ADEQUATE DESCRIPTION OF HEAVY OIL VISCOSITIES AND A METHOD TO ASSESS OPTIMAL STEAM CYCLIC PERIODS FOR THERMAL RESERVOIR SIMULATION

A Thesis

by

ALONSO LUIS MAGO

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

May 2006

Major Subject: Petroleum Engineering

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Approved by:

Chair of Committee,	Maria A. Barrufet
Committee Members,	Daulat D. Mamora
	Luc Ikelle
Head of Department,	Steve Holditch

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ABSTRACT

Adequate Description of Heavy Oil Viscosities and a Method to Assess Optimal Steam Cyclic Periods for Thermal Reservoir Simulation. (May 2006)

Alonso Luis Mago, B.S., Simon Bolivar University

Chair of Advisory Committee: Dr. Maria A. Barrufet

A global steady increase of energy consumption coupled with the decline of conventional oil resources points to a more aggressive exploitation of heavy oil. Heavy oil is a major source of energy in this century with a worldwide base reserve exceeding 2.5 trillion barrels. Management decisions and production strategies from thermal oil recovery processes are frequently based on reservoir simulation. A proper description of the physical properties, particularly oil viscosity, is essential in performing reliable modeling studies of fluid flow in the reservoir. We simulated cyclic steam injections on the highly viscous Hamaca oil, with a viscosity of over 10,000 cp at ambient temperature, and the production was drastically impacted by up to an order of magnitude when using improper mixing rules to describe the oil viscosity. This thesis demonstrates the importance of these mixing rules and alerts reservoir engineers to the significance of using different options simulators have built in their platforms to describe the viscosity of heavy oils. Log linear and power mixing rules do not provide enough flexibility to describe the viscosity of extra heavy oil with temperature. A recently implemented mixing rule in a commercial simulator has been studied providing satisfactory results. However, the methodology requires substantial interventions, and cannot be automatically updated. We provide guidelines to improve it and suggest more flexible mixing rules that could easily be implemented in commercial simulators.

We also provide a methodology to determine the adequate time for each one of the periods in cyclic steam injection: injection, soaking and production. There is a lot of speculation in this matter and one of the objectives of this thesis is to better understand and provide guidelines to optimize oil production using proper lengths in each one of these periods. We have found that the production and injection periods should be similar in time length. Nevertheless, the production period should not be less than the injection period. On the other hand, the soaking period should be as short as possible because it is unproductive time in terms of field oil production for the well and therefore it translates into a negative cash flow for a company.

I dedicate this thesis to:

YOU for always being there with me.

My wife: *Marjorie Carolina Nogueira de Mago*

and

My parents and brother: *Alonso Dimas Mago Tovar*
Irma Angelica Huncal Diaz
Ricardo Martin Mago Huncal

Thanks for giving me your love, guidance and support throughout this entire journey.
It was fun and I believe we all enjoyed the ride...

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I would like to start by saying that a thesis is not a one person work. There were numerous people involved in this thesis, and, without the help of all of them, I wouldn't have finish my M.S. at Texas A&M University.

I would like to give special thanks to my advisor and chair of my M.S. committee, Dr. Maria A. Barrufet, for her continuous guidance, advice, support, enthusiasm, and encouragement throughout my research and education at Texas A&M University. She also had long nights during this thesis. I truly appreciate that.

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I would especially like to thank my wife, Marjorie Nogueira "La Chocha". You drive my life and make it better. I am, and I will always be a better person if I'm with you. Thank you for your immeasurable love and support.

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CHAPTER I

INTRODUCTION

1.1 Present status of the problem

Domestic and overseas exploitation of heavy oil reservoirs represents a large percentage of the portfolio of many major oil companies in Texas and the US. Thermal recovery of heavy oils relies on several physical mechanisms. The most important are oil viscosity reduction, thermal expansion, steam distillation, and possible emulsion formation. Although crucial for modeling enhanced oil recovery processes, the phase behavior and the in-situ viscosities of heavy oils under a steamflood remain largely speculative.

Most thermal reservoir models consider that oil will not vaporize (the dead-oil assumption) and that water and oil are non-soluble in each other. However, since steam may extract over 50% of this oil on a weight basis, this approach is not appropriate. Additionally, the solubility of water in a hydrocarbon liquid phase can be as high as 40 mole% at typical steam flood temperatures (400^{o}-500^{o}F).[1] Dissolved water in the hydrocarbon-rich phase has a strong effect on its density and viscosity therefore it will have a strong effect upon the oil mobility within the reservoir.

Currently used viscosity models fail for thermal applications. In thermal EOR the oil viscosity changes due to temperature and compositional changes: water dissolved in oil acts as a solvent lowering the oil viscosity, while the loss of lighter hydrocarbons thickens this oil mixture. Compositional thermal simulation of heavy oils using an equation of state is a relatively new practice. Due to computational requirements, full field simulation using a continuous fluid characterization is not practical. Compositional simulation for CO_2 flooding have been very extensively investigated in the last 20 years,[2] but since compositional simulations of heavy oils is relatively new characterizing those oils for cyclic steam injection has not been established. Equations of state (EOS) are not sufficiently accurate to be predictive. Therefore, the predicted properties from the EOS must be tuned to available experimental data. The quality of tuning depends on the quality of lab data, the type and detail of results, and the range of conditions that the tests cover. Compositional simulators require a great deal of computer resources and typically run much slower than black oil simulators. However, the amount of time that is required decreases significantly if the number of components in the EOS decreases. This is a simulator design tradeoff.

This thesis follows the style and format of the *Journal of Petroleum Technology*.

One of the objectives of this thesis is develop a description that uses the least number of components yet reproduces PVT behavior within a reasonable tolerance (5%).

On the other hand, in order to accommodate compositional systems, the properties of all the individual components are averaged using a mixing rule. It is logical to conclude that, if the EOS is imperfect for pure substances, it will be even less perfect for mixtures. Many of the viscosity correlations need recalibration of the parameters to deal with specific fluids. This thesis documents and evaluates currently used mixing rules in reservoir simulators to estimate the viscosity of heavy oils.

When analyzing the secondary recovery process, the primary individual property to take into consideration is the mobility ratio (permeability/viscosity). This serves to measure the ratio between the mobility of the displacing fluid (water) and the mobility of the displaced fluid (oil). For heavy oils the mobility ratio is so high that these projects are often considered uneconomic, primarily because significantly higher volumes of water must be injected if results matching those from light crude oils are to be expected. It is therefore reasonable that for these crude oils any successful recovery technique must reduce crude oil viscosity in order to increase crude oil mobility. Therefore, heat application is one of the easiest methods to reduce the crude oil viscosity and increase the heavy oil mobility.[3]

This thesis analyzes one of the thermal methods of enhanced oil recovery: cyclic steam injection, more colloquially referred in the industry as huff and puff. A typical huff and puff cyclic steam stimulation consists of three periods: injection, soaking, and production. During the injection period, the well is steamed at the highest possible injection rate to reduce heat losses.[4] Once the specified volume is injected, the well is shut in for a period of time to allow a more uniform heat distribution. Finally, if the reservoir pressure is sufficiently high, the well is brought on production at a higher flow rate than the original rate as a result of decrease in oil viscosity. There is a lot of speculation as to what is the adequate time for each one of these periods. One of the objectives of this thesis is to better understand and provide guidelines to optimize oil production using proper lengths in each one of these periods.

Cyclic steam injection also is used as a precursor to steam drives. In reservoirs containing very viscous crudes, the flow resistance between wells may be so great that steam injection rates are severely limited, making steam drives both technically inefficient and uneconomic. Cyclic steam injection reduces the flow resistance near wells, where the resistance is most pronounced; this alone improves the injection rate attainable during steam drives by reducing the resistance flow between the wells.[5] Repeated cyclic steam injection reduces the flow resistance still farther from the wells

and may lead to connecting the heated zones of adjacent wells and further improving the operability of steam drives.

1.2 Objectives

The main objectives of this research are as follows:

- Define the proper characterization of heavy oil to be used in simulation for cyclic steam injection.
- Determine the best mixing rule used in commercial simulators to evaluate the viscosity of heavy oils.
- Evaluate the impact on oil production of these mixing rules from reservoir simulation studies.
- Perform a systematic analysis of cyclic steam injection to provide guidelines that maximize oil recovery at minimal cost considering the overall economics of a cyclic steam injection project.

CHAPTER II

LITERATURE REVIEW

All thermal recovery processes tend to reduce the reservoir flow resistance by reducing the viscosity of the crude. The thermal recovery processes used today fall into two classes: those in which a hot fluid is injected into the reservoir and those in which heat is generated within the reservoir itself.

The latter are known as in-situ processes, an example of which is in-situ combustion or fire flooding. Processes combining injection and in-situ generation of heat have been tested[4] but currently are not practiced to any great extent. Thermal recovery processes also can be classified as thermal drives or stimulation treatments. In thermal drives, fluid is injected continuously into a number of injection wells to displace oil and obtain production from other wells. In thermal stimulation treatments, only the reservoir near production wells is heated. Driving forces present in the reservoir-such as gravity, solution gas, and natural water drive-effect the improved recovery rates once the flow resistance is reduced. Stimulation treatments also can be combined with thermal drives; any pore volumes of injected water are required to in which case the driving forces are both natural and imposed. In thermal stimulation treatments, the reduction in flow resistance also may result from the removal of organic or other solids from openings in the casing, the liner, the screen, and even from the pores of the reservoir rock.[6]

Thermal simulation is probably one of the most challenging aspects of reservoir simulation at present. From a numerical point of view, the inclusion of thermal effects involves a number of different issues from conventional reservoir engineering such as: temperature dependent viscosities, steam properties, heat losses, and averaging thermal properties.[5] These effects make thermal reservoir simulation very complex and difficult to analyze.

2.1 Current thermal simulation practices

There are different ways to simulate thermal recovery methods. A number of thermal recovery processes can be simulated such as steam injection, cyclic steam injection, steam flood, or steam assisted gravity drainage (SAGD) in different commercial simulators. Nevertheless, it is the reservoir engineer’s responsibility to decide what type of thermal option is the most appropriate provided the reservoir description and oil characteristics.

Dead oil has been widely used in heavy oil reservoir simulation where the oil phase is represented by a single non-volatile component. On the other hand, compositional simulation models assume that, by nature, reservoir fluid properties are dependent not only upon the reservoir temperature and pressure but also on the composition of the fluids. Compositional simulation is needed to model reservoir processes such as depletion, miscible flooding, steam cycling, steam flooding with solvents, and gas cycling.[7] In this type of simulations there are some processes that can only be seen with compositional simulation such as distillation effects or solvent mixtures.

Several important observations and practical applications have arisen out of detailed equation of state (EOS) studies of heavy oils for thermal processes. These include the compositional dependence of equilibrium ratios (*K*-values) in steam distillation processes, possible *K*-value reversals, and the capability of predicting the physical properties of hydrocarbon condensate in "casing blow" and an estimate of the amount in the field situation. The compositional dependence of the *K*-values is clearly explained with the high temperatures injected in the reservoir. The lighter components are going to distillate first, and even more in the Hamaca oil where it has a reasonable amount of lighter components. This process will change the composition of the Hamaca oil, which will directly impact the *K*-values and therefore the production of this oil.[8]

2.2 Oil recovery under cyclic steam injection

A typical "huff and puff" cyclic steam stimulation consists of three periods: injection, soaking, and production. During the injection period (**Fig 2.1**), the well is usually steamed at the highest possible injection rate in order to reduce heat losses. In this thesis, one injection rate was used (500 BCWE) but with different periods of time: 5, 10, 20, and 25 days, since one of the objectives is to find an optimum. This will be further explained in the methodology.

Other fluids can be used instead of steam but none have been found to be as effective. Hot water introduces a larger volume of water per unit of heat in injected, and its use results in higher water saturations. This can affect the producing oil cut adversely.[9]

Injected steam heats the rock and fluids around the well. It is canalized into the formation due to gravity segregation, preferential injection into high-permeability strata, and adverse viscosity ratios. Once the desired steam volume is injected, the well is shut-in for a period of time. This period is aimed at attaining partial steam condensation to heat the rock and fluids and bringing about a more uniform injected heat distribution. It is not clear yet how long the well has to be shut-in and therefore there is a lot of speculation in terms of soaking timing period.

During the injection and soaking periods, there is a significant reduction in the original oil viscosity down to perhaps a few centipoises across the steam zone. This process could have order of

magnitude reduction between the original viscosity and the viscosity at 450 °F. Oil and water undergo a thermal expansion process, which is higher for the former, and due to sand pressurization free gas, if any, is forced to go back in solution. Immediately before the well is brought on production, the steam-heated sand contains high-mobility oil, steam, and water. As pressure in the sand interface is lowered as a result of fluid production, several driving forces act to expel oil and other fluids towards the well, which may be pumped. If the reservoir pressure is sufficiently high, which depends on the amount of steam injected, the flow rate will be substantially higher than the original rate (cold production) just as a result of the increased oil mobility.

