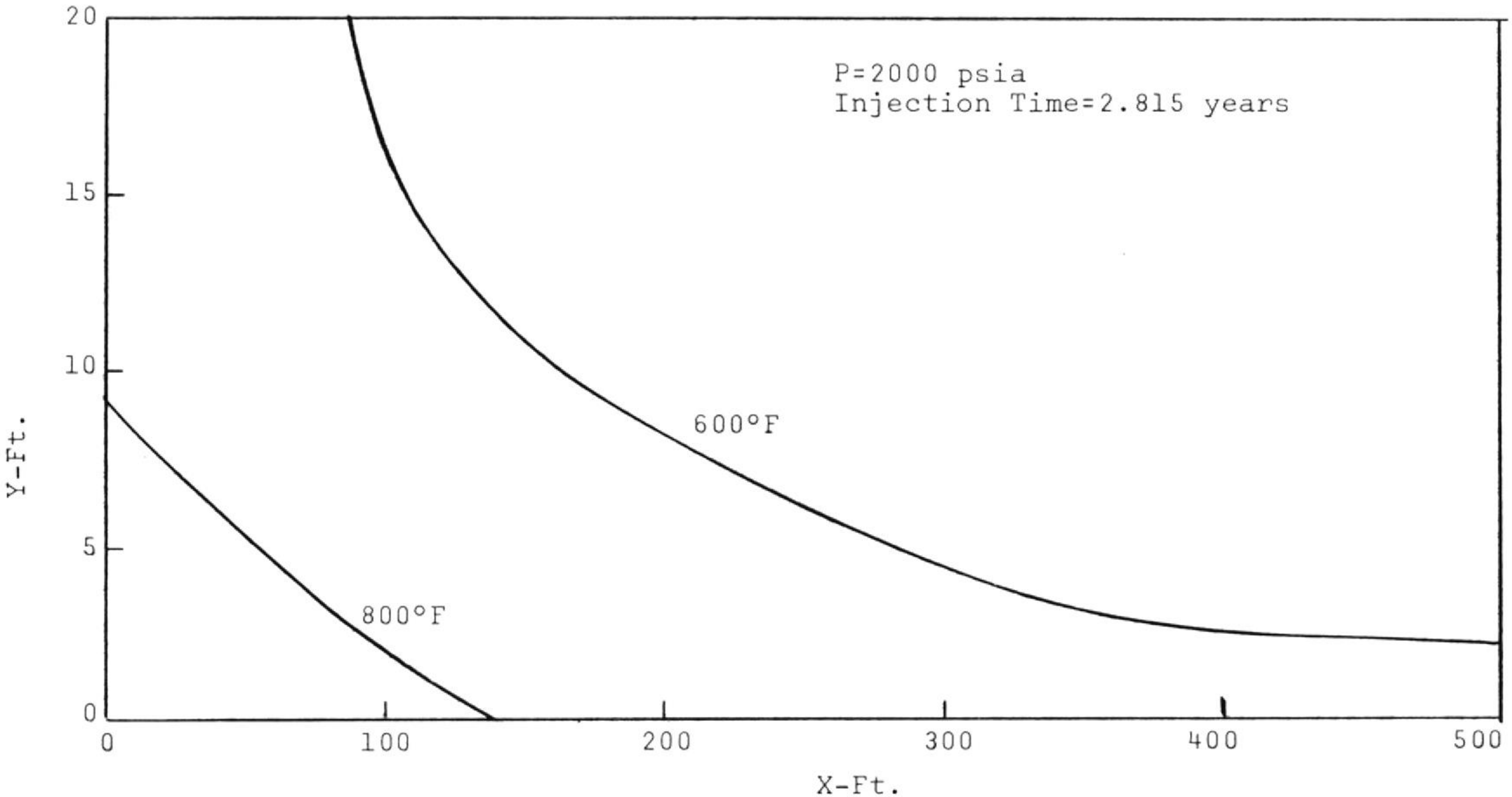

Figure 44. Formation Isotherms for Case 6.

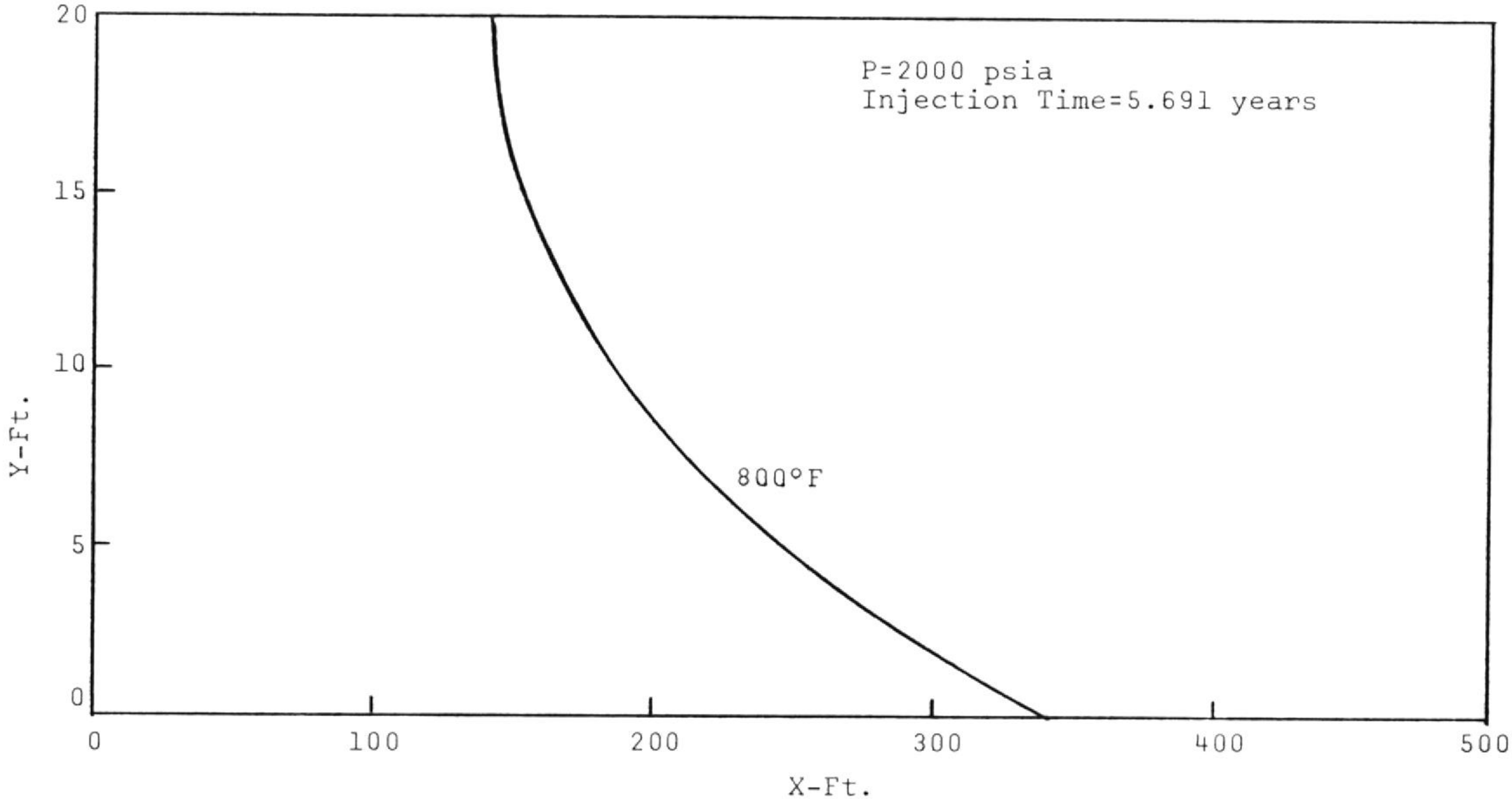

Figure 45. Formation Isotherms for Case 6.

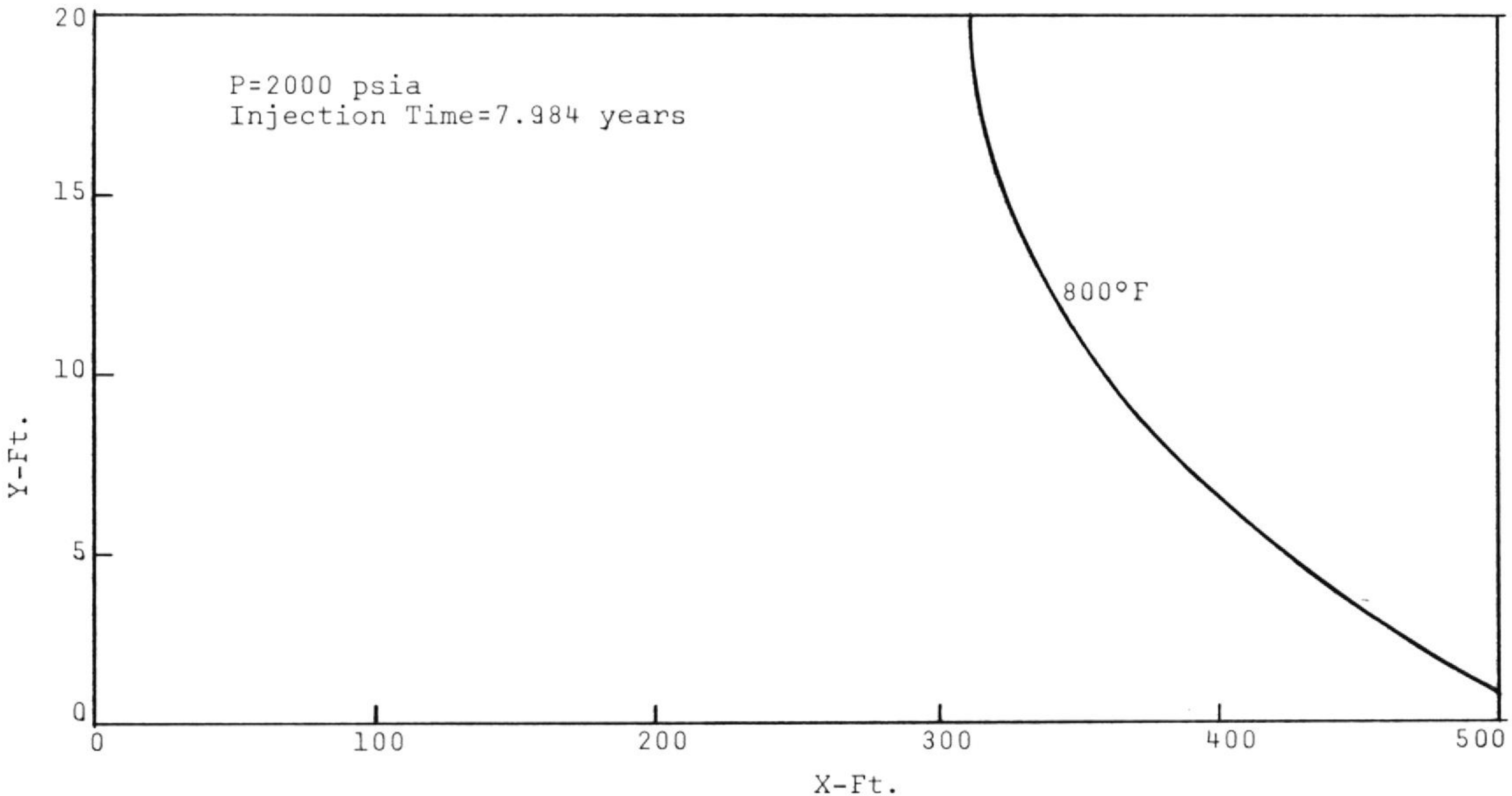

Figure 46. Formation Isotherms for Case 6.

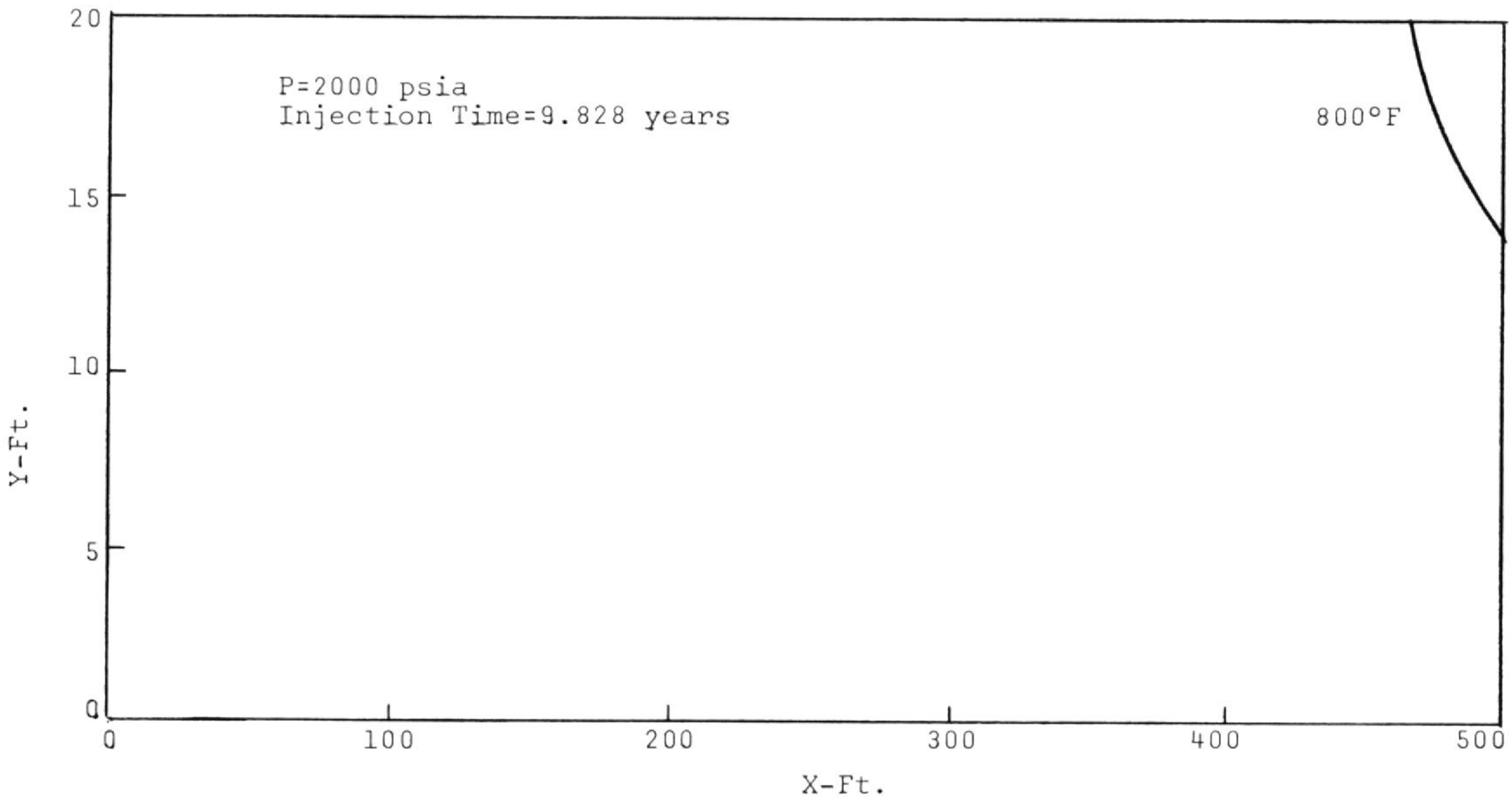

Figure 47. Formation Isotherms for Case 6.

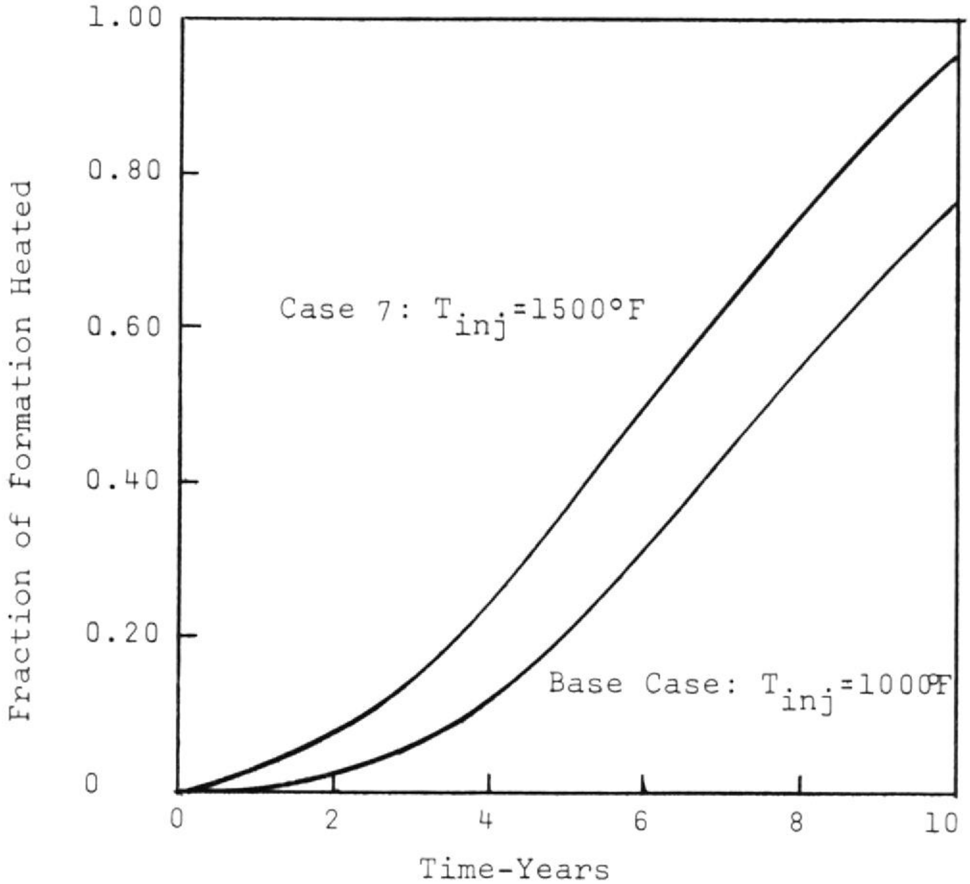

Figure 48. Fraction of Formation Heated to 800°F or Higher for Case 7.

