FINAL YEAR PROJECT II: DISSERTATION REPORT

CASE STUDY OF THERMAL INJECTION IN HEAVY OIL RESERVOIR

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CERTIFICATION OF APPROVAL

CASE STUDY OF THERMAL INJECTION IN HEAVY OIL RESERVOIR

By

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May 2014

CERTIFICATION OF ORIGINALITY

This is to certify that I am responsible for the work submitted in this project, that the original work is my own except as specified in the references and acknowledgements, and that the original work contained herein have not been undertaken or done by unspecified sources or persons.

MOSTAFA SHARAF ELDIN HASSAN SAAD

ABSTRACT

A study has been done on thermal injection – as an enhanced oil recovery - in heavy oil reservoir. Two types of thermal injection were discussed. These methods are cyclic steam stimulation and steam flooding.

The simulation part was done using Eclipse 300 and literature data. Moreover, steam flooding technique was used in simulating the reservoir. It was confirmed that thermal injection is significant in heavy oil reservoir.

It was shown that the viscosity is the main variable that affects the production rate and the recovery factor of the field. By decreasing the value of this variable the production rate was significantly increased. Using thermal injection increased the recovery factor from 3.75% to 56.5%.

ACKNOWLEDGMENT

I would like to send my sincere thanks to everyone who helped me to go through all the hard times and challenges faced during the completion of my final year project and its report.

First and foremost, I want to thank God Almighty. Who is the ultimate source of all good, and who made everything that I have achieved possible.

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1. INTRODUCTION

1.1 Background of Study

Enhanced oil recovery (EOR) is used to increase the amount of crude oil that can be produced from the oil field. The increase is 40-60% compared to 20-40% to the primary and secondary recovery. When advanced technique are used in EOR, it is called quaternary recovery.

Nowadays, there are several methods of EOR. These types are carbon dioxide injection, microbial injection, polymer flooding and steam flooding. In this case study thermal injection will be discussed.

As Manrique et al. (2010) mentioned that Thermal injection is the most frequently used method in recovery of heavy oil. The main idea of thermal injection is to introduce heat to the reservoir. This heat will increase the temperature in order to increase the mobility of the oil.

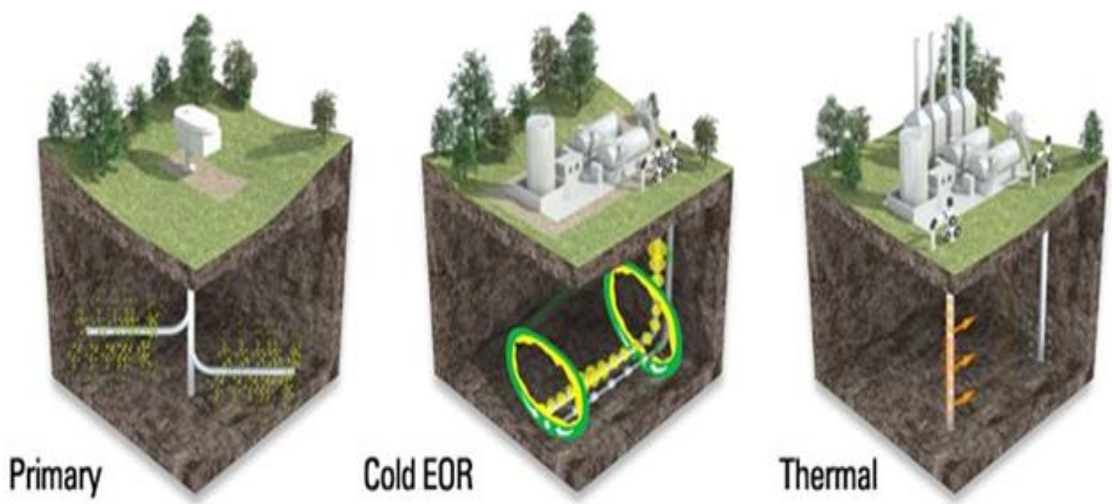


Figure 1: Different types of recovery (Premier Energy Company showed this Figure during EOR workshop in 2010)

1.2 Problem statement

Petroleum companies are looking for oil in a very remote areas; like deep waters, areas where the temperature is below zero and to develop fields in areas like these is very costly, instead we can still produce the remaining amount of heavy oil in the existing fields by applying thermal injection to increase the recovery factor through introducing the enhanced oil recovery techniques. This is due to the high viscosity of the heavy oil which makes it hard to be extracted in its original conditions.

1.3 Objectives

1- To screen the thermal injection method for heavy oil reservoir.

2- To visualize the thermal injection results using Eclipse office.

3- To prove that thermal injection increase the percentage of oil recovered from the reservoir.

1.4 Scope of study

The scope of study of this case study is to study the thermal injection and its types. To gather as much information about thermal injection from several sources such as articles, books, researches and previous case studies. Eclipse program will be used to simulate a reservoir.

1.5 Relevancy and Feasibility

Enhanced oil recovery is a very important aspect in the industry. According to the high contribution of heavy oil with high percentage between all liquids of all types, thermal injection is very important technique in order to extract it. Increasing the recovery factor of oil is the main target to all companies, a lot of researches are carried out in this direction.

By applying the enhanced oil recovery techniques millions of barrels of oil can be extracted from existing fields, as it increases the recovery up to 60 % of the oil in the reservoir, billions of dollars are invested in enhanced oil recovery researches to get the maximum amount of recovery with the lowest possible cost from the existing fields before moving to the remote areas.

When the recovery factor increases, the ratio between the total return from the project to the total cost will decreases. This decrease will affect the society as the oil price all over the world will decrease as well.

2. LITERATURE REVIEW.

As Dusseault, M. B. (2001) demonstrated that Heavy oil is any liquid petroleum that has API between 18° to 25°. It is oil that has high viscosity between 10 and 100 cp. It has high specific gravity or density compared to other type of crude oil. The chemical composition of heavy oil starts with 5 carbons (C_5+).

Heavy oil contributes with high percentage between all the liquids of all types. About 70% of all liquid estimates are heavy oil. Heavy oil are located in depth between 1000ft to 10000 feet only.

Oil production has 3 types which are primary recovery, secondary recovery and tertiary recovery.

Primary recovery is the type in which the production of oil are from the natural mechanisms. These mechanisms are the water drive mechanism and the gas mechanism. The water mechanism is due to the water below water/oil contact displaces the produced oil and forces the oil to be produced. This is due to the high pressure the water exerts on the oil. On the other hand, the gas drive mechanism is due to the expansion of gas which exerts pressure on the oil from above which helps in the production of oil.

Secondary recovery are used when there are no sufficient pressure in the reservoir to force the oil to be produced. It is used to increase the natural reservoir drive. It can be used to inject water into the reservoir or to re-inject the natural gas again to the reservoir. In which it maintains enough pressure to produce oil again.

Tertiary recovery or Enhanced oil recovery is used to increase the mobility to make the production of oil easier.

When exploration risks, environmental risks, permitting issues, oil recovery speed and implementation costs are taken into consideration, the solution is the enhanced oil recovery which is the means for all demands.

Oil consumption rate is at approximately 90 million barrels per day. One third of the production will be increased in the next 15 years so it can meet the world demands. Eighty five billion dollars ($85 Billion) of annual investments are required to provide the market stability to 2025.

According to all the previous inquiries, the world market needs Enhanced oil Recovery. That is because it is the ultimate way to give you the optimum production and optimum recovery factor from the reservoir.

By using Enhanced oil recovery, oil can be produced with less expenses, faster and without any disturbance to the environment from the existing wells. Enhanced oil recovery can prolong the oil field life by 25 to 30 years when applied on proven reserves.

2.1 Critical review.

K. Alnoaimi (2010) stated that the main idea in the thermal injection is to introduce heat to the reservoir. In which it will lead to decrease in the viscosity. In Figure 2 it shows the relation between the oil viscosity and the temperature for a typical heavy oil. As indicated in Figure 2 that the viscosity decreases as the temperature increases.

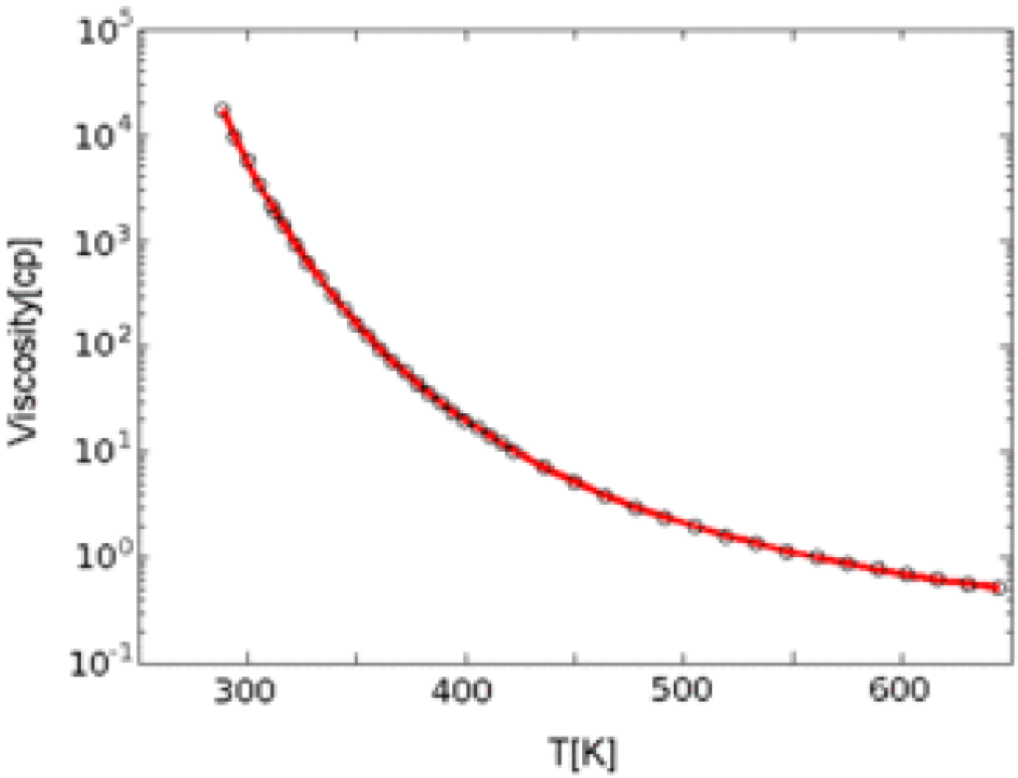


Figure 2: Viscosity vs. Temperature (K. Alnoaimi (2010))

And also from the graph it is very clear that the viscosity rapidly decreases with the increase of temperature specifically at lower temperature which means by introducing small amount of heat in cold formation it will rapidly decreases the viscosity. By decreasing the viscosity the mobility of the heavy oil will increase which make the oil production easier.

The most common way in thermal injection is the steam injection. Water has three states which are solid (ice), liquid (water) and gas (water vapor). In steam injection, the only concern is with liquid and gas phases, and the changing from one phase to another. The region in which water is existing with two phases - liquid and gas – is the important part in steam injection in the oil field.

2.1.1 Steam properties

As mentioned by Moritis, G. (2000), word steam is not accurate designation. Steam not only refers to the gas phase of water, but it refers to the liquid phase as well. It refers also to their co-exist from any temperature starting from 32° F and more, and any pressure starting from 0.1 psi and more. Steam can be either 100% liquid, liquid and gas, or 100% gas. The region in which the water change from one phase to another is called steam quality and it is defined as:

$$f_s = \frac{m_v}{m_v + m_l}$$

Heat capacity is very important term in steam injection. Steam injection depends on increasing the temperature in which it leads to further study to the steam properties. Heat capacity unit is Btu/(lbm.°F). Btu means the British thermal unit. It is defined as the amount of energy needed to increase or decrease one pound of water by 1°F. Pure water has the highest heat capacity between all solid and liquid substances.

Specific heat can be calculated by dividing the heat capacity of any substance to the pure water heat capacity. Specific capacity of petroleum is 0.5, which means it has half the heat capacity of water. In addition, sandstone has 0.2. Water is the highest substance that carries heat per pound that is why it is used in steam injection. The temperature range in which this heat is carrying is very wide – 32 °F to 700 °F - which makes it the best fluid to be used in many processes including steam injection.

Atkins, Peter and de Paula (2006) mentioned another steam property that is the basis for the steam injection calculation, which is the change in enthalpy. Enthalpy is the amount of heat released or used at constant pressure within a system and it is defined as:

$$H = U + PV$$

Change in enthalpy is very useful and it is defined as:

$$\Delta H = \Delta U + \Delta PV$$

Atkins et al. also mentioned that sensible heat (h_f) is the amount of heat used to change the temperature of a substance but do not change its phase. On the other hand, the amount of heat that is needed to change the phase of the substance but does not change the temperature is called latent heat (h_{fv}). The total heat (h_v) in 100% quality steam is:

$$h_v = h_{fv} + h_f$$

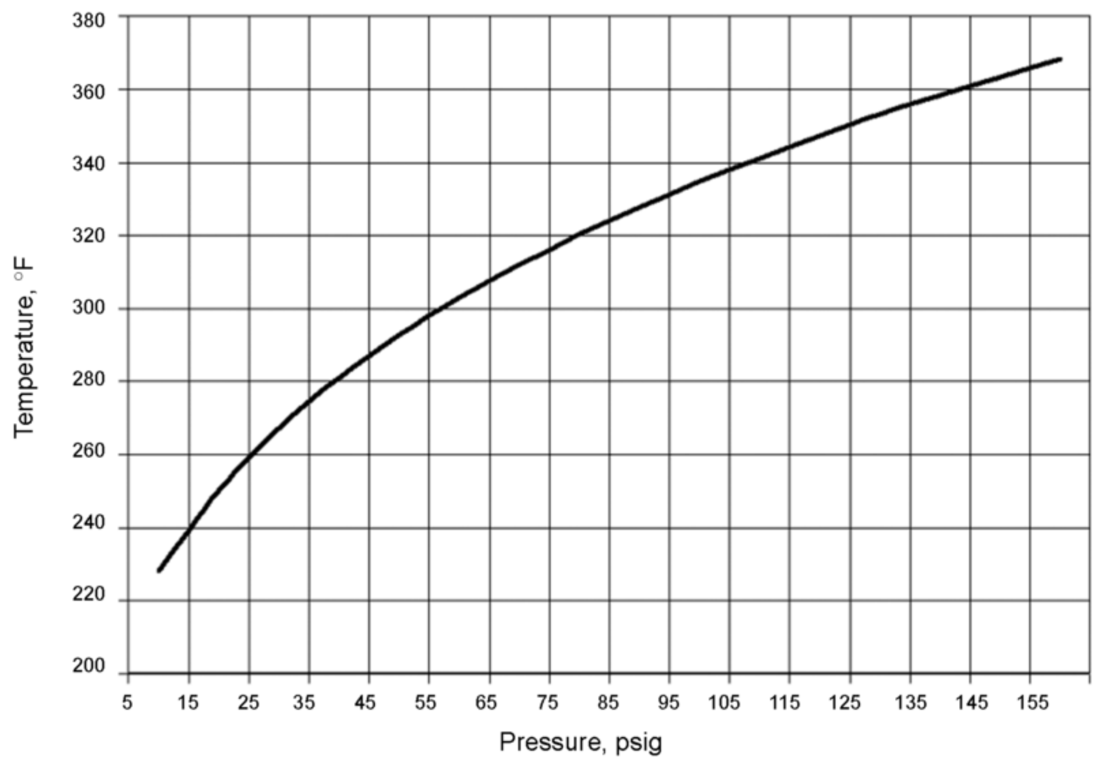


Figure 3: saturation steam temperature vs. saturated steam pressure (Keenan et al. (1969))

Steam can exist only at certain temperature for a given pressure while its phase is changing as shown in Figure 3.

As mentioned by Keenan et al. (1969) and Chien (1992), the following equations were derived with an acceptable accuracy of few percent for most steam injection calculations:

$$T_s = 116.79 p_s^{0.2229}, ^\circ F$$

$$\upsilon_s = 0.02 + f_s \left(\frac{443}{p_s} - 0.02 \right), ft^3/lbm$$

$$\rho_s = 5.06 e^{0.000359} p_s - 5, lbm/ft^3$$

$$h_f = 91 p_s^{0.2574}, \text{ Btu/lbm}$$

$$h_{fv} = 1318 p_s^{-0.08774}, \text{ Btu/lbm}$$

$$h_v = 1119 p_s^{0.01267}, \text{ Btu/lbm}$$

$$h_{f_s} = \frac{f_s(1318)}{p_s^{0.08774}} + 91 p_s^{0.2574}, \text{ Btu/lbm}$$

The previous equation are the most accurate equations in calculating the steam injection manually. They are suitable for many calculations. If more accurate and precise calculations needed, computer application is used.

2.1.2 Reservoir Heating

Marx and Langenheim (1959) were the first to adapt the solution mentioned by Carslaw and Jaeger (1950) and publish it. They assumed that the equations for temperature response in a thin plate and, backed in perfect contact to a semi-infinite solid after sudden exposure to constant-heat input.

They came out with a graph to the heat distribution in the reservoir which is shown below:

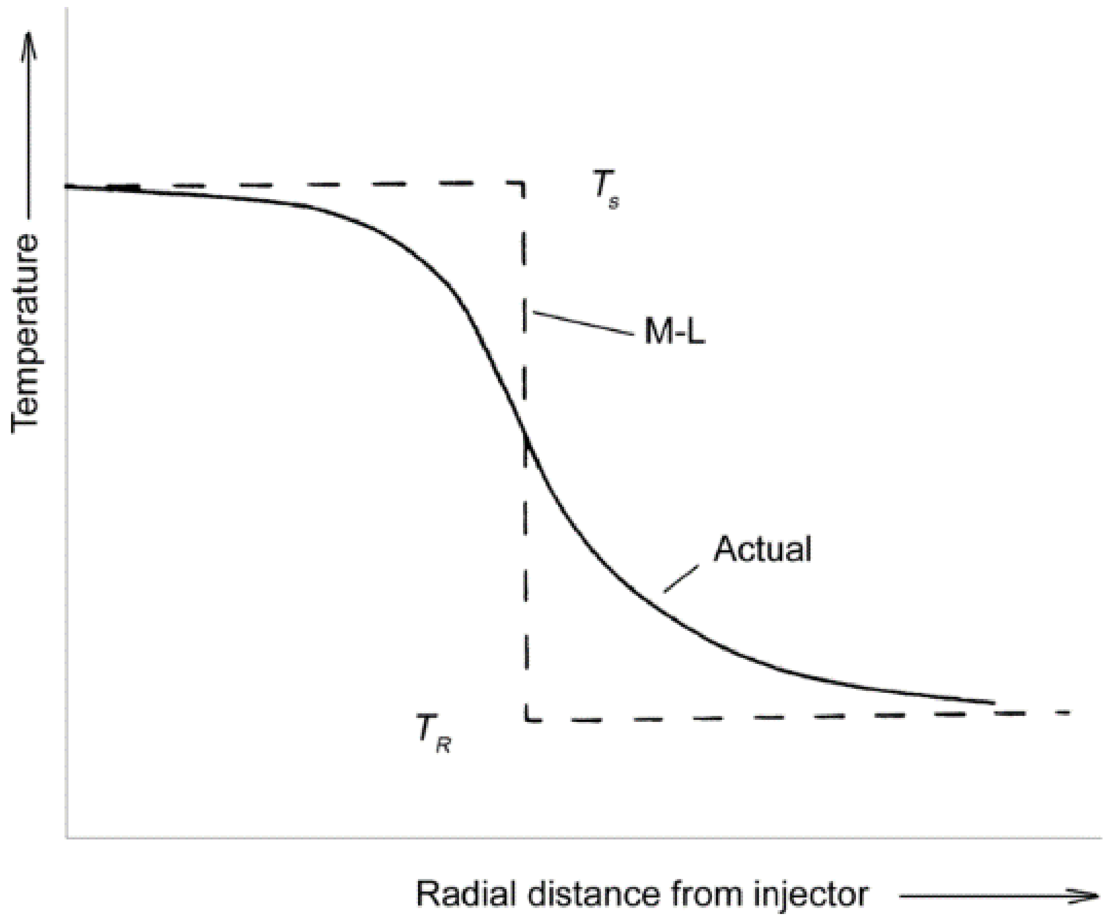


Figure 4: Temperature profile

According to Figure 4, the area most affected by the thermal injection is the one that is closest to the injector well. As the radial distance increases the temperature effect also decreases, until it reaches the point where the reservoir temperature is the initial reservoir temperature.

2.1.3 Steam injection techniques

There are several techniques of thermal injection. The most two common techniques will be discussed which are cyclic steam stimulation and steam flooding.

2.1.3.1 Cyclic Steam Stimulation

It is called **Huff & Puff**. Cyclic steam is based on one vertical well. This well will be used first to inject the steam and then is used to produce the oil. It is done on three stages which are injection, soaking and production as shown in Figure 5.