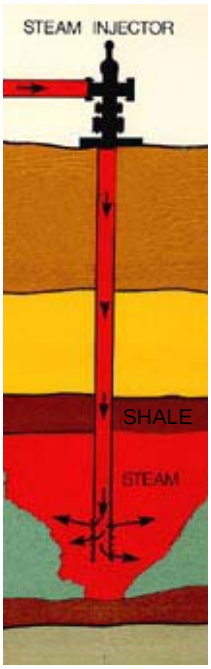

Fig. 2.1—Steam injector for cyclic steam injection.

If the formation is considerably thick and involves a relatively few horizontal barriers, hot oil flowing to the well is dominated by gravity. As oil is lifted from the hot zone, it is partially replaced by oil flowing from the adjacent cold zone in the formation. Not all the reservoirs are suitable for cyclic steam injection, but high porosity (>30%) and moderate to high oil saturations, along with low depths (<5000 ft) and the feasibility of producing steam at economical rates make some

reservoirs suitable for cyclic steam injection.[10] The reservoir description of this thesis will be better explain in the next chapter.

2.3 Oil viscosity mixing rules

Clearly, viscosity has an important role in the production of oil. However, petroleum industry practice has been to assume that fluid properties are well characterized and that all the uncertainty associated with numerical reservoir simulation is related to uncertainty only in the spatial distribution of rock properties.

Usually viscosity values required in compositional simulation are either obtained by measuring lab samples or by one of the available prediction methods. A comparative experimental study[11] by five different laboratories of an identical heavy oil sample showed a spread in viscosity data on the order of ±20%. Nothing shows that a standard petroleum sample characterization would normally be more accurate than these results. Hernandez *et al.*[12] found that for heavy oil an error of ±10% in viscosity will propagate an error in the cumulative production; for the most heterogeneous reservoir studied, the error was approximately ±10%. This error is not necessary equal in all the cases. It could be higher depending of time of production and it will also propagate with time. At today's prices, this would correspond to an enormous amount of profit.

The uncertainties in the prediction of heavy oil viscosity underscore how critical understanding viscosity mixing rules is to accurately simulating heavy oils. The overall oil viscosity must be reproduced from an adequate mixing of the pseudocomponent viscosities. Since compositions are changing due to distillation effects these mixing rules must include compositions. This thesis demonstrates the importance of these mixing rules and alerts reservoir engineers to the significance of using different options simulators have built into their platforms to describe the viscosity of heavy oils.

Numerous mixing rules have been studied and implemented in different commercial simulators. A review by API indicates that no single correlation can represent the viscosities of all hydrocarbon mixtures.[13,14] Some common mixing rules implemented in commercial simulators are:

Arrhenius[13] (or log) mixing rule (**Eq. 2.1**),

$$\mu_o = \prod_{i=1}^{Nc} \mu_{oi}^{x_i} \quad \text{,……...…..(2.1)}$$

and power-law mixing rule (**Eq. 2.2**),[13]

$$\mu_o = \left[\sum_{i=1}^{Nc} \left(x_i \mu_{oi} \right)^n \right]^{(1/n)} \quad \text{,.....(2.2)}$$

where *n* is an adjustable exponent that depends upon the components and their proportions in the mixture, *Nc* is the number of pseudocomponents, x_i is the mole fraction of each pseudocomponent in the reservoir and μ_{oi} is the viscosity for each one of them.

This thesis demonstrates that these two mixing rules do not provide enough flexibility to describe the viscosity of extra heavy oil with temperature. Simulations were performed using cyclic steam injections on the highly viscous Hamaca oil with four pseudocomponents, with a viscosity of over 10,000 cp at ambient temperature, and the production was dramatically impacted by up to an order of magnitude when using these improper mixing rules to describe the oil viscosity.

Additionally, this project analyzes a recently implemented mixing rule in a commercial simulator (**Eq.2.3**); [15] this new mixing rule is similar to the Arrhenius mixing rule but it has a greater flexibility since the weight of each pseudocomponent can be modified:

$$\mu_o = \prod_{i=1}^{Nc} \mu_{oi}^{\,f(x_i)} \quad \text{,.....(2.3)}$$

where $f(x_i)$ is introduced by the user in the data file and is obtained from a least squares regression to match the viscosity profile with temperature for the whole oil. The results show that this new flexible mixing rule provides more accurate values of oil viscosity and, therefore, a more precise forecast in the simulation.

2.4 Hamaca oil

The largest known hydrocarbon deposit in the world, the Orinoco Belt, contains oil with a gravity ranging from 9 to 14 ºAPI. The Hamaca project encompasses more than 400 square miles of the Orinoco Belt and is believed to contain more than 31 billion barrels of extra-heavy oil (9 ºAPI).[16]

Hamaca, a joint venture between Petroleos de Venezuela S.A. (PDVSA), ConocoPhillips and ChevronTexaco, produced an average of 22,100 net BOPD in 2003. Hamaca's net production is increased to 60,000 BOPD after an upgraded facility was completed in 2005. The Hamaca project is believed to be recoverable over a 35-year period with current technology.[17]

In fields like Hamaca, where extra-heavy oil is produced, cyclic steam injection and steam flooding have been used for years to improve recovery. Distillation effects are observed due to the high temperatures of the steam being injected. Solvents and additives have also been used to accelerate the production of extra heavy oils.[16] Therefore; compositional simulation is needed to model such reservoir processes that involve thermal stimulation. **Table 2.1** presents the composition and main physical properties of the Hamaca fluid sample used in this study.

TABLE 2.1—HAMACA OIL COMPOSITION AND PHYSICAL PROPERTIES

Components	Fluid composition, mole %
N_2	0.03
CO_2	1.92
C_1	29.04
C_2	0.29
C_3	0.15
i-C_4	0.07
n-C_4	0.12
i-C_5	0.08
n-C_5	0.08
C_6	0.31
C_7	0.72
C_8	0.11
C_9	0.06
C_{10+}	67.02
Total Mole %	100.00
C_{10+} Properties	
Gas gravity (air = 1)	1.008
Molecular weight	531.886
Fluid Properties	
Molecular weight	363.48
GOR (SCF/STB)	111.5
Gas gravity (air = 1)	0.6346
Oil gravity, ºAPI	9.3

CHAPTER III

METHODOLOGY AND SIMULATIONS

PVTSim[18] was the simulator used to reduced the number of components to a suitable number and determine the oil viscosity. The real viscosity for the Hamaca oil can be observed in **Table 3.1.** It was obtained through personal communication with PDVSA-Intevep and this sample was taken from the Orinoco Belt in Venezuela. PVTSim used the Lohrenz-Bray-Clark (LBC) correlation to calculate the viscosity of each one of the pseudocomponents at the conditions desired. The LBC correlation is probably the most used one in reservoir simulation models. The correlation was based on the Jossi-Stiel-Thodos correlation and modified by Lohrenz *et al.*[19]

It has been reported in the literature that a minimum of four pseudocomponents is required to accurately simulate thermal processes and recovery mechanisms in the steamflooding of a heavy oil (10-15 ºAPI).[5] Therefore, four pseudocomponents were used to perform the simulations.

TABLE 3.1—HAMACA OIL VISCOSITY

Temperature (°F)	Oil viscosity (cp)
120	25000
160	6430
210	945
250	245
290	79
320	35
450	3

In the next figure (**Fig 3.1)** the Hamaca oil viscosity was simulated with PVTSim to match the real viscosity. It is important to mention that the viscosity vs. temperature behavior was

predicted for different pressures of 100, 500 and 1000 psia and the difference was not significant for this project (less than 5%); therefore, a pressure of 500 psia. was taken to run the rest of the simulations. The impact of high temperatures in the viscosity behavior of the extra heavy Hamaca oil can also be observed in that figure and better understand the reason to inject steam to produce this type of extra heavy oils.

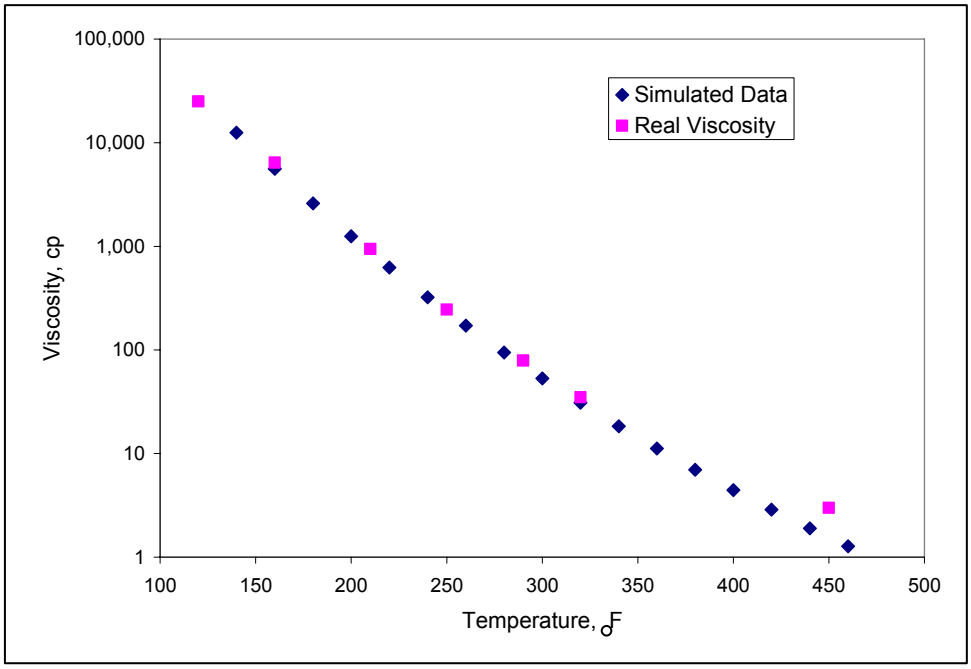

Fig. 3.1—Description of the Hamaca oil viscosity versus temperature simulated with PVTSim.

3.1 Viscosity of the pseudocomponents

In this thesis, PVTSim was used to simulate the viscosity of the Hamaca oil and to match the real viscosity. It is important to mention that once the tuning was done, the Hamaca oil will be referred to the one obtained through simulation in PVTSim.

Four pseudocomponents were obtained after lumping the lighter components and splitting the plus fraction following the concept that the best lumping arranged would be the one which predicts the closest phase behavior to the prediction from the original system in terms of the oil viscosity. **Table 3.2** shows the definition of the four pseudocomponents used in simulation. The mole

fractions of the components describe the original composition of the fluid before the cyclic steam injection process began.

TABLE 3.2—DEFINITION OF COMPONENTS USED IN SIMULATION

	Components			
	C_1 - C_{31}	C_{32} - C_{46}	C_{47} - C_{60}	C_{61} - C_{80+}
Mole fraction	0.6246	0.1481	0.1091	0.1183
T_c (°F)	1,296.9	1,686.8	1,908.6	2,149.1
p_c (psi)	285.05	225.14	228.68	236.99
Acentric factor	0.4354	1.2614	1.5296	1.7704
Molec. weight	140.34	537.74	741.29	975.41

The viscosity of each of the lumped pseudocomponents can be observed in **Fig. 3.2**. To obtain the viscosity of each one of the pseudocomponents, the real viscosity profile for the Hamaca oil was input in the simulator. The LBC viscosity model was tuned by performing a regression (**Eq. 3.1**). This was achieved principally by modifying the critical volumes of the pseudocomponents, but it also needed some other modifications such as acentric factor, and molecular weight. The regression function to be minimized is the normalized root mean square (RMS) error of predicted pseudocomponents minus experiment results to the given Hamaca oil viscosity profile. Once the viscosity is matched with the new pseudocomponents, the viscosity of each pseudocomponent is obtained by simulating each one of them separately at a constant pressure of 500 psia and the same range of temperatures as the Hamaca oil as it was explained before.

$$RSM = \sum_{T=100}^{T=500} \left[\mu^{p}{}_{oi} - f(\mu^{p}{}_{oi}) \right]^2 = \min , \quad \text{.....(3.1)}$$

where $f(\mu^{p}{}_{oi})$ is one of the predicted results and it varies with each one of the mixing rules used.