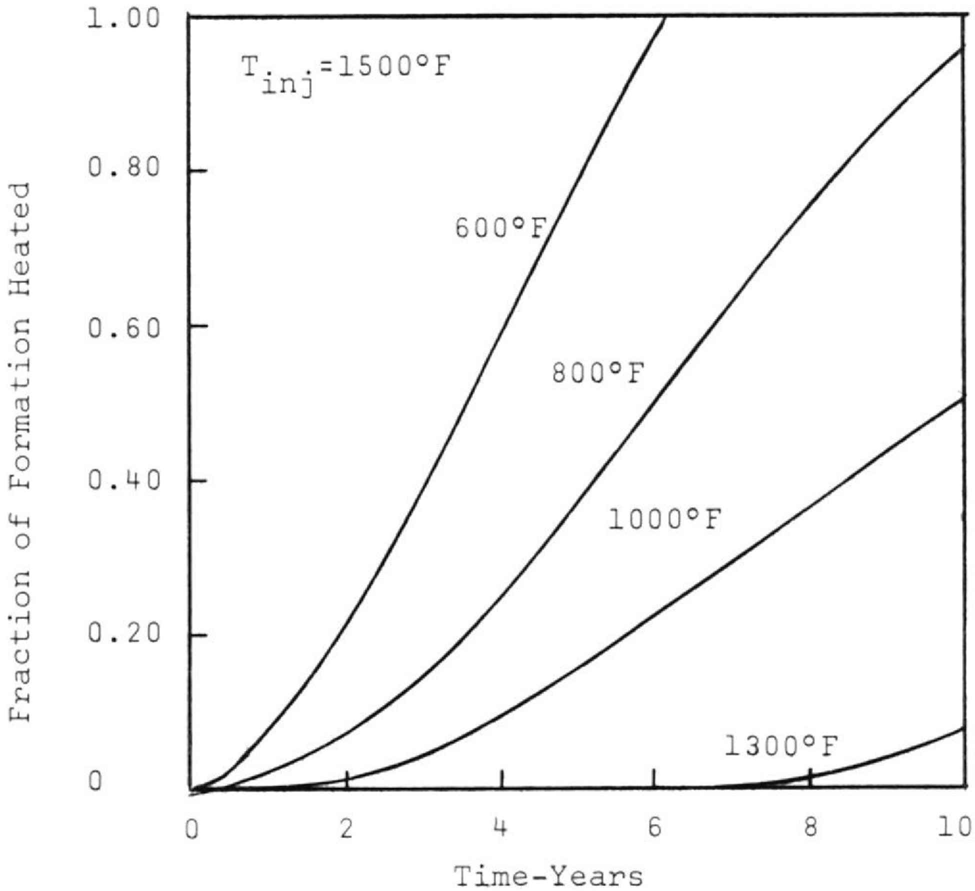

Figure 49. Fraction of Formation Heated to 800°F or Higher for Case 7.

Also, notice in Figure 49 that in Case 7, 51 per cent of the formation is heated to 1000°F or higher in 10 years and 8 per cent to 1300°F or higher in the same period of time.

Figures 50 to 54 are formation isotherms for injection times of 0.568, 2.815, 5.691, and 9.828 years. It is observed that the penetration of isotherms in both horizontal and vertical directions is greater in Case 7 than in the Base Case, because of a higher temperature gradient.

Although, a higher injection temperature gives rise to a greater heating rate, special attention must be focused on the possibility of carbonate decomposition when oil shales reach more than 1000°F (E. E. Jukkola et al. (1953)). This is an important fact when establishing the optimal value of the injection temperature in the recovery of oil from oil shale.

Cases 8 and 9. Influence of the Distance to the Boundaries

If the distance to the no-flow boundaries is shortened a considerable improvement in formation heating rate results.

Figure 55 shows results of these calculation, where the fraction of formation heated to 800°F or higher is presented as a function of time for distances of 10 ft (Case 9), 20 ft (Base Case) and 40 ft (Case 8) to the boundaries. In the Base Case, 76 per cent of the formation is heated to 800°F or higher in 10 years. However,

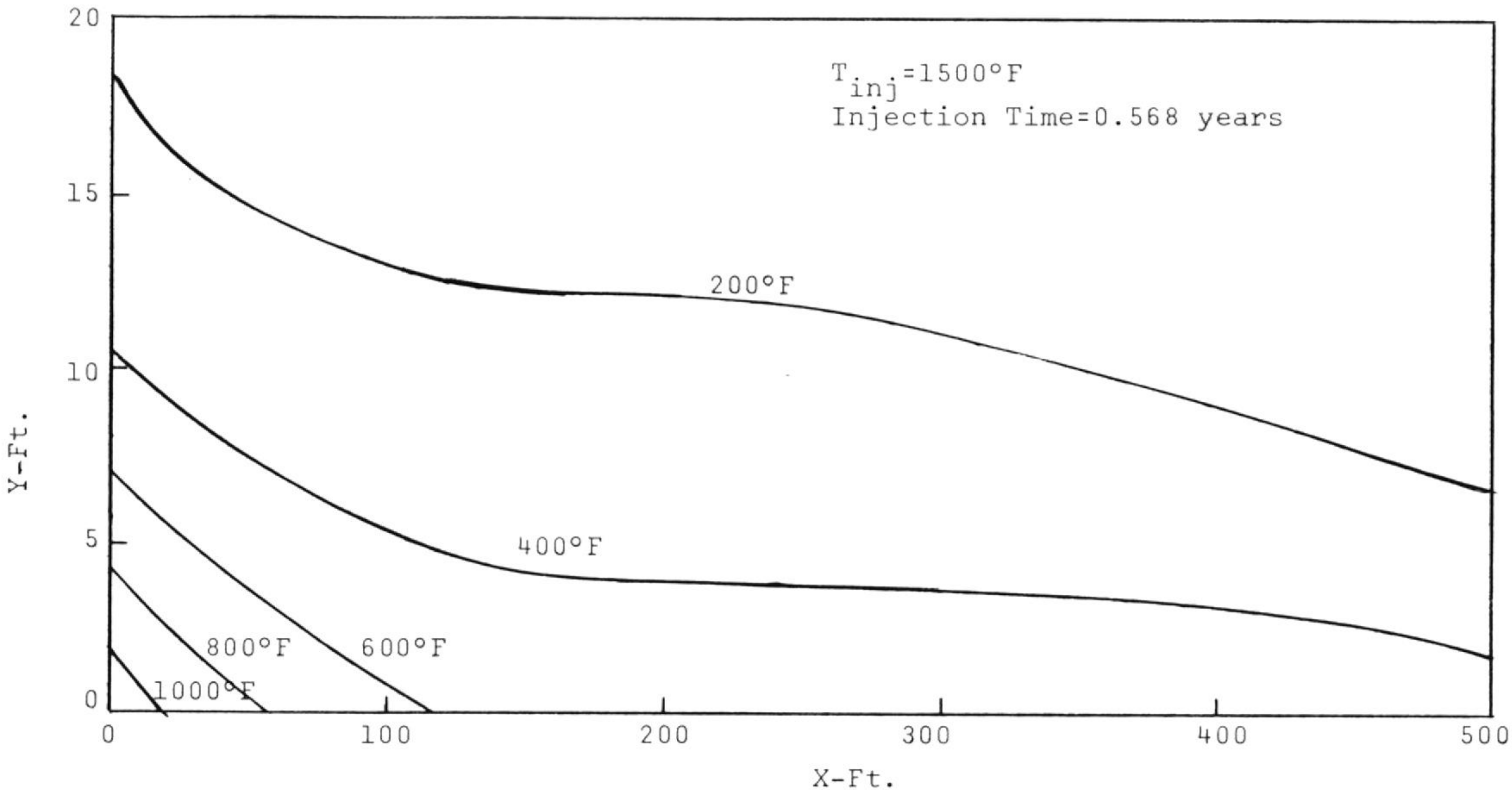

Figure 50. Formation Isotherms for Case 7.

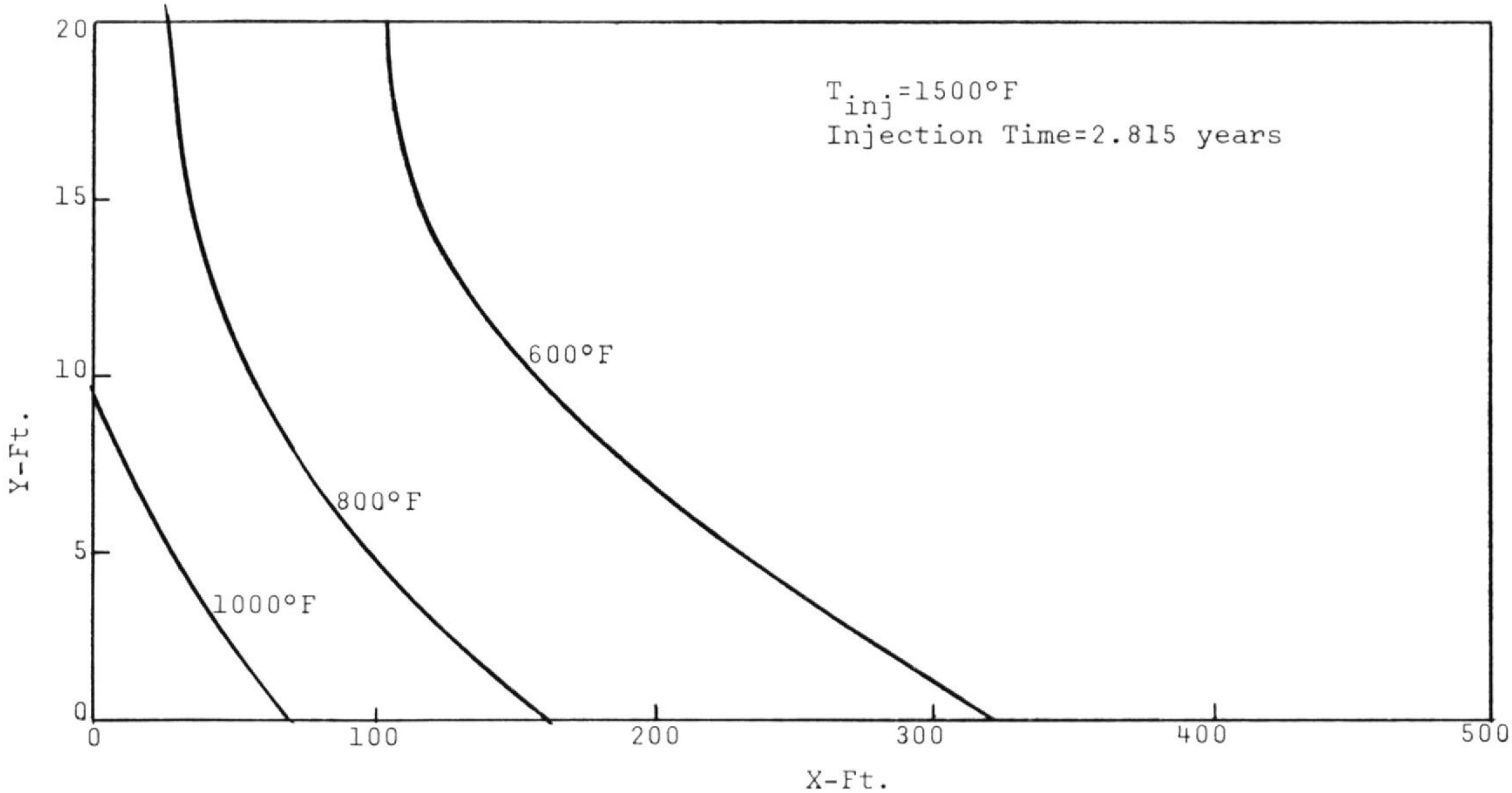

Figure 51. Formation Isotherms for Case 7.

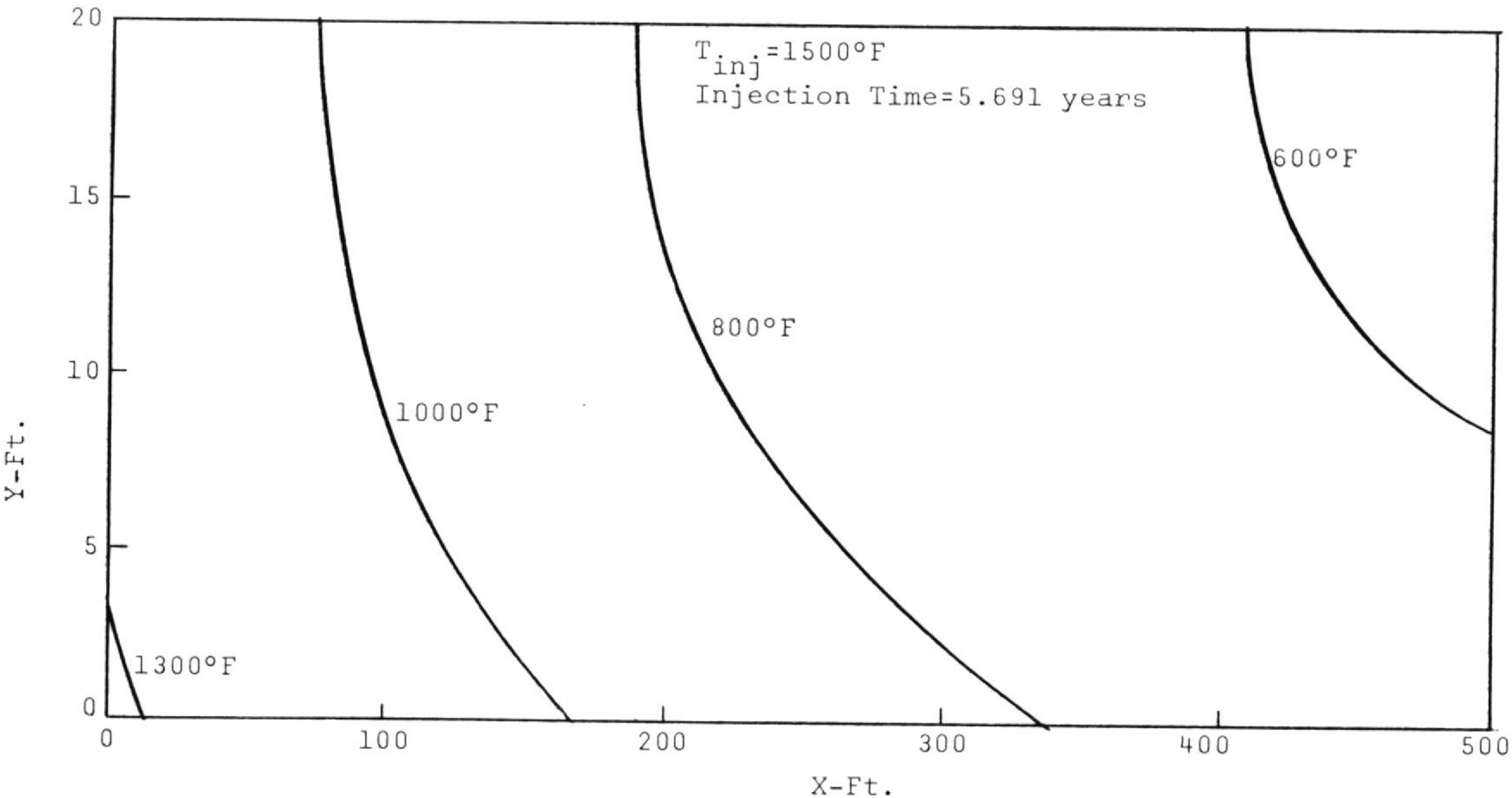

Figure 52. Formation Isotherms for Case 7.