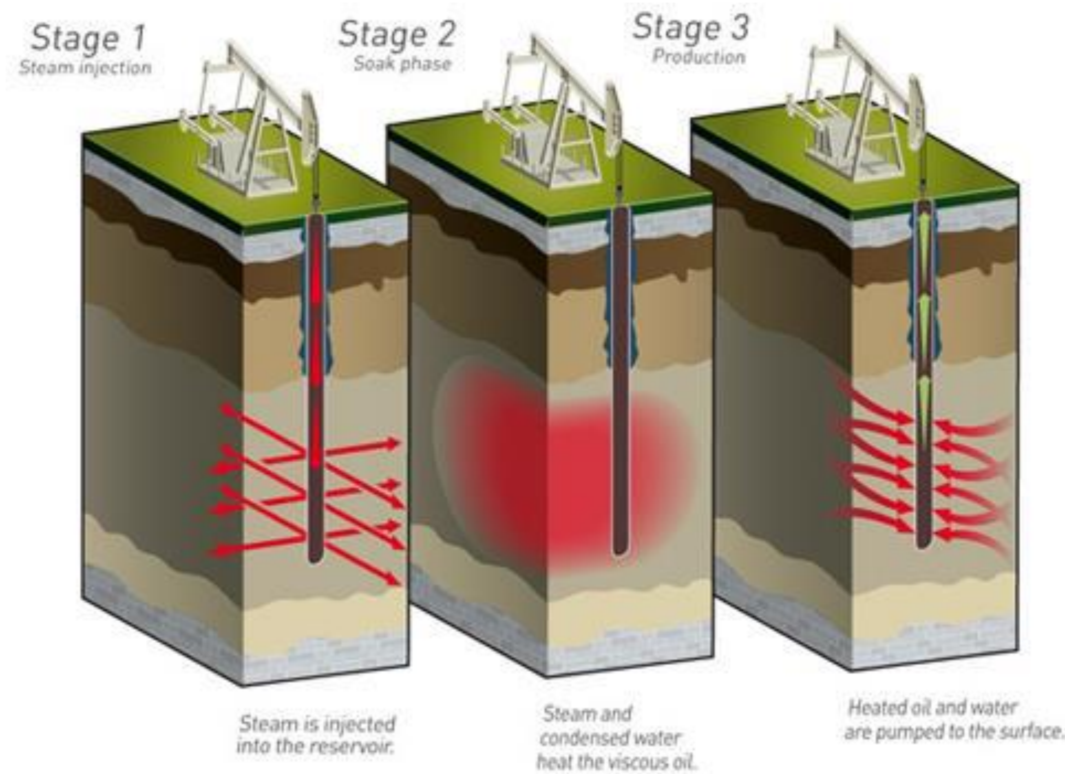


Figure 5: cyclic steam stimulation steps (Alvarez and Han (2013))

First we determine the amount of steam that is needed to be injected in the reservoir. After the amount of steam needed to heat the reservoir is determined, the first stage of the cyclic steam stimulation is ready, which is injection of steam into the reservoir, as shown in the previous Figure.

After the steam is injected into the reservoir the well is shut down to let the reservoir heat and this stage is called soaking. After the heat is already spread through the reservoir the viscosity decreases due to the increase in the temperature. The increase in temperature will lead to increase in the mobility and as a result of that the well is converted into production well, as shown in the previous Figure. The well will continue to produce until the effect of the heat injected disappears and then again the cycle will be repeated.

This cycle will be repeated until economical limit is reached, normally the larger percentage of the oil is produced in the first cycles.

Alvarez and Han (2013) posted that it is better to do some cyclic steam stimulation before switching to another enhanced oil recovery method, such as steam flooding method.

Cyclic steam stimulation recovery factor is in the range of 10 to 30%. It has some limitations:

- Applied for reservoir which their thickness are greater than 30 feet.
- Applied for reservoir in which it depth less than 3000 feet.
- It is desirable that the reservoir has high porosity and oil saturation.

2.1.3.2 Steam flooding

Vertical wells

Not like Cyclic steam stimulation, in steam flooding some wells are used for injection and others are used for production, as shown in Figure 6.

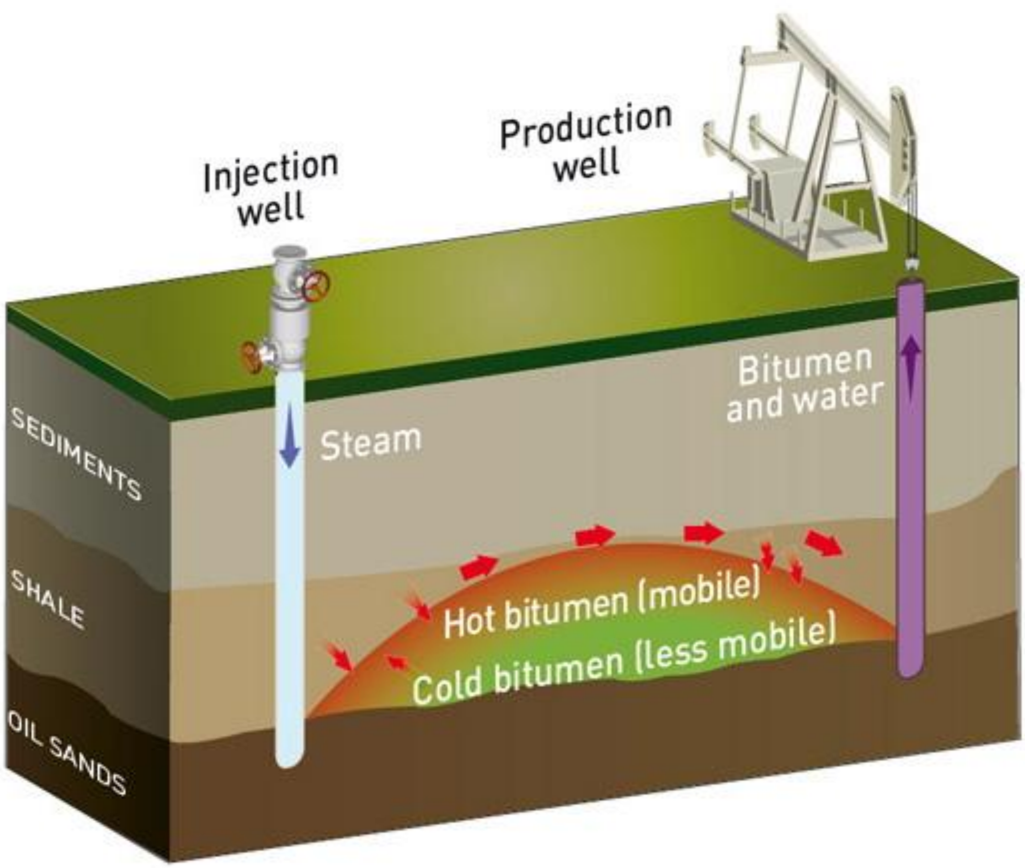


Figure 6 : Steam flooding using vertical wells (Harrigal and Clayton (1992))

Usually the distance between the two wells around 100 meters. In this method high quality steam injection is used. The same mechanism as cyclic steam stimulation is used also here in steam flooding. Steam is introduced to the reservoir to heat the reservoir which will decrease the viscosity. As Harrigal and Clayton (1992) demonstrated that steam flooding has another mechanism which is the steam and hot water physically displaces the oil.

Steam flooding recovery factor is between 40 to 60%, which is higher than that of the cyclic steam stimulation. By using steam flooding method, it can reach a point in which it will not be economically to use it as EOR so it is better to be switched to water flooding.

Horizontal wells

It is called Steam-Assisted Gravity Drainage .Jiang, Q. et al. (2009) mentioned that it is considered to be an advanced form of steam flooding. SAGD is differ than the Cyclic steam stimulation and Steam flooding, in which SAGD uses two horizontal wells which are few meters apart, as shown in Figure 7. The upper well inject the steam. The injected steam will increase the temperature which lead to decrease in the viscosity. This decrease in viscosity will result in high mobility of the oil toward the lower well. The lower well is the production well as explained before. Oil moves to the lower well due to the gravity effect.

McCormack, M. (2001) said that SAGD recovery factor is between 40 to 60%. It has some limitations:

- The pay zone must be greater than 40 feet.
- The permeability should be greater than 3 Darcy.
- Absence of bottom or top water.

At the mean time there are attempts to improve SAGD and increase its limitations by add non-condensable gas to the steam stream.

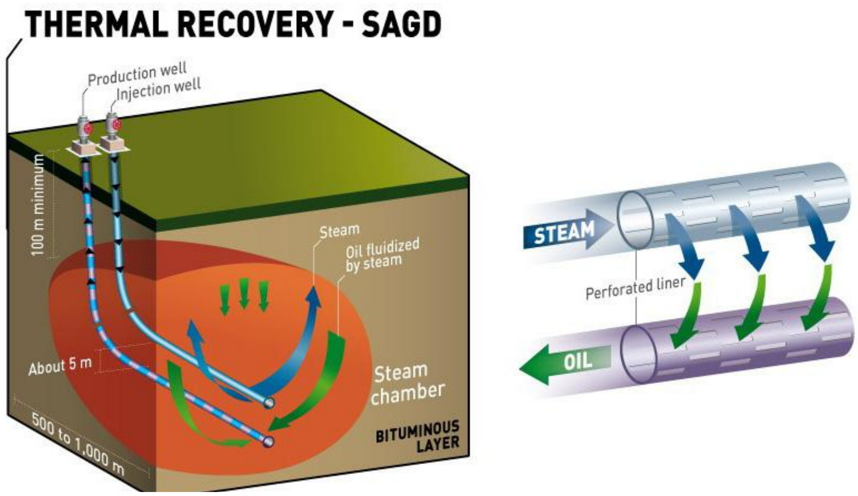


Figure 7: Steam flooding using horizontal wells (Jiang, Q. et al. (2009))

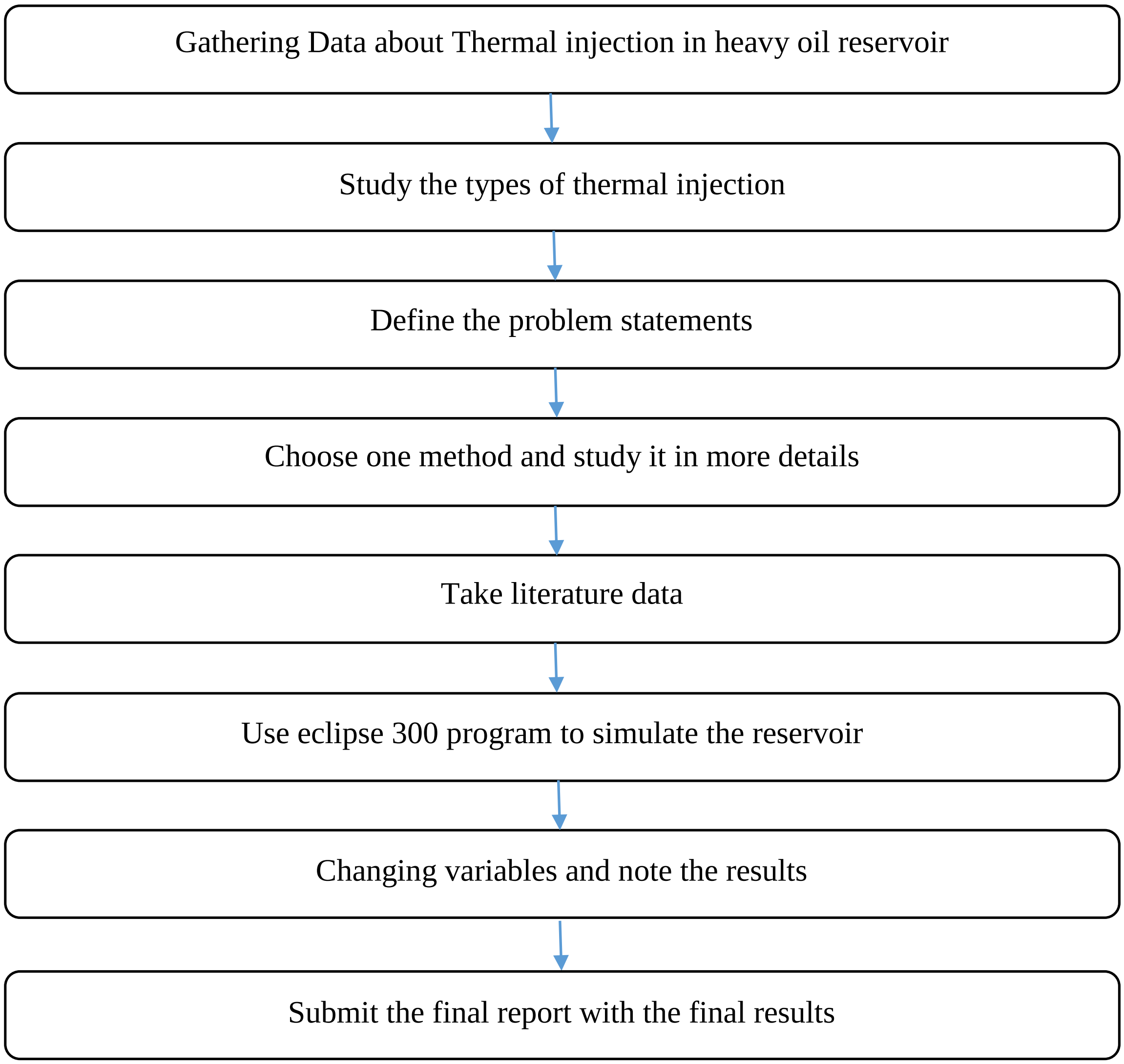
<u>Steam flooding is chosen for furthermore study due to the following reasons:</u>

1. According to the study that was done by Manrique, E. J. et al. (2010); it was mentioned that the steam flooding has the fastest rate of increase in the average reservoir temperature. This will lead to the greatest rate of net recovery as compared to cyclic steam stimulation. Steam flooding exhibited a much quicker payout of development capital and a greater present value return per dollar invested.
2. Manrique et al. (2010) also mentioned that cyclic steam stimulation recovered the same percentage of original oil in place as steam flooding. However, cyclic steam took longer time than steam flooding to recover the same amount of oil.
3. In general, steam flooding recover more than cyclic steam stimulation. As mentioned before, cyclic steam stimulation can only recover 10 to 30% while steam flooding can recover from 40 to 60% of the original oil in place.

3. Methodology

3.1 FlowChart

This section will include a flowchart for the project and the steps that will be followed till reach the final step.



3.2 Project activities

There are several steps to achieve the objectives and goals of this case study.

According to the previous flow chart the steps are:

1- Gathering the data about the thermal injection in heavy oil reservoir from a wide range of books, articles and research papers.

2- Study the types of the thermal injection from the gathered information which are cyclic steam stimulation and steam flooding.

3- Defining the problem statement in the case study which will be the main objective to solve it.

4- Choosing one method in order to make a close study and concentrate all the work on it, due to the time constraint. This method is steam flooding

5- Bring a literature data file.

6- Using Eclipse 300 to compile the file and simulate the reservoir.

7- Sensitivity study will be carried out by changing the injection temperature and note the changes.

8- At the end is the submission of the final report including the final results.

3.3 Key milestones and Gantt chart

No.	Detail / Week No.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
1	Project Work Continues															
2	Preparing the progress report															
3	Submission of progress report															
4	Pre-SEDEX															
5	Preparing the Final Report															
6	Submission of Final Report Draft															
7	Submission of Dissertation (Soft Bound)															
8	Submission of Technical Paper															
9	Viva															
10	Submission of Dissertation (Hard Bound)															

Process

Suggested Milestone

4. Results and Discussion.

In results and discussion chapter, literature data file about heavy oil reservoir will be studied and interpreted. The steam flooding is the thermal injection simulation technique that will be used. This chapter will prove that performing thermal injection increases the reservoir recovery factor. When the temperature increases it will lead to decrease in the viscosity which will lead to increase in the production of the field. It will also prove that thermal injection by using steam flooding has a recovery factor between 40 to 60 % as mentioned in the literature review.

This chapter will be divided into 4 subclasses. The first topic will be studying the reservoir before doing thermal injection. In this topic, initial properties of the reservoir will be discussed. The second topic, when the reservoir is injected by steam flooding at 160 °F. In this topic the change in reservoir conditions will be monitored and interpreted. The third topic, when the reservoir is injected by steam flooding at 190 °F. The last topic, is the comparison between the previous three topics.

In Eclipse 300, there is no key word to get graph of average reservoir temperature or average reservoir viscosity. So the reservoir conditions and properties will be discussed in terms of grid blocks. The mentioned reservoir dimension is 20 x 20 x 1 grid blocks. The grid block (1, 1, 1) will be chosen for detailed temperature and viscosity interpretation throughout the results and discussion. This grid block is chosen because it is the grid block where the production well is drilled. The graphs for the other grid blocks are provided in the appendix for further understanding.

4.1 At initial reservoir condition

The initial condition of the reservoir was simulated by Eclipse.

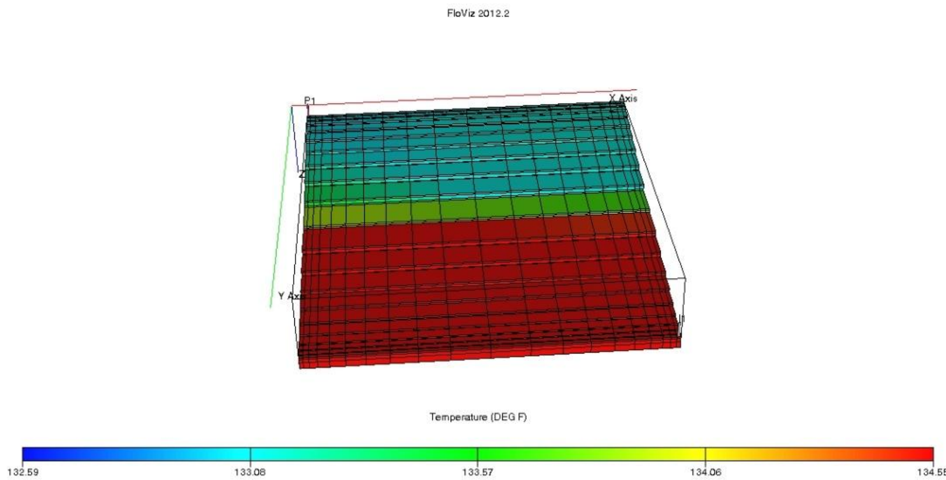


Figure 8: temperature distribution before production

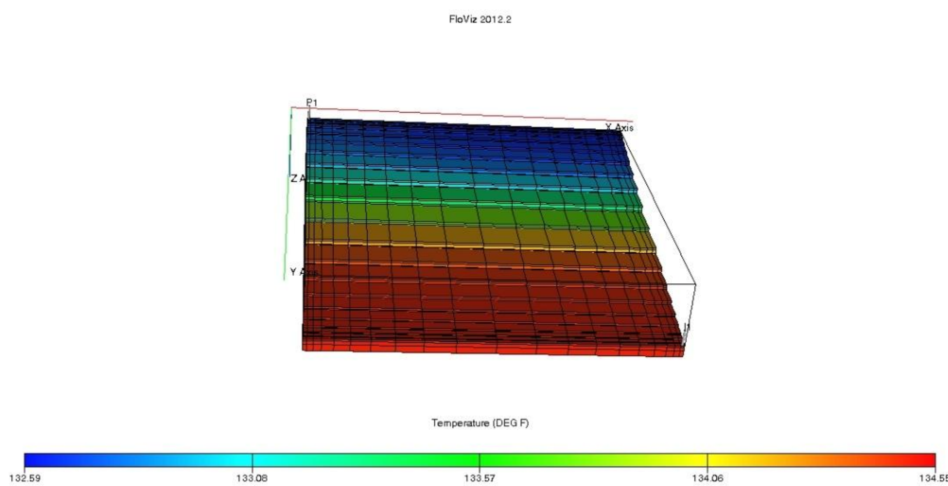


Figure 9: temperature distribution after production

The previous 2 Figures show the temperature distribution before and after production respectively. The temperature of the area surrounding the production well (at the top left corner, called P1) before production is 133.2°F and after production is 132 °F.