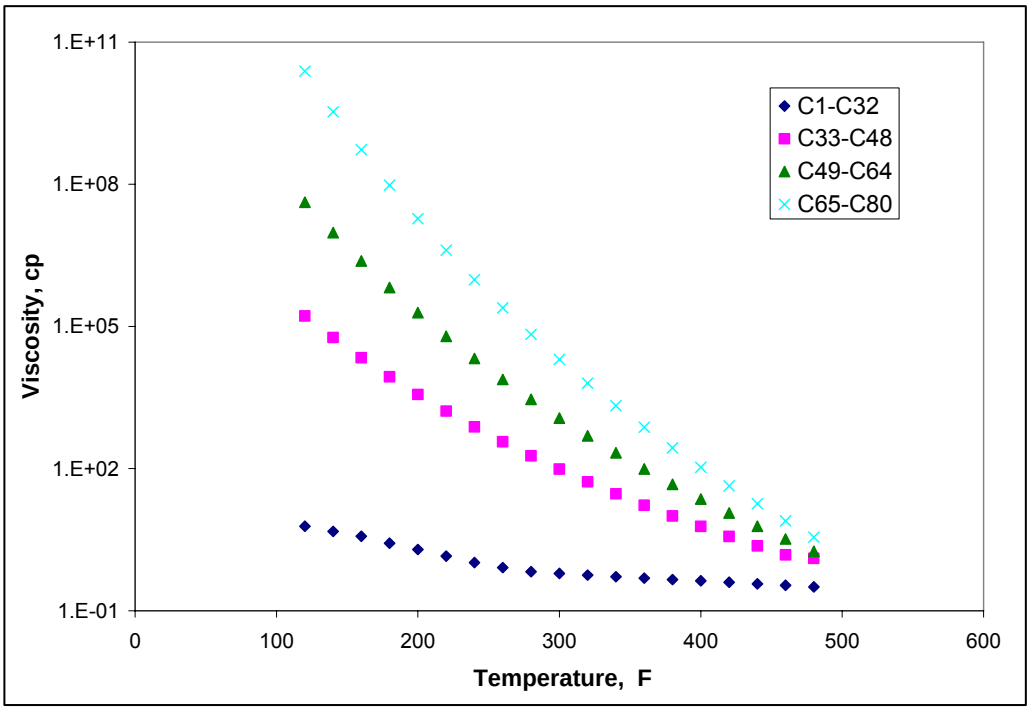

Fig. 3.2—Viscosity profile of the pseudocomponents.

Fig. 3.2 illustrates the simulated viscosities of the selected pseudocomponents, note that there are very large differences between light and heavy component, this stresses the need to define and adequate mixing rule, since small compositional differences will provide substantially different viscosities.

The following action was to plot the oil viscosity obtained from the different mixing rules, and to match the heavy oil viscosity when possible. Note that the log mixing rule does not provide any degree of freedom. This part of the project was done in a spread sheet in EXCEL. First, the heavy oil viscosity provided by PVTSim after the tuning process was input in the spread sheet with the viscosity of each one of the pseudocomponents. Second, calculate the heavy oil viscosity with the log Arrhenius mixing rule and with the power law mixing rule. In this latter case, a regression was conducted to determine the best exponent that fits the heavy oil viscosity profile. Then, we evaluated the new flexible mixing rule from ECLIPSE. This mixing rule also requires least squares regression to obtain the best values for each number that multiple each one of the pseudo viscosities. In this latter case, since four pseudocomponents are being use, then there are four variables to regress and the match is almost perfect throughout all the temperatures. In **Fig. 3.3**, all these mixing

rules were plotted in a semilog chart and compared to the original viscosity of the Hamaca oil. The first mixing rule evaluated was the Arrhenius mixing rule and it does not match any points of the original Hamaca oil. This one is the worst of all the mixing rules and this was expected since there are no variables to modify to match any data. The power law mixing rule offers a better approach at temperatures between 100 to 200°F but at temperatures over 300°F, it does not offer a satisfactory match. Finally, it can be observed that the best results are obtained with the new flexible mixing rule since this has more variables to regress than any of the other mixing rules. The match is almost perfect at low and high temperatures. However, it is very important to understand that since the regression was done at the beginning of the simulation, the composition was fixed for each one of the pseudocomponents. It has been explained before the importance of the distillation effects in compositional simulation and this compositional dependence is eliminated when fixing the weights or variables to regress for each one of the pseudocomponents in **Eq. 2.3**. This will later be discussed with other results.

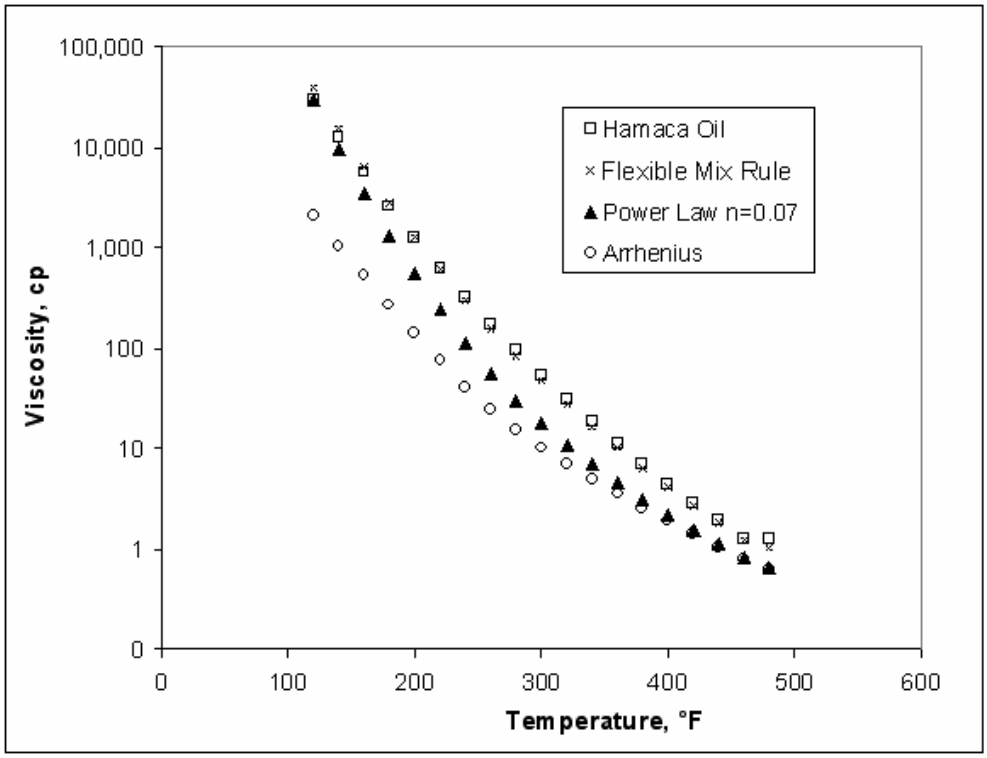

Fig. 3.3— Comparison of different viscosity mixing rules with the extra heavy Hamaca oil.

3.2 Reservoir characteristics

One of the goals of this thesis is to better understand the impact of these mixing rules in a cycling steam injection simulation. Simulations were carried out with the objective of determining the effects of different mixing rules over seven cycles of steam injection and oil extraction. The simulation package used for modeling was ECLIPSE 300, which is a compositional simulator. It can be run in fully implicit, IMPES and adaptive implicit (AIM) modes. On this thesis, the simulations were run using three phases: oil, gas, and water; radial grid, fully implicit, and in thermal option live oil, which allows the simulation of multiple hydrocarbon components in both oil and gas phases.

Radial geometry was used to perform the simulations. Cell coordinates were specified in terms of *r*-*θ*-*z* values. In this thesis log spacing was used in the radial direction to better simulate and capture the wellbore response. This can be observed in **Table 3.3**.

TABLE 3.3—LOG SPACING USED IN RADIAL GRID

Inner radius, ft	0.3
Outer radius, ft	167.94
Cells, #	Cells, ft
1	0.49
2	1.14
3	2.44
4	4.84
5	8.80
6	14.67
7	22.36
8	31.01
9	38.82
10	43.33

The well was completed from top to bottom and injection occurred in all the layers. In **Fig. 3.4**, log spacing and size of the cells can be observed. The porosity was assume constant throughout the reservoir at 30% and the permeability was the same in the radial and theta direction, but it was cut to half in the z direction since the horizontal permeability is usually higher than the vertical permeability. The relative permeabilities were taken from SPE Case 1 and they are in Appendix A.

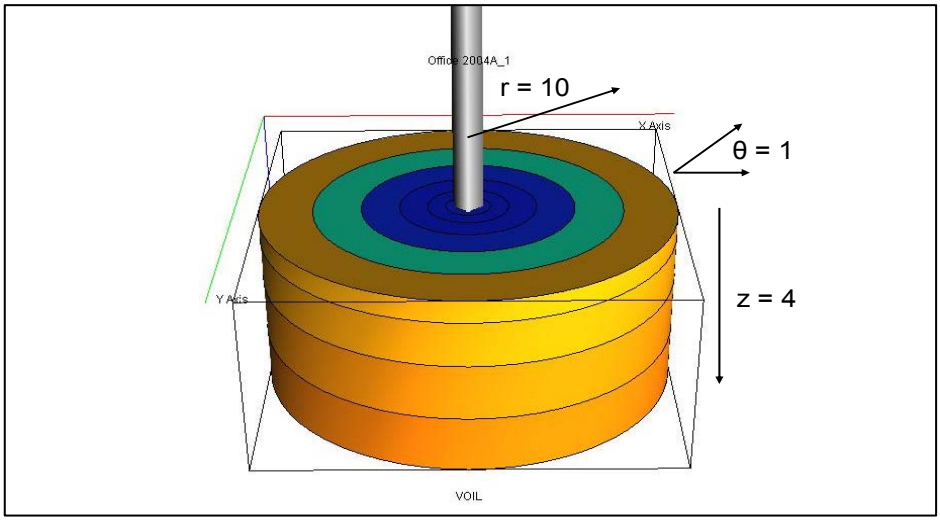

Fig. 3.4—Cell description in the reservoir.

Description of the cycling period, steam and reservoir description is found in **Table 3.4**. In this simulation, seven cycles were completed to produce oil. The steam injection period used for each cycle was obtained from the second part of this thesis that is performing a systematic analysis of cycling steam injection in terms of injection, soaking and production periods to provide guidelines that maximize oil recovery at minimal cost considering the overall economics of a cyclic steam injection project. The cycle that was selected to perform all the simulations to assess the impact of oil viscosity mixing rules in cycling steam injection is describe as follows: 25 days of injection, 15 days of soaking and 250 days of production. That cycle was repeated seven times in the reservoir to measure the oil produced during a total of 2,030 days. One of the constrains to produce the oil was the bottom hole pressure of 2000 psi. This will further be explained with a figure and different simulations.

TABLE 3.4—DATA USED IN SIMULATION FOR PERIOD, STEAM, AND RESERVOIR DESCRIPTION

Cycling period	
Periods	7
Injection time, D	25
Soaking time, D	15
Production time, D	250
Total time of production, D	2,030
Steam Description	
Steam quality, %	70
Injection temperature, °F	500
Injection rate, CWE	500
Reservoir Description	
Top depth, ft	800
Number of cells, r	10
Inner radius, ft	0.3
Outer radius, ft	167.94
Number of cells, θ	1
Number of cells, z	4

Size of cells in z, ft			
10	20	25	25
Porosity			
0.3	0.3	0.3	0.3
Permeability z, md			
1,000	250	500	1,000

To calculate the *K*-values, Wilson's correlation was used (**Eq. 3.2)**. This correlation is actually built in the simulator. All the critical properties were input in the simulator from PVTSim for each one of the pseudocomponents. However, the acentric factor was obtained from Katz and Firoozabadi[20] for each one of the pseudocomponents.

$$K_i(p,T) = \frac{p_{c_i}}{p} \exp\left[5.373697(1+\omega_i)\left(1+\frac{T_{c_i}}{T}\right)\right], \quad (3.2)$$

3.3 Simulation of different viscosity mixing rules

In the following figures, some performance indicators where used to compare the impact of different mixing rules in cycling steam injection. These indicators are cumulative oil production, oil production rate, water cut, and bottom hole pressure.

In these figures, the Hamaca oil represents the simulated extra heavy oil with one pseudocomponent predicted by PVTSim. It is usual to use black oil simulation to model extra heavy oils even though it has been explain before the need for compositional simulation. On the other hand, the other two simulations are performed with two different mixing rules and four pseudocomponents. One of them is the Arrhenius mixing rule and the other is the new flexible mixing rule. The power law mixing rule is not available in ECLIPSE 300 and therefore it will not be shown in the next figures.

In **Fig. 3.3**, the only mixing rule that matches the viscosity of the Hamaca oil was the new flexible mixing rule. The Arrhenius and traditional power law mixing rule failed to describe the viscosity behavior leading to a lower viscosity value at almost all temperatures. This problem is also visualized in **Fig. 3.5** where the cumulative oil production is almost double when simulating cycling steam injection using an incorrect mixing rule in comparison to the other two that are very similar. This result was expected because simulating a lower viscosity will cause the oil to flow easier through the reservoir; hence, obtaining a higher cumulative oil production.