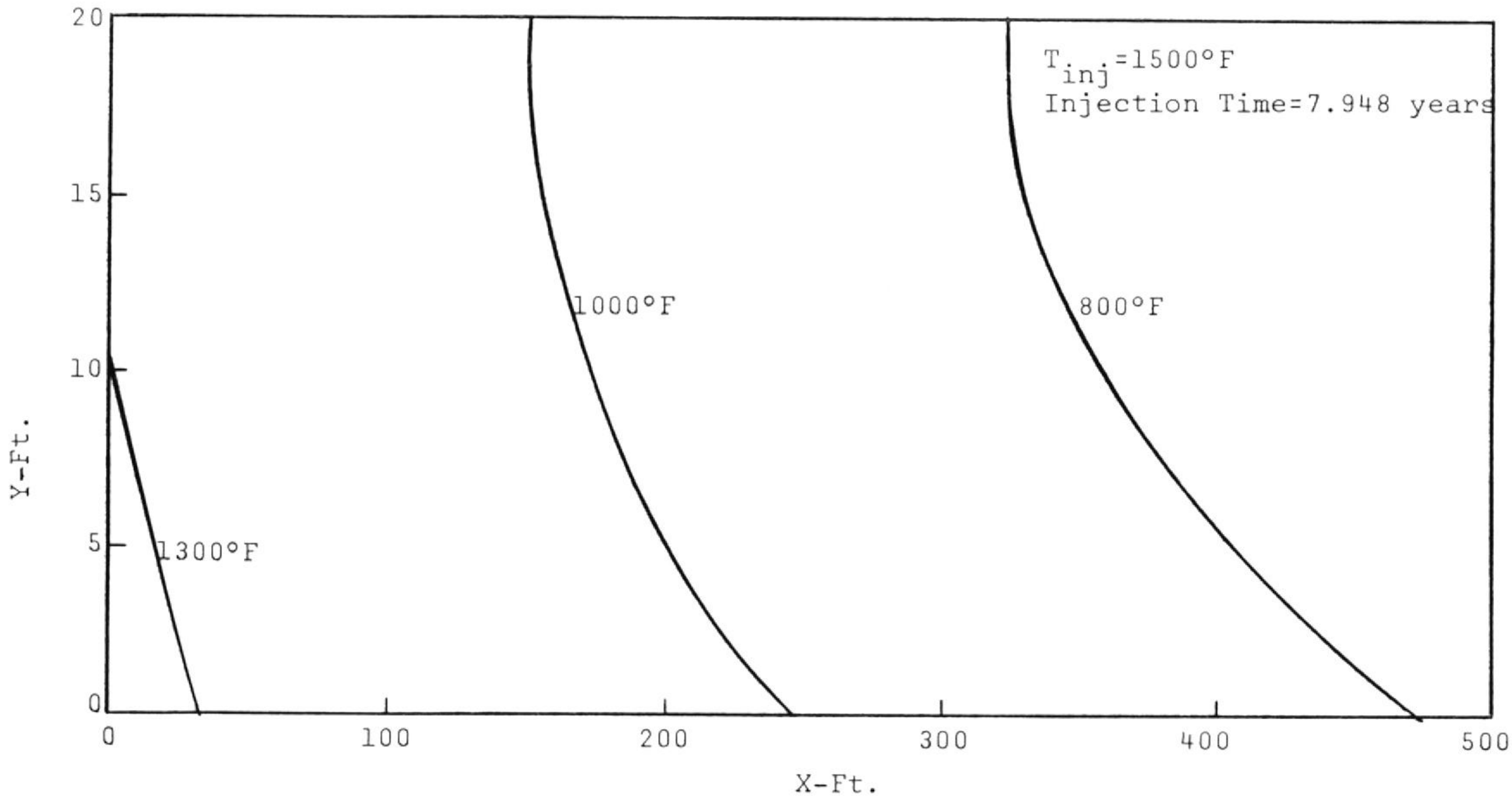

Figure 53. Formation Isotherms for Case 7.

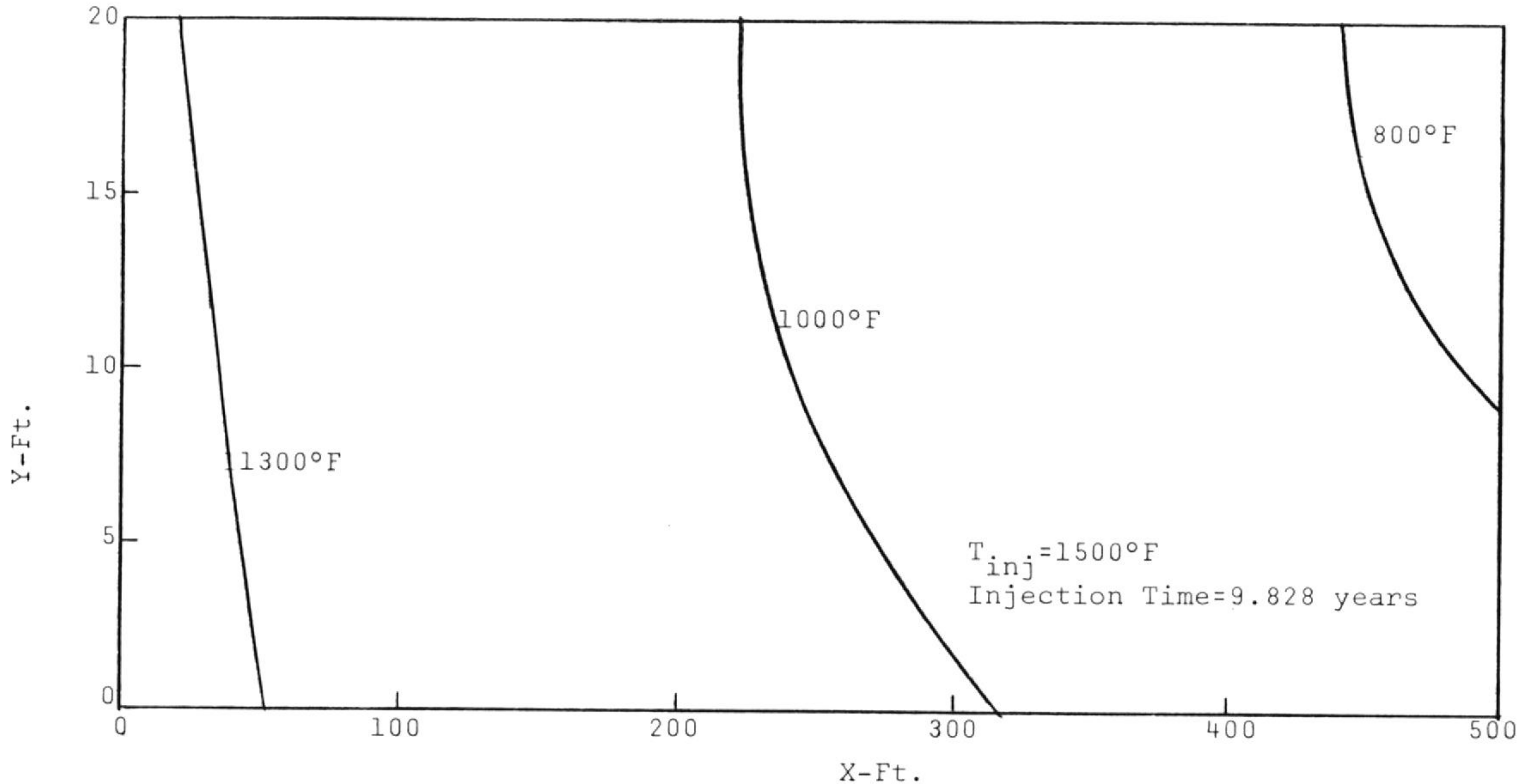

Figure 54. Formation Isotherms for Case 7.

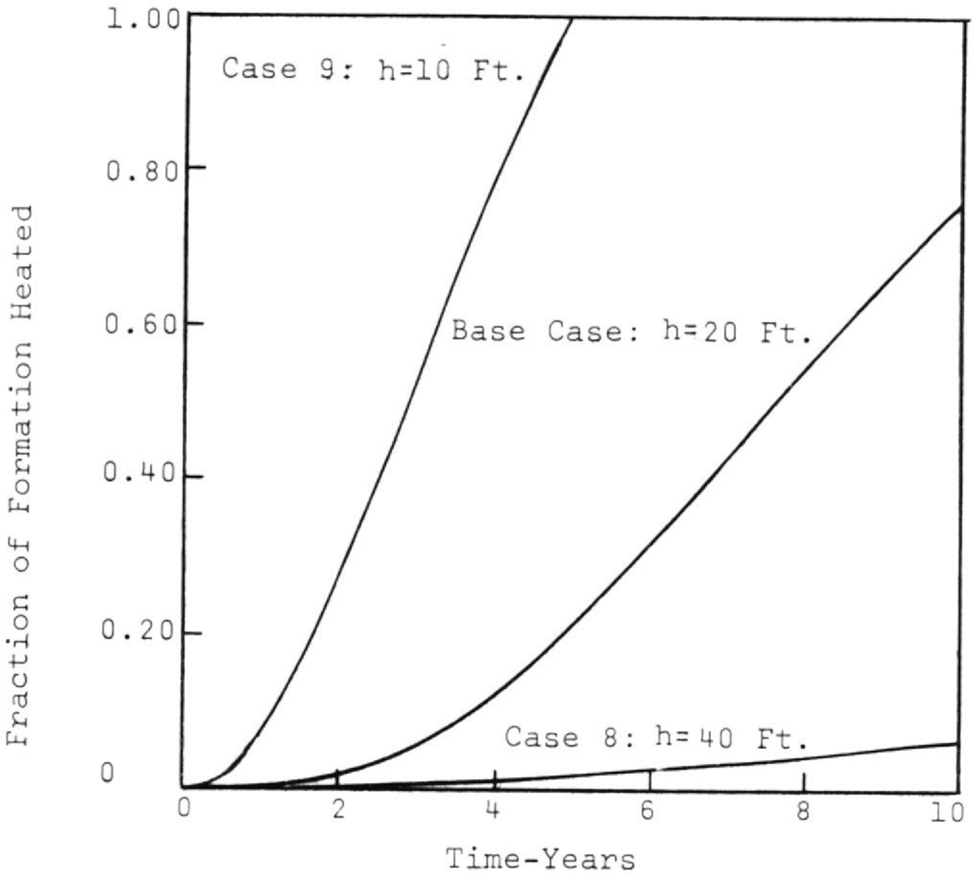

Figure 55. Fraction of Formation Heated to 800°F or Higher for Cases 8 and 9.

when distance is doubled to 40 ft (Case 8) only seven per cent of the formation is heated to the same temperature. The opposite occurs when the distance to the boundaries is shortened to 10 ft (Case 9), in which case the entire formation is heated to 800°F or higher in 3.9 years.

Figures 56 and 57 show results for Cases 8 and 9 for fraction of formation heated to 600°F and 800°F.

Figures 58 through 67 are thermal isotherms for both cases and several injection times.

Case 10. Influence of Horizontal and Vertical Thermal Diffusivities

Figure 68 shows results for the Base Case (a_x=0.015 sq.ft/hr, a_y=0.010 sq.ft/hr) compared with Case 10, where both conductivities have twice the value (a_x=0.030 sq.ft/hr, a_y=0.020 sq/ft/hr). As can be observed in a period of 10 years 97 per cent of the formation is heated to 800°F or higher in Case 10 compared with 76 per cent corresponding to the Base Case.

Figure 69 presents results for Case 10 when fraction of formation heated is referred to 600°F as compared with 800°F.

Figures 70 through 74 are formation isotherms for injection times of 1.395, 3.548, 5.701, 8.034, and 10.007 years.

These results show that when the thermal diffusivities characteristics of the oil shale formation are low, a long time is required to heat the formation to a given temperature.

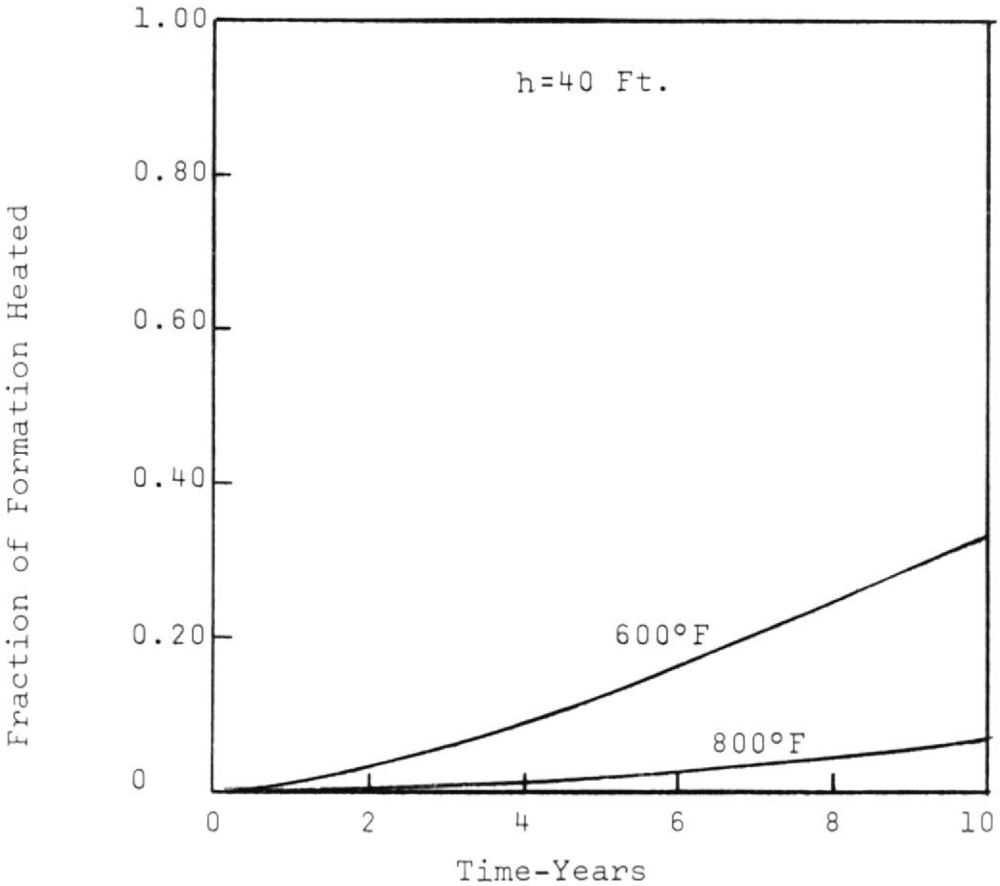

Figure 56. Fraction of Formation Heated to Specified Temperature for Case 8.

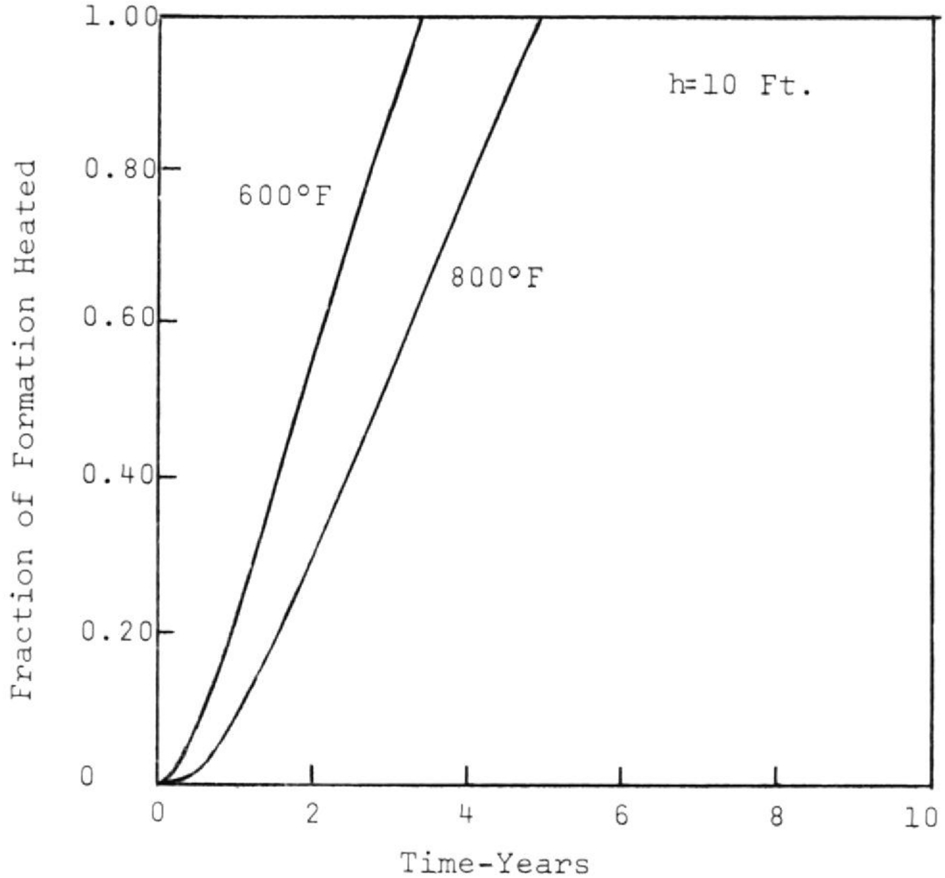

Figure 57. Fraction of Formation Heated to Specified Temperature for Case 9.

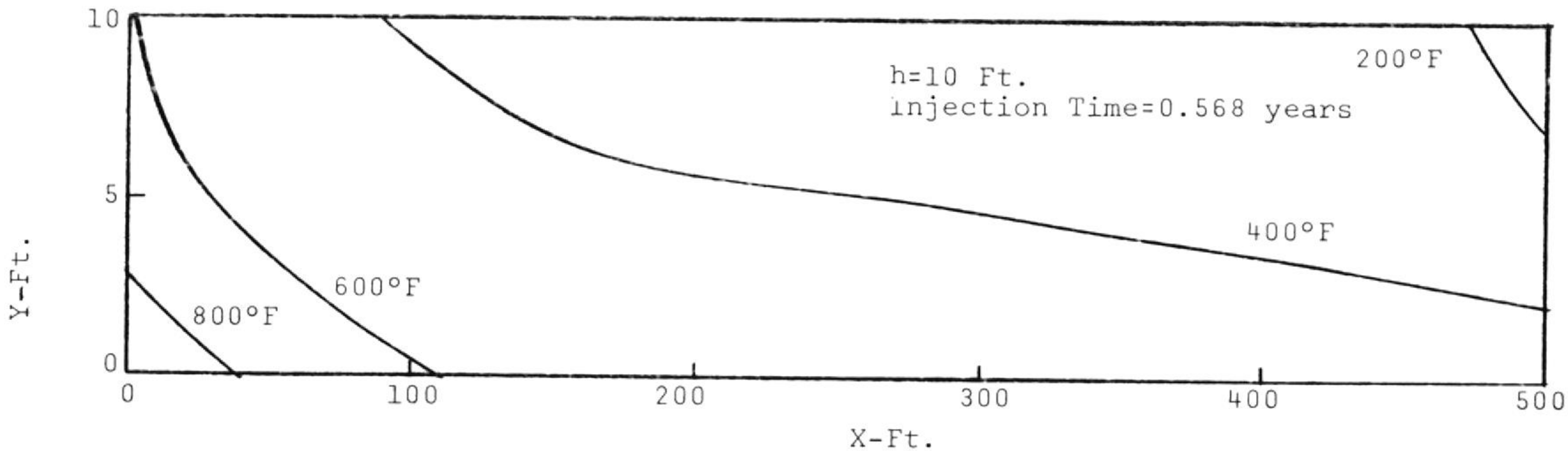

Figure 58. Isotherms for Case 9.