The following graphs provides the temperature of the reservoir of grid block (1, 1, 1) versus time

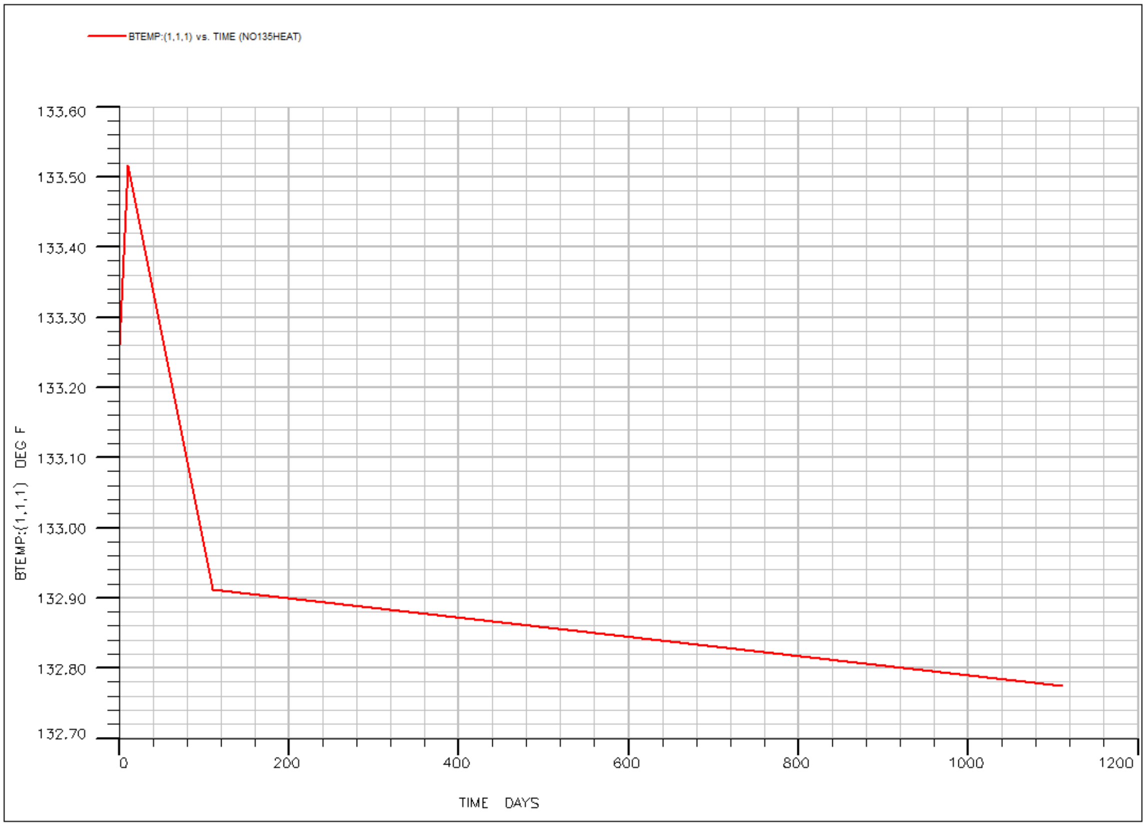


Figure 10: temperature vs. time of grid block (1,1,1)

The temperature as shown slightly increased due to the presence of high temperature places as shown in Figure 8. This high temperature places is transferring heat to the surroundings, as the heat is transferee due to the difference in temperature between two or more regions. Then it is start to decrease due to the production process.

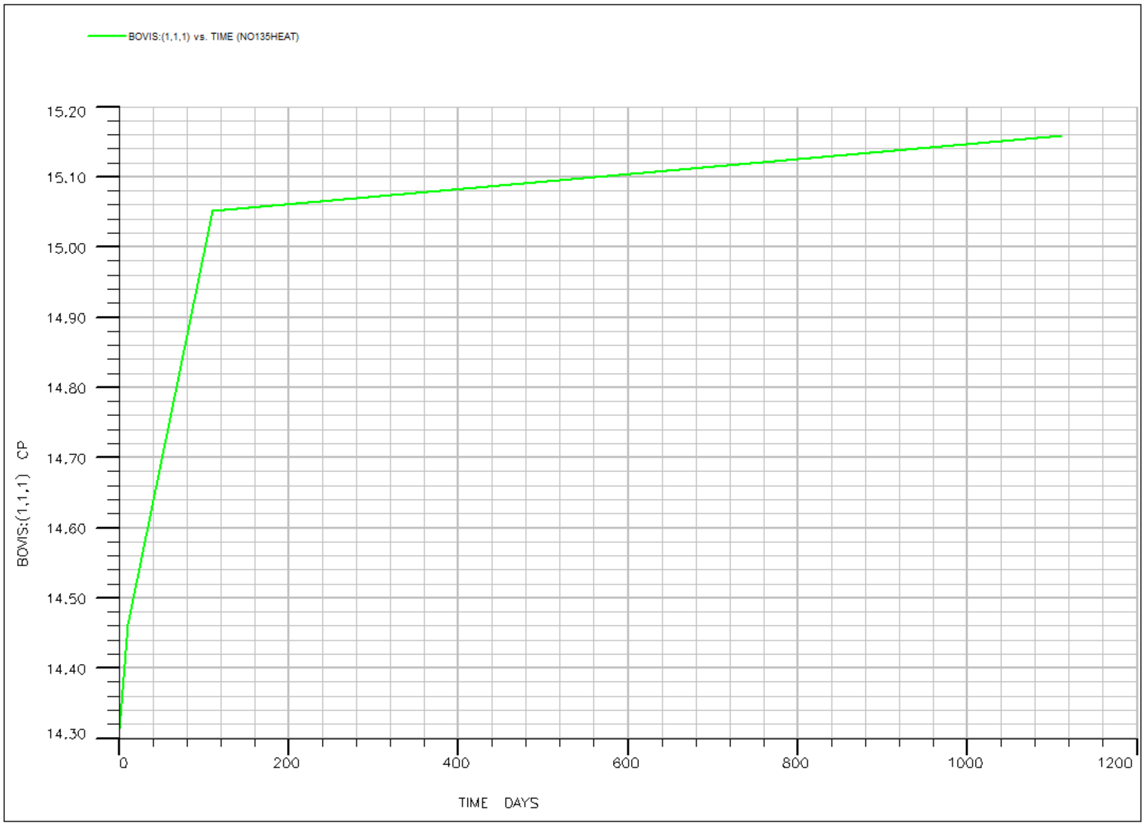


Figure 11: viscosity vs. time of grid block (1, 1, 1)

By comparing Figure 10 and 11, it is clearly shown that as the temperature was decreasing - due to the production - the viscosity was increasing. It is also shown that the initial oil in place is 340,000 STB.

The following 3 Figures shows the total oil production (FOPT), the field production rate (FOPR) and the recovery factor respectively versus time (FOE). The initial viscosity in this grid block (1, 1, 1) is 14.32 cp which lies in the heavy oil range (10 cp to 100cp).

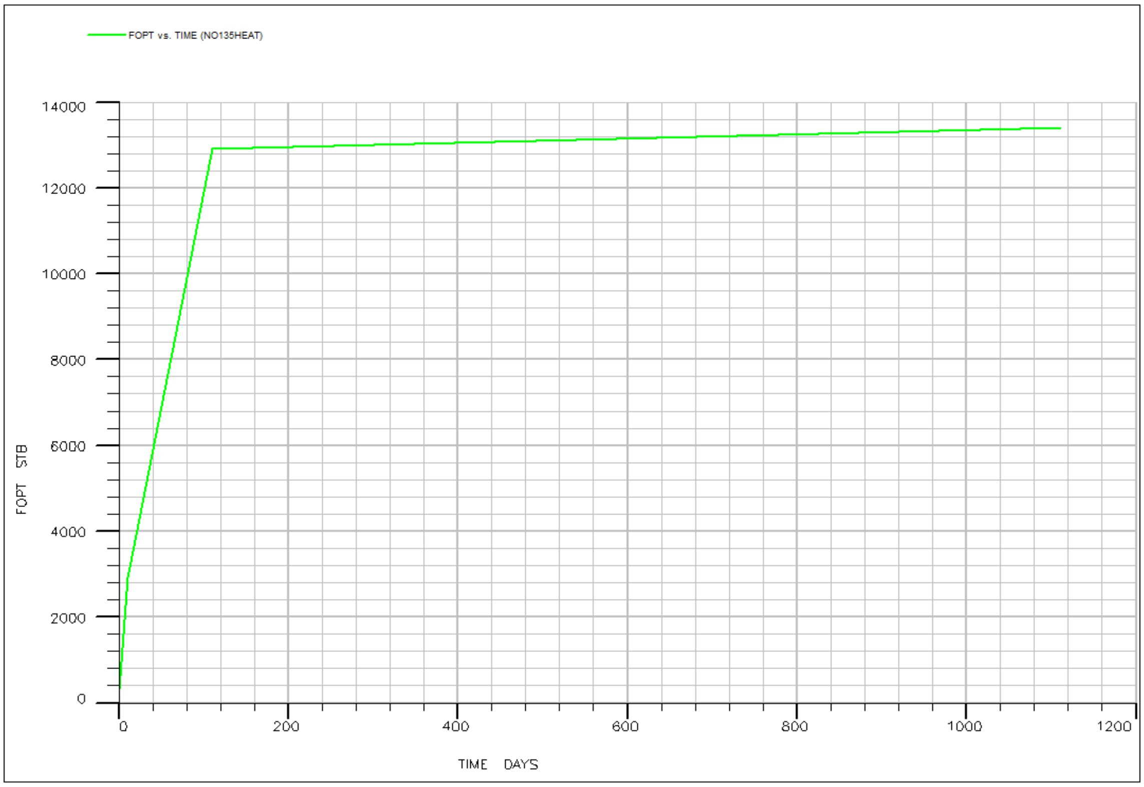


Figure 12: Field Oil Production Total vs. time

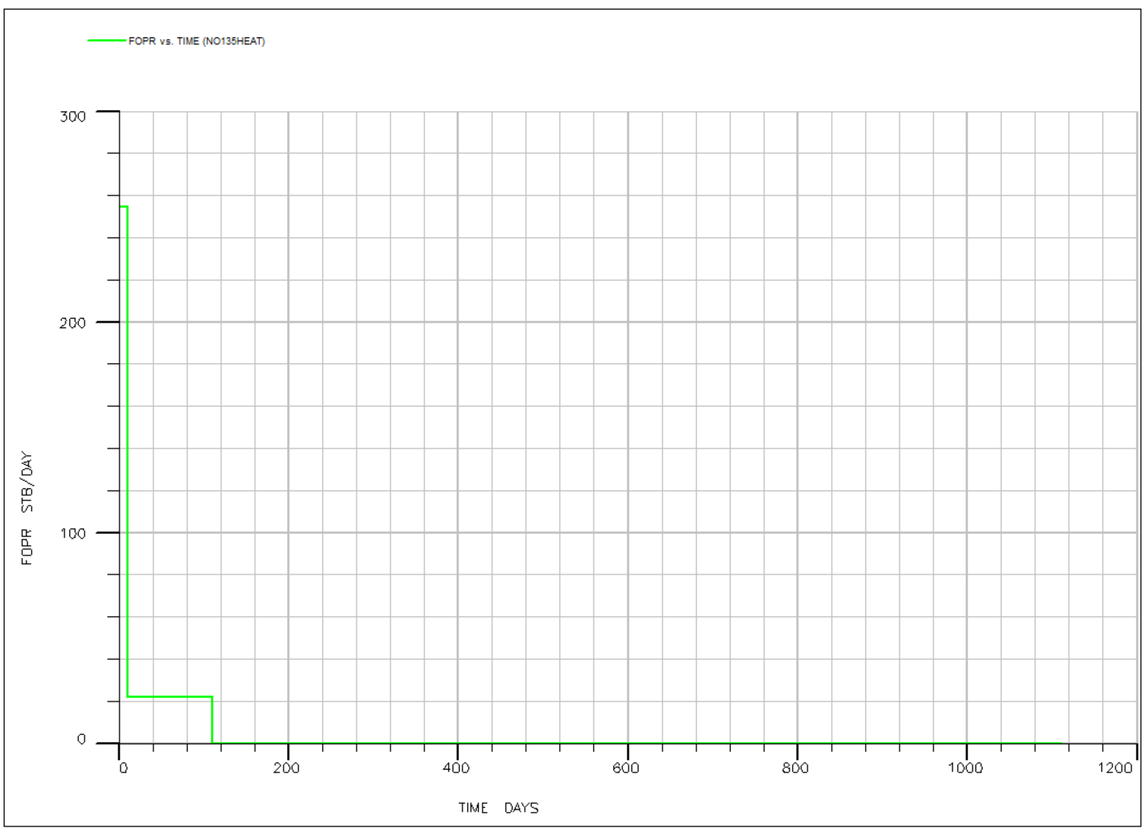


Figure 13: Field oil production Rate vs. time

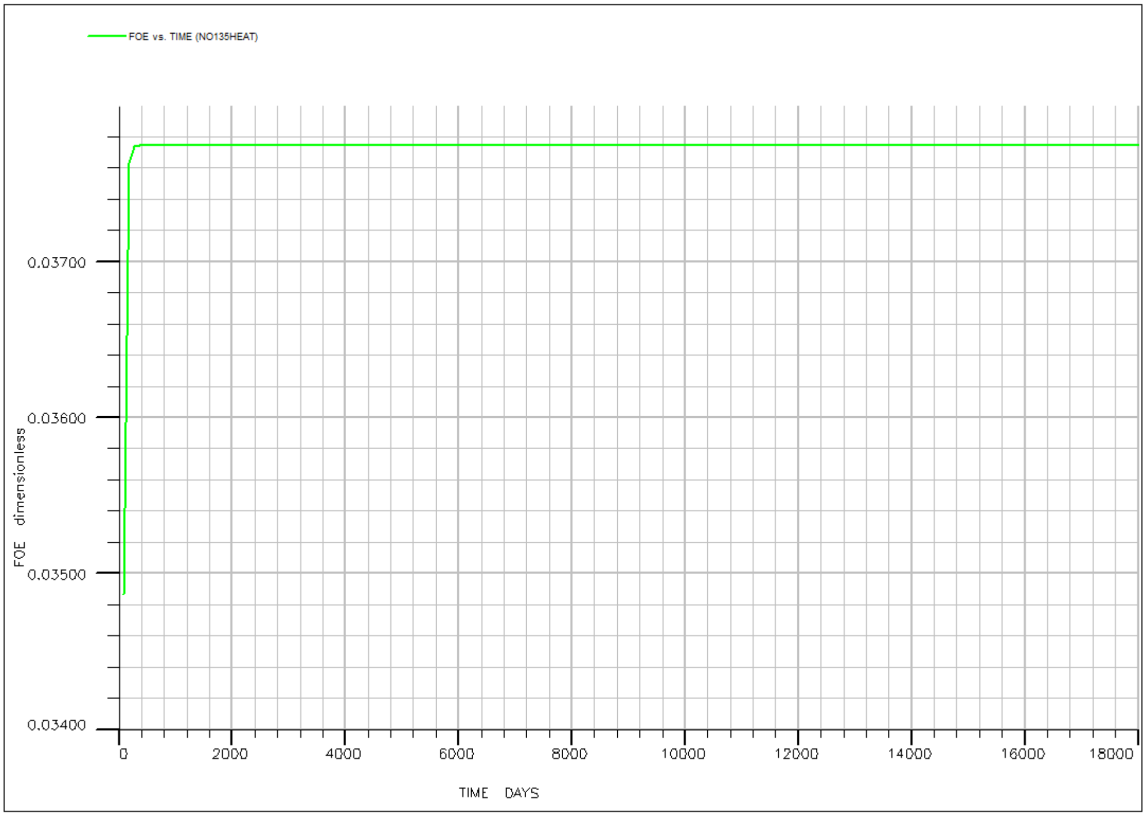


Figure 14: Recovery factor vs. time

As shown in the previous three Figures, the recovery factor is very small 3.75% with total production of 13200 STB. This is due to the high viscosity which prevent the oil from moving from one place to the other. Further explanation will be provided in this chapter.

More graphs are available in Appendix A for further study.

4.2 Steam Injection at 160 °F

After steam injection at 160 °F, the following results were collected. Figures 15 and 16 shows the reservoir temperature distribution before and after injection. The production well (called P1) is at the top left corner and the injection well is at the lower right corner (called I1)

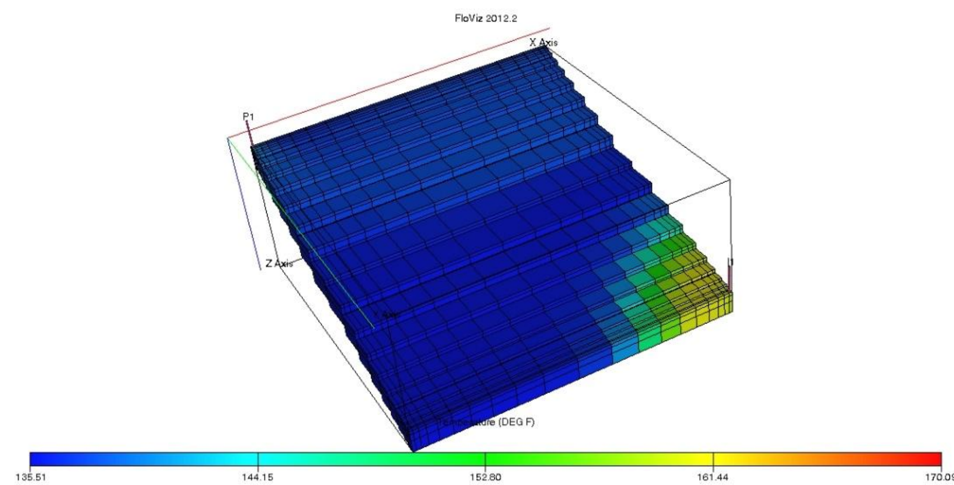


Figure 15: Temperature distribution in the reservoir before production

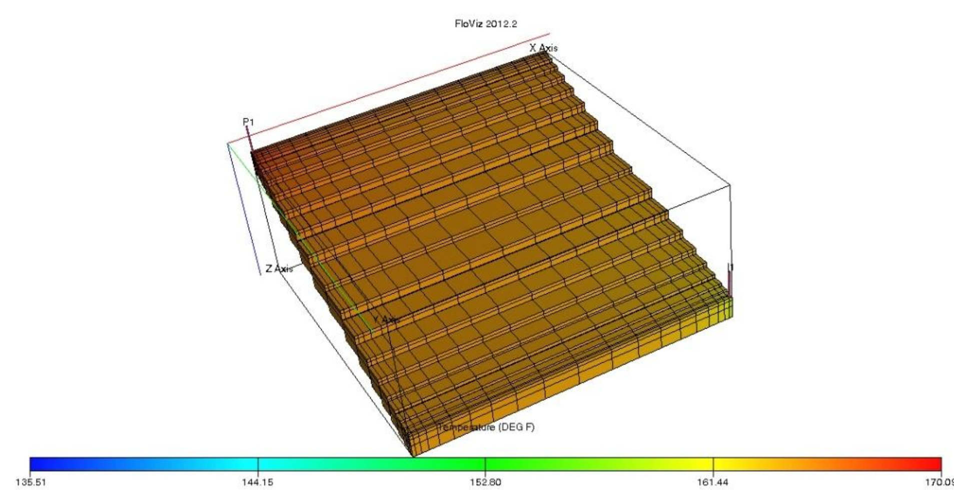


Figure 16: Temperature distribution in the reservoir after production

The temperature of the area surrounding the production well before production and injection is 134°F and after production and injection is 162 °F.

The following graphs provides the temperature of the reservoir of grid block (1, 1, 1) versus time

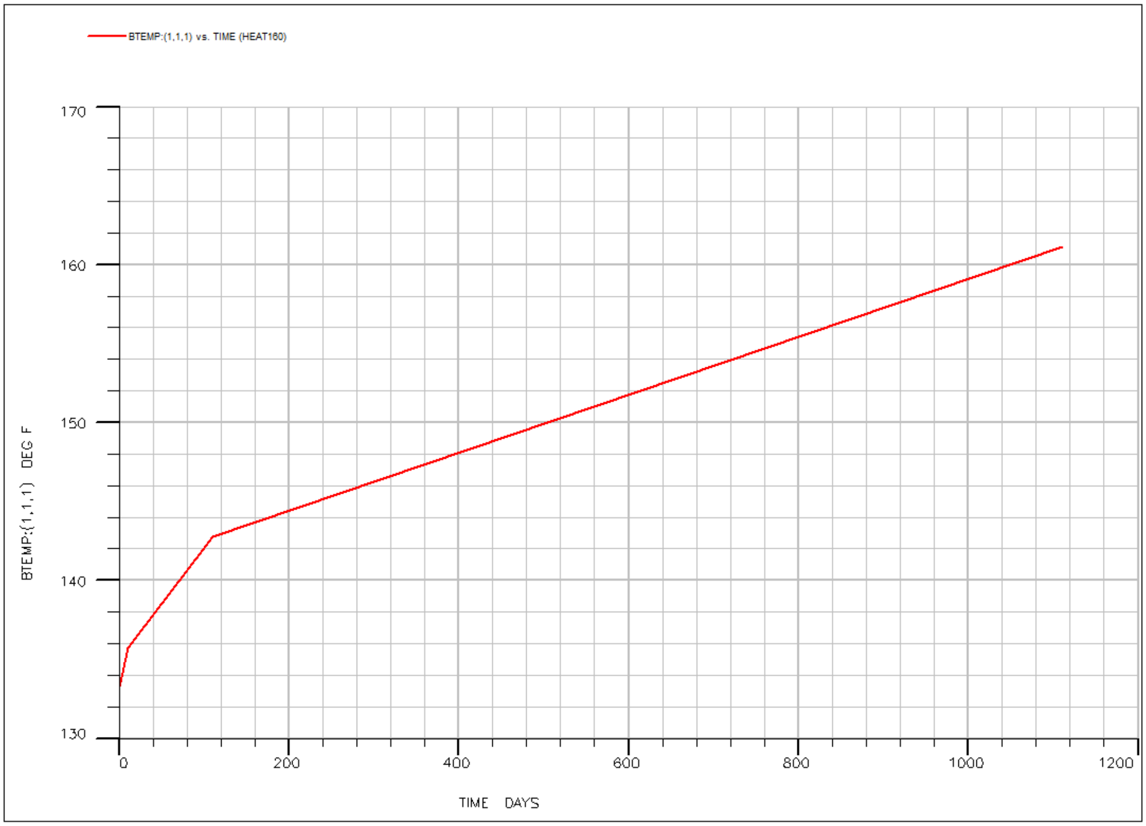


Figure 17: temperature vs. time

The temperature as shown is increased due to the steam flooding. By comparing Figure 17 and 18, it is clearly shown that as the temperature increases - due to the injection - the viscosity decreases.