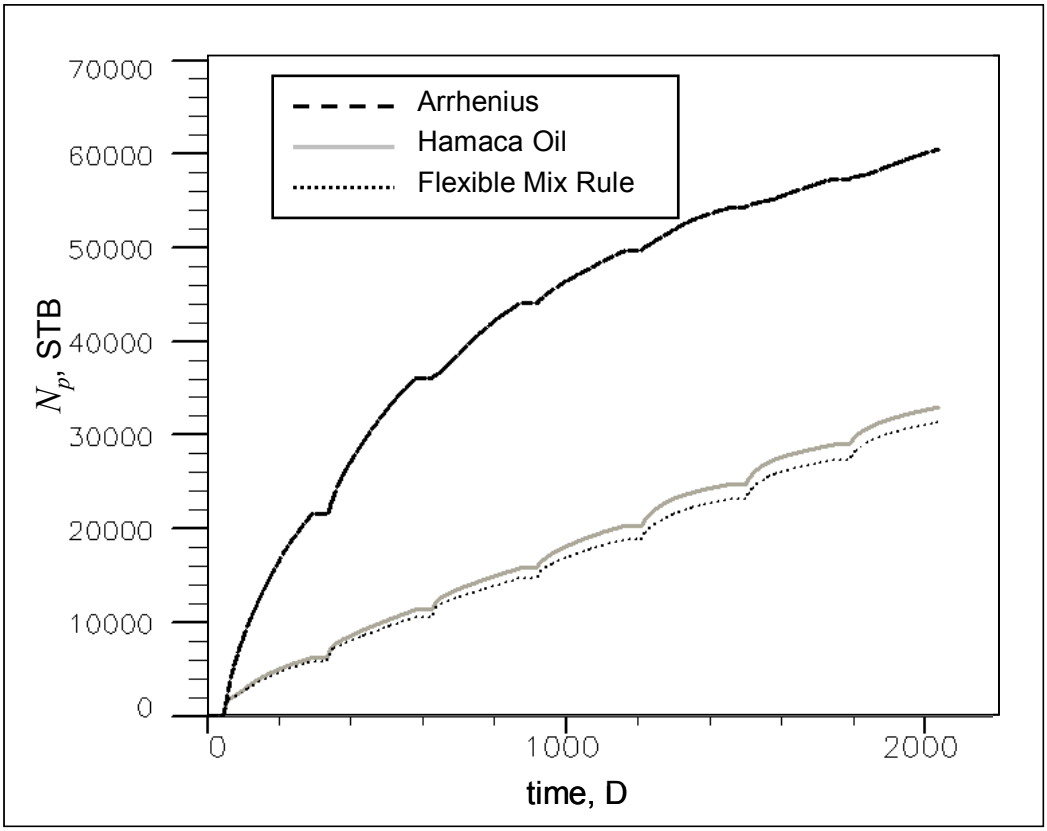

Fig. 3.5— Cumulative oil production is overestimated by the Arrhenius mixing rule.

The oil production rate is observed in **Fig. 3.6**. The Hamaca oil and the new flexible mixing rule produce almost at the same rate during the seven cycles. However, the Arrhenius simulation again failed to describe the actual behavior of the Hamaca oil.

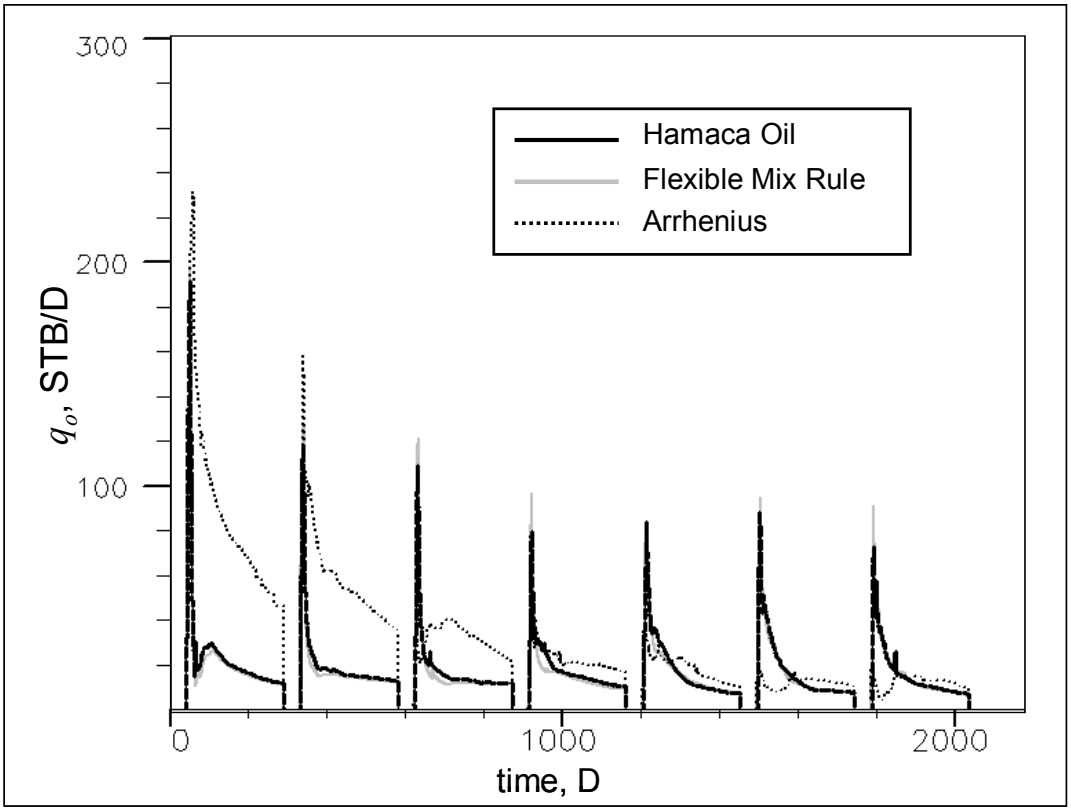

Fig. 3.6— The Hamaca oil production rate is matched by the new flexible mixing rule during seven cycles.

Fig. 3.7 shows the water cut during the simulation**.** The interesting fact about this figure is that, even though the overall water produced is very close in all the simulations, the water cut in the Arrhenius mixing rule simulation is lower because the well is producing more oil than the other two simulations.

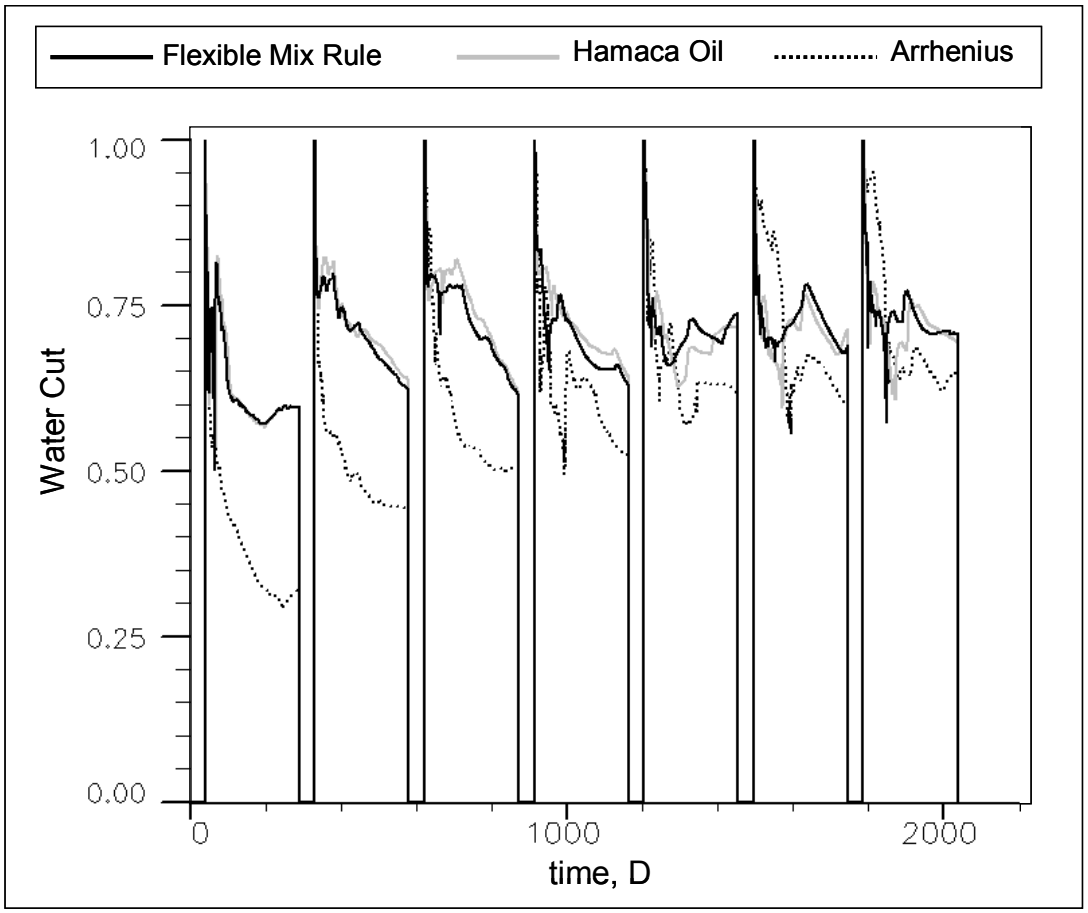

Fig. 3.7— Water cut is underestimated by the Arrhenius mixing rule.

The constraint in these simulations was the bottom hole pressure set at 2,000 psi. This means that if the well reaches that pressure when the steam is being injected this will shut in and continue with the cycle. This value was never reached during injection for none of the simulations. Since the viscosity predicted by the Arrhenius mixing rule was always lower, then the bottom hole pressure

in **Fig. 3.8** for the new flexible mixing rule and the Hamaca oil was always higher than the Arrhenius simulation.

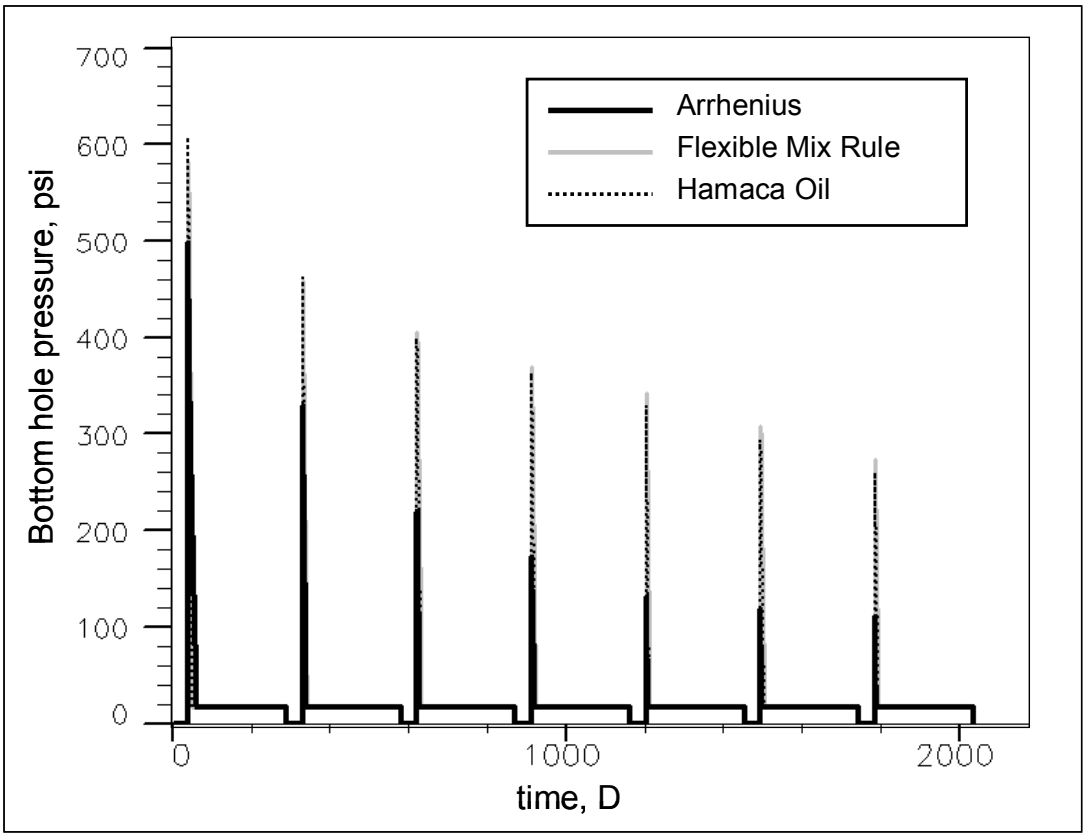

Fig. 3.8—Bottom hole pressure distribution.

After evaluating four parameters, such as the cumulative oil production, the production oil rate, the water cut, and the bottom hole pressure, it is evident that the Arrhenius mixing rule does not provide enough flexibility to describe the viscosity of the Hamaca oil in this cycling steam stimulation study. The new flexible mixing rule leads to the best results matching the viscosity of the Hamaca oil simulation.