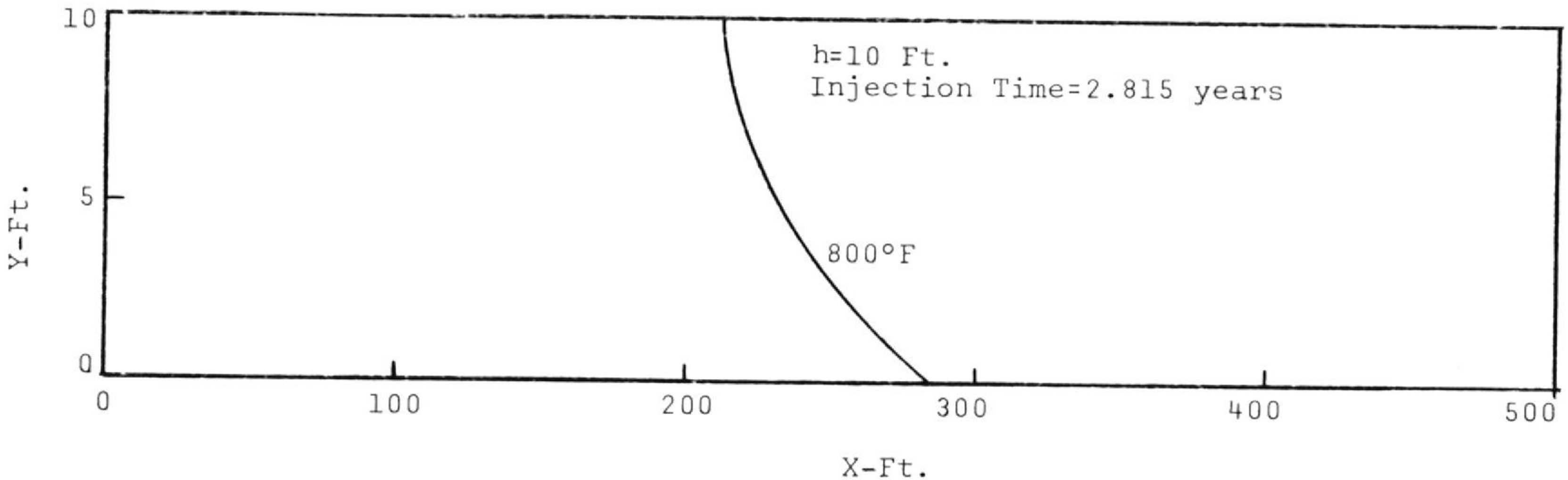

Figure 59. Formation Isotherms for Case 9.

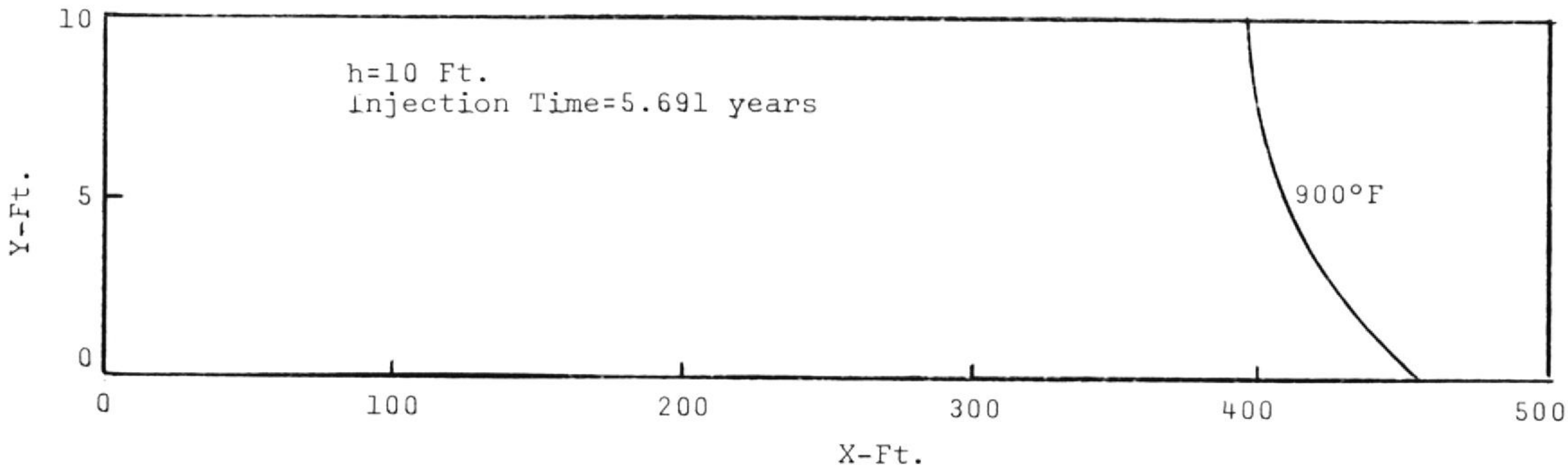

Figure 60. Formation Isotherms for Case 9.

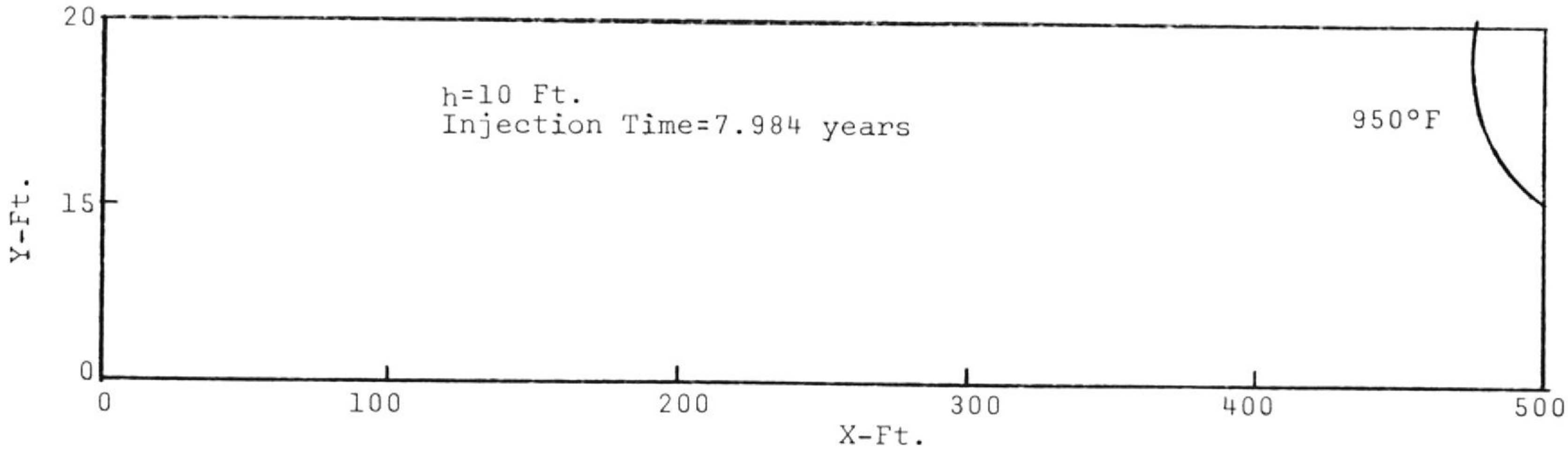

Figure 61. Formation Isotherms for Case 9.

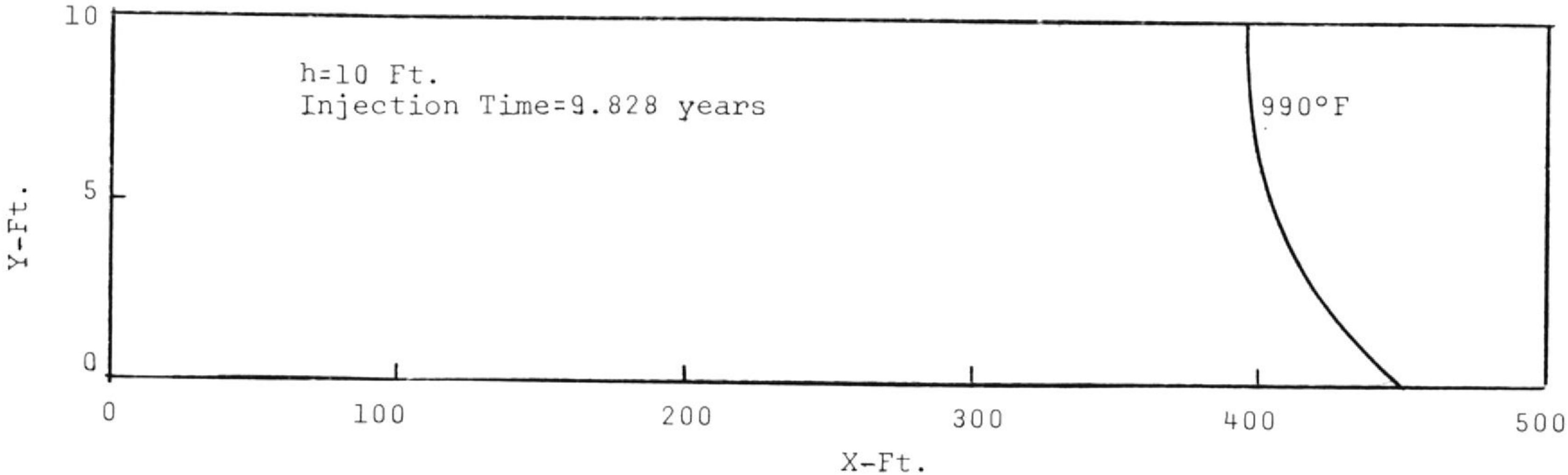

Figure 62. Formation Isotherms for Case 9.

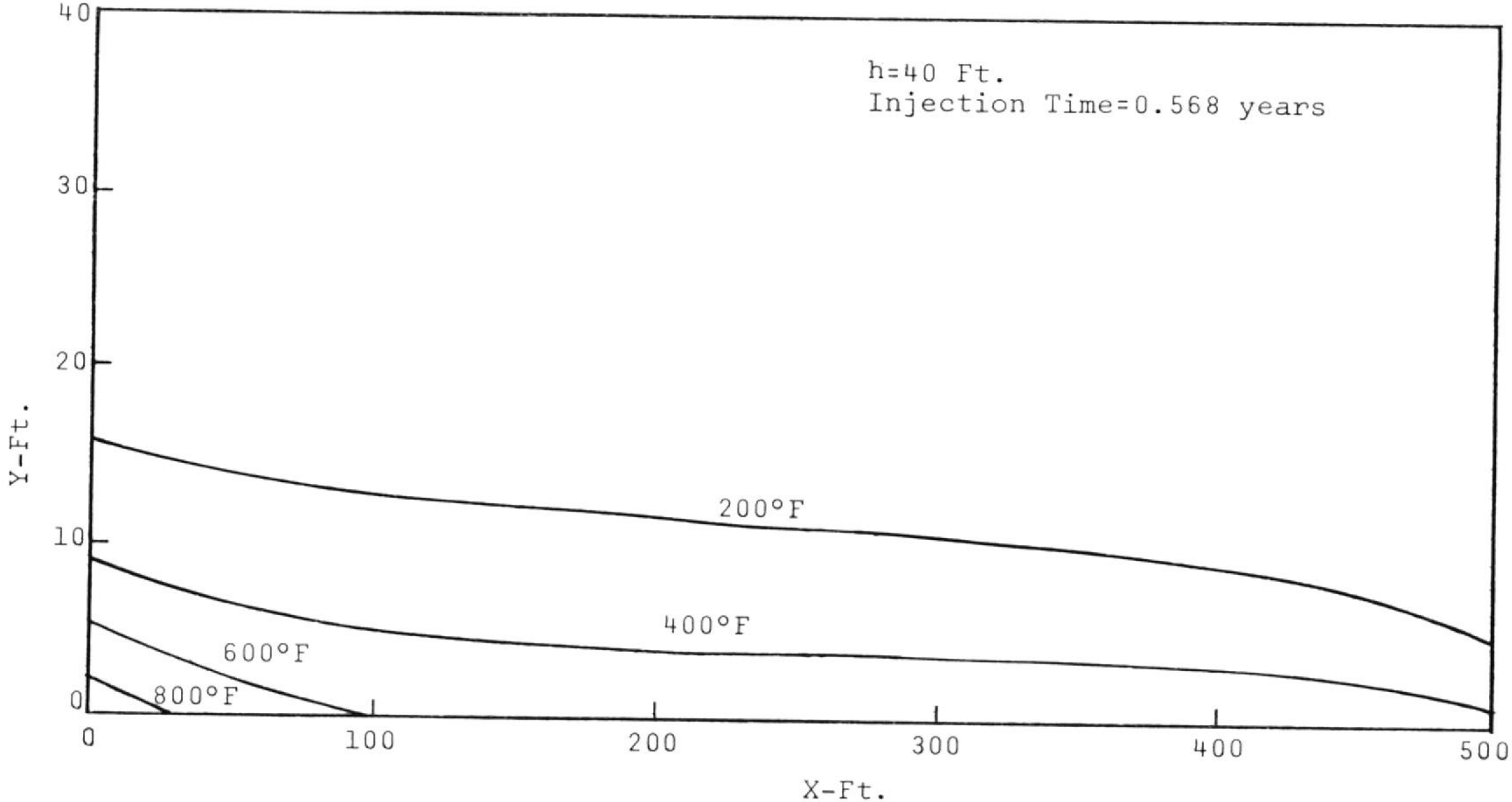

Figure 63. Formation Isotherms for Case 8.

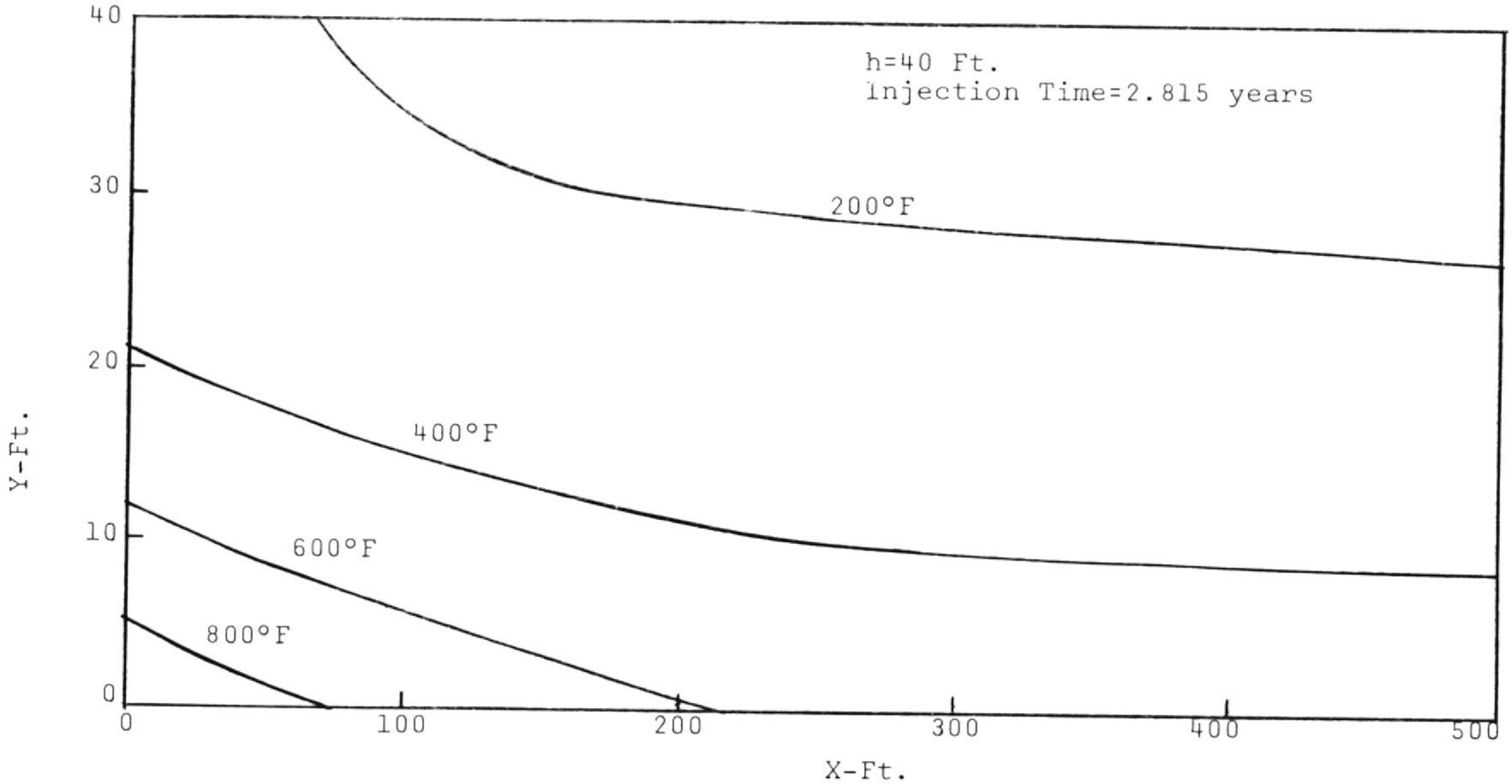

Figure 64. Formation Isotherms for Case 8.