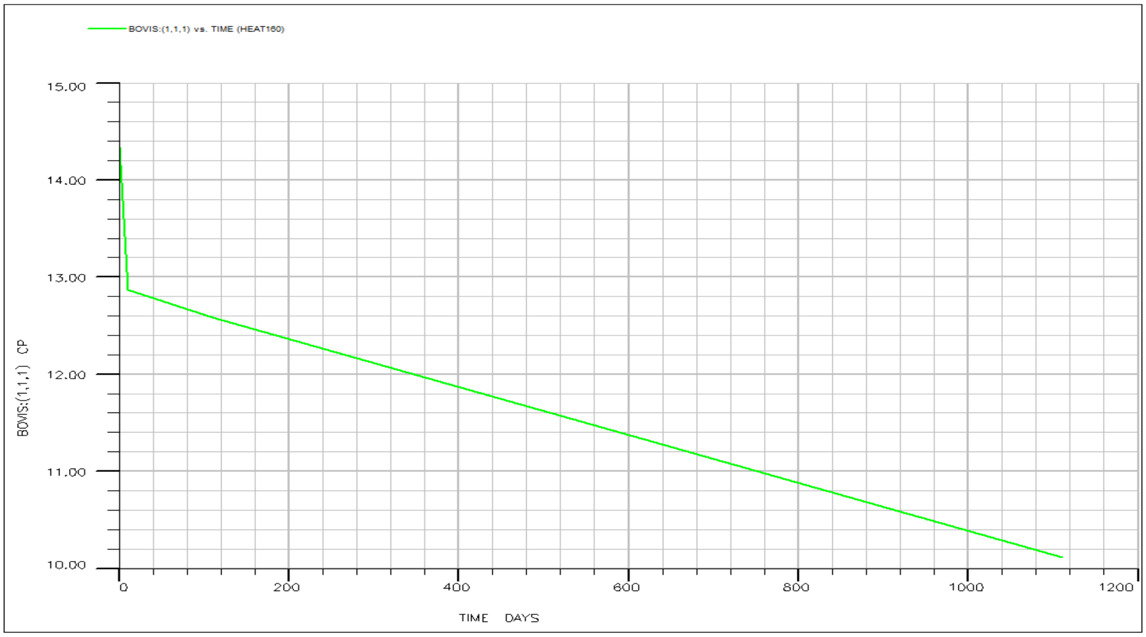


Figure 18: viscosity vs. time for grid Block (1,1,1)

The following 3 Figures shows the total oil production (FOPT), the field production rate (FOPR) and the recovery factor (FOE) respectively versus time. The initial viscosity in this grid block (1, 1, 1) is 14.32 cp which lies in the heavy oil range (10 cp to 100cp).

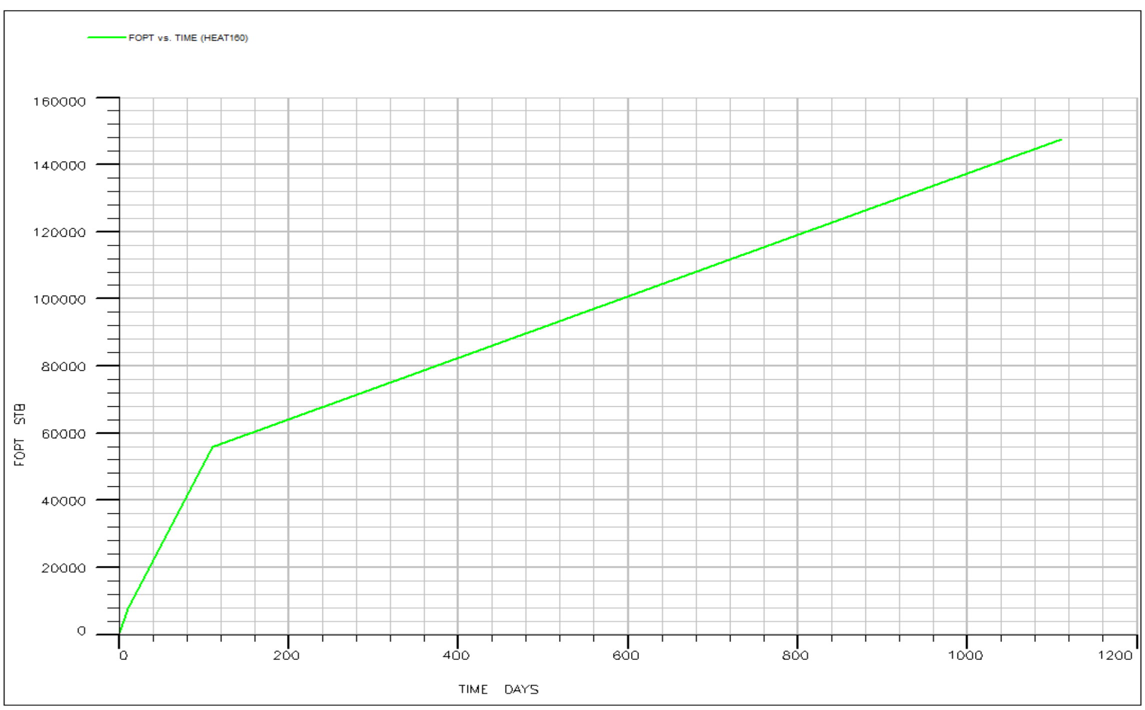


Figure 19: Field Oil Production Total vs. Time

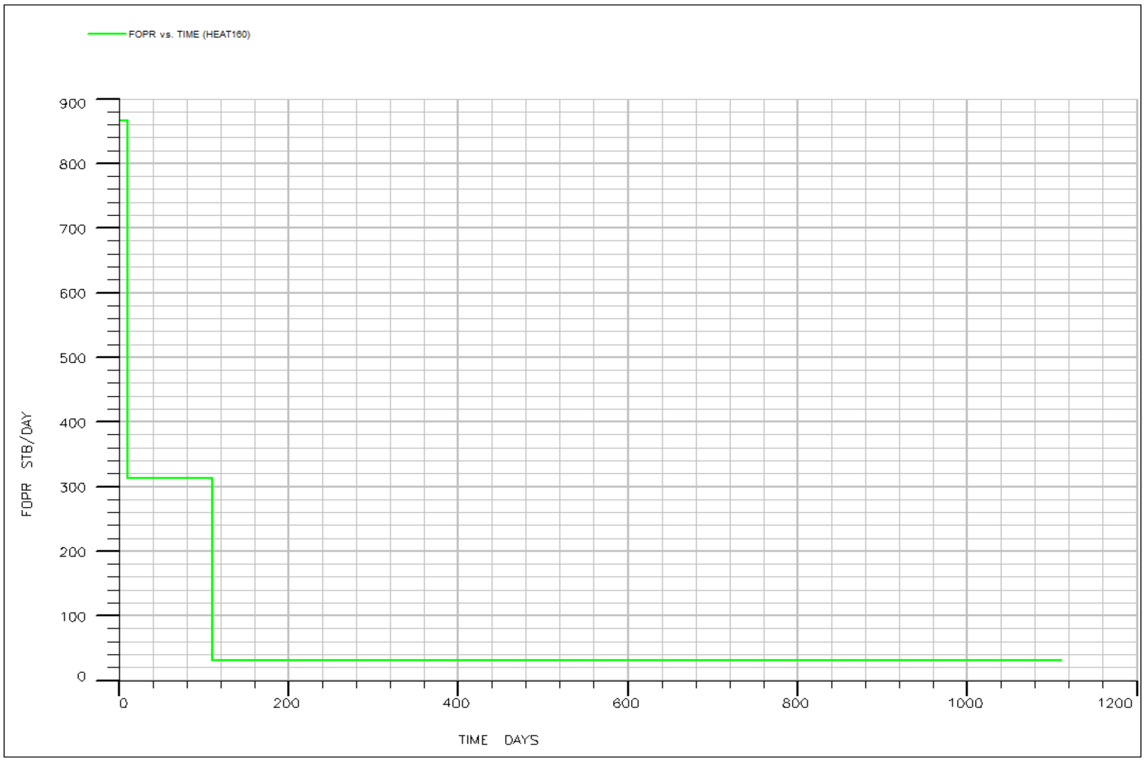


Figure 20: Field Oil Production Rate vs. Time

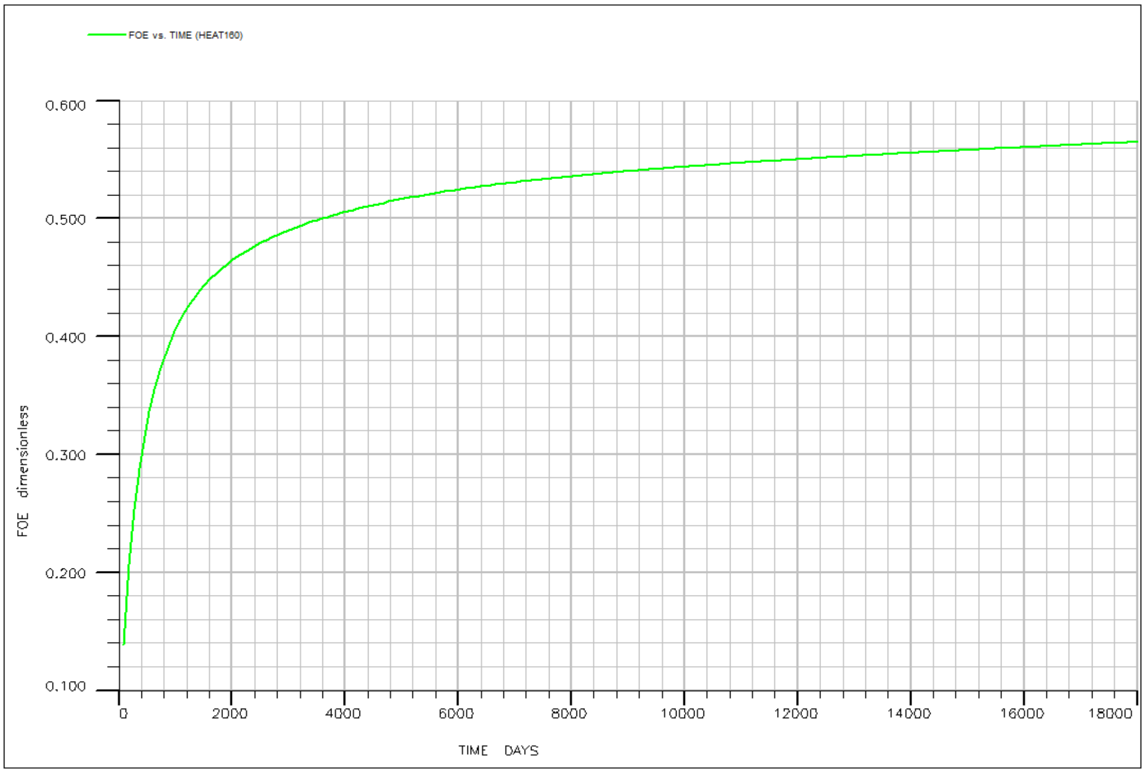


Figure 21: Recovery Factor vs. Time

As shown in the previous three Figures, the recovery factor increased to 56.5%, which is a big jump from the initial recovery factor (3.775%) with total production of 148,000 STB. This is due to the steam flooding which increased the temperature as shown in Figure 17. This increase in temperature lead to decrease in the viscosity as shown in Figure 18. Increase in the production was the result of decreasing the viscosity.

More graphs are available in Appendix B for further study.

4.3 Steam Injection at 190 °F

After increasing the steam flooding to 190 °F, the following results were collected. Figures 22 shows the reservoir temperature distribution after injection. The production well (called P1) is at the top left corner and the injection well is at the lower right corner (called I1)

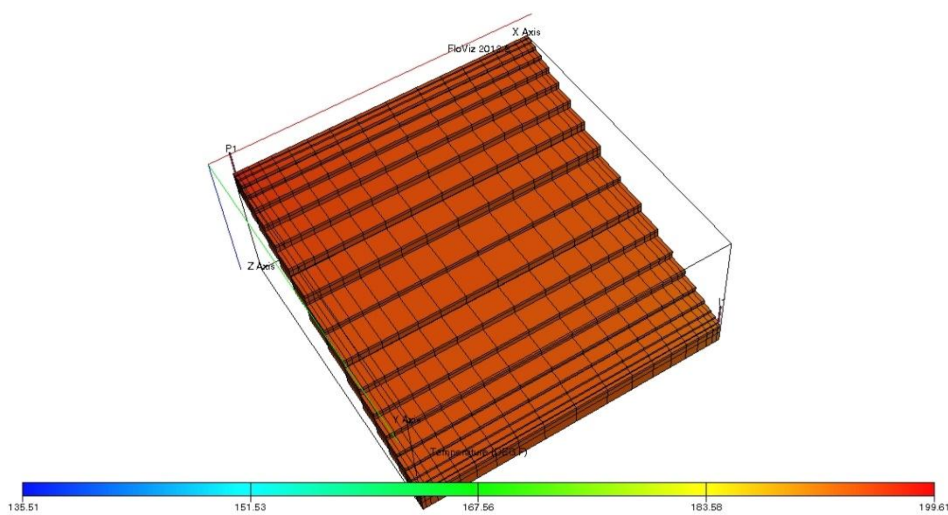


Figure 22: Temperature distribution after injection

The temperature of the area surrounding the production well after production and injection is 182 °F. The following graphs provides the temperature of the reservoir of grid block (1, 1, 1) versus time

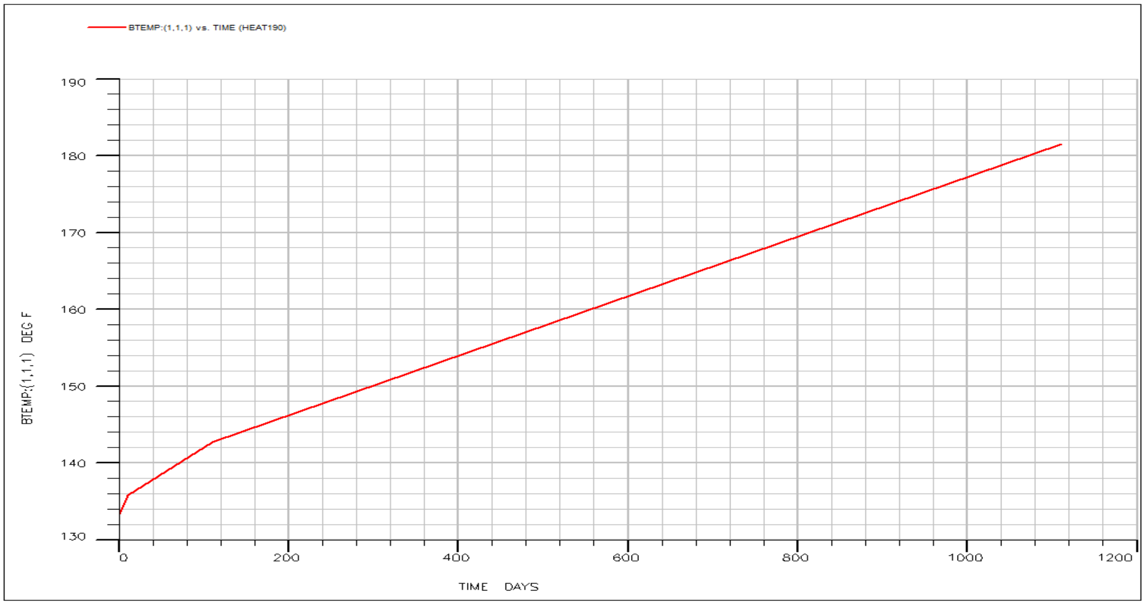


Figure 24: Temperature vs. Time

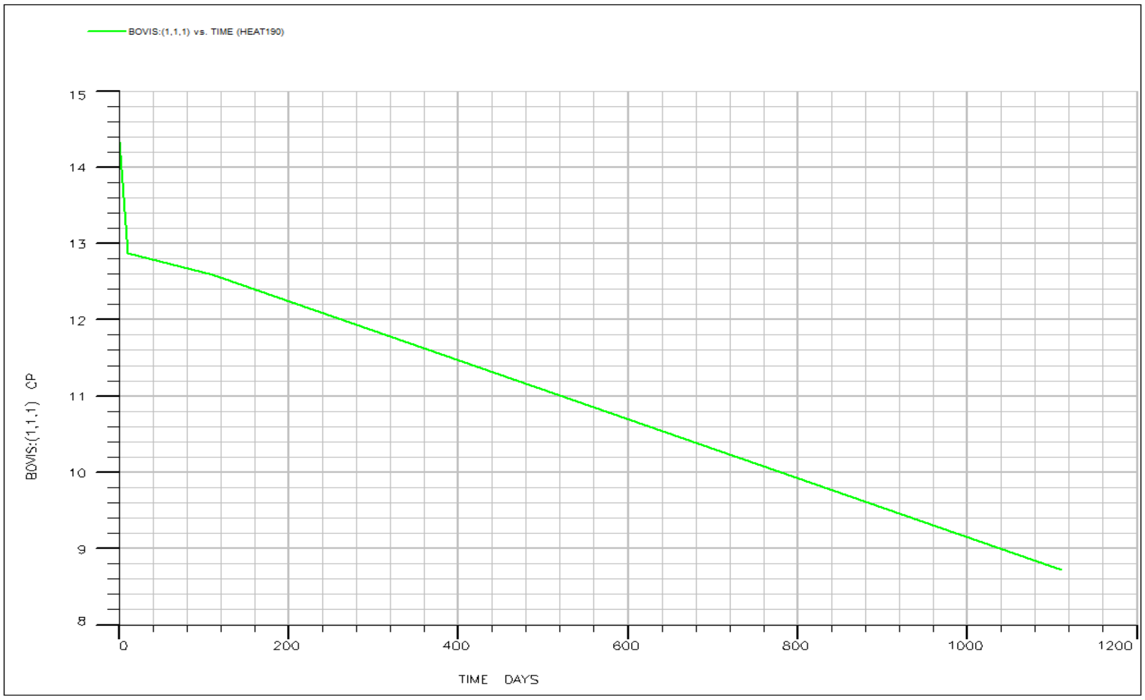


Figure 23: Viscosity vs. Time

The temperature as shown is increased due to the steam injection. By comparing Figure 23 and 24, it is clearly shown that as the temperature increases - due to the injection - the viscosity decreasing (As mentioned before in steam flooding with 160 °F subclass).

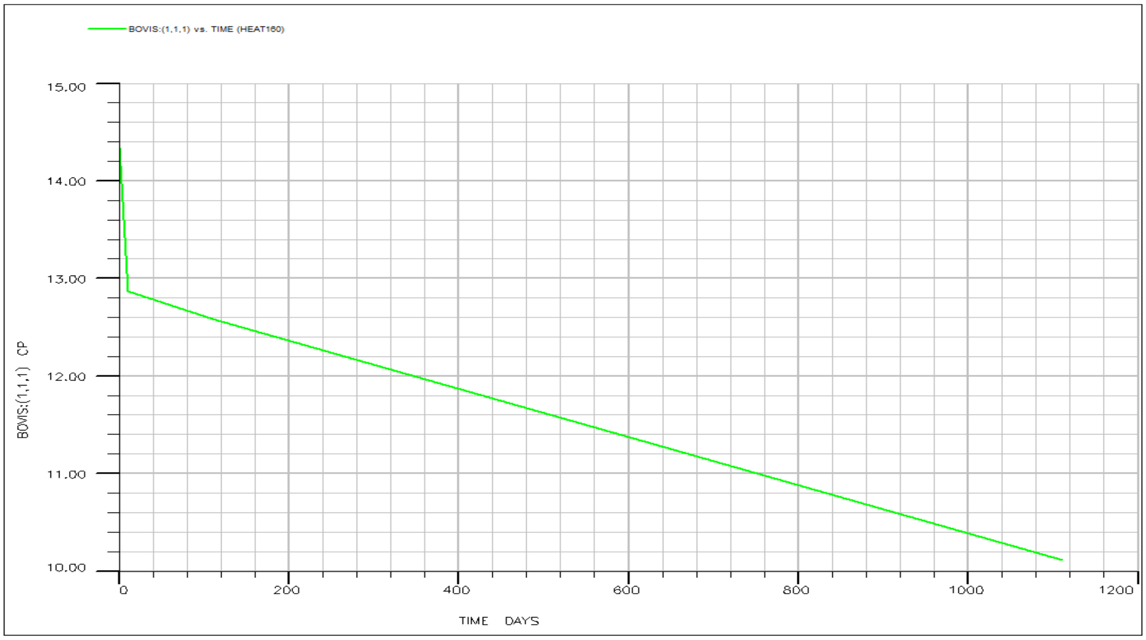


Figure 25: viscosity vs. time for grid Block (1,1,1)

The following 3 Figures shows the total oil production (FOPT), the field production rate (FOPR) and the recovery factor (FOE) respectively versus time. The initial viscosity in this grid block (1, 1, 1) is 14.32 cp which lies in the heavy oil range (10 cp to 100cp).