However, in cyclic steam stimulation, as well as in other thermal recovery processes, the oil viscosity changes not only because of temperature but also due to compositional changes. Evidence of these compositional changes is observed in **Table 3.5**, where the composition of each

pseudocomponent in the liquid phase in the near wellbore gridblock (1,1,4) is reported at the beginning and at the end of the production stages for each of the seven cycles. At the beginning of the production stages, high temperature, 411°F to 460°F, causes the lighter components to be less abundant in the liquid phase because there is vaporization. At the end of the production stages, lower temperature, 247°F to 257°F, causes the lighter component molar composition to increase back again but only to 0.59 instead of 0.62. The fact that the final liquid compositions at the end of the cycle are not the same as the initial oil composition indicates that there is oil vaporization.

Compositional changes are not considered in black oil models. The four-component simulation presented in this thesis demonstrates that the oil composition presented in **Table 2.1** changes with time in the wellbore vicinities. These results could be summarize in two main conclusions. First, a compositional model allows producing oil by distillation. This is ignored in the one component black oil model. Second, the new flexible mixing rule viscosity model assumes 'fixed' compositions equal to the initial oil. There is a need to further improve the mixing rule, with enough flexibility to include compositional changes. If this were predicted accurately the mobility would improve further. From a practical view point less steam would be required to produce the same amounts of oil.

TABLE 3.5 —COMPOSITIONAL CHANGES IN THE PRODUCED WELL STREAM TO INDICATE DISTILLATION EFFECTS

Cycle	t (D)	p (psi)	T (°F)	Mole fraction of components			
				x_1	x_2	x_3	x_4
1	40	466	460	0.0519	0.0497	0.4176	0.4808
	165	27	252	0.6246	0.1482	0.1090	0.1182
2	330	380	440	0.0007	0.0937	0.4298	0.4758
	455	26	248	0.5963	0.1593	0.1172	0.1271
3	620	333	428	0.0002	0.1318	0.4132	0.4548
	745	25	247	0.5838	0.1642	0.1209	0.1311
4	910	311	422	0.0003	0.1541	0.4031	0.4425
	1,035	27	250	0.5864	0.1631	0.12	0.1302
5	1,200	290	415	0.0001	0.1838	0.3895	0.4265
	1,325	28	252	0.588	0.1625	0.1196	0.1297
6	1,490	281	412	0.0001	0.1967	0.3836	0.4196
	1,615	29	254	0.5887	0.1623	0.1194	0.1296
7	1,780	277	411	0.0000	0.2097	0.3776	0.4126
	1,905	30	257	0.5888	0.1622	0.1194	0.1295

CHAPTER IV

GUIDELINES FOR CYCLIC STEAM INJECTION

In this part of the project, the main objective is to perform a systematic analysis of cyclic steam injection to provide guidelines that maximize oil recovery at minimal cost considering the overall economics of a cyclic steam injection project.

4.1 Simulations for cyclic steam injection

In order to create some guidelines for scheduling periods in cyclic steam injection, several reservoir simulations cases were performed using the thermal compositional simulator ECLIPSE 300. The first set of simulations is summarized in **Table 4.1**. All possible combinations were completed, for a total of 64 runs, before making other simulations to better understand some of the observed trends. This part of the project was performed using the same reservoir and cyclic steam injection conditions described in **Table 3.4**. It is important to mention that the analysis of this thesis has been restricted to the same injection rate, same temperature, same quality of steam and also the same type of oil.

TABLE 4.1—CYCLIC STEAM INJECTION COMBINATIONS

Injection (D)	Soaking (D)	Production (D)
5	3	20
10	7	30
20	10	40
25	15	50
Number of runs = $(I_{periods}) \times (S_{periods}) \times (P_{periods}) = 4 \times 4 \times 4$		

Since the scope of this project was to find guidelines to maximize oil recovery at minimal cost, there were three very important results to analyze. The first one was the field oil production total (FOPT), which represents the positive cash flow in the economical analysis of a thermal project. The second one was the field energy injection total (FEIT), which represents the most

important cost associated with a thermal recovery project. Finally, the last one is time, because of the time value of money in project evaluation.

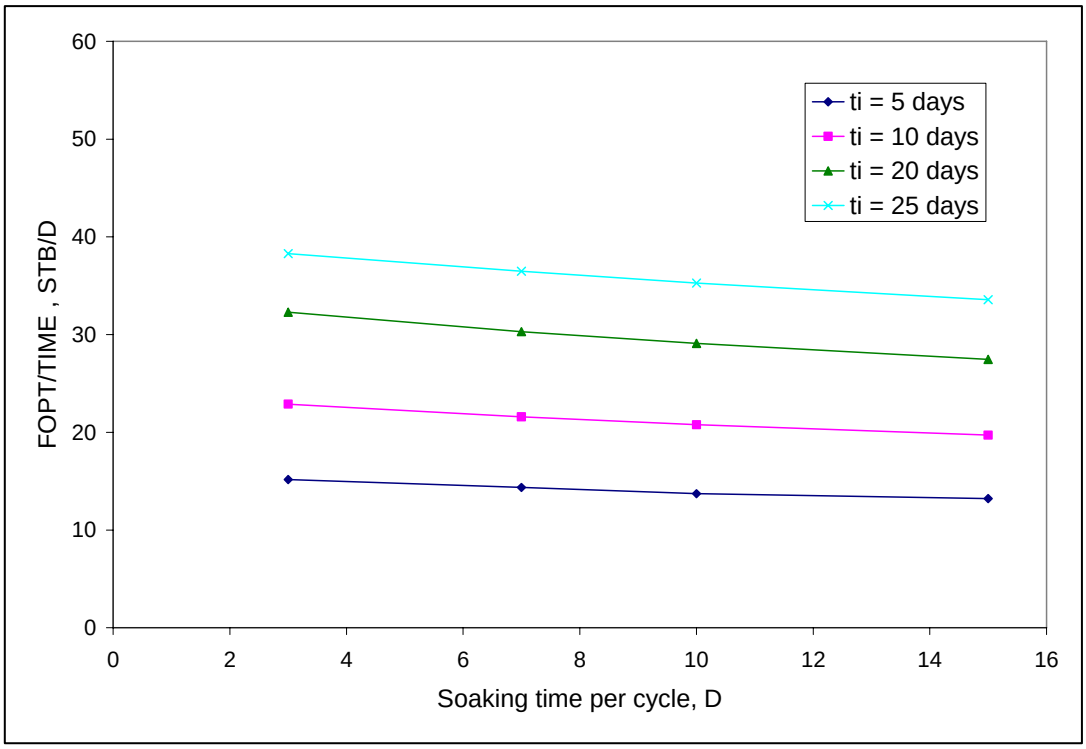

Fig. 4.1—Impact of injection and soaking periods on the oil production rate using 40 days of production per cycle.

The first observation when making the simulations is that the soaking period apparently does not produce much more oil and therefore is a time that is unproductive express in terms of field oil production total. In **Fig. 4.1**, FOPT/TIME refers to the average oil production rate (STB/D) including unproductive injection and soaking periods. In this figure, the production period was held constant to observe what the impact of soaking in the injection period is. It can be observed that for all the injection periods, the average oil production rate is higher when the soaking period of each cycle has the lowest value of three days. This was observed in all the simulations even though this figure represents only 16 simulations. Other simulations were completed with no soaking period and it provides even better values. This behavior can also be understood when the FOPT is

observed. For example, for 25 days of injection the difference in FOPT between 3 days and 15 days of soaking, after 7 cycles is 540 STB. This represents 2.8 % in terms of recovery but it takes 84 more days to produce this amount of oil. Following the concept of time value of money and also cost of operations 540 STB do not justify 84 more days of operations in a well. From these simulations the first guideline could be made. The soaking period should be as short as possible because it is unproductive time for the well and therefore it translates into a negative cash flow for a company.

Some very important observations can be made in the following figures. In **Fig. 4.2**, the relationship between injection and production can be observed in terms of average oil production rate and then in **Fig. 4.3**, how does the injected and produced energy affect cyclic steam injection for different injection and production times.

In **Fig. 4.2**, the first very important observation is that the soaking period is constant in this plot at three days because it was shown before that it would provide the maximum average oil production rate for all the injection periods. Also, every production time line has an optimal injection period. For example, for 30 days of production periods the optimal injection time is 25 days where an average of 39 STB/D is produced. Another maximum is observed in the production time lines for 20 days and 40 days. For 20 days the optimal injection period is 20 days and for 40 days of production time, the optimal injection time is 30 days. Another point to notice is that for the production line of 50 days, the reservoir have not yet reach a maximum which indicates that the optimal injection time base on average oil production and its trend would be higher than 25 days.

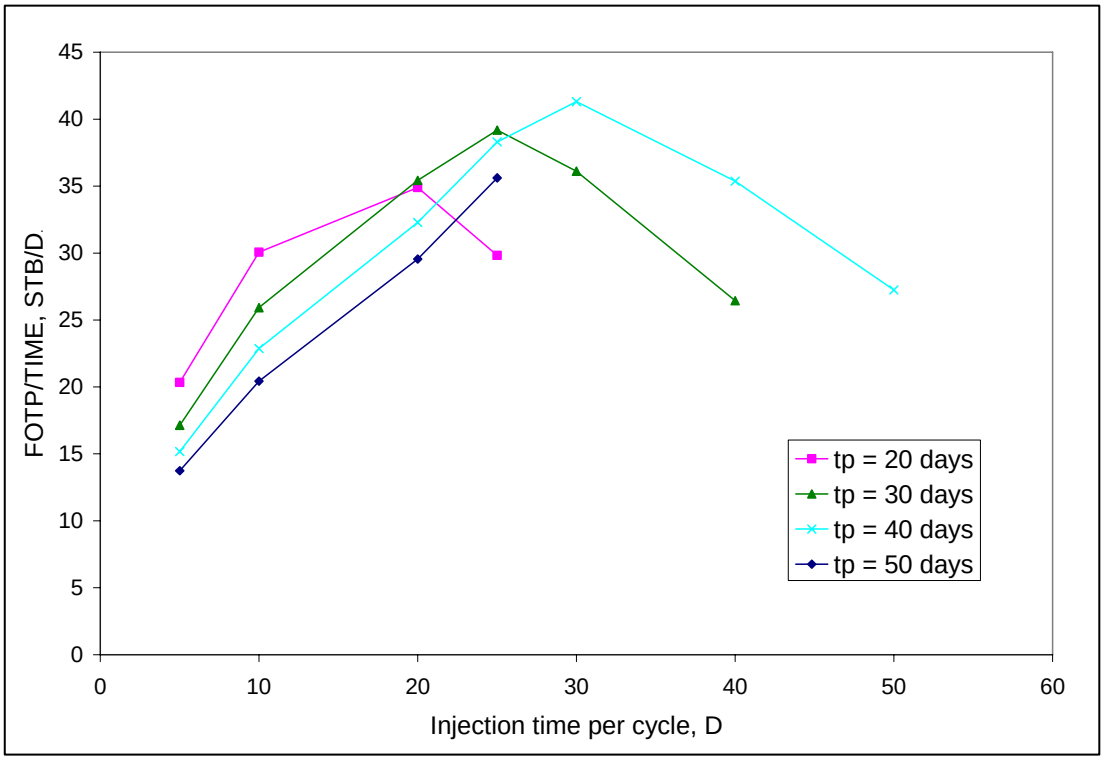

Fig. 4.2—Optimal oil production rate for different injection and production times at a constant soaking time of 3 days.

On the other hand, on **Fig. 4.3**, the "y" axis indicates an average profit in terms of energy per day that a company would have selling the energy produced. This takes into account the energy produced, the energy spent, and the time doing the project. To calculate the total energy produced, the heat value of oil was found to be 138,500 BTU/gal for a fuel oil type #2.[21] This is better explained in Appendix C. This was used to calculate how much energy was produced and plot a good indicator of efficiency in this process. These two plots complement each other because there has to be a compromise between oil produced and energy used to obtain an optimal value for injection. Again in this figure, an optimal can be observed for each production time. These optimums values match with the optimums in **Fig. 4.2**. These observations imply that at the optimal oil production rate, there is also an optimal average energy produced and they match each other.