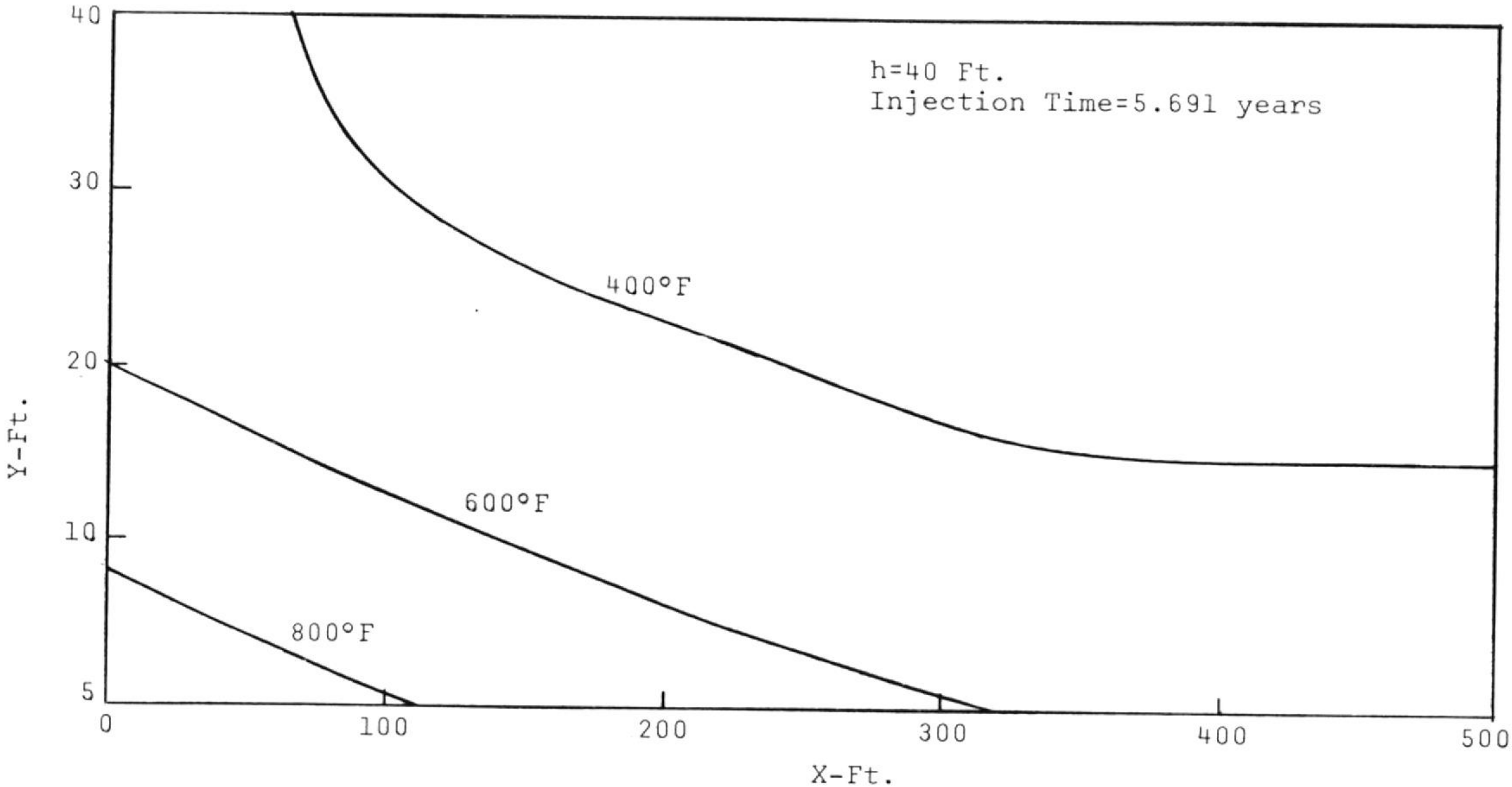

Figure 65. Formation Isotherms for Case 8.

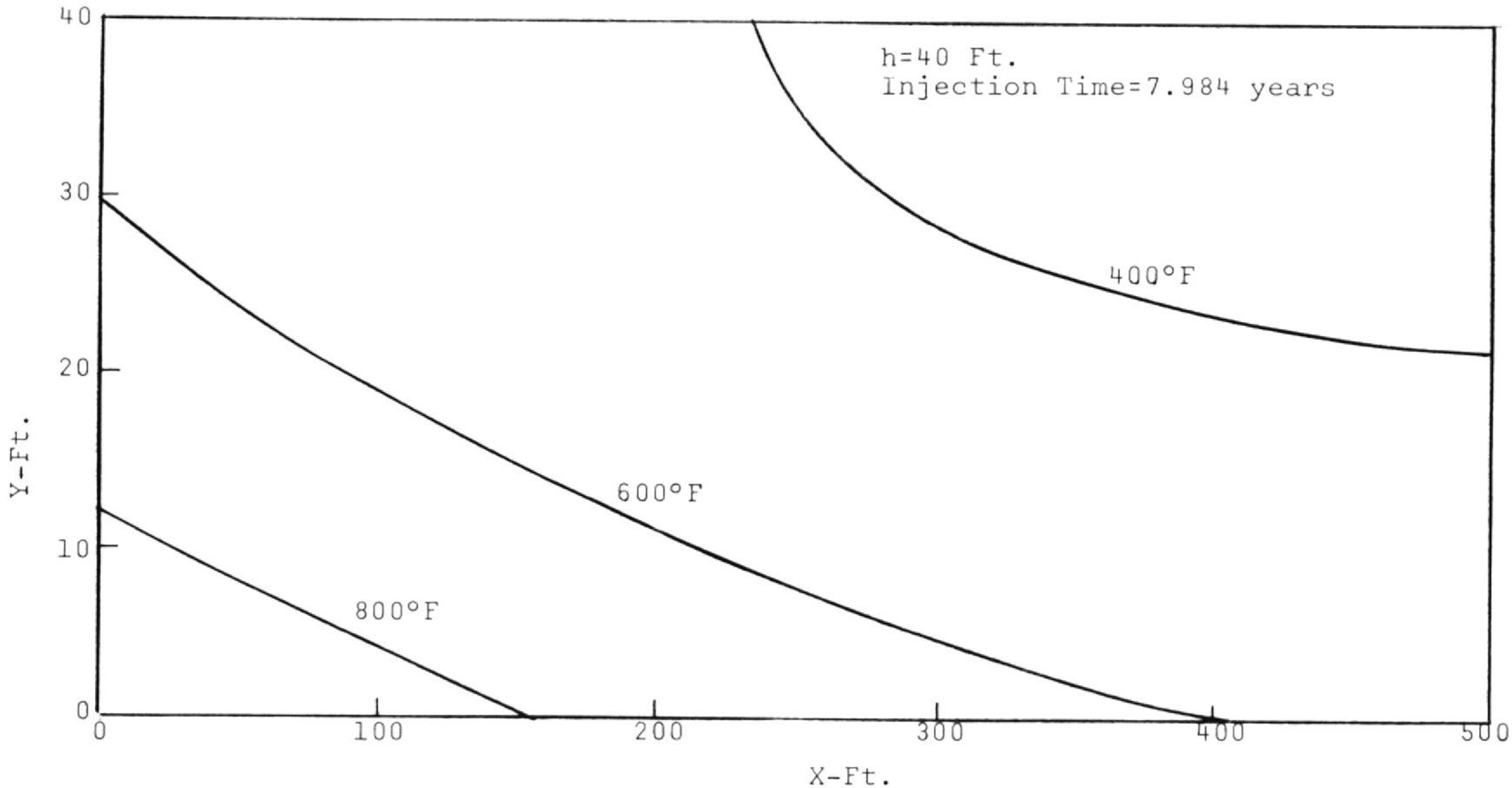

Figure 66. Formation Isotherms for Case 8.

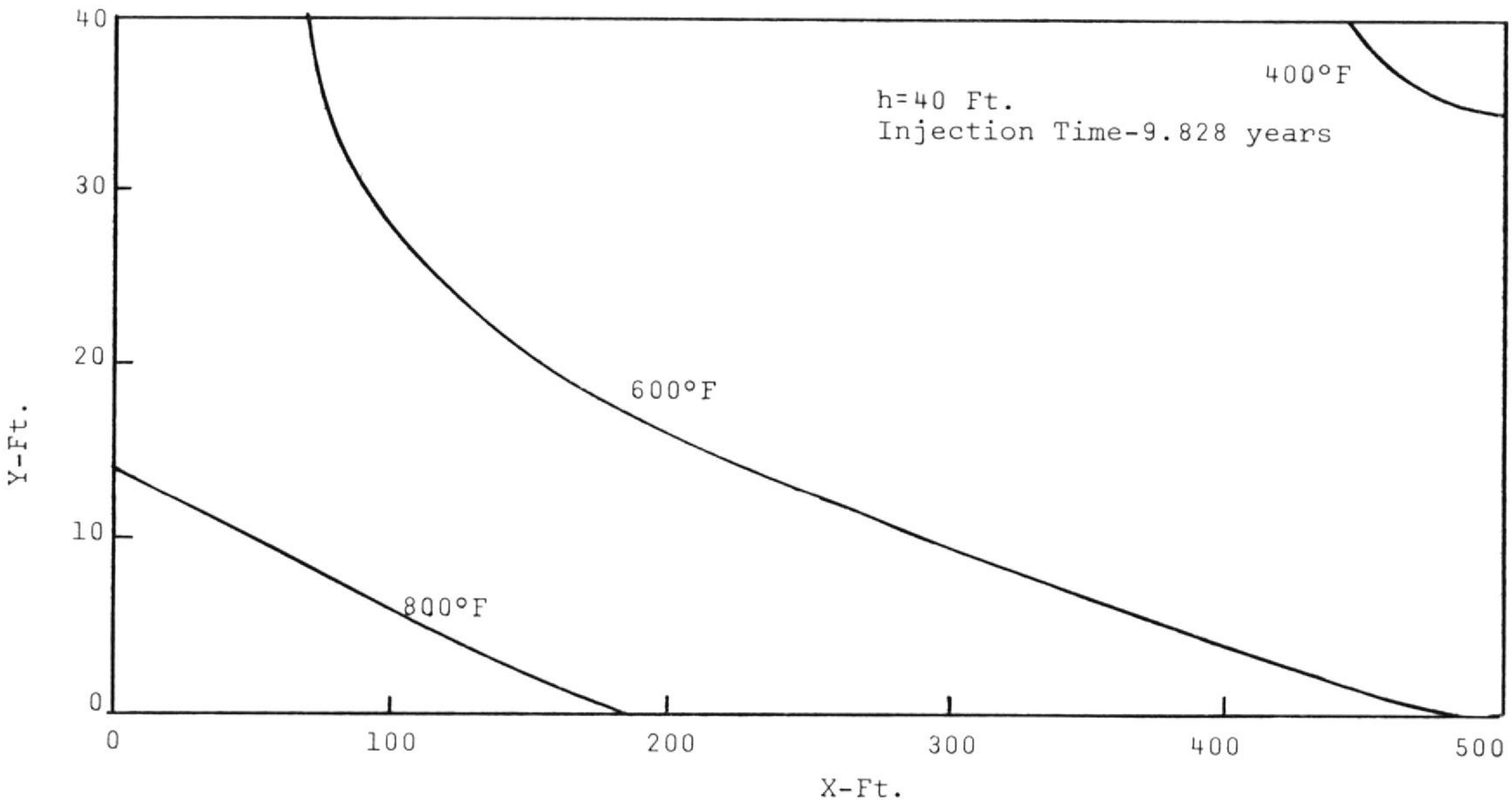

Figure 67. Formation Isotherms for Case 8.

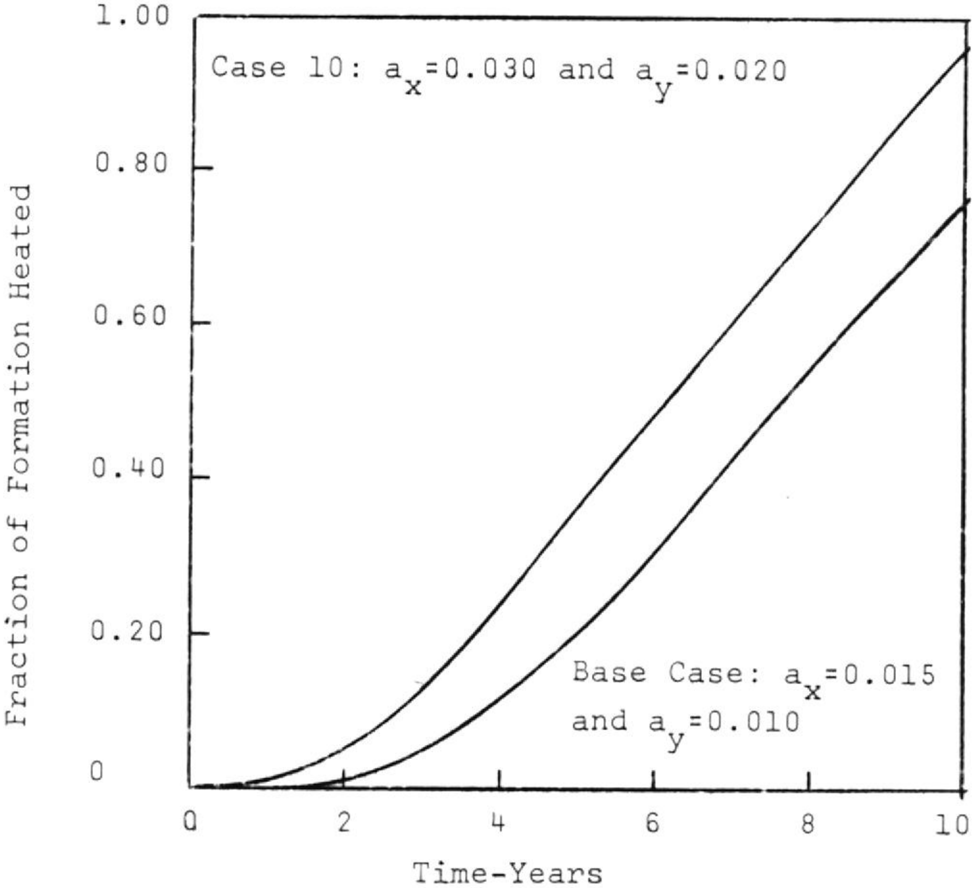

Figure 68. Fraction of Formation Heated to 800°F or Higher for Case 10.

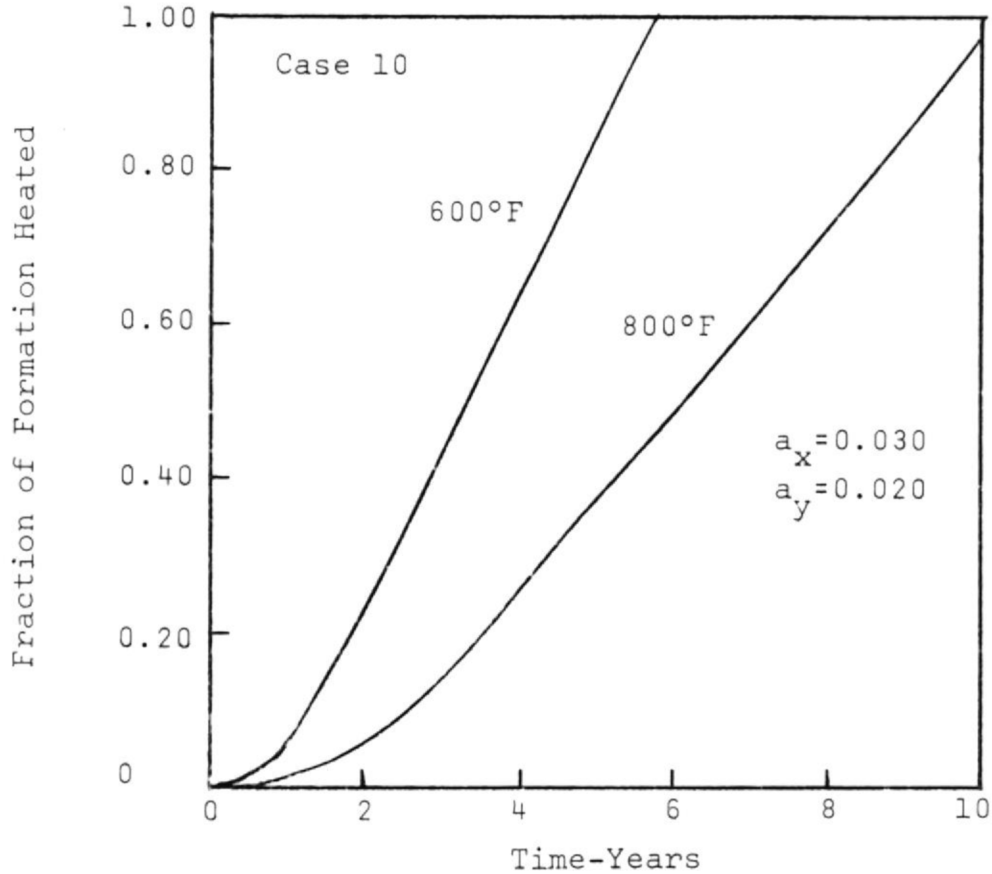

Figure 69. Fraction of Formation Heated to Specified Temperature for Case 10.