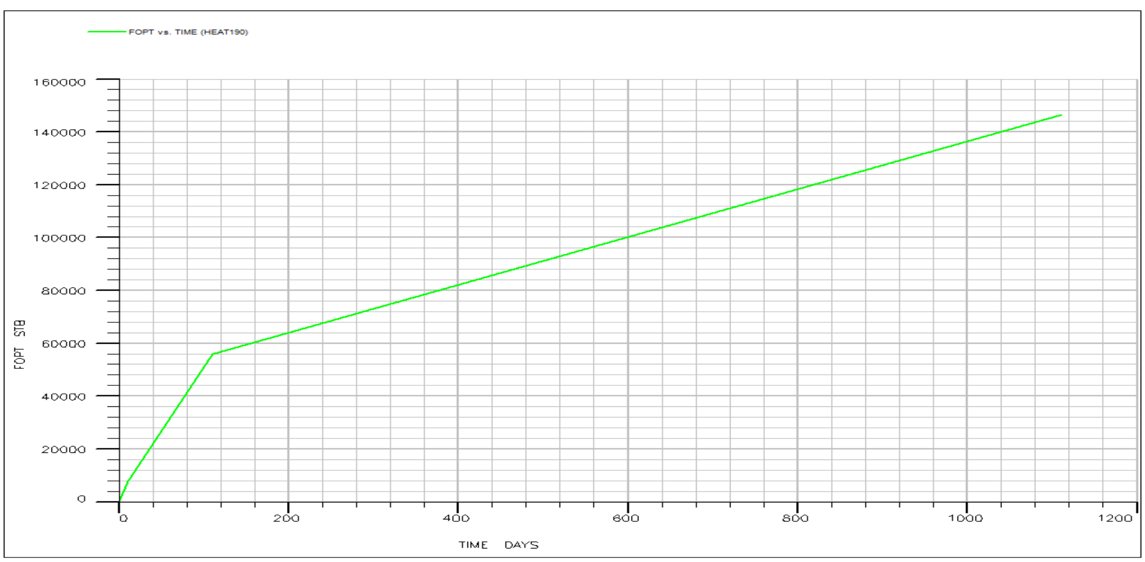


Figure 26: Field Oil Production Total vs. Time

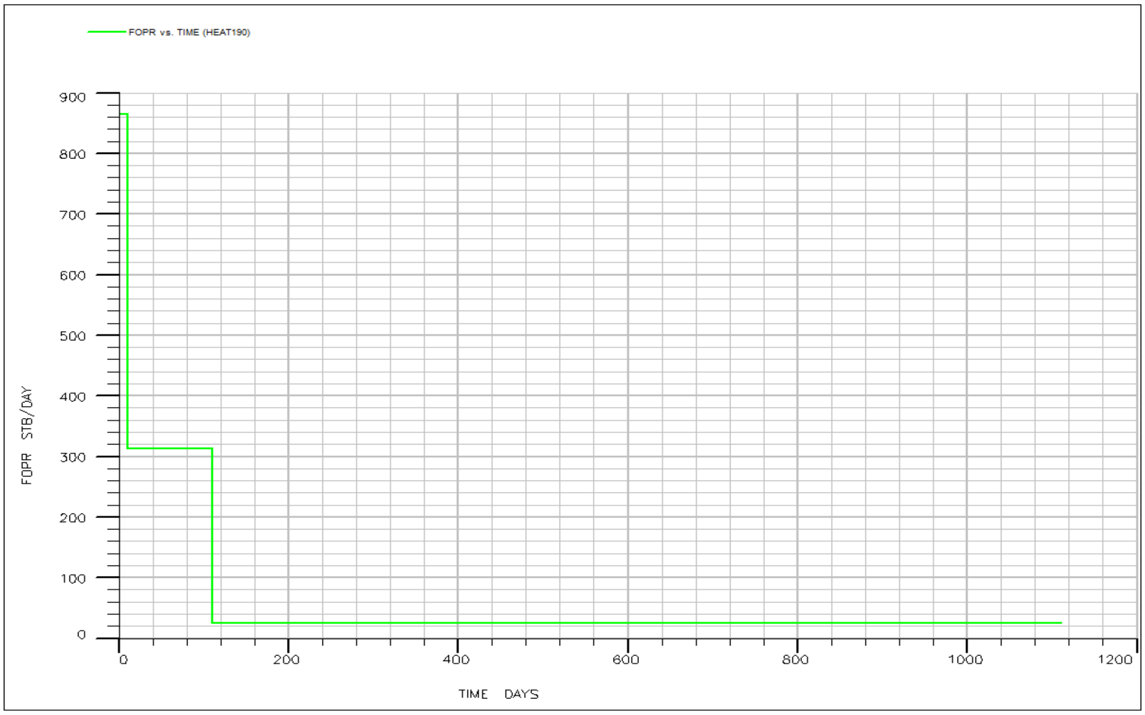


Figure 28: Field Oil Production Rate vs. Time

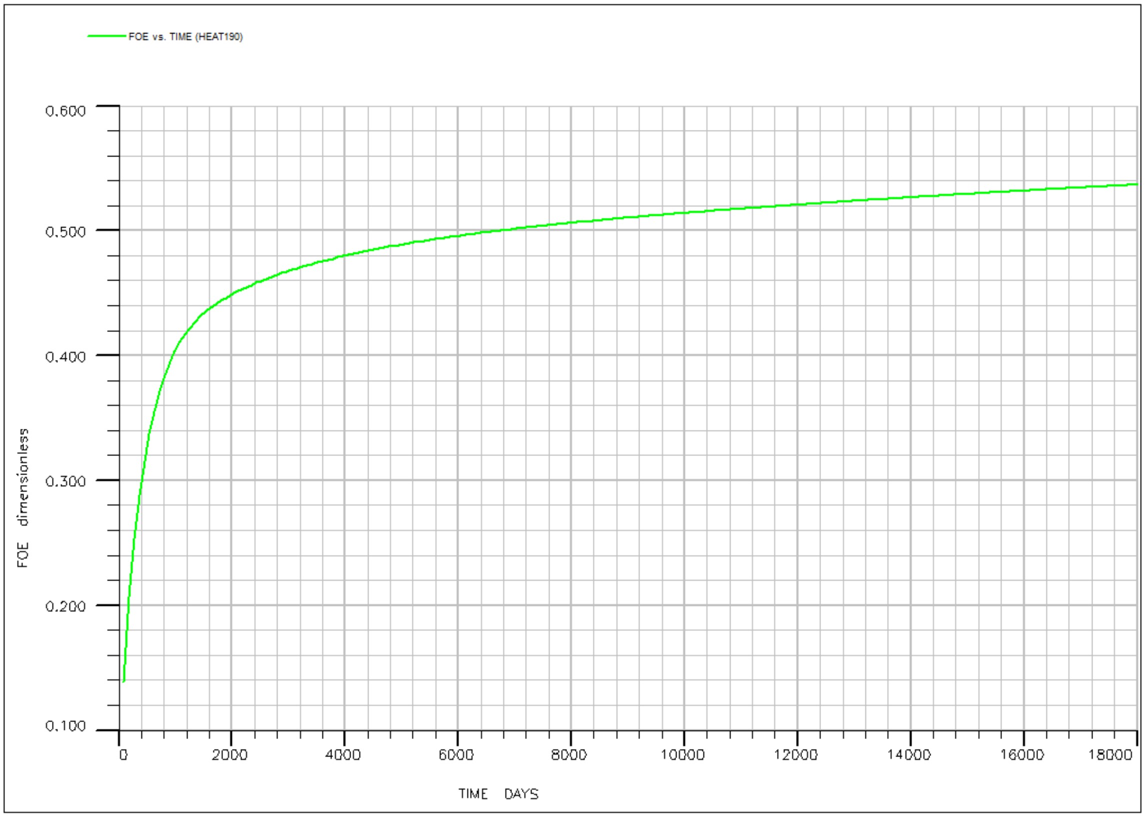


Figure 27: Recovery Factor vs. Time

As shown in the previous three Figures, the recovery factor is 54%, with total production of 145,000 STB.

More graphs are available in Appendix C for further study.

4.4 Comparing the results

This part is for simplifying the results and make it easier to compare and interpret them.

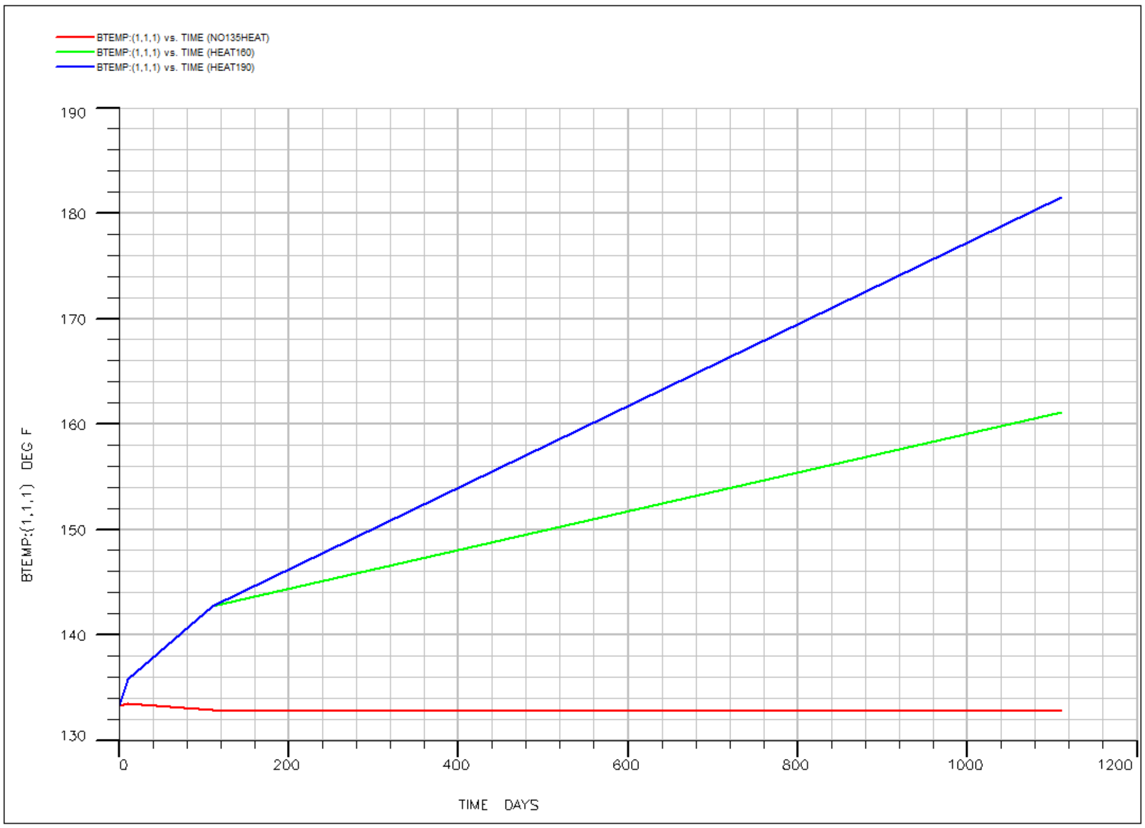


Figure 29: Temperature vs. time for different injection temperatures

The previous graph shows the difference in the temperature between the same grid block (1, 1, 1) but for different injection temperature. The red line is for the initial condition. The light green line for steam flooding with 160 °F. The blue line for the steam flooding with 190°F. This graph is for the temperature throughout the production life for the field. For the blue and light green lines the temperature keeps in increasing, no matter how many oil are produced. Due to the presence of the injection source which continues feeding them with heat. However, the red line is inclining throughout the production. This is due to the production of oil.

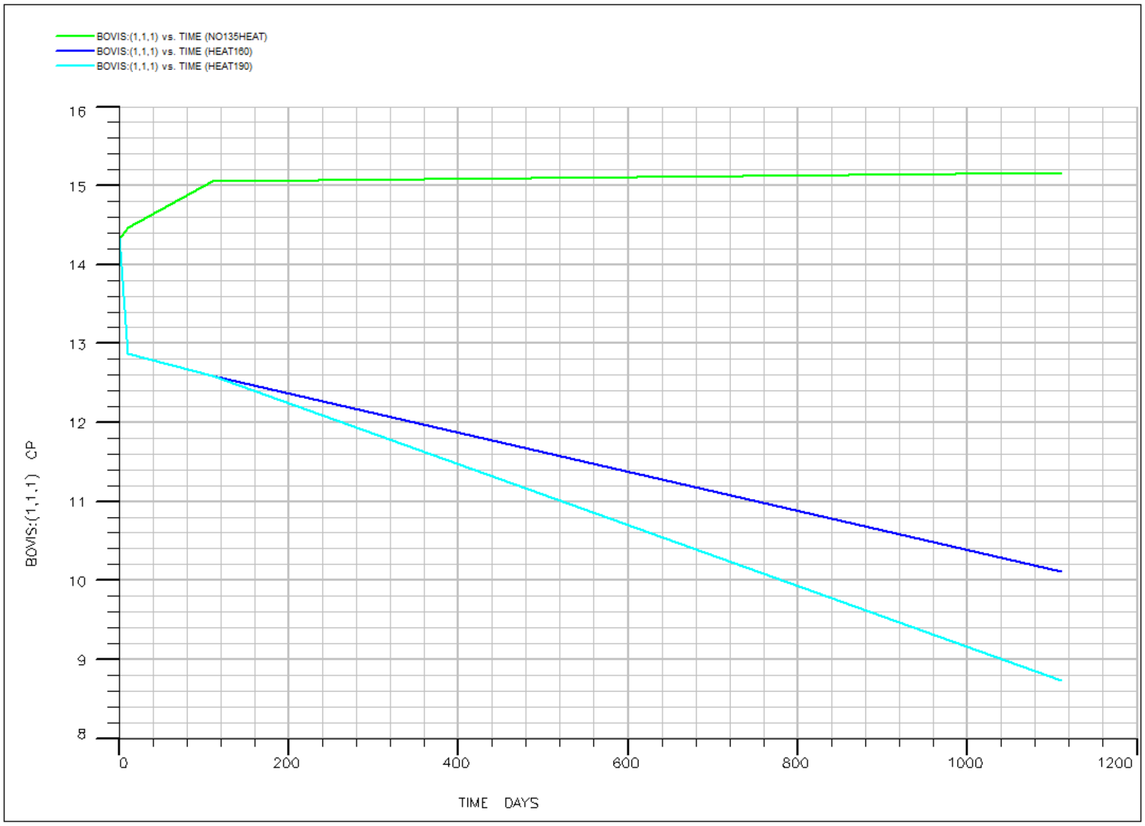


Figure 30: Viscosity vs. time for different injection temperatures

The viscosity in normal reservoirs increases throughout the production life of the well. That is shown in Figure 30 represented by the light green line. While, the blue and cyan lines are for the two injection cases. This shows that as the temperature increases the viscosity decreases. In addition, the previous Figure shows that the drop in viscosity for the steam injection at 190 °F is more than that of 160 °F, which shows the significance of the temperature in changing the viscosity.

The difference in the viscosity between the three cases will affect the total production of the field. The following graph is the production total versus time for the different cases.

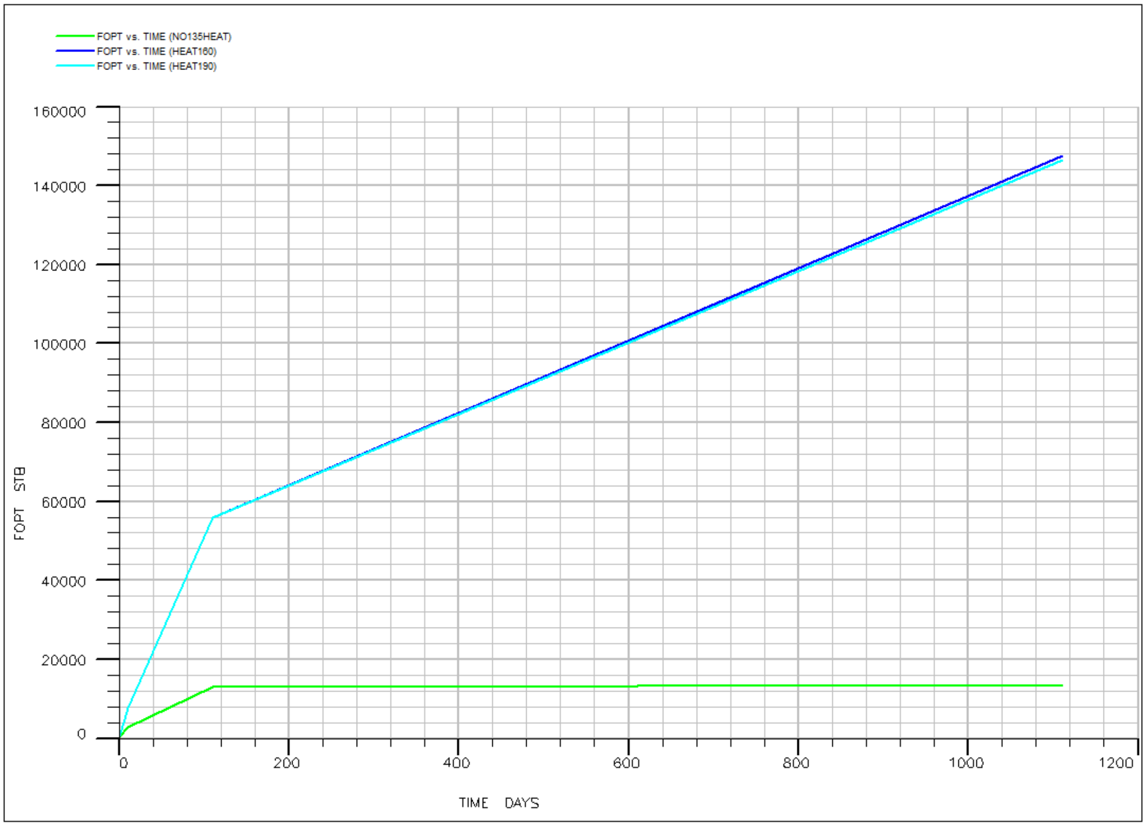


Figure 31: Field Oil Production Total vs. Time for different injection cases

Figure 31 shows that the difference of production before and after injection is huge. The light green line is the total field production before injection. While, the blue and cyan lines is for the total field production after injection with different temperature.

This graph shows the importance of the steam flooding in the heavy oil reservoir, in which it significantly increases the total oil production. The previous graph also shows that steam injection with 160 °F gives more total production than steam injection at 190 °F. However, this contradicts with the concept of as the viscosity decreases the mobility of oil increases and the production increases. This can be explained as mentioned before in the steam flooding technique that was discussed in the literature review. In steam flooding technique, not only it increases the temperature but it push the oil physically to the production area as well. So as the temperature increases and approaches the boiling point, some of the steam injected will be converted to gas phase. Gas phase steam injection only increases the temperature, but it does not push the oil physically compared to the liquid phase. The previous graph does not show the difference in total production between steam injection at 160 °F and 190 °F. The difference between those two injections are clear in the recovery factor graph.

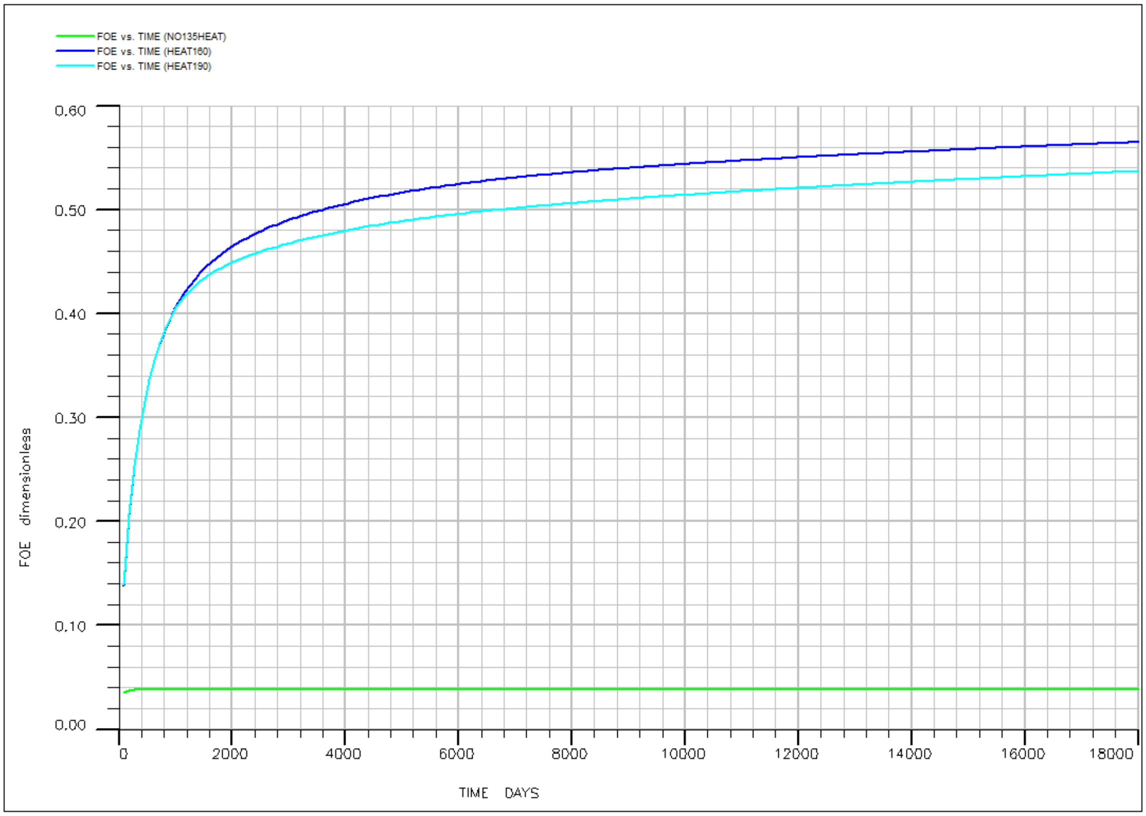


Figure 32: Recovery Factor vs. Time for different injection temperature

As shown in Figure 32, the recovery factors for initial condition, steam flooding at 160 F and steam flooding at 190 F is 3.75%, 56.5% and 54%, respectively.