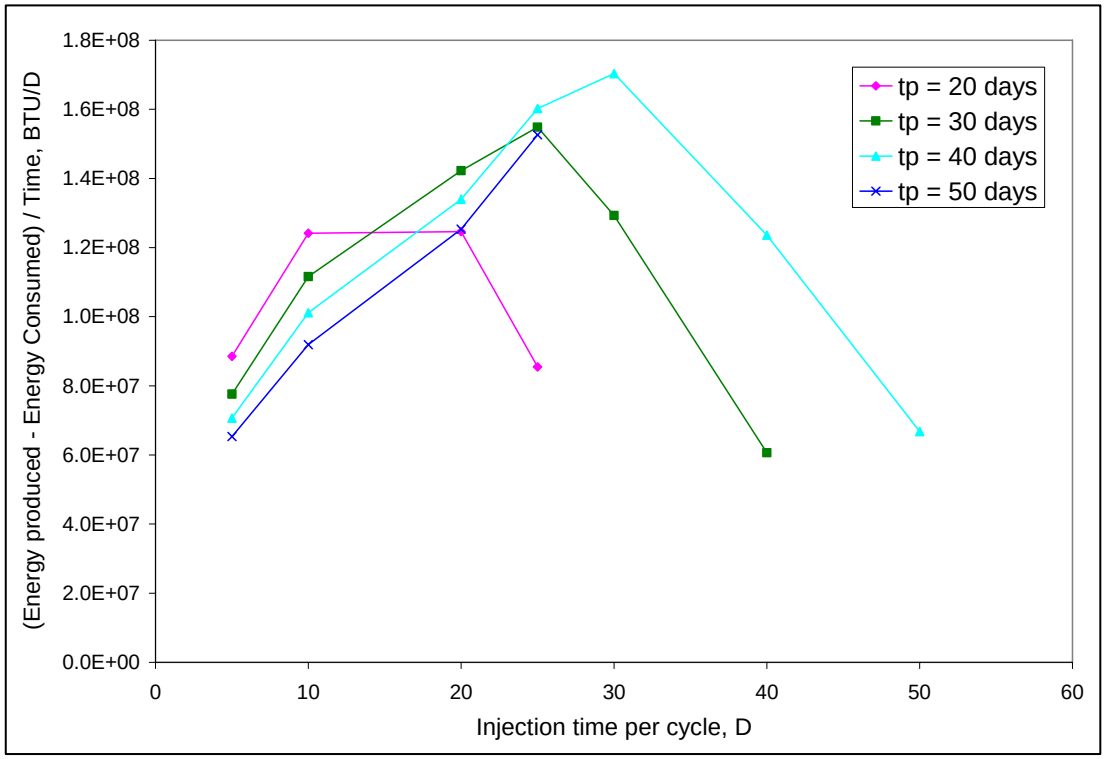

Fig. 4.3—Optimal energy production for different injection and production times at a constant soaking time of 3 days.

With these observations, another very important conclusion can be made and it is supported in **Fig. 4.4** also. Under the current conditions of the reservoir and cyclic steam injection, the optimal production period has to be equal or just about 30% higher than the injection period. Therefore, it is better to have short cycles with similar injection and production periods.

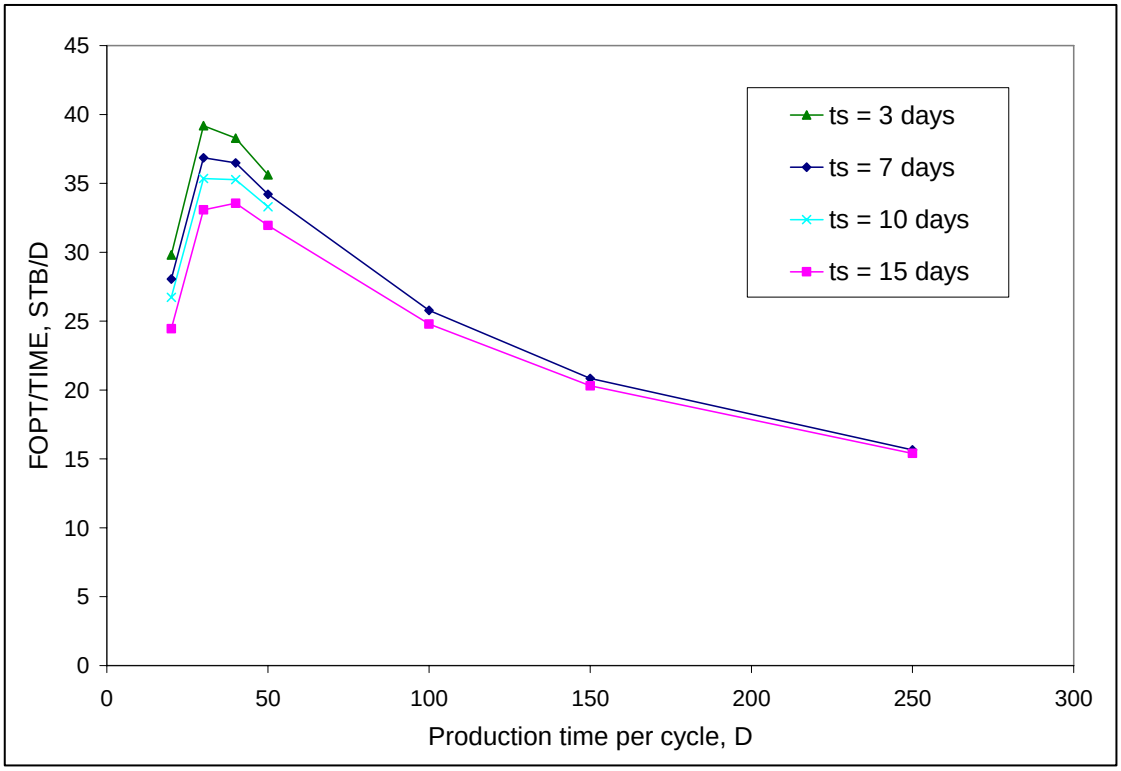

Fig. 4.4—Average oil production rate for steam cycles of 25 days of constant injection varying soaking and production times shows optimal production times lower than 40 days.

In **Fig. 4.4**, some of the guidelines described before are confirmed. In this case, the injection period is held constant at 25 days and a comparison between production periods and soaking periods can be observed. For this case, some other simulations were done to observe the common observed plateau of in oil production rate with time and better understand the figure. The first point that clearly can be observed is that the maximum average oil production is again obtained at the smallest soaking period. On the other hand, for an injection period of 25 days, the highest oil production peak is at 30 days but no less than 20 days, which confirms that the production and injection periods should be similar in time length. Nevertheless, the production period should not be less than the injection period.

CHAPTER V

SUMMARY, CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary

There were two main objectives in this thesis. The first one was to assess the impact of oil viscosity mixing rules in cyclic steam injection understanding specially the impact in oil production from reservoir simulation studies. The other objective was to perform a systematic analysis of cycling steam injection to provide guidelines that maximize oil recovery at minimal cost considering the overall economics of a cyclic steam injection project. This thesis was done using two different simulators for reservoir engineers, PVTSim and ECLIPSE 300. Results have been presented and conclusions and recommendations are described next.

5.2 Conclusions

Main conclusions arising from assessing the impact of oil viscosity mixing rules in cyclic steam injection of extra heavy oils are summarized as follows.

1. Cumulative oil production is drastically impacted when using improper mixing rules to describe the oil viscosity.
2. The log linear and power law mixing rules do not provide enough flexibility to describe the viscosity of extra heavy oil with temperature.
3. The best results are obtained with the new flexible mixing rule when using pseudocomponents because this implements more variables to regress than any of the other mixing rules.
4. The new flexible mixing rule can be matched at low and high temperatures; however, the compositional dependence is eliminated when fixing the weights for each pseudocomponent in the mixing rule for viscosity.

Conclusions from proving guidelines to optimize oil production using proper lengths in each one of the periods for cyclic steam injection are summarized as follows:

1. A method has been developed to determine the optimum lengths of production and injection periods.
2. From the cash flow point of view, the soaking period should be as short as possible because it is unproductive time in terms of field oil production for the well and therefore it translates into a negative cash flow for a company.

5.3 Recommendations

This thesis analyzes two different problems. The first one illustrates and explains with an example the importance of different mixing rules used in reservoir simulation and alerts reservoir engineers the significance of using different options simulators have built in their platforms to describe the viscosity of heavy oils. Compositional simulation is needed to model reservoir processes such as depletion, miscible flooding, steam cycling, and gas cycling.

We recommend new simulators to implement more flexible mixing rules including a compositional model because it will provide a more accurate simulation and consequently better results in the field.

The other important factor analyzed is the lengths of the cycling steam injection periods. In these simulations, a specific reservoir was used with certain characteristics. The time was included in the economic analyzes but we recommend to do a more detail economic analysis taking into account different operational functions such as type of injector, heat losses in case shorter injections periods are perform, net present value, internal rate of return and also different reservoir characteristics such as heat conductivity. Those types of studies would help to better understand the behavior of the heat in the reservoir and also the impact of other operational functions in the optimization of cyclic steam injection in heavy oils.

NOMENCLATURE

$BCWE$ = Barrel of cold water equivalent

K_i = K-value for pseudocomponent i

Nc = number of pseudocomponents

N_p = cumulative oil production, STB

p = pressure, psi

p_c = critical pressure, psi

q_o = oil production rate, STB/D

t = time, D

T = temperature, °R

T_c = critical temperature, °R

x_i = mole fraction of pseudocomponent i

μ_o = oil viscosity, cp

μ_{oi} = viscosity of pseudocomponent i, cp

ω_i = acentric factor of pseudocomponent i

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APPENDIX A

DATA FILE FROM ECLIPSE USED FOR SIMULATIONS

```
-- Steam Injection Problem
-- 2D R-Z Radial Model
-- 3 Component Problem: Water and 2 Live Oil Components

RUNSPEC   ========================================

LIVEOIL

DIMENS
-- cells in r, Theta and z
10 1 4 /


WATER
OIL
GAS

RADIAL

FIELD
--UNITS

COMPS
4    /

THERMAL
-- ENABLE THE THERMAL OPTION

FULLIMP
-- FULLY IMPLICIT SOLUTION

GRID     ========================================
INIT

INRAD
-- INNER RADIUS OF THE RESERVOIR
 0.3  /
DRV
-- size of the cells in the radial direction
-- These follow the log spacing
0.490 1.140 2.448 4.841 8.801
14.674 22.366 31.014 38.827 43.336 /
```

```
DTHETAV
-- SIZE IN THE THETA DIRECTION
360.0                   /

DZV
-- SIZE OF THE CELLS IN THE Z DIRECTION
 10.0  20.0  25.0  25.0  /

PERMR
-- PERMEABILITY VALUES IN THE RADIAL DIRECTION
 10*2000.0  10*500 10*1000.0  10*2000.0  /

PERMTHT
-- PERMEABILITY VALUES IN THE AZIMUTHAL DIRECTION
 10*2000.0  10*500 10*1000.0  10*2000.0  /

PERMZ
--PERMEABILITY VALUES IN THE Z DIRECTION
 10*1000.0  10*250.0   10*500.0  10*1000.0  /

PORO
-- FRACTIONAL POROSITY VALUE
 10*0.3 10*0.3 10*0.3 10*0.3  /

TOPS
-- DEPTH AT THE TOP OF EACH GRID BLOCK
10*800.0
10*810.0
10*830.0
10*855.0
 /

THCONR
-- ACTIVATES THE CALCULATION OF THERMAL CONDUCTION OF HEAT IN THE
ROCK
-- SUPPLIES ROCK THERMAL CONDUCTIVITIES
 40*24.0  /

HEATCR
-- ROCK VOLUMETRIC HEAT CAPACITY VALUE
 40*35.0  /

PROPS    ========================================

HEATVAP
-- CONSTANT PART OF THE HEAT OF VAPORIZATION OF EACH OIL COMPONENT
178.01 70.25 43.18 22.99 /

CNAMES
C1-C31 C32-C46 C47-C60 C61-C80/
```

```
TCRIT
-- CRITICAL TEMPERATURES OF EACH COMPONENT in R
1296.912 1686.841 1908.635 2149.125 /

PCRIT
-- CRITICAL PRESSURES OF EACH COMPONENT
285.05 225.14 228.68 236.99 /

-- FROM Katz & Firoozabadi
ACF
0.4354 1.2614 1.5296 1.7704 /

MW
-- MOLECULAR WEIGHT OF EACH COMPONENT
140.34 537.735 741.287 975.409 /

DREF
-- REFERENCE DENSITY AT P AND T IN THE RESERVOIR 500psi,100F
30.516 74.060  92.387 111.919 /


THERMEX1
-- THERMAL EXPANSION COEFFICIENT

.00036 .00036 .00036 .00036 /

CREF
--OIL COMPONENT LIQUID COMPRESSIBILITY (1/PSI)
-- Heavier components have lower cref
.000005 .000003 .000002 .000001 /


KVWI
-- K VALUES FITTING FUNCTION

TCRITW
1165.14 /

PCRITW
3208.2356 /


THANALB
-- ITS SET TO REQUEST ANALITIC WATER AND STEAM DENSITIES TO BE USED.
-- ITS SET BY DEFAULT
```

```
SPECHA
-- FIRST COEFFICIENT OF THE COMPONENT LIQUID SPECIFIC HEAT.
-- TO CALCULATE LIQUID ENTHALPY
-- THE SECOND COMPONENT IS WITH "SPECHB" KEYWORD
.55 .55 .55 .55/

TEMPVD
-- TEMPERATURE (2ND COLUMN) VS DEPTH DATA FOR EACH REGION
  800.0  150.0 /

STCOND
-- STANDARD CONDITIONS (T,P)
60 14.7 /

SWFN
-- WATER SATURATION FUNCTION
-- WAT. SAT. / WAT. REL. PERMEABILITY / WAT-OIL CAPILLARY PRESSURE
   .4500   .0000   0.0
   .4900   .0003   0.0
   .5300   .0018   0.0
   .5700   .0049   0.0
   .6100   .0101   0.0
   .6500   .0177   0.0
   .6900   .0279   0.0
   .7300   .0410   0.0
   .7700   .0572   0.0
   .8100   .0768   0.0
   .8500   .1000   0.0
  1.0000   .1000   0.0
 /

SGFN
-- GAS SATURATION FUNCTION
-- GAS. SAT. / GAS. REL. PERMEABILITY / GAS-OIL CAPILLARY PRESSURE
   .0000   .0000   0.0
   .0600   .0000   0.0
   .1090   .0063   0.0
   .1580   .0179   0.0
   .2070   .0329   0.0
   .2560   .0506   0.0
   .3050   .0707   0.0
   .3540   .0930   0.0
   .4030   .1171   0.0
   .4520   .1431   0.0
   .5010   .1708   0.0
   .5500   .4000   0.0
  1.0000   .4000   0.0
/
```

```
SOF3
-- OIL SATURATION FUNCTION
-- OIL. SAT. / OIL-WAT. REL. PERMEABILITY / OIL-GAS REL.PERMEABILITY

  .0000   .0000   .0000
  .1000   .0000   .0000
  .1500   .0000   .0049
  .1900   .0040   .0160
  .2300   .0160   .0334
  .2700   .0360   .0571
  .3100   .0640   .0871
  .3500   .1000   .1235
  .3900   .1440   .1661
  .4300   .1960   .2151
  .4700   .2560   .2704
  .5100   .3240   .3320
  .5500   .4000   .4000
 1.0000   .4000   .4000
/

GASVISCT


100     0.00001         0.00001         0.00001         0.00001
120     0.00001         0.00001         0.00001         0.00001
140     0.00001         0.00001         0.00001         0.00001
160     0.00001         0.00001         0.00001         0.00001
180     0.00001         0.00001         0.00001         0.00001
200     0.00001         0.00001         0.00001         0.00001
220     0.00001         0.00001         0.00001         0.00001
240     0.00001         0.00001         0.00001         0.00001
260     0.00001         0.00001         0.00001         0.00001
280     0.00001         0.00001         0.00001         0.00001
300     0.00001         0.00001         0.00001         0.00001
320     0.00001         0.00001         0.00001         0.00001
340     0.00001         0.00001         0.00001         0.00001
360     0.00001         0.00001         0.00001         0.00001
380     0.00001         0.00001         0.00001         0.00001
400     0.00001         0.00001         0.00001         0.00001
420     0.00001         0.00001         0.00001         0.00001
440     0.00001         0.00001         0.00001         0.00001
460     0.00001         0.00001         0.00001         0.00001
480     0.00001         0.00001         0.00001         0.00001
500     0.00001         0.00001         0.00001         0.00001
520     0.00001         0.00001         0.00001         0.00001
540     0.00001         0.00001         0.00001         0.00001
560     0.00001         0.00001         0.00001         0.00001
580     0.00001         0.00001         0.00001         0.00001
600     0.00001         0.00001         0.00001         0.00001  /
```