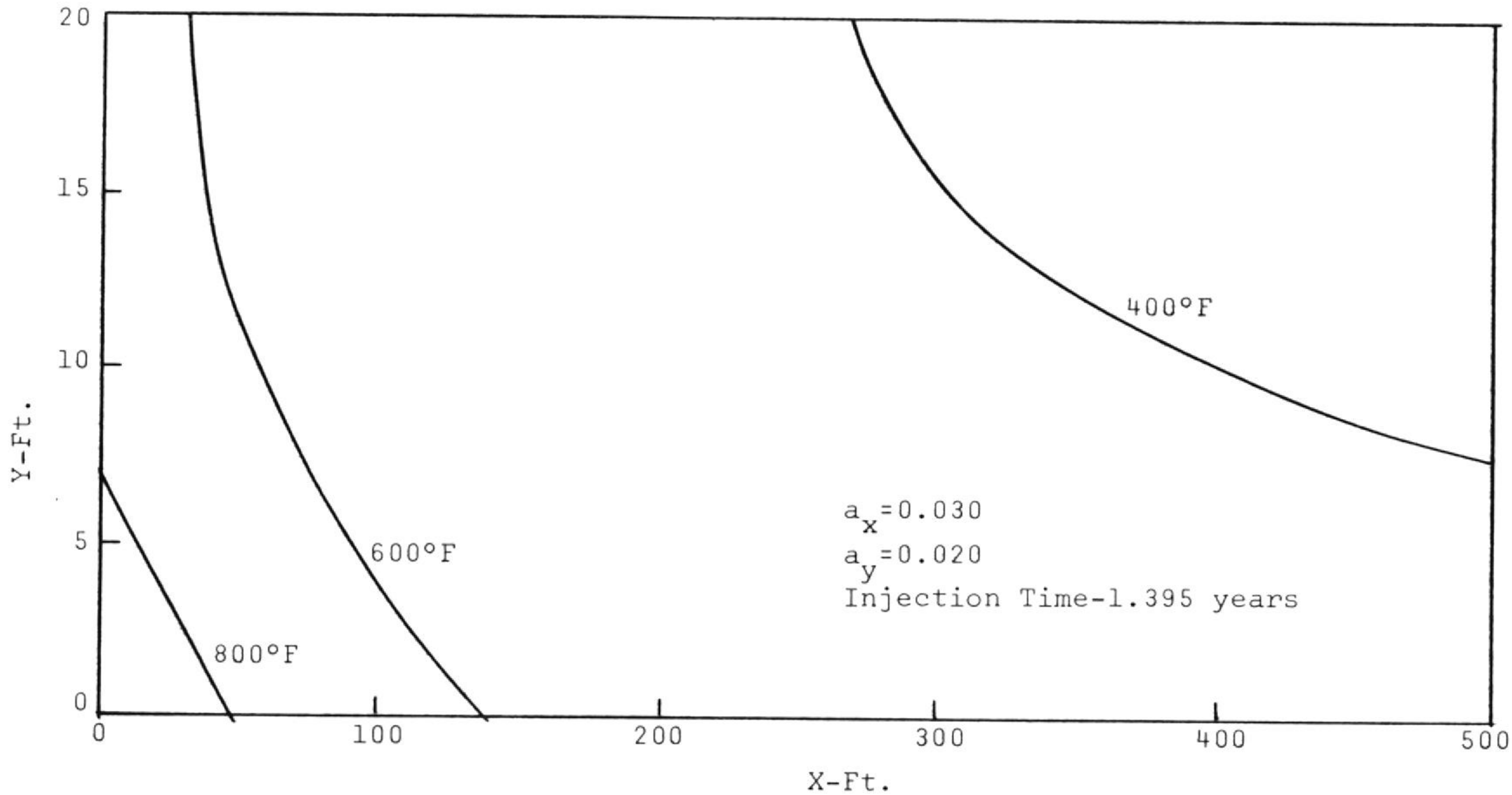

Figure 70. Formation Isotherms for Case 10.

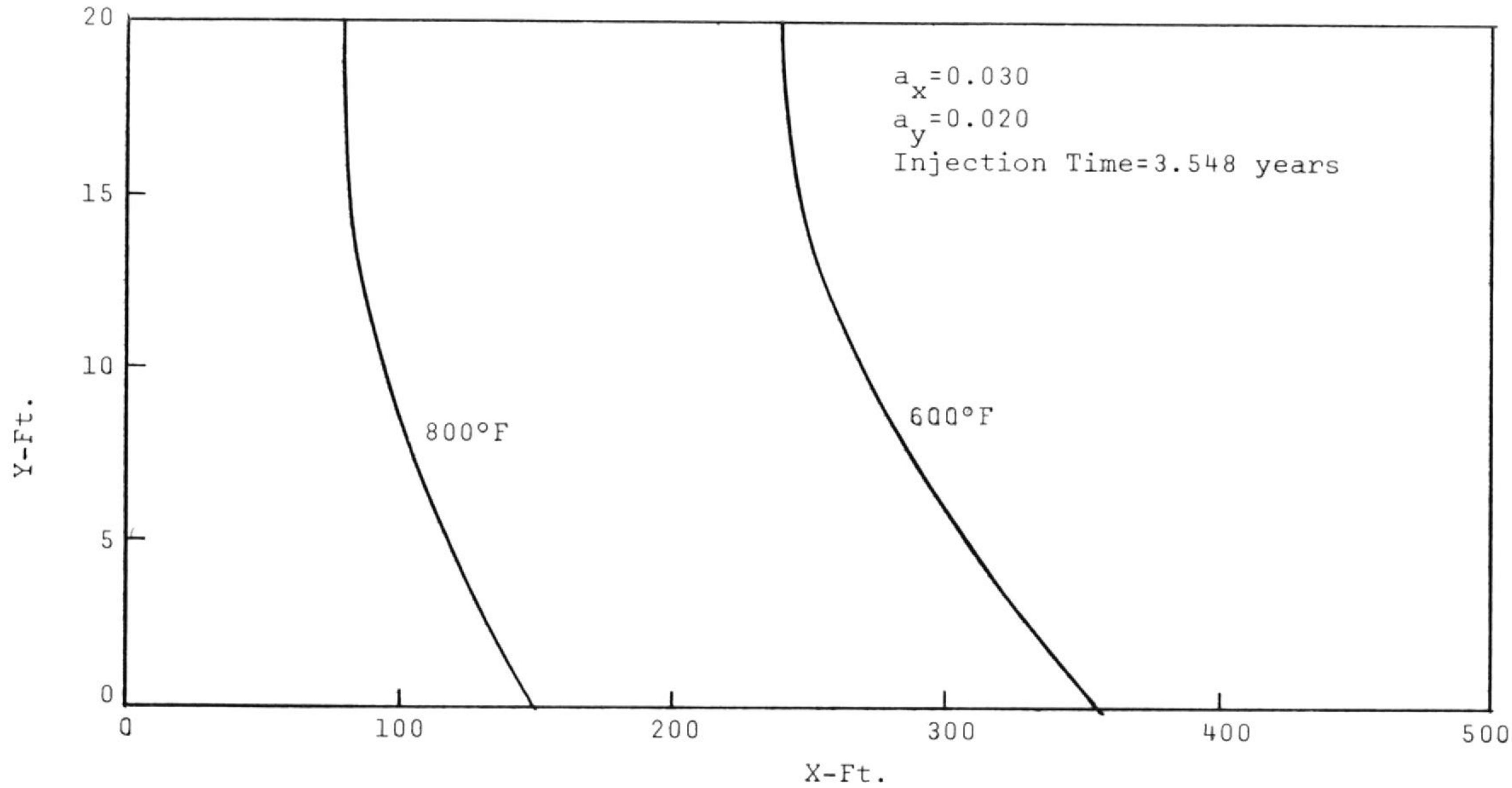

Figure 71. Formation Isotherms for Case 10.

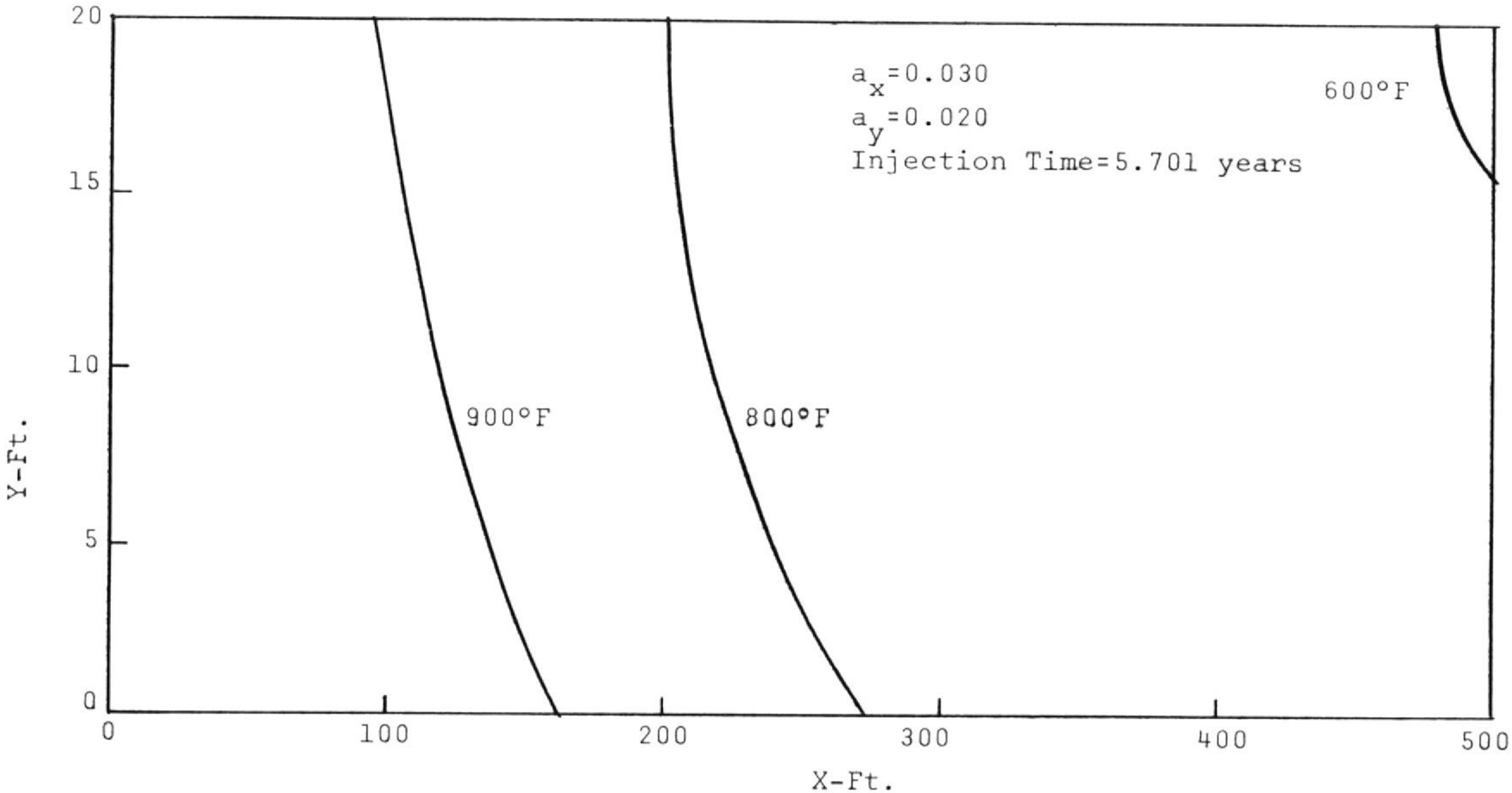

Figure 72. Formation Isotherms for Case 10.

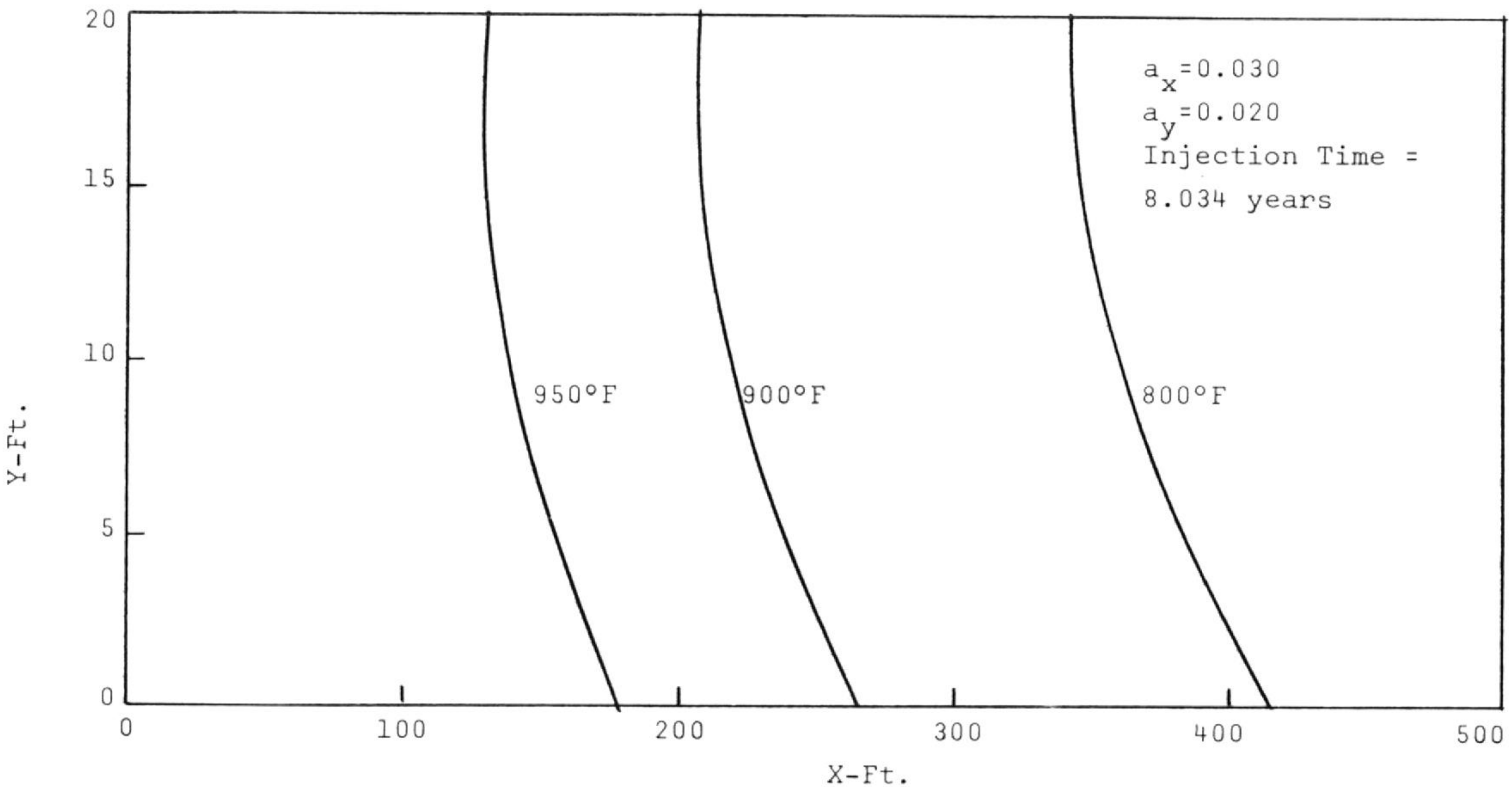

Figure 73. Formation Isotherms for Case 10.

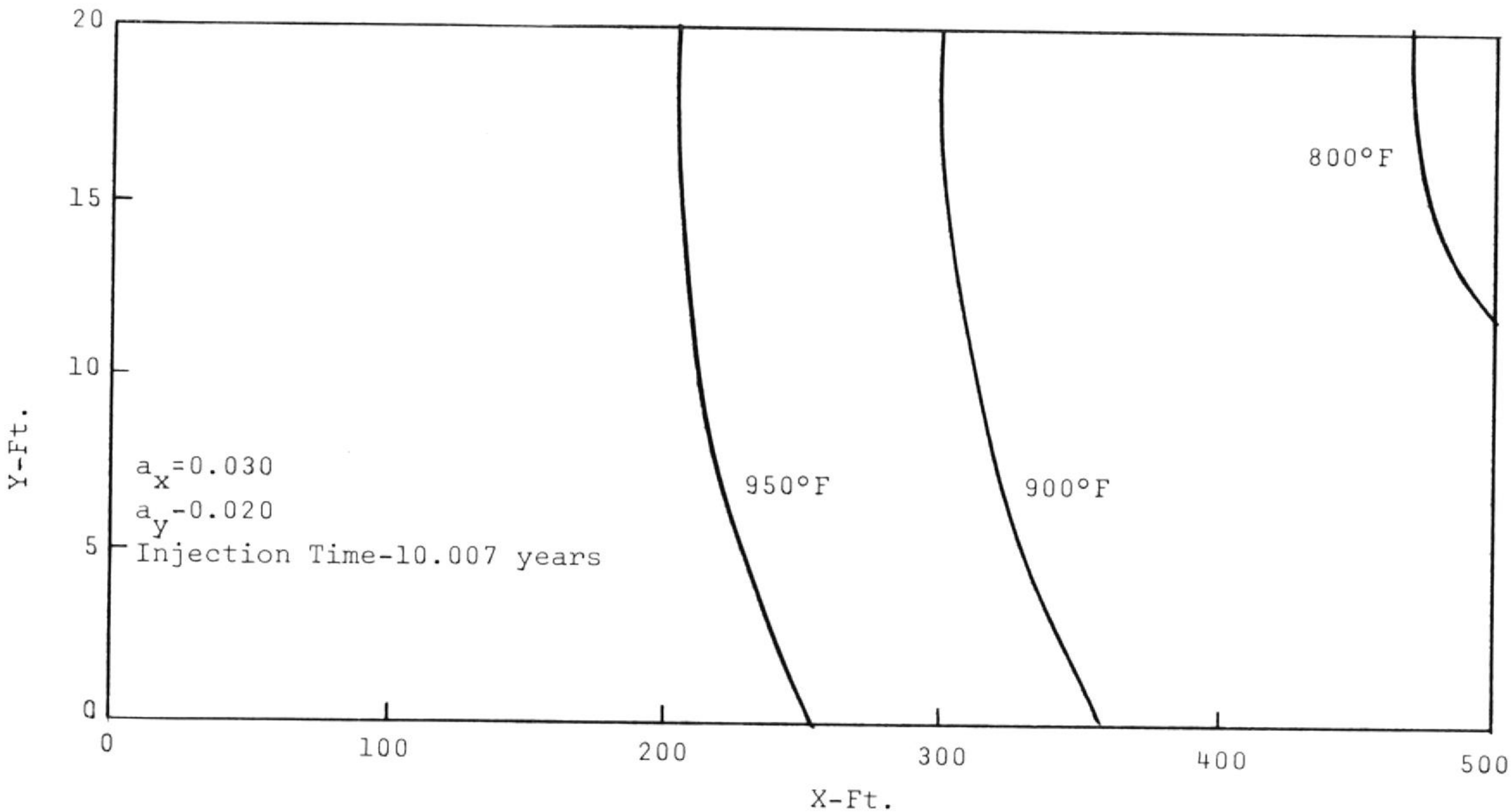

Figure 74. Formation Isotherms for Case 10.