The difference between the recovery factor of 160 F and 190 F, is due to the increase of the percentage of the gas in the injection steam. As the gas quality increases the ability of the steam to physically push the oil to the production well decreases – as explained earlier in the literature review- as well.

More graphs are available in Appendix D for further study.

5. Conclusion and Recommendations

In conclusion, Enhanced oil recovery is very important in extracting heavy oil; especially thermal injection. Thermal injection increases the temperature of the reservoir. When the temperature increases the viscosity decreases and the mobility increases. This will facilitate the movement of the oil from its place to the production well, in which it will increase the total oil production. Therefore the recovery factor will also increase.

Nomenclature

H: enthalpy in KJ

ΔH: change of enthalpy in KJ

P: pressure in psia KPa

T_s: Steam temperature, °F

U: Internal energy in KJ

ΔU: change of Internal energy in KJ

V: volume in ft^3 [m^3]

ΔV: change of volume in ft^3 [m^3]

f_s : Steam quality

h_f: Enthalpy of liquid portion of saturated steam, Btu/lbm [kJ/kg]

h_{f_s}: Enthalpy of < 100% quality saturated steam, Btu/lbm [kJ/kg]

h_{fv}: Enthalpy of vapor portion of saturated steam, Btu/lbm [kJ/kg]

h_v: Enthalpy of 100% quality (saturated) saturated steam, Btu/lbm [kJ/kg]

m_v : vapor mass in lbm [kg]

m_l : Liquid mass in lbm [kg]

p_s: Steam pressure psia [kPa]

ρ_s: Density of dry steam, lbm/ft^3[kg/m^3]

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Appendices

Appendix A

All the graphs in this appendix are related to the initial reservoir condition before injection.

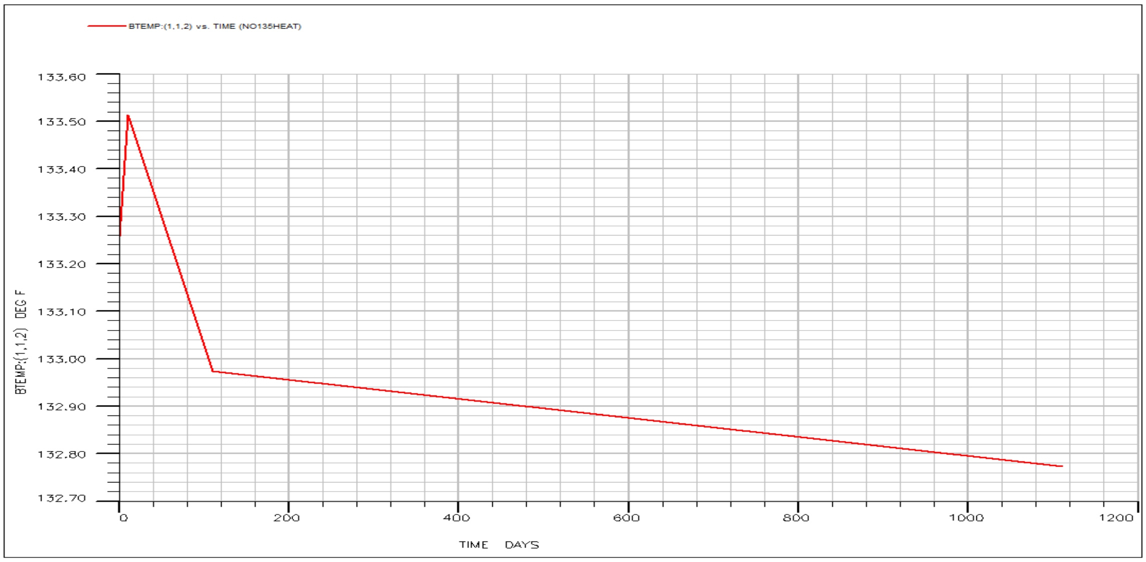

Figure 33: temperature vs. time for grid block (1,1,2)

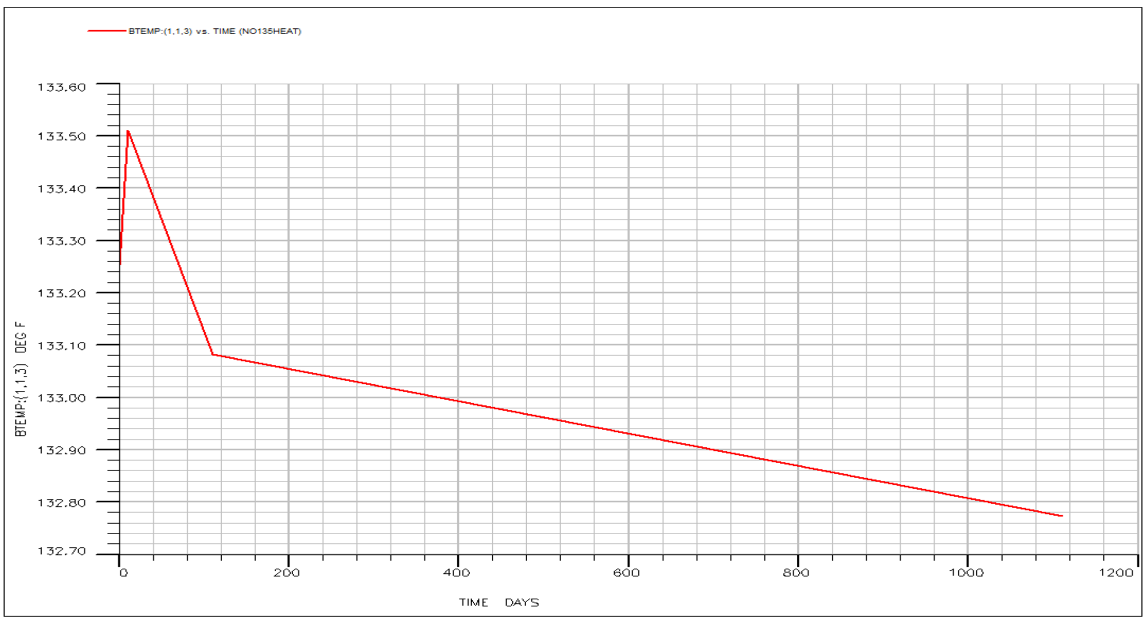

Figure 34: temperature vs. time for grid block (1,1,3)

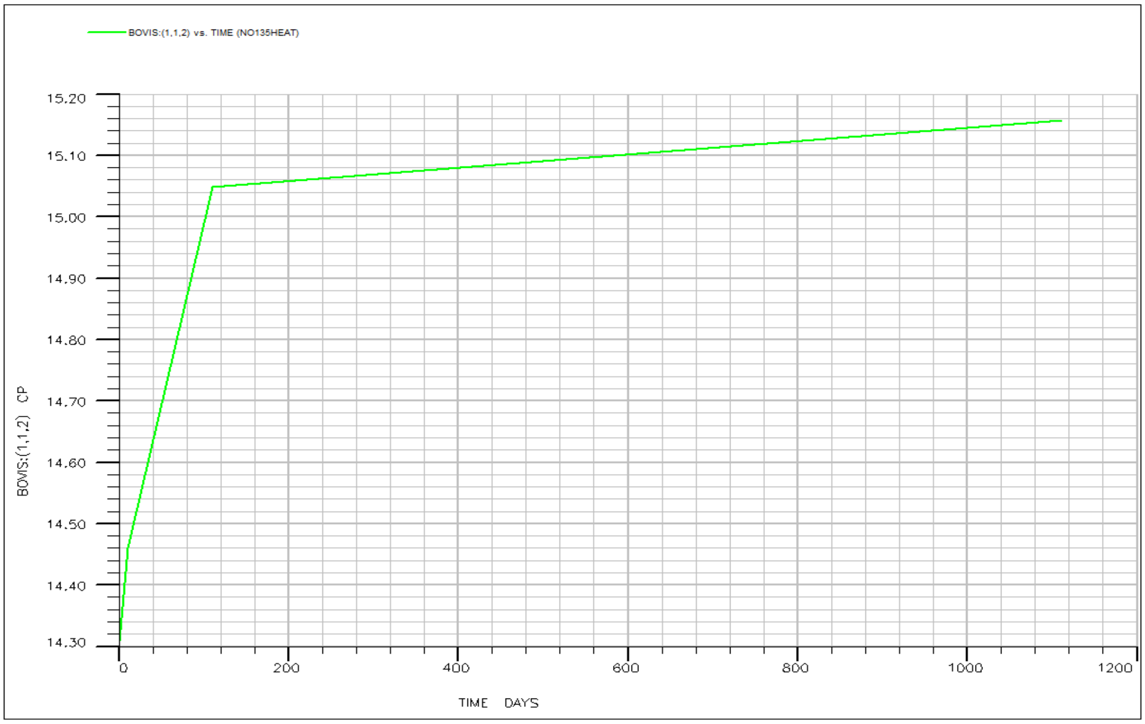

Figure 35: viscosity vs. time for grid block (1,1,2)

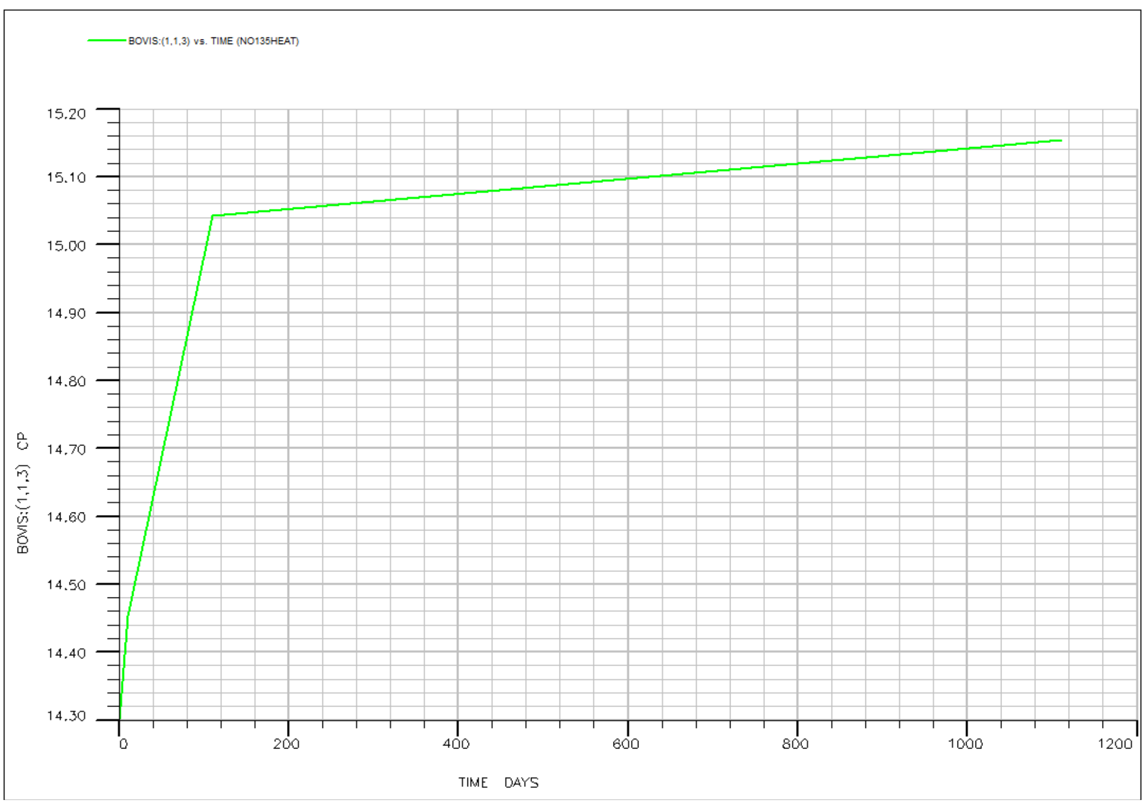

Figure 36: viscosity vs. time for grid block (1,1,3)

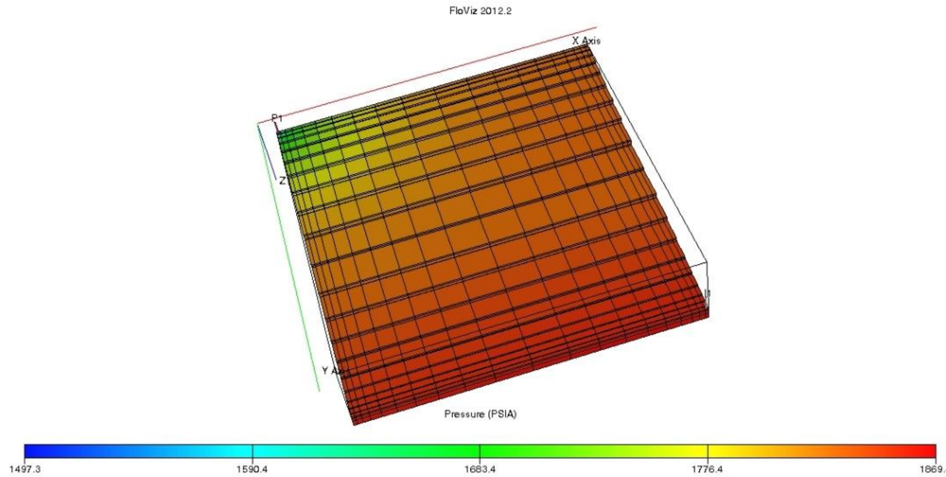

Figure 37: pressure profile for the field before production

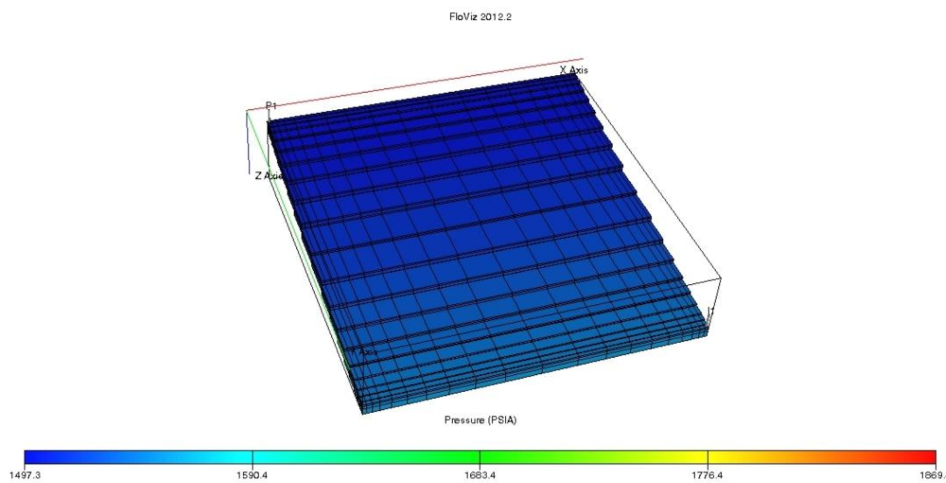

Figure 38: pressure profile for the field after production

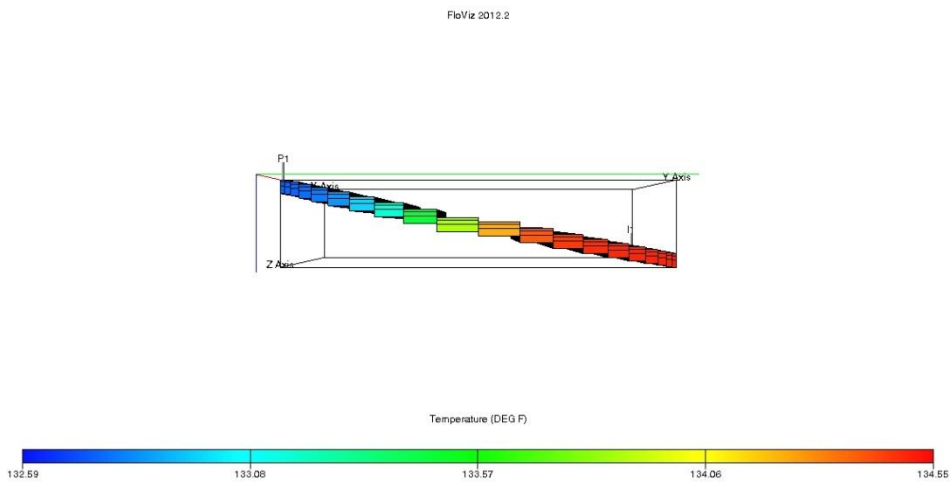

Figure 39: side view for the temperature profile after production

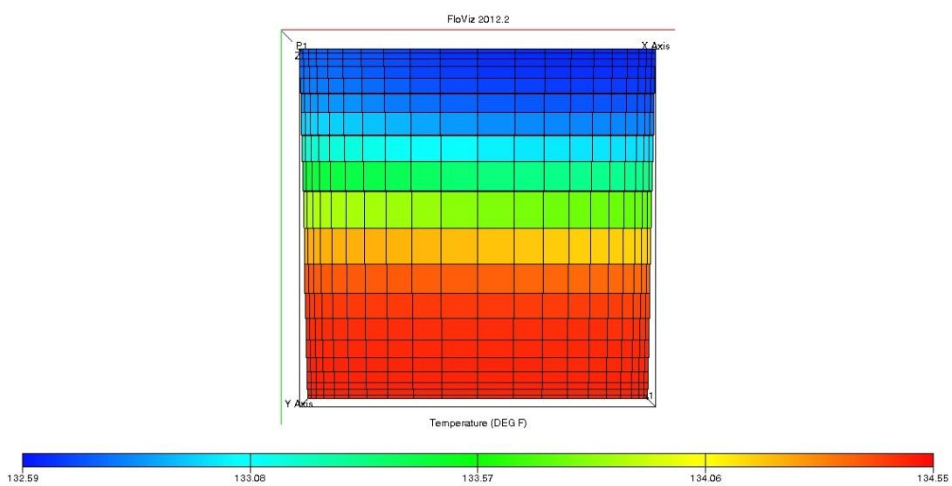

Figure 40: top view for the temperature profile after production

Appendix B

All the graphs in this appendix are related to the reservoir condition when steam flooding at 160 °F.