OILVISCT

100.0000	7.9736	507852.1875	204141280.0000	201946349568.0000
120.0000	6.0742	165410.0938	41949336.0000	24431953920.0000
140.0000	4.7119	58060.6172	9579801.0000	3403012096.0000
160.0000	3.7156	21804.7520	2406514.7500	538307072.0000
180.0000	2.6596	8705.9766	659079.6875	95559672.0000
200.0000	1.9635	3675.0364	195250.5625	18838326.0000
220.0000	1.4262	1632.1090	62135.6602	4086150.5000
240.0000	1.0374	759.2587	21111.4141	967234.1875
260.0000	0.8156	368.5558	7616.4297	248045.0469
280.0000	0.6690	186.0335	2903.5515	68468.3359
300.0000	0.6121	97.3448	1164.5562	20224.8340
320.0000	0.5639	52.6581	489.4937	6359.9082
340.0000	0.5225	29.3742	214.8638	2119.0935
360.0000	0.4866	16.8592	98.1812	744.9728
380.0000	0.4551	9.9356	46.5690	275.2699
400.0000	0.4263	6.0012	22.8685	106.5358
420.0000	0.3983	3.7088	11.5991	43.0506
440.0000	0.3700	2.3417	6.0634	18.1116
460.0000	0.3430	1.5084	3.2603	7.9121
480.0000	0.3186	1.2642	1.8000	3.5804
500.0000	0.2967	1.2642	1.2642	1.6747
520.0000	0.2770	1.2642	1.2642	1.2642

/

OILVINDX
-- Keyword that modifies the oil viscosity to match data

0.0000	0	0	0	0
0.1000	0.1413	0.8587	0.0000	0.0000
0.2000	0.1413	0.8587	0.0000	0.0000
0.3000	0.1413	0.8587	0.0000	0.0000
0.4000	0.1413	0.8587	0.0000	0.0000
0.5000	0.1413	0.8587	0.0000	0.0000
0.6000	0.1413	0.8587	0.0000	0.0000
0.7000	0.1413	0.8587	0.0000	0.0000
0.8000	0.1413	0.8587	0.0000	0.0000
0.9000	0.1413	0.8587	0.0000	0.0000
1.0000	1	1	1	1

/

PVTW
-- WATER PVT FUNCTION

-- Pref	Bw	Cw	Vw	Cvw
-- PSIA	RB/STB	1/PSI	CPOISE	1/PSI
75.000	1.0	3.E-08	.3	7.E-09

/

```
ROCK
-- ROCK COMPRESSIBILITY
-- REF. PRESSURE / ROCK COMPRESSIBILITY
75.0  5.0E-04  /

ZI
0.62455 0.14812 0.10905 0.11828 /

SOLUTION  ========================================


EQUIL
----  Ddat    Pdat     Dwoc    Pcog    Dgoc    Pgoc  It1  It2  Iac Iin
       800.0   350.00   880.0   0.0      760.0  0.0   1     1    0   1  /


RPTRST
--OUTPUT FOR THE PRINT FILE
BOIL DENO ENERGY HOIL PRES SOIL TEMP VOIL
/

SUMMARY  =========================================

FOPT
FOPR
FEPR
FEIR
FHLR
FHLT
FPR
FOSAT
FWPR
FWIR
FWPT
FWCT

BVOIL
1 1 4/
/

WTEMP
/

WBHP
/

WWCT
/

TCPU
```

```
MSUMLINS


RUNSUM

EXCEL

FEIT

SCHEDULE  ====================================

TRANGE
--TEMPERATURE RANGE FOR THE RESERVOIR (EXPECTED)
 70.0   650.0  /

RPTPRINT
-- s F R G S W C s nl
  1 1 0 0 0 0 0 1 0 /

RPTSCHED
--PRINT FOR SCHEDULE SECTION

PRES MLSC ENERGY HOIL HWAT TEMP SOIL VOIL VWAT SWAT SGAS  /

WELSPECS
--NAME,F OR G, I LOC, J LOC, REF DEPTH FOR BHP, MAIN STREAM...
I  FIELD  1 1  1* WATER /
P  FIELD  1 1  1* LIQ /
/

COMPDAT
-- COMPLETION DATA
-- NAME, I, J, K UPPER, K LOWER, STATUS, ? / ? / WELL BORE DIAMETER
I   1 1 1 4  OPEN 1 1* 0.6 /
P   1 1 1 4  OPEN 1 1* 0.6 /
/

--TSCRIT
-- TIME STEPPING CRITERIA
--1     2       3    4      5     6      7      8    9    10     11
--initT minT   maxT maxInc Dec targTTE  maxTTE TTPT MTPT TSCT    MxWT
--1.      .00002  50   2     0.5   0.2    10.    0.5  1    0.2     40
-- 12     13   14    15    16    17    18       19    20
--maxPT maxSC ATPT   SACT maxSA  TEMT  maxTEM
-- 1*    10     0.25   0.3  0.9    1*    1*       -1  -1 /

--
**********************************************************************************
**********
```

```
include
30-3-30.txt/
end
```

The word include adds a file to be read with the data file. This was done to better organize all the simulations. The following is the include file for this data file:

```
**************************************************************************
--Cycle: 1
----------------------------------------------------------------------

WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/


TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /


--
**************************************************************************
```

```
--Cycle: 2
**********************************************************************************
**********
WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/


TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /


**********************************************************************************
--Cycle: 3
**********************************************************************************
**********
WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/



WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
```

```
I  0.70  500  /
/

TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /

**********************************************************************************
--Cycle: 4
**********************************************************************************
**********
WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/

TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
```

```
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /


**************************************************************************
--Cycle: 5
--------------------------------------------------------------------------

WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/

TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /


**************************************************************************
**********
--Cycle: 6
```

```
**********************************************************************************
**********
WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/

TSTEP
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /

**********************************************************************************
--Cycle: 7
--
**********************************************************************************

WCONINJE
-- NAME, CONTROL BY RATE, SURFACE FLOW RATE OR UPPER LIMIT, 1*, BHP OR
UPPER LIMIT
I  WATER OPEN  RATE 500 1* 2000 /
/
WINJWAT
-- WATER INJECTION: NAME, QUALITY, TEMP.
I  0.70  500  /
/


TSTEP
```

```
30 / --Inject 30 days

WELOPEN
I  SHUT /
/

TSTEP
3/ --Soak 3 days

WCONPROD
P  OPEN LRAT 3* 500 1* 17 /
/
TSTEP
30 / --Produce for 30 days

WELOPEN
P  SHUT /
/
TSTEP
 1 /

--
**************************************************************************************
END
```

APPENDIX B

STEPS FOR TUNING THE VISCOSITY

There are a number of small details that need to be considered when making a regression. Some of the steps to make a regression on the viscosity are described as follows:

1. Need to specify the experiments to be used in the regression. There are many types of experiments that could be used. In the case of viscosity data we need temperature, pressure, oil viscosity and gas viscosity.

2. In most of the simulators, including PVTSim, you may assign weights for the experiments associated with your data. In the case of heavy oils, it is very important to make sure the higher weight is in oil viscosity rather than the gas viscosity because the gas viscosity would probably be negligible in comparison to the oil viscosity.

3. Usually there is a need to specify an equation of state and what type of correlation are you going to be using to calculate the viscosity: CBS or LBC correlation. In this case, LBC correlation was used to perform the regression in PVTSim.

4. It is usual to match the phase behavior of a fluid and then match the viscosity data. It is strongly recommended to do that because if the viscosity is matched first, the user may have a lot of problems getting to match the other experiments.

5. One of the first variables usually use to make a regression are the critical volumes. In the case of PVTSim, there is a box with regression variables were you can chose on what variables to regress and usually you can start with critical volumes of the heaviest fractions first.

6. It is very important to remember that the user may modify the default selection of regression parameters, but the number of regression parameters must not exceed the number of experimental data points.

7. In PVTSim, with the LBC viscosity correlation three regression options exist. The default one is to let the regression determine a unique correction factor to be multiplied with the critical volumes of the pseudo-components. It is further possible to determine optimum values of the five coefficients $a_1 - a_5$ in the LBC correlation. A third option is to combine the V_c and $a_1 - a_5$ regression. For this thesis, the latter option was used.

8. The critical volume only affects the viscosities if the LBC correlation has been specified. Some of the following component properties may be specified as regression parameters:
    a) Tc
    b) Pc
    c) VPEN (Volume shift parameter)
    d) Vc
    e) kij (binary interaction parameters)

9. For the binary interaction parameters it is possible to specify single pairs of components for which the binary interaction parameters are to be adjusted. Alternatively one may specify a component triangle. The binary interaction parameters for each component pair contained in this triangle will in that case be adjusted equally. In PVTSim, the user may specify a maximum allowed adjustment for each parameter.

10. It is common to modify the component properties of the heaviest component because there is usually an experimental uncertainty in all its properties of 5 to 10 %. Therefore, when binary interaction parameters are modified, generally the user might start with the interaction between the lighter components and the heaviest component.

There are some other hints that might be useful to read. This can usually be found in the help menu of the simulators. In the case of PVTSim, there is a complete section specifically for the regression experiments. On the other hand in the ECLIPSE manual, particularly in the PVTi manual, there is a very useful workflow to better understand regression parameters and matching experimental data.

APPENDIX C

HEAT VALUE OF OIL

There was a study made in University of Connecticut, Storrs CT, in May 2005. This study explains what types of fuels there are in the market and also the heat value for them. It takes data from the US Department of Energy. The fuel chosen to determine the heat value of the Hamaca Oil was Fuel # 2 because it is the type of fuel more related to heavy oil. Nevertheless Fuels # 4 and # 6 provide even a higher heat value and this would translate into a higher profit for the company.