The results are quite sensitive to the value of thermal diffusivity used.

Optimal Case. Illustration of the Application of this Study in Determining Optimal Parameter Values

It is not the objective of this case to establish actual optimal parameters in the process of oil recovery from oil shale described in Chapter IV. The purpose of this last case is to illustrate how the previous study of the parameters could be used for estimating optimal conditions.

The parameter values in this Optimal Case are selected from among those considered in the previous cases, and because they are found to accelerate the heating process. Exception is made with two parameters: injection temperature and distance to the boundaries. A temperature of 1000°F is choosen because of the probability of carbonate decomposition of temperatures greater than 1000° F (E. D. Jukkala (1953)). A distance of 20 feet to the boundaries is selected for comparison purposes with the majority of the other cases considered.

The parameter values selected in this optimal case are as follows:

Injection Rate: 3000 lb/sq.ft-hr

Fracture Length: 500 feet

Fracture Thickness: 0.03 feet

Steam Pressure: 2000 psia

Injection Temperature: 1000°F

Distance to the Boundaries: 20 feet

Horizontal Diffusivity: 0.030 sq.ft/hr

Vertical Diffusivity: 0.020 sq.ft/hr

Figure 75 shows the fraction of the formation heated to 800°F or higher for the Optimal Case compared with the other cases considered. A great improvement in the heating process is achieved when the optimal parameters are considered. In fact, for these values, 3.3 years are required to heat all the formation to the desired temperature.

Figure 76 presents fraction of formation heated to 600, 800, 900, and 950°F as a function of time for the optimal values.

Figure 77 is the temperature distribution in the fracture for periods of 0.366, 1.395, and 3.010 years. As can be observed in a period of 0.366 years only 32 per cent of the fracture length is at the saturation temperature (635.82°F) but for 1.395 years all the steam is superheated.

Figure 78 through 82 show formation isotherms for the optimal case and injection times of 0.366, 1.395, 2.471, 3.010, and 4.625 years. These curves present a greater penetration in both horizontal and vertical directions in comparison with the previous cases considered.

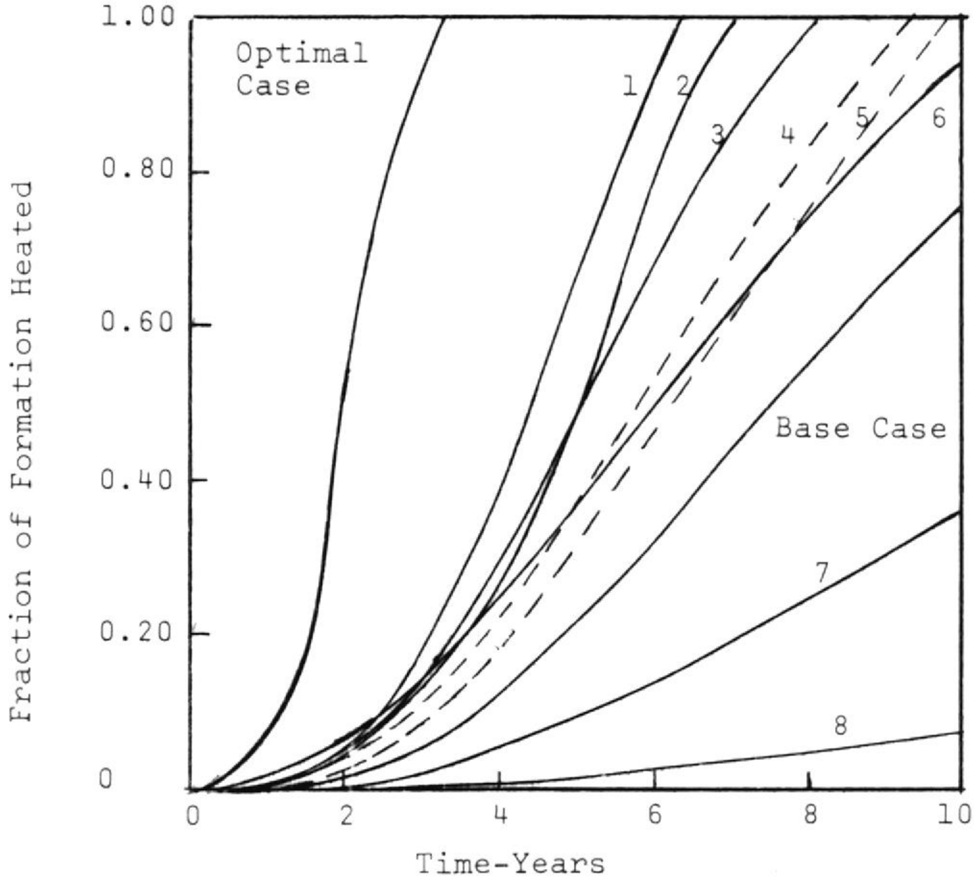

Figure 75. Fraction of Formation Heated to 800°F or Higher. Comparison Between All the Cases.

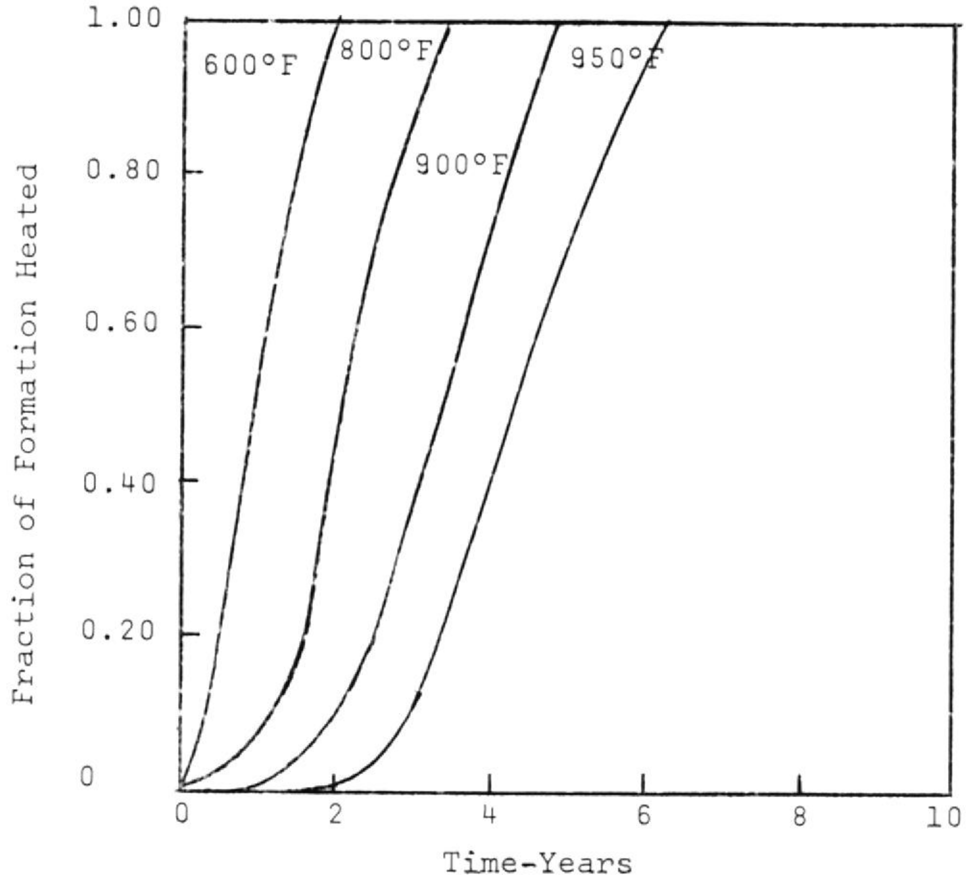

Figure 76. Fraction of Formation Heated to the Specified Temperature for the Optimal Case.

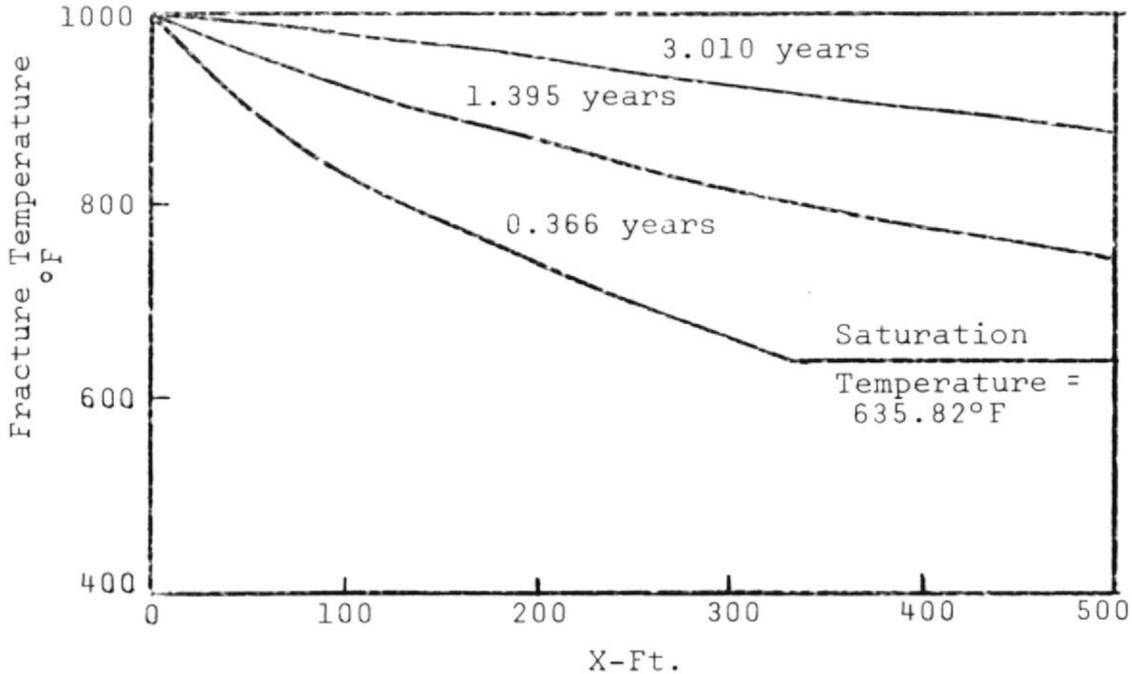

Figure 77. Temperature Distribution in the Fracture for the Optimal Case.

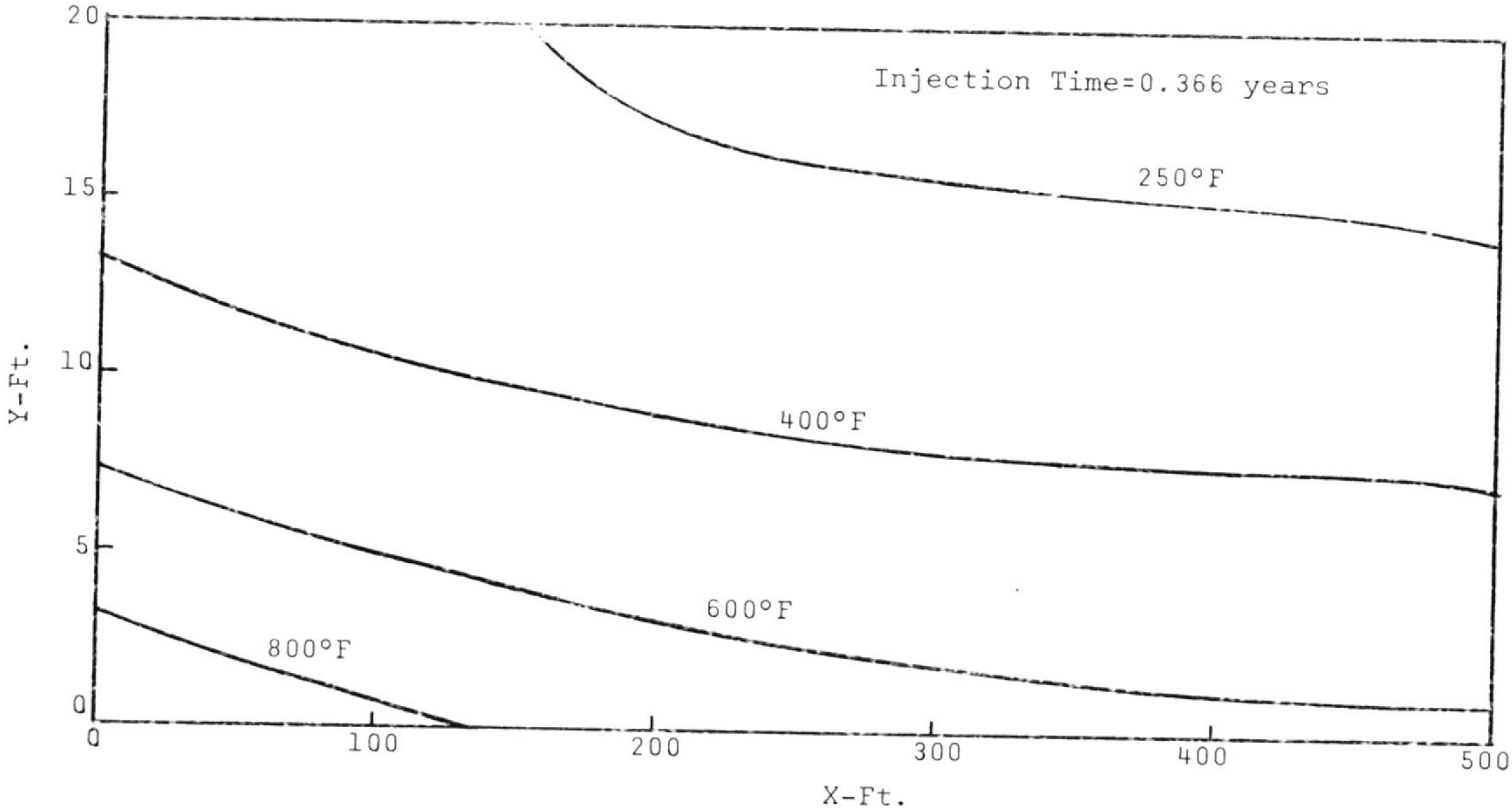

Figure 78. Formation Isotherms for the Optimal Case.