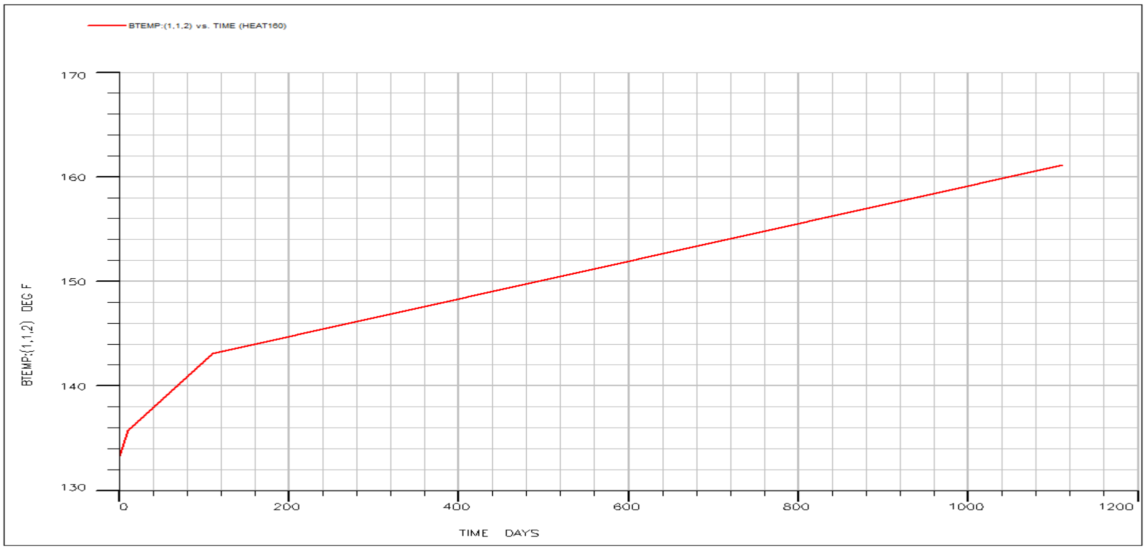

Figure 41: temperature vs. time for grid block (1,1,2)

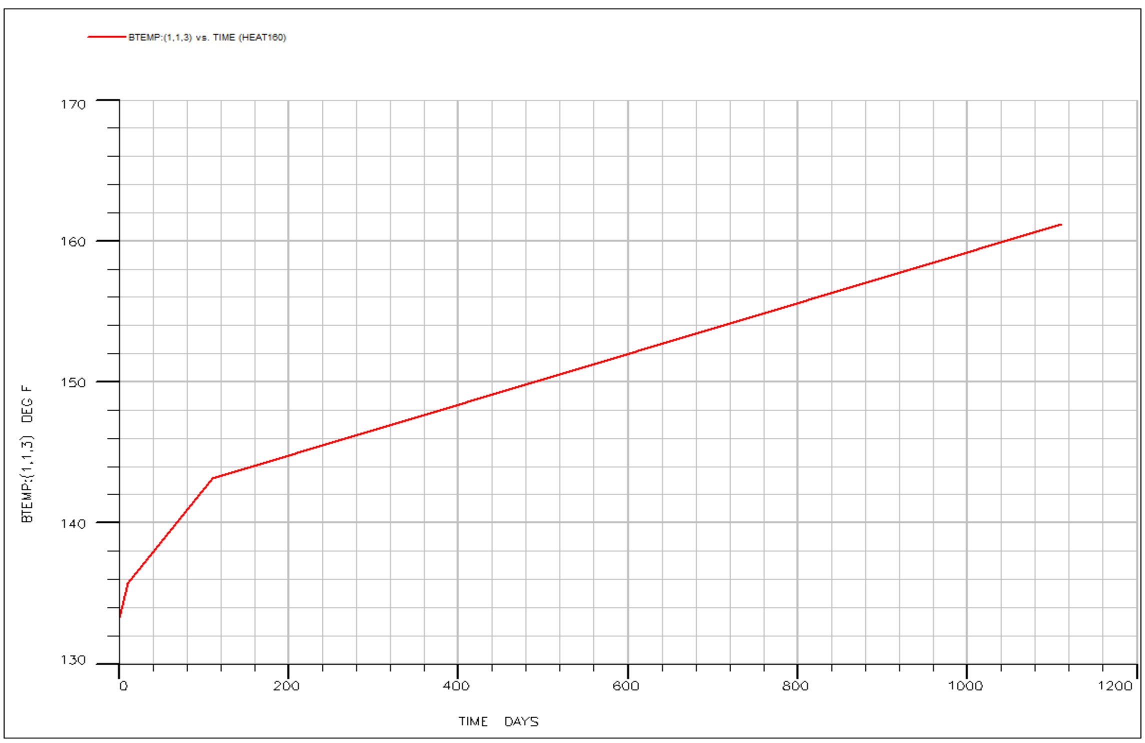

Figure 42: temperature vs. time for grid block (1,1,3)

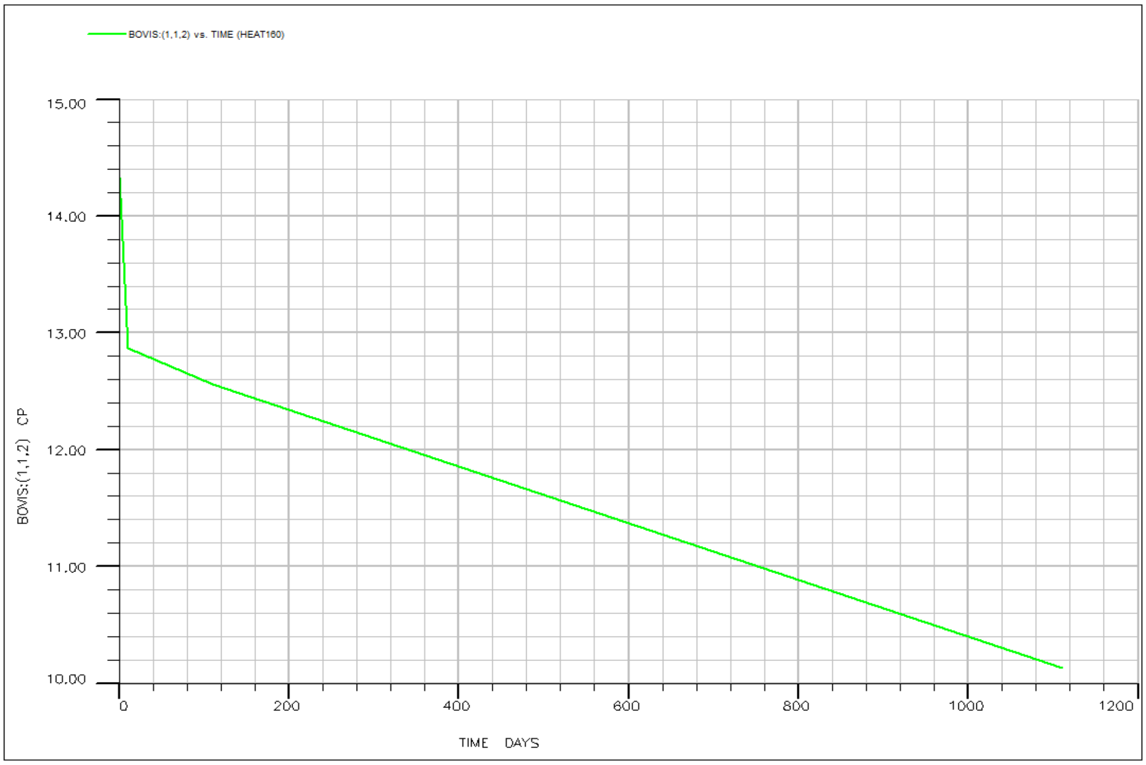

Figure 43: viscosity vs. time for grid block (1,1,2)

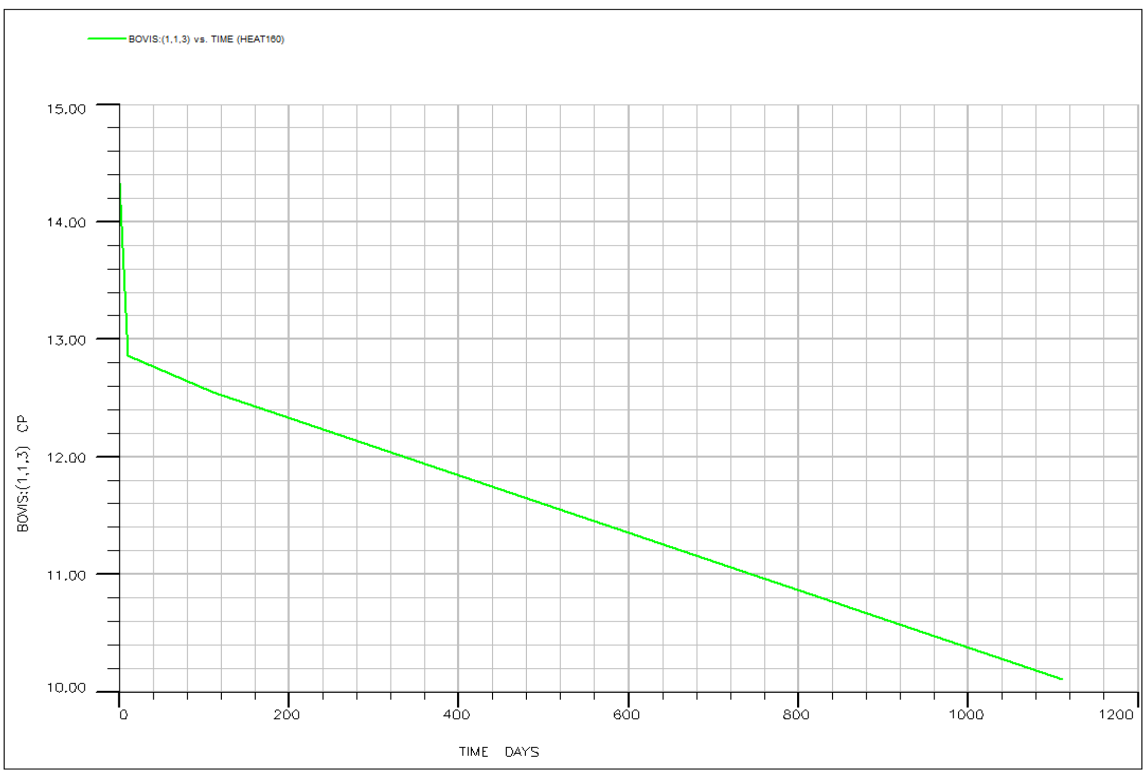

Figure 44: viscosity vs. time for grid block (1,1,3)

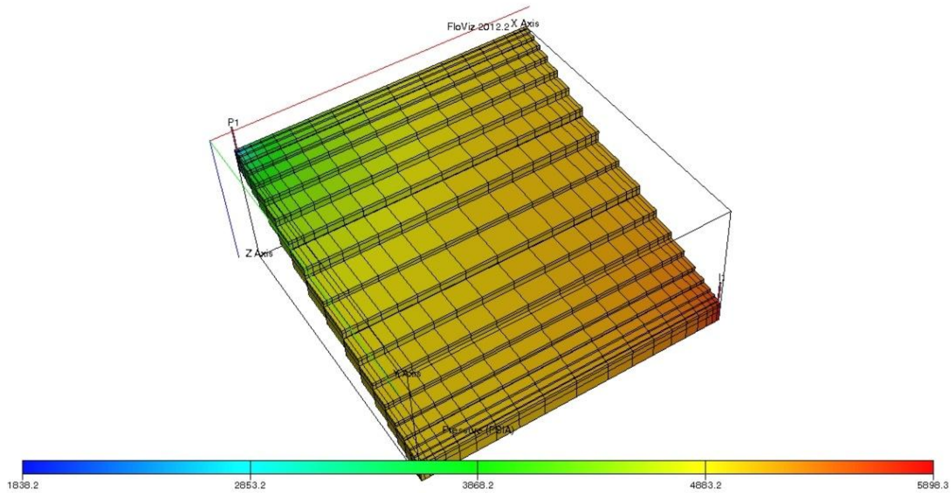

Figure 45: pressure profile for the field before production

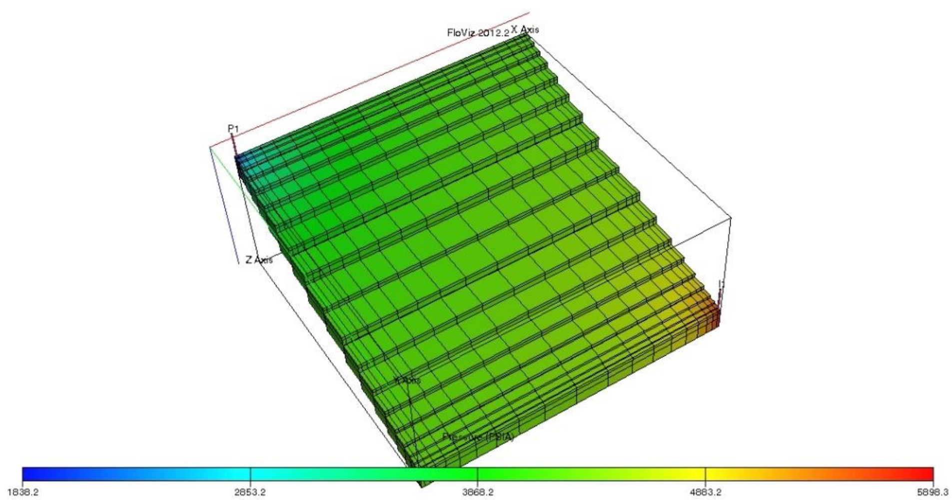

Figure 46: pressure profile for the field after production

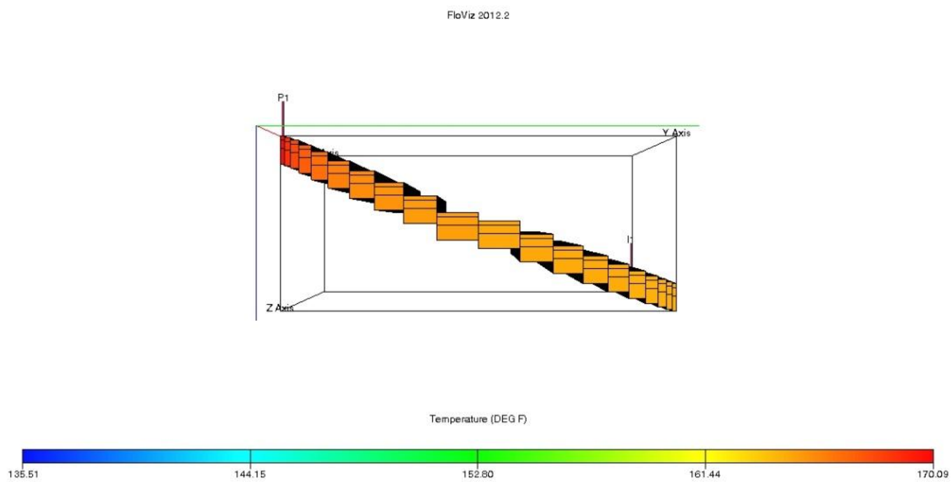

Figure 47: side view for the temperature profile after production

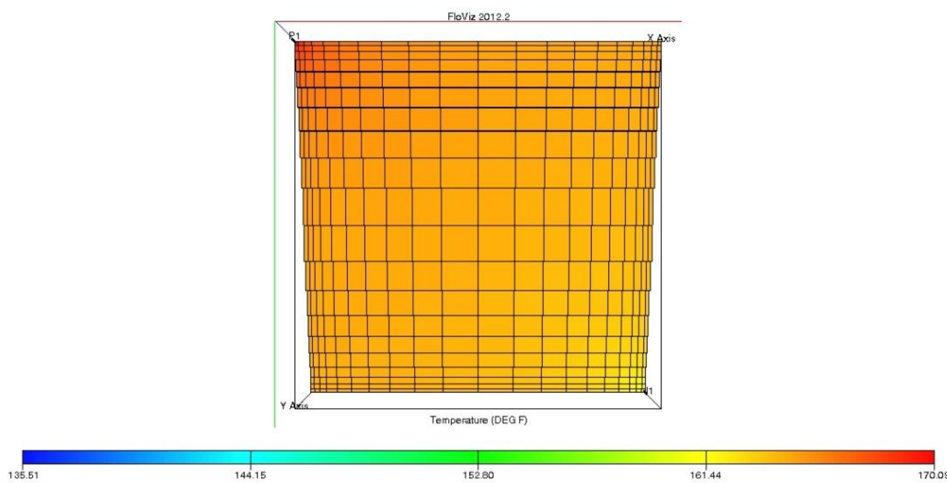

Figure 48: top view for the temperature profile after production

Appendix C

All the graphs in this appendix are related to the reservoir condition when steam flooding at 190 °F.

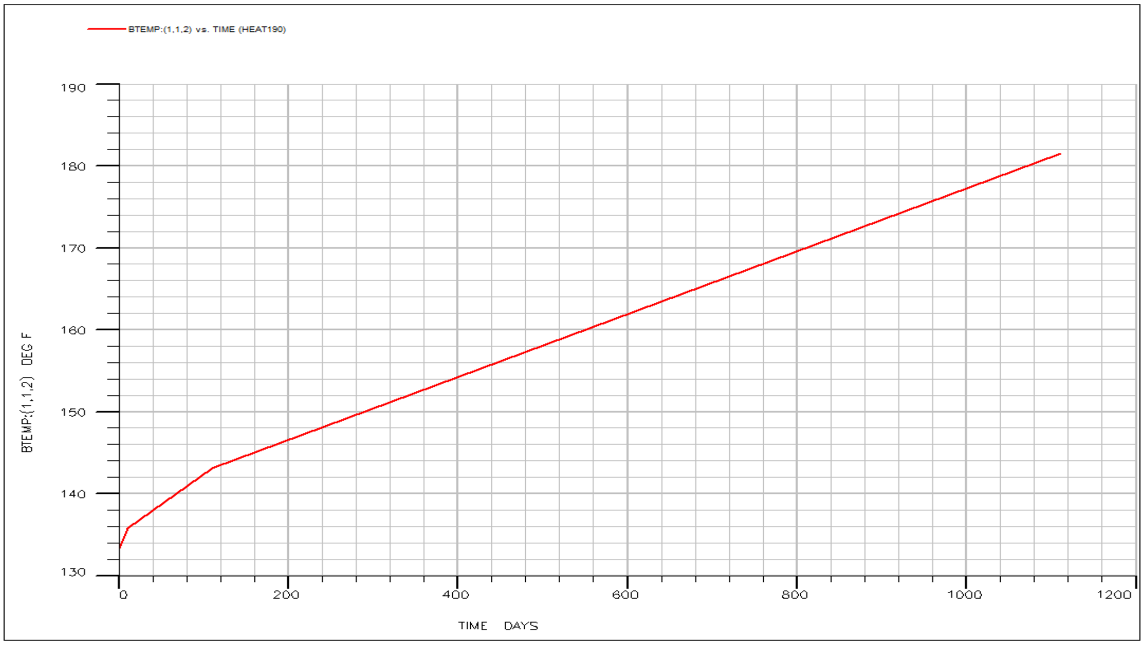

Figure 49: temperature vs. time for grid block (1,1,2)

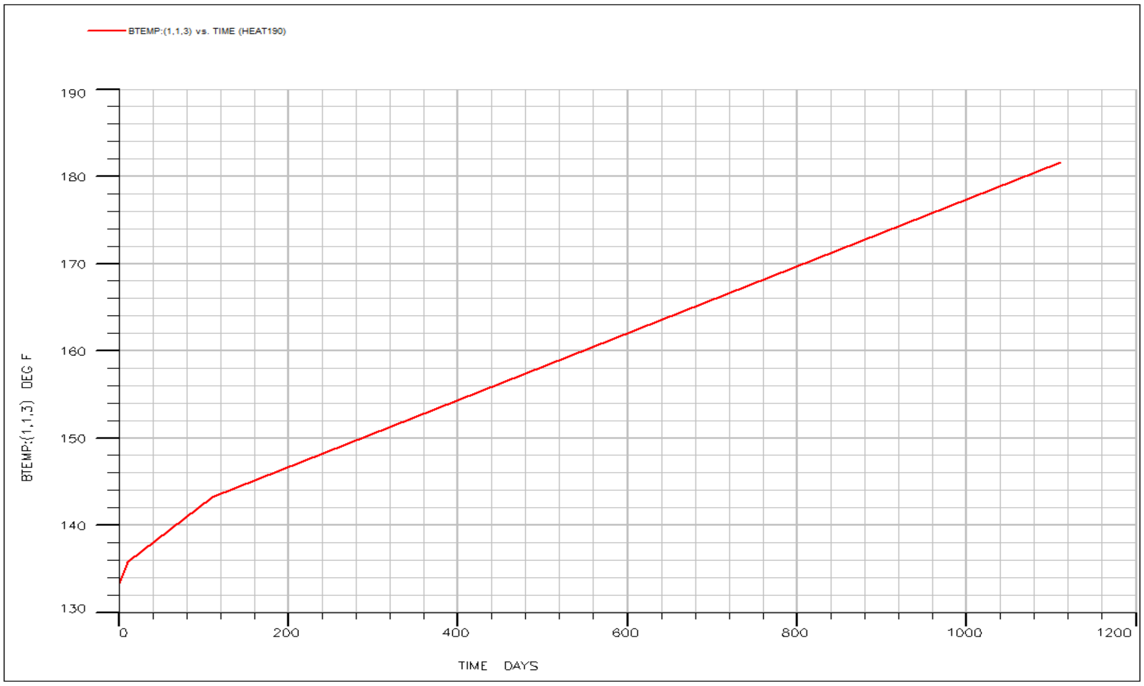

Figure 50: temperature vs. time for grid block (1,1,3)

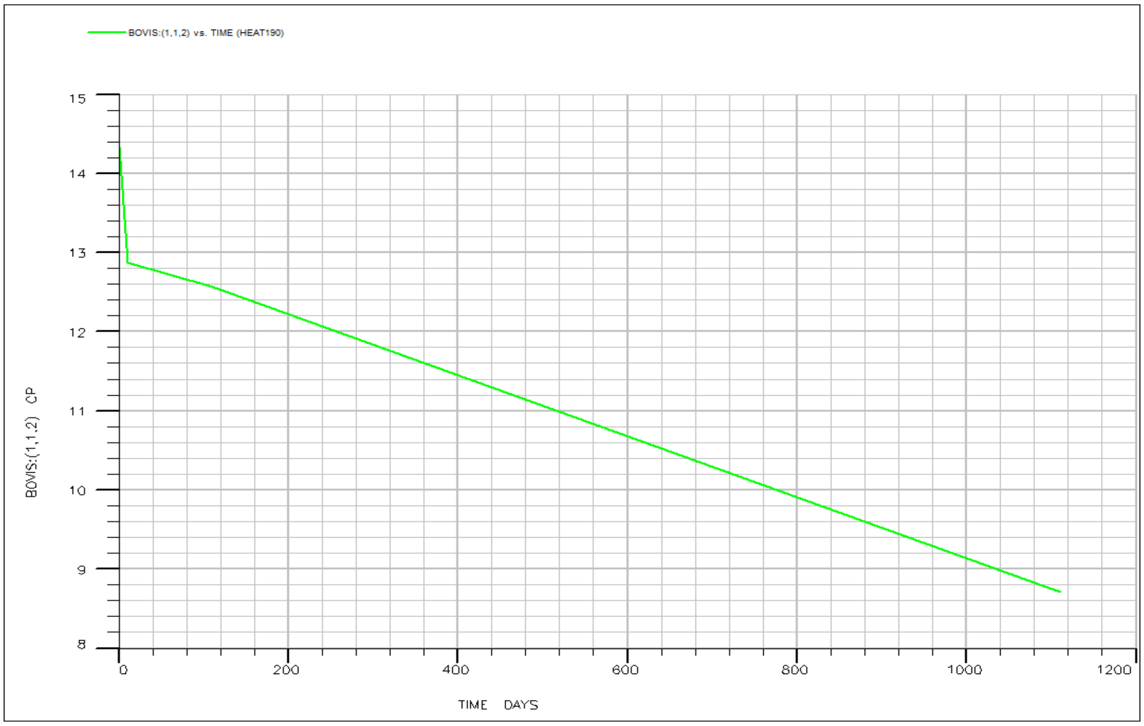

Figure 51: viscosity vs. time for grid block (1,1,2)