Calculations

ECLIPSE provides the field oil production total in standard barrels. Therefore, the calculation for one simulation would be the following:

Assuming 138,500 BTU/gal:

$$Energy\ produced = 4127\ STB \times 42\frac{gal}{STB} \times 138{,}500\frac{BTU}{gal} = 2400675900\ BTU$$

This was done with all the simulations to obtain the energy produced by the oil. The energy injected in the reservoir can be found in the simulation in BTU.

The study done with the types of fuels is the following:

Fuels and Alternate Heat Sources for Commercial Greenhouses

Which fuel is best? The right answer depends on price, convenience and availability. Some fuels have a higher heat value than other and some heating units have a greater efficiency. A good way to compare the cost of fuel is on a million Btu basis. What is the cost of one million Btu's of heat?

By definition, one Btu equals the amount of energy required to raise a pound of water 1ºF. It takes 8.3 Btu's to raise 1 gallon of water 1ºF.

Gaseous Fuels

Natural gas is one of the most economical fuels, although it is not available to growers in all areas. It needs no on-site storage as it is piped from transmission lines. Natural gas burns cleanly, requires

little equipment maintenance and may be used in central boilers or remote unit heaters. Some suppliers include an “interruptible clause” which allows them to interrupt the supply in time of extreme need, usually during cold spells when fuel is needed to heat homes. A backup fuel supply and equipment to burn it is essential under these conditions.

For larger users, it is best to buy “direct purchase” form one of the large suppliers near a well head. Adding the transmission cost through the pipelines will give you a total fuel cost.

Propane (Liquefied Petroleum Gas) is a clean, gaseous fuel much like natural gas. It is obtained as a byproduct of oil refinery operations or by stripping natural gas. It is liquefied by moderate pressures at normal temperatures. Although it is more expensive than natural gas it can be readily obtained where natural gas in not available. Maintenance is minimal, but a storage tank and preheater are needed.

Propane is best purchased by the transport load which requires a 30,000 gallon tank, usually buried. Purchase should be made during the time of year when the price is lowest.

Fuel Oil

No. 2 oil is usually comparably priced with natural gas but may be more expensive in some locations especially where it has to be transported a long distance from the supply point. It is a relatively clean fuel that demands slightly more burner maintenance than gas. Oil requires on-site, above ground storage tanks that must have a containment in event of a leak or spill. Oil stored in outdoor, above-ground tanks may become difficult to pump in temperatures near 0ºF. Insulated tanks or additives to the fuel protect against this hazard.

No. 4 and 6 oils have a higher heating value than No. 2 but because of low sulfur restrictions, they are usually similar in price. These oils require preheating and greater attention to equipment operation. They are subject to the same storage and temperature limitations as No. 2 oil.

Contracting for the winters fuel needs when the price is low, usually August or early September can save considerable money and insure that you have a supply for the winter.

Alternate Heat Sources

A heating system using an alternative fuel can be installed to meet the total heat needs of the greenhouse but is generally too expensive. It is more common to install a system that will supplement the present heating system and provide for part of the heat needs. It is only for a few hours per heating season, the coldest nights, that you need the total installed capacity of the furnaces or boilers.

Most heating systems that use an alternative fuel tend to be more expensive than a conventional furnace or boiler that is mass produced. To be attractive, the fuel or heat source should be readily available at a low cost. Even though there has been little government support for research on alternative fuels, considerable progress has been made in developing more efficient equipment and systems during the past few years.

Systems that burn fuels, such as wood, coal and waste oil require more attention and labor. Maintenance costs may also be greater and should be readily available.

The following is a short review of some of the more common alternative fuels and heat sources. A detailed economic study should be done before purchasing a system. It may be a better choice to invest in upgrading the present system to make it more efficient.

Wood - Where readily available, wood is an important alternative. The fuel is relatively inexpensive as forest residue, mill waste, chips or sawdust. The cost is in the transportation and handling.

For example, the fuel oil requirement for a 20,000 sq ft greenhouse located in Connecticut would be about 20,000 gallons for the heating season. If wood is substituted as a fuel source, it would require about 110 cords of hardwood. This means handling about 220 tons if the furnace was fired by hand. The cost of the wood is only $6000 delivered in log length compared to about $35,000 for the oil. This difference is enough to have a reasonable payback for the equipment and to pay for a night fireman.

Furnaces and boilers are available that burn cordwood, chips and sawdust. Heat value of the fuel depends on the moisture content. For example, green, whole tree chips have a heat value of about 8 million Btu/ton whereas dried chips will give about 14 million Btu/ton.

If the wood is burned at high temperatures (more than 1500 ° F) very little smoke or pollution occurs. Most commercial units will pass EPA standards.

Coal - Coal is a low-cost fuel source in some areas. Most coal used in the eastern part of the U.S. is anthracite. Bituminous coal is more common in other parts of the country. The farther you are from the mines, the greater the cost due to the increased transportation. One ton of coal has the equivalent heat value of 150 - 180 gallons of fuel oil or 2,100 - 2,500 therms of natural gas.

A coal heating system requires more labor to operate, produces ashes that have to be disposed of and requires a covered storage area to prevent it from freezing. Operation is usually more difficult as the ignition temperature is 800 ° F to 900 ° F compared to about 550ºF for wood.

Waste oil - Collection centers for waste oil from cars and trucks are common throughout the U.S. Some of the oil is cleaned and reused for lubrication. Much of it is available as a fuel at a few cents/gallon. Waste oil that has not been processed requires a settling tank to trap water and sludge. Considered a hazardous waste, these have to be disposed of to meet EPA regulations.

Waste oil has a heat equivalent of about 135,000 Btu/gallon, similar to fuel oil #2. Furnaces and boilers designed to burn waste oil are available in many sizes. They have automatic control and operate similar to an oil or gas unit.

Methane - Methane is a combustible gas that is commonly available from landfills or from the decomposition of animal manure. If cleaned of impurities, it could be used to power autos or other engines. Methane straight from a landfill can be burned directly in a furnace or boiler. It has a heat value of about 500 Btu/cu ft about ½ that of pure methane.

The Burlington County Resource Recovery Greenhouse operated in cooperation with the Plant Science Department at Rutgers University, New Brunswick NJ has been operating on methane gas produced at the adjacent landfill for several years. In Connecticut, a fuel cell which generates electricity and heat has been operated off landfill gas for several years.

Waste Heat - There are many sources of heat that are going to waste. Common sources include process manufacturing, incinerators and power plants. Some plants are set up to generate electricity and give heat as a by product. The heat may be available as high temperature water or steam but more commonly can only be obtained as low-grade heat of less then 150 ° F. In these cases, a heat exchanger, such as, the Modine Type GLW unit heater is needed to recover the heat for a greenhouse. In other cases, the water can be put directly into a floor heating system.

Geothermal heat - The temperature of the soil at 8' to 12' below the surface remains fairly uniform at about 50 ° F year-round. Water in wells or ponds also stays about the same temperature. In some areas of the U.S. high temperature water or steam is available from deep well sources. There is a potential to capture this heat either directly as with the high temperature steam or through heat pumps or earth tubes to help heat a greenhouse.

Heat pumps work like a refrigerator in reverse taking the heat from the ground source and transferring it to the greenhouse. Earth tubes capture the heat in ventilation air that is then blown into the greenhouse. The 50 ° F air or water could also be used to cool the greenhouse in the summer. The cost of most geothermal systems is fairly high and many things need to be considered before installing such a system.

Although significant savings are possible with the above systems, a substantial investment in equipment and facilities may be required. A thorough analysis of the economics and fuel or heat reliability should be made. It is also best if you can talk to other growers who have similar installations.

You can make your own comparison of fuel costs using the following formulas:

Natural gas	$/MBtu = $/therm x 12.5
Propane	$/MBtu = $/gal x 13.5
#2 fuel oil	$/MBtu = $/gal x 9.0
#4 fuel oil	$/MBtu = $/gal x 8.6
#6 fuel oil	$/MBtu = $/gal x 8.2
Waste oil	$/MBtu = $/gal x 10.7
Cordwood – hardwood	$/MBtu = $/cord x 0.07
Cordwood – softwood	$/MBtu = $/cord x 0.12
Sawdust – green	$/MBtu = $/ton x 0.16
Anthracite coal	$/MBtu = $/ton x 0.055
Bituminous coal	$/MBtu = $/ton x 0.06

The above assumes heating unit efficiency of 80% for natural gas, propane and fuel oil and 70% for cordwood, sawdust and coal.

Approximate Heating Value of Common Fuels (US Department of Energy-2005)

Natural Gas	1,030 Btu/cu ft	100,000 Btu/therm
Propane	2,500 Btu/cu ft	92,500 Btu/gal
Methane	1,000 Btu/cu ft	

Landfill gas	500 Btu/cu ft	
Butane	3,200 Btu/cu ft	130,000 Btu/gal
Methanol		57,000 Btu/gal
Ethanol		76,000 Btu/gal
Fuel Oil		
Kerosene	135,000 Btu/gal	
#2	138,500 Btu/gal	
#4	145,000 Btu/gal	
#6	153,000 Btu/gal	
1 Barrel of oil	42 gal	
Waste oil	125,000 Btu/gal	
Biodiesel – Waste vegetable oil	120,000 Btu/gal	
Gasoline	125,000 Btu/gal	
Wood		
Softwood	2-3,000 lb/cord	10–15,000,000 Btu/cord
Hardwood	4-5,000 lb/cord	18–24,000,000 Btu/cord
Sawdust – green	10-13 lb/cu ft	8-10,000,000 Btu/ton
Sawdust – kiln dry	8-10 lb/cu ft	14-18,000,000 Btu/ton
Chips – 45% moisture	10-30 lb/cu ft	7,600,000 Btu/ton
Hogged	10-30 lb/cu ft	16-20,000,000 Btu/ton
Bark	10-20 lb/cu ft	9-10,500,000 Btu/ton
Wood pellets – 10% moisture	40-50 lb/cu ft	16,000,000 Btu/ton
Hard Coal (anthracite)	13,000 Btu/lb	26,000,000 Btu/ton
Soft Coal (bituminous)	12,000 Btu/lb	24,000,000 Btu/ton
Rubber – pelletized	16,000 Btu/lb	32-34,000,000 Btu/ton
Plastic	18-20,000 Btu/lb	
Corn – shelled	7,800-8,500 Btu/lb	15-17,000,000 Btu/ton
cobs	8,000-8,300 Btu/lb	16-17,000,000 Btu/ton
Electricity	3412 Btu/kilowatt hour	

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University of Connecticut , Storrs CT

May 2005

This information was obtained from the following web page:
http://www.umass.edu/umext/floriculture/fact_sheets/greenhouse_management/jb_fuels.htm

APPENDIX D

VBA CODE FOR LOGARITHMIC SPACING

The following VBA function was written to calculate the logarithmic spacing to better simulate a radial flow in the well.

```
'By Alonso Mago
'College Station, March 19, 2005
'This program calculates the logarithmic spacing to better
'simulate a radial flow in the well.

Dim N As Integer, re As Double, rw As Double
Dim c As Double, check_con As Double
Dim i As Integer, k As Integer
Dim delta_Rad() As Double, Rad() As Double
Const small_number As Double = 10 ^ -10
Const error As Double = 10 ^ -10

Sub calculate_radius()
  Call ReadData

  With Sheets("Sheet1")
   .Range("A12:AA65000").ClearContents
  End With

  ReDim delta_Rad(0 To N): ReDim Rad(0 To N)
  delta_Rad(0) = small_number: Rad(0) = small_number
  c = (re / rw) ^ (1 / N)

  Do
    For i = 0 To N
      If i = 0 Then
        delta_Rad(i) = delta_Rad(i) + small_number
      Else
        delta_Rad(i) = delta_Rad(i - 1) * c
      End If
    Next

    For i = 0 To N
      Rad(i) = Rad(i) + delta_Rad(i)
    Next

  Loop Until (re - Rad(N)) < error

  For i = 0 To N
```

```
    If i = 0 Then
      delta_Rad(i) = c
    Else
      delta_Rad(i) = Rad(i) - Rad(i - 1)
      With Sheets("Sheet1")
       .Cells(i + 11, 3).Value = i
       .Cells(i + 11, 7).Value = Rad(i)
       .Cells(i + 11, 5).Value = delta_Rad(i)
      End With
    End If
  Next

End Sub

Public Sub ReadData()
  With Sheets("Sheet1")
    N = Range("N")
    re = Range("re")
    rw = Range("rw")
  End With
End Sub
```

VITA

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Papers: Mago, A.L., Barrufet, M.A. and Nogueira, M.C.: "Assessing the Impact of Oil Viscosity Mixing Rules in Cyclic Steam Stimulation of Extra-Heavy Oils," paper SPE 95643 presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, Texas, 9–12 October.