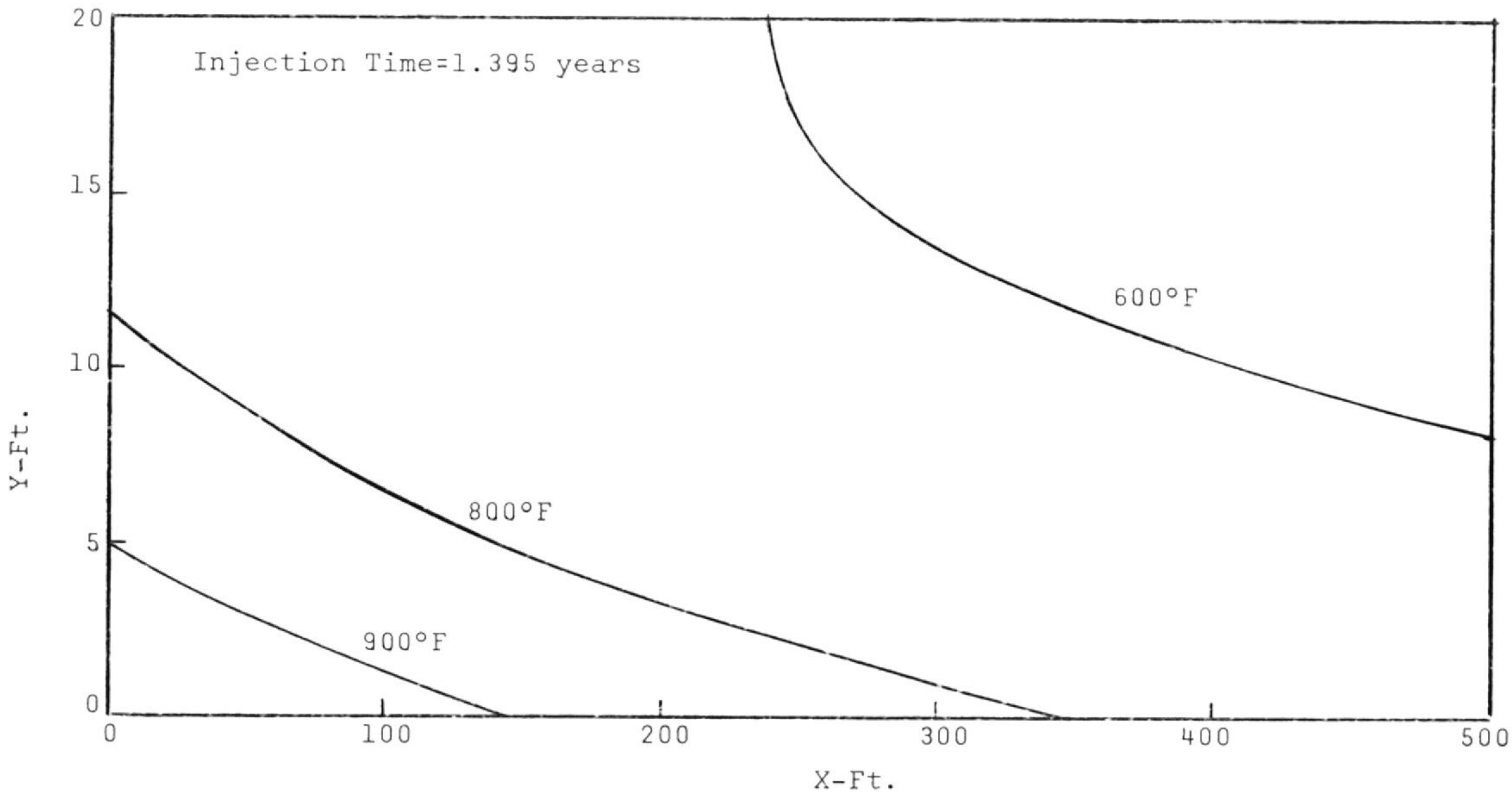

Figure 79. Formation Isotherms for the Optimal Case.

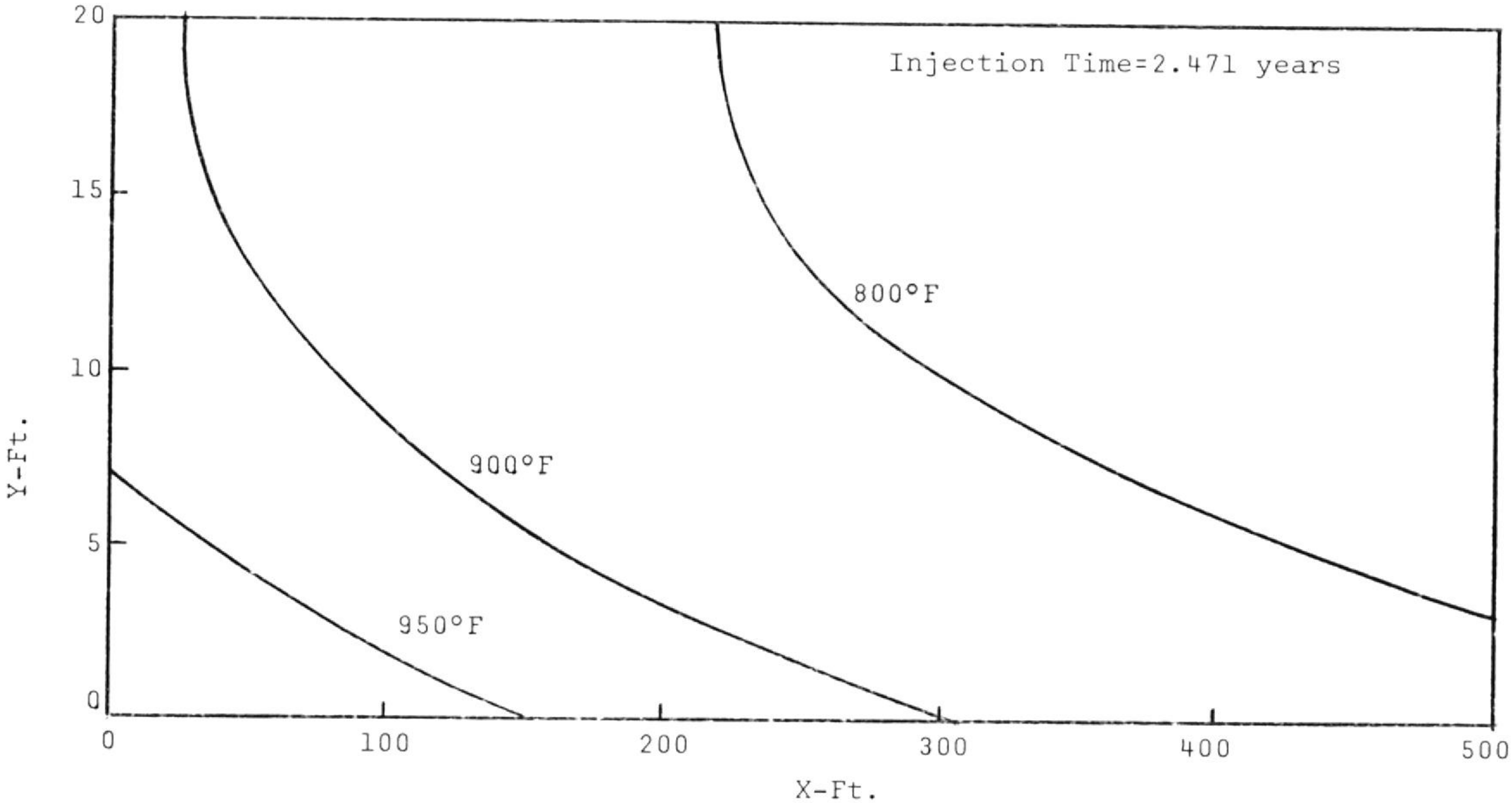

Figure 80. Formation Isotherms for the Optimal Case.

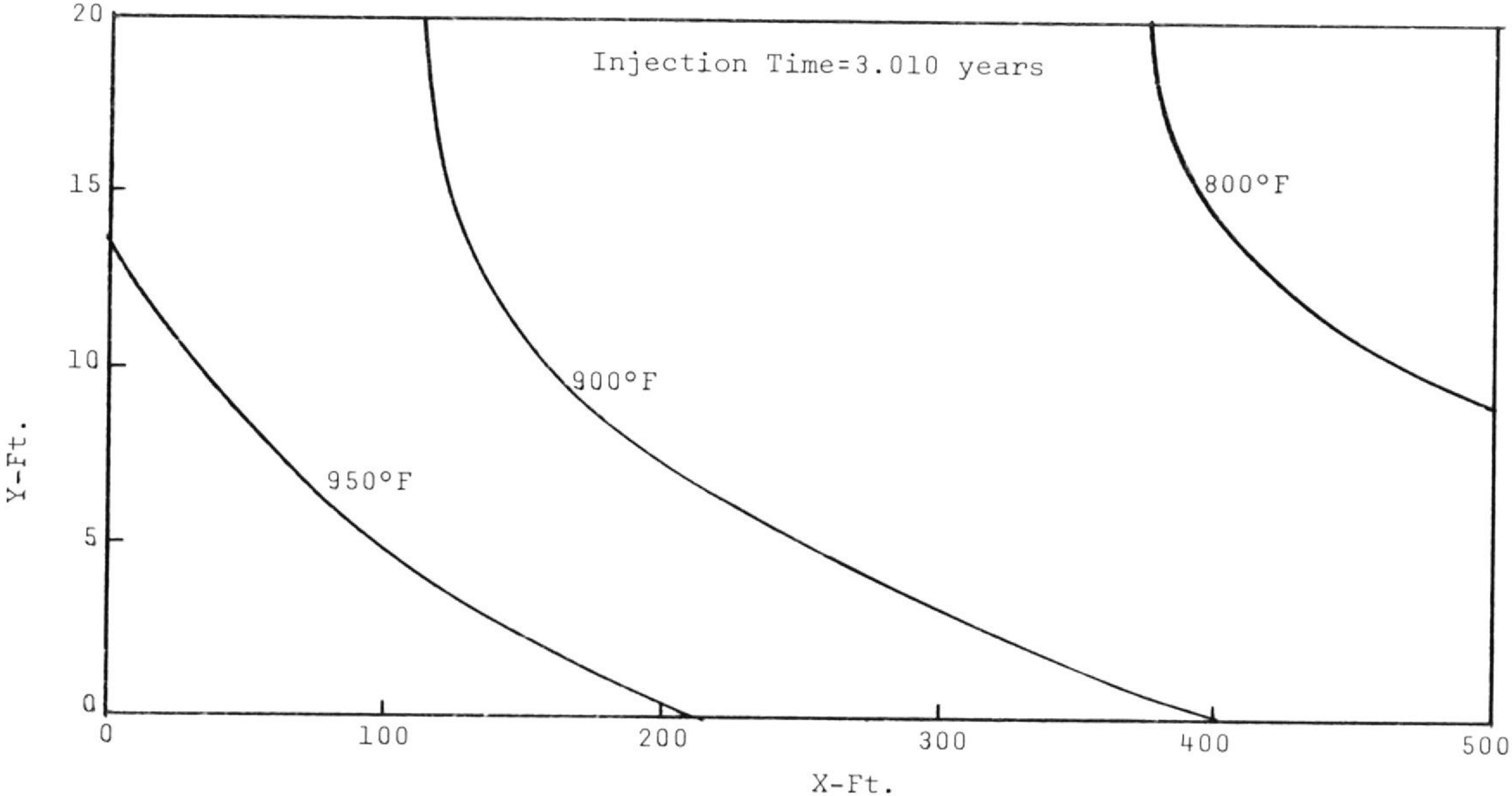

Figure 81. Formation Isotherms for the Optimal Case.

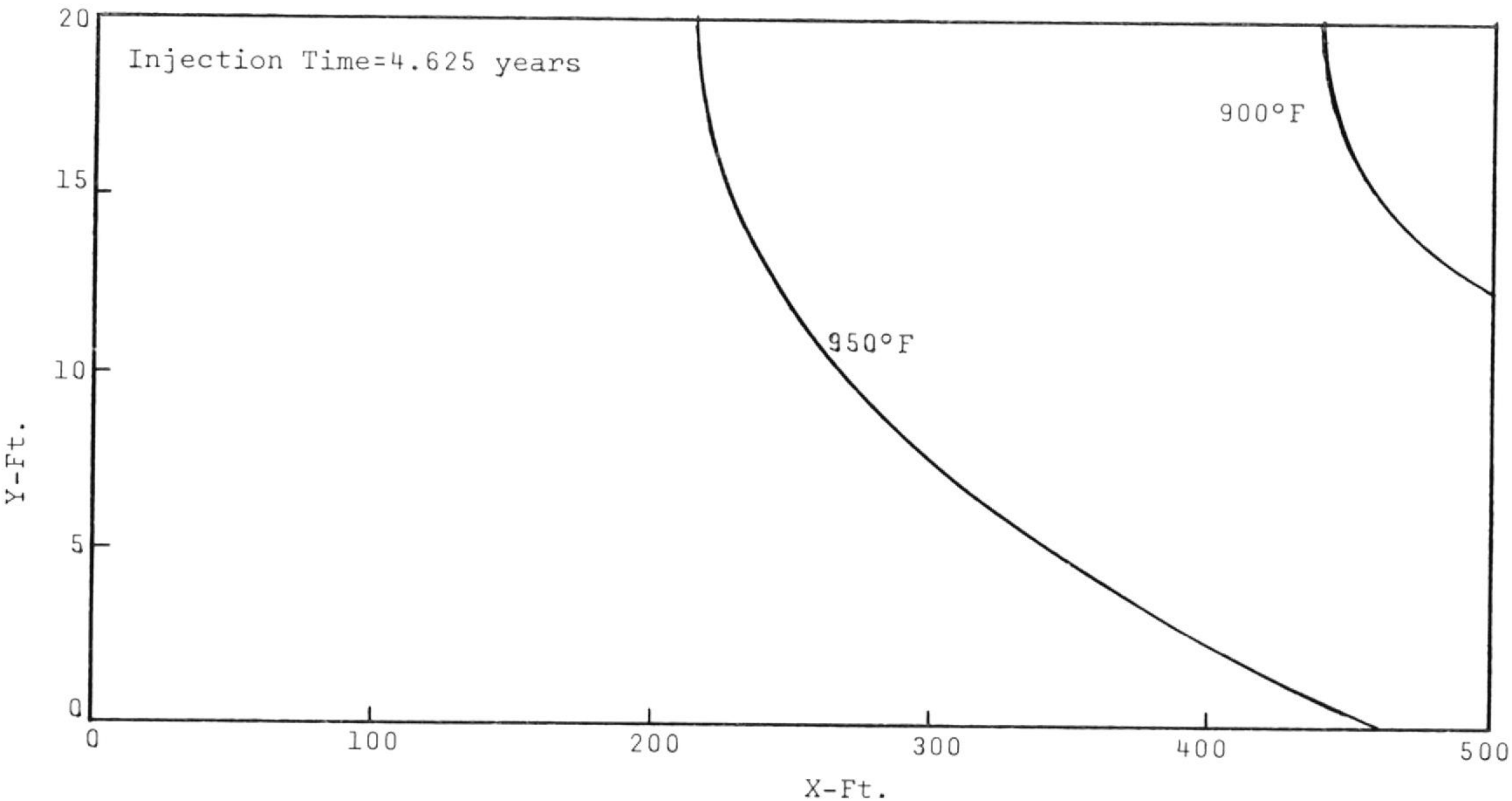

Figure 82. Formation Isotherms for the Optimal Case.

CHAPTER VI

SUMMARY AND CONCLUSIONS

In the present work, the mathematical model proposed by Lesser, Bruce, and Stone was developed, tested, and then used to conduct a more extensive study of the parameters involved in the oil shale conduction heating process, when steam is injected at a high temperature into the formation. This heating process is accomplished by creating artificial fractures in order to create communication between the injection and production wells. Heat is conducted into the formation and when a certain temperature is reached (about 600°F or higher), kerogen pyrolyzes releasing liquid and gaseous products which are produced with the injected fluid at a low temperature in the production well.

The knowledge of the temperature distribution in the formation and the fracture as a function of time is necessary in estimating the amount of oil and gases which can be recovered from the oil shale. This calculation also requires laboratory experiments to determine how much kerogen pyrolyzes at each temperature.

Formation and fracture temperature distributions and the fraction of formation heated to 800°F or higher were observed in the present work for a series of ten cases, in which the parameters were changed one at a time, with the remaining parameters at values used in a pre-established

Base Case. In this manner, the effect of each parameter was measured separately and results are presented.

Among the parameter values studied, a set of parameters were found to accelerate the heating process, and was selected as an "optimal case." Results are also presented for this "optimal case."

It is not the objective of this work to establish actual optimal parameter values, rather it is to illustrate how the results can be used to obtain some insight in determining those parameters. In a real case, optimal parameter values will depend on the specific characteristics of the oil shale and the technical and economical feasibility.

From all the cases studied in the present work, the following conclusions can be derived:

1. A long time (from 3.3 to more than 10 years) is required to heat all the formation to 800°F or higher. This is because of the low thermal diffusivities characteristic of the oil shale formations.
2. When injection rate, steam pressure, injection temperature, fracture thickness or thermal conductivities in both horizontal and vertical direction are increased the heating process is accelerated.
3. When the distance of the boundaries or the length of the fracture is increased, the time required to heat all the formation to a certain temperature is greater.

4. In all cases where the heating process is accelerated, a decrease in the heating efficiency was observed.
5. Isotherms can be used to estimate the oil and gas recovery from oil shale based on laboratory experiments.
6. The possibility of injecting back into the system the heat produced with the injection fluid and pyrolysis products should be considered in order to increase the heating efficiency of the process.
7. Results of pilot or actual projects are necessary for establishing the approximation of the estimates using the model.
8. The simplicity of Lesser et al. model makes it suitable for using in conducting preliminary evaluation, not only in the oil recovery from oil shale process here considered, but also in systems containing immobile bitumen such as tar sands and reservoirs with low permeability containing highly viscous oil.

NOMENCLATURE

C_f = formation heat capacity, but/lb°F

H = specific enthalphy of fluid, but/lb

Ho = H(To,So), but/lb

H_{inj} = $H(T_{inj}, S_{inj})$, but/lb

h = distance from fracture to no-heat flow boundary, feet

k_x = thermal conductivity in the x-direction

k_y = thermal conductivity in the y-direction

L = fracture length, feet

p = fluid pressure, psia

Q = heat conducted into formation, but/ft^2-hr

S = vapor quality, fraction

So = vapor quality of fluid initially in fracture, fraction

S_{inj} = vapor quality of injected fluid, fraction

T = temperature, °F

To = initial temperature of formation and fluid, °F

T_{inj} = temperature of injected fluid, °F

t = time, hour

v = fluid velocity, ft/hr

v_{inj} = fluid velocity at point of injection, ft/hr

x = horizontal distance from injection well, feet

y = vertical distance from fracture, feet

a_x = thermal diffusivity in the x-direction

a_y = thermal diffusivity in the y-direction

δ = fracture thickness, feet

ε = weighting given to explicit vertical heat conduction, fraction

ρ = fluid density, lb/ft^3

ρo = $\rho(To, So)$, lb/ft^3

ρ_{inj} = $\rho(T_{inj}, S_{inj})$, lb/ft^3

ρ_f = formation density, lb/ft^3

Superscripts

n = time level

Subscripts

f = refers to formation

i,j = x and y direction indices

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