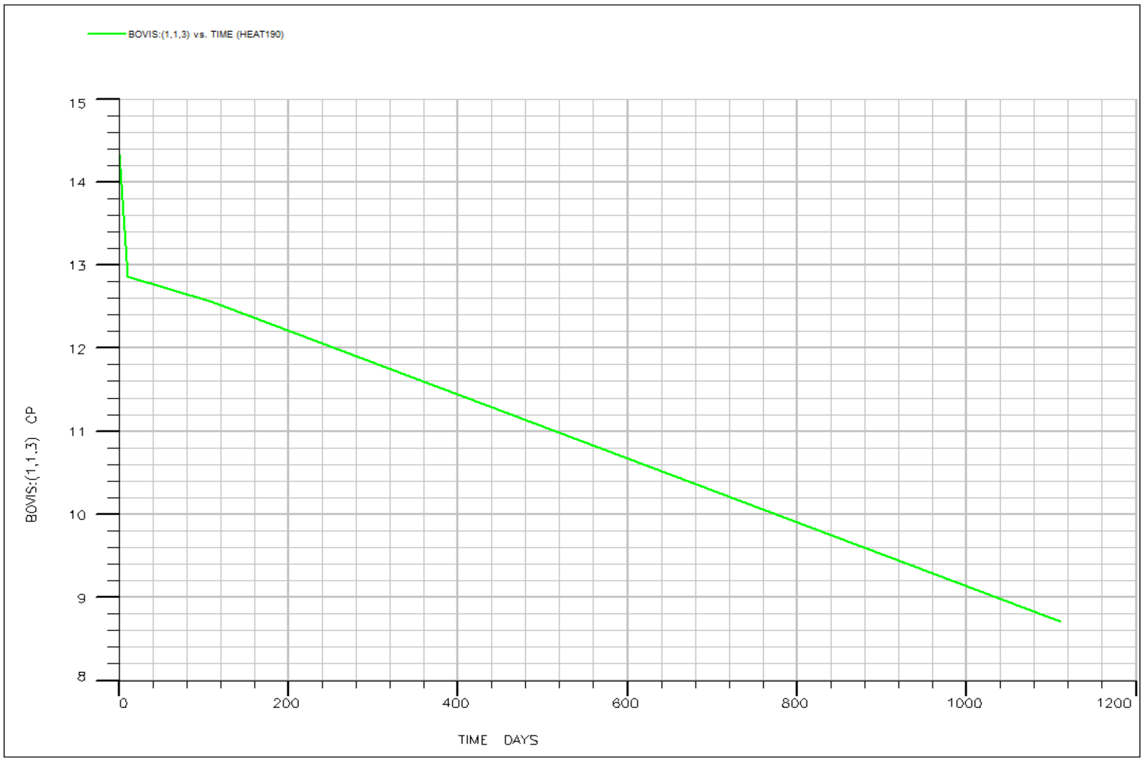

Figure 52: viscosity vs. time for grid block (1,1,3)

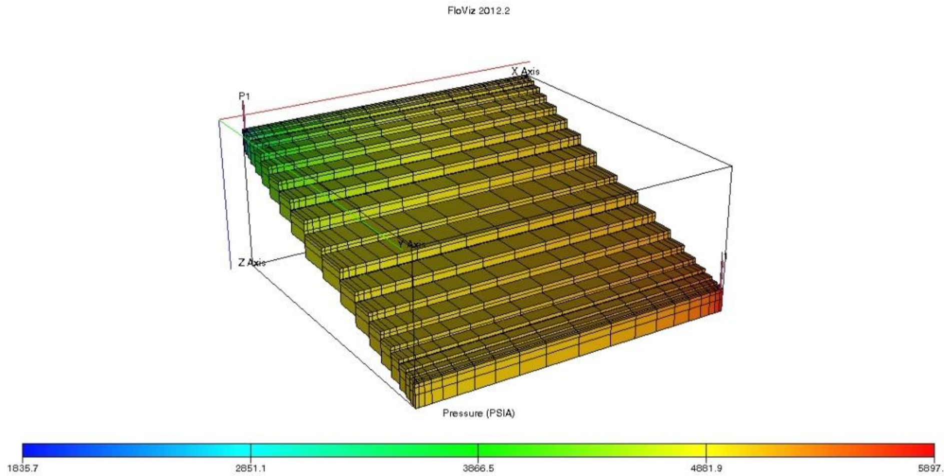

Figure 53: pressure profile for the field before production

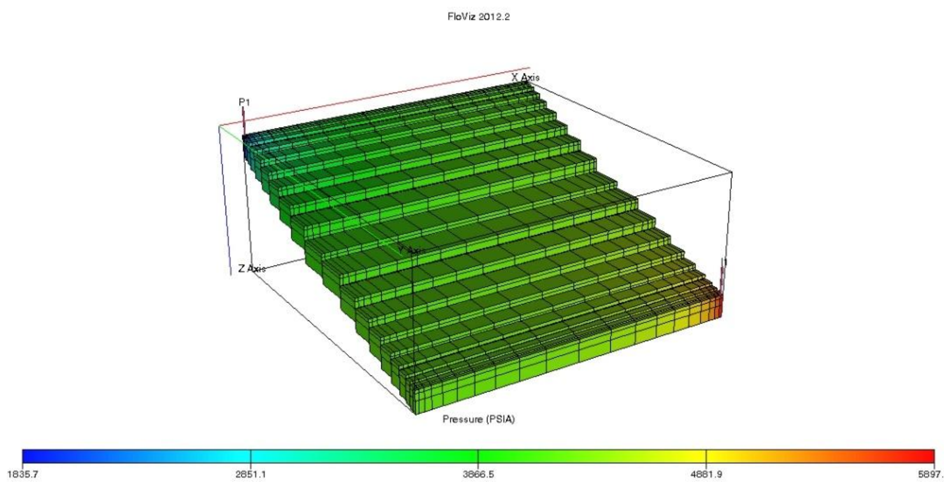

Figure 54: pressure profile for the field after production

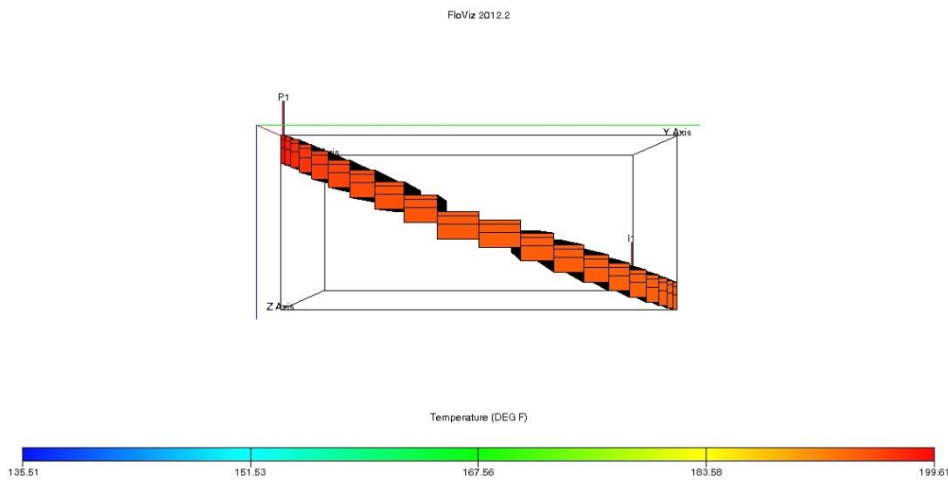

Figure 55: side view for the temperature profile after production

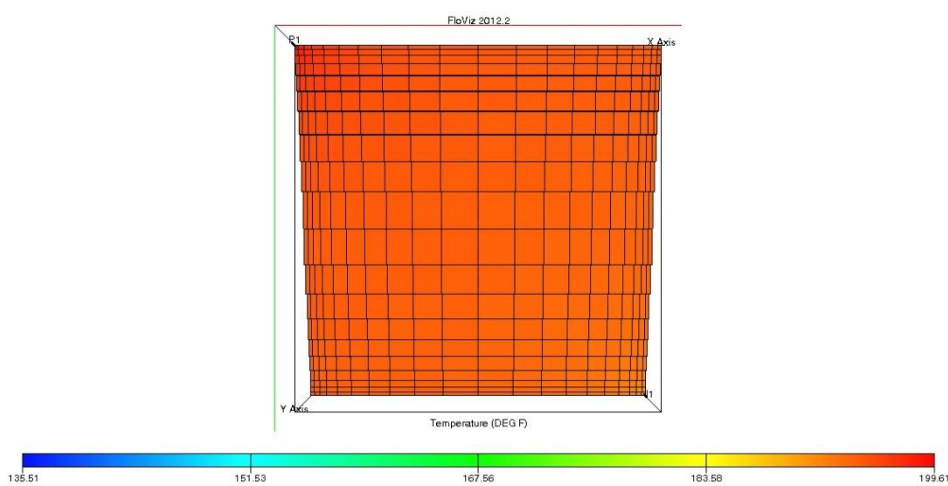

Figure 56: top view for the temperature profile after production

Appendix D

All the graphs in this appendix for comparison between the three reservoir conditions.

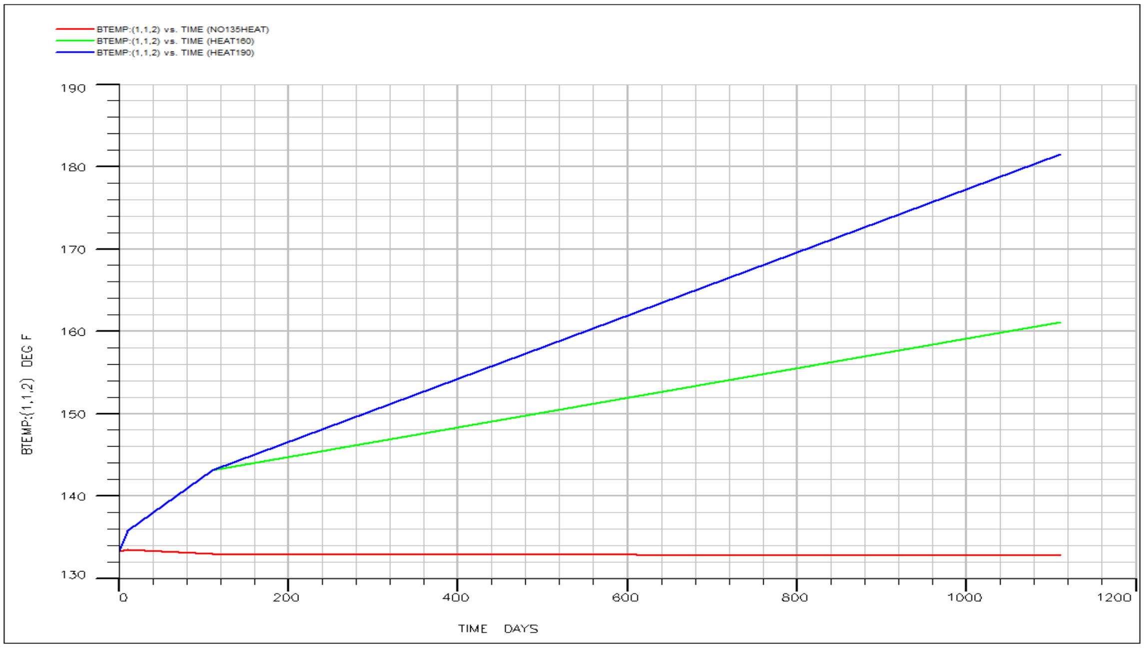

Figure 57: temperature vs. time for grid block (1,1,2)

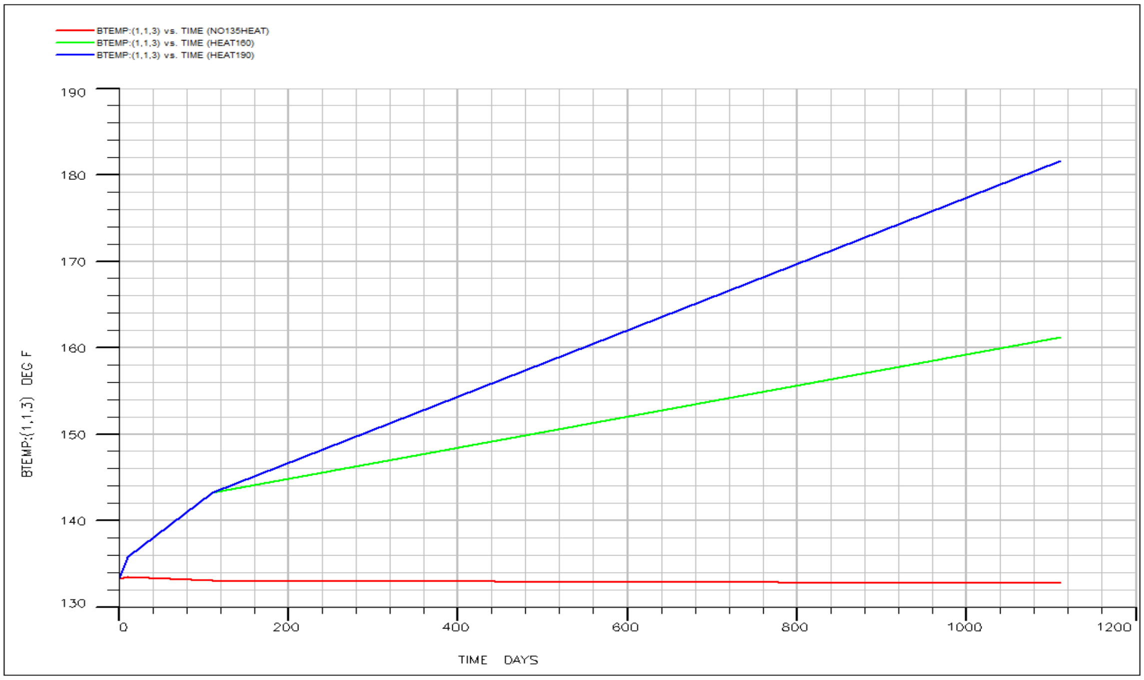

Figure 58: temperature vs. time for grid block (1,1,3)

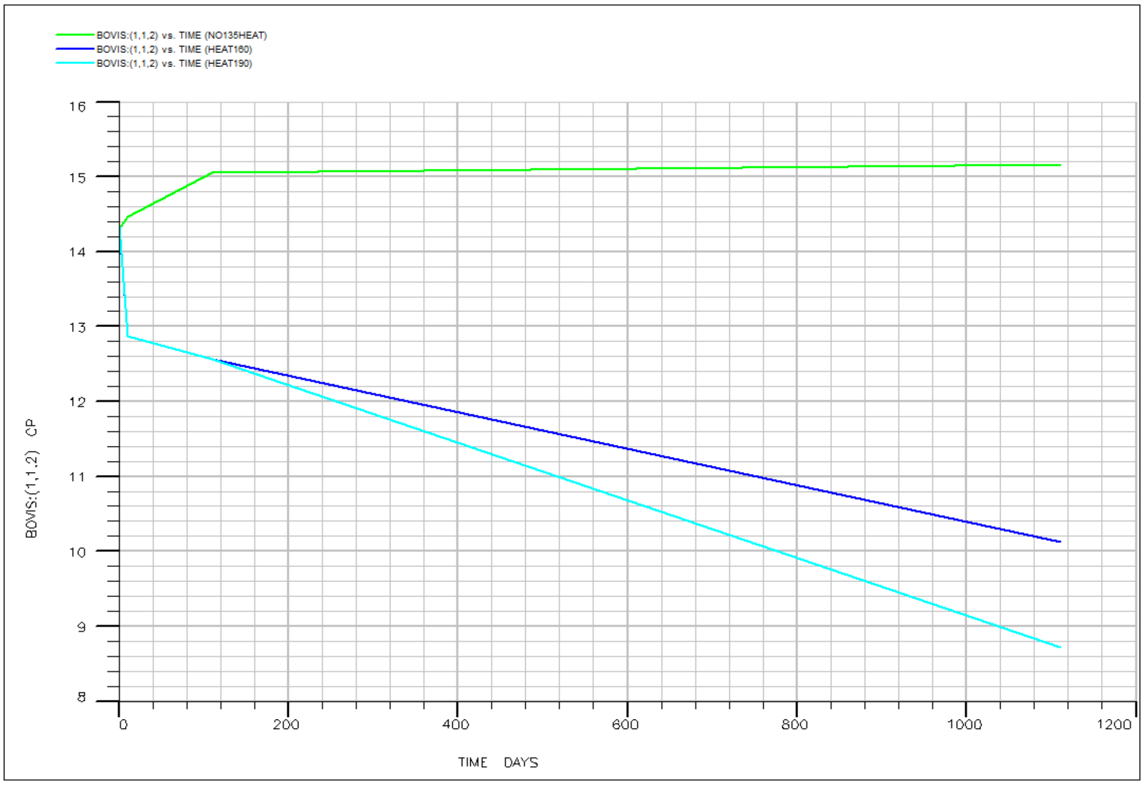

Figure 59: viscosity vs. time for grid block (1,1,2)

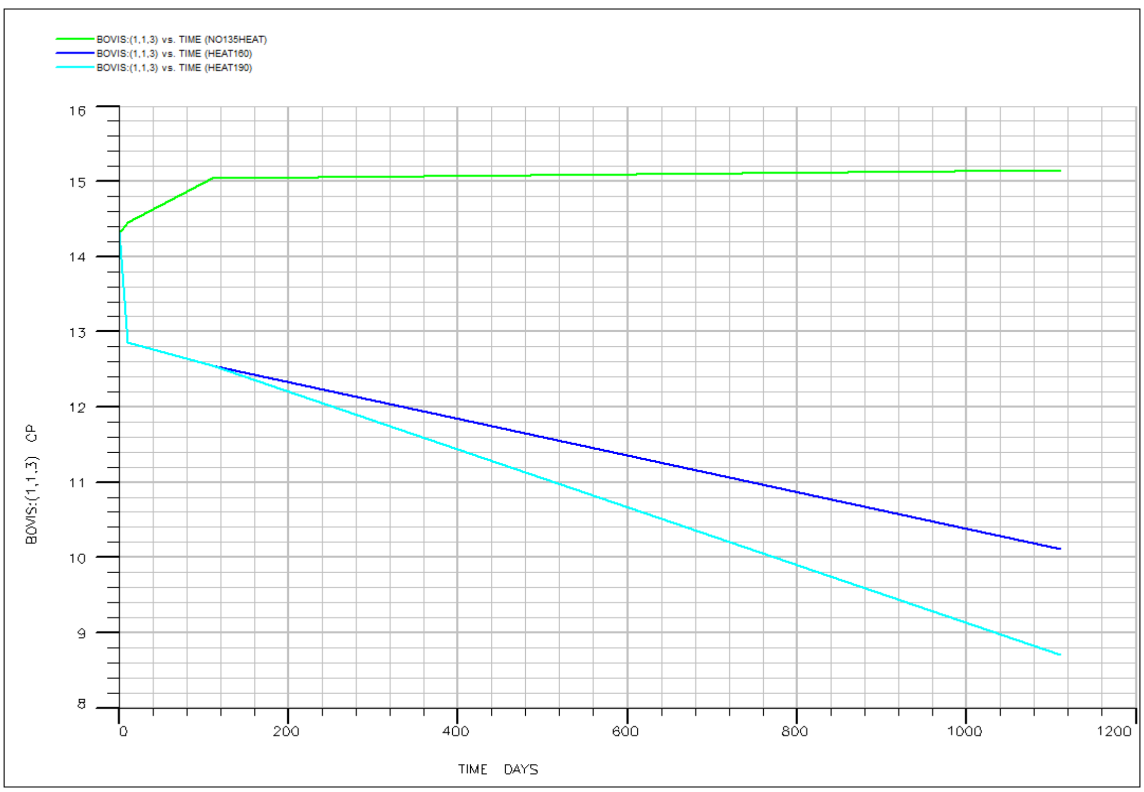

Figure 60: viscosity vs. time for grid block (1,1,3)