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Optimization of Steamflooding Heavy Oil Reservoirs

Anuj Suhag, Rahul Ranjith, Karthik Balaji, Zumra Peksaglam, and Vidhi Malik, University of Southern California; Ming Zhang, Frontida Biopharm, and Dike Putra, Rafflesia Energy; Zein Wijaya, HESS; Diyar Dhannoon, Texas A&M University; Cenk Temizel, Aera Energy LLC

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Abstract

Conformance improvement is the key to success in most enhanced oil recovery (EOR) processes including CO_2 flooding and steamflooding. In spite of technical and economic limitations, foam has been used as dispersions of microgas bubbles in the reservoir to enhance mobility. Steam-foam has numerous applications in the industry, including heavy oil reservoirs, which are a significant part of the future energy supply. Steam-foam applications have been used to prevent steam channeling and steam override, thus improving overall sweep efficiency, in both continuous steam and cyclic steam injection processes. The objective of this study is to investigate the key components of this complex process, where relatively high temperatures are recorded, in order to have a robust understanding of chemistry and the thermal stability of surfactants.

The efficiency and therefore economics of the steam-foam process are strongly reliant on surfactant adsorption and retention. This requires a good understanding of the process for effective sizing of the foam injected. In this study, a commercial reservoir simulator is used where surfactant transport is modeled with surfactant availability and is determined by a combination of surfactant adsorption, surfactant thermal decomposition, and oil partitioning due to temperature. The degree of mobility decrease is interpolated as a result of factors that contain aqueous surfactant kind and concentration, the presence of an oil phase, and the capillary number. An empirical foam modeling method is employed with foam mobility decrease treated by means of modified gas relative permeability curves.

The simulation results outline the sensitivity of these parameters and controlling agents, providing a better understanding of the influence of surfactant adsorption and thus, a number of chemicals to be used in an efficient manner. Optimum values for decision parameters that we have control on have been determined by coupling a commercial optimization software with the reservoir simulator. Uncertainty parameters such as surfactant adsorption have been analyzed in terms of significance on the recovery process.

Even though steamflooding is thoroughly studied in the literature, there is no recent in-depth study that not only investigates the decision parameters but also uncertainty variables via a robust coupling of a reservoir simulator and an optimization/uncertainty software that model use of foam in steamflooding. This study aims to fill this gap by outlining the optimization workflow, the comparison of parameters with tornado charts and providing useful information for the industry.

Introduction

Crude oil can be classified as light oil, moderate oil, heavy oil and extra heavy oil based on their API gravity. The standard specific gravity used to measure oil density is API gravity. Its purpose is to compare the density of oil to that of water with the help of a calculation designed to ensure consistency in measurement. Less dense oil or 'light oil' is preferred over denser oil because it contains greater quantities of hydrocarbons, which can further be converted into gasoline. The API values for each 'weight' are as follows:

- Extra Heavy – °API < 10.0
- Heavy – °API < 22.3
- Medium – °API between 22.3 and 31.1
- Light – °API > 31.1

A lot of present proven reserves of crude oil comes from the high API gravity heavy crude oil fields from Venezuela and tar sands of Canada. The world is estimated to have 429.4 billion barrels of heavy oil. 62% of the world's technically recoverable heavy oil is located in the western hemisphere. Crude having viscosity over 200 cp is classified as heavy crude. The extra refining required to turn heavy oil into gasoline needs a higher energy input for the same energy output, which decreases the energy returned on energy invested (EROEI) ratio. EROEI determines the valuability and profitability of a barrel of crude. The different kinds of heavy crude are shown in Table 1.

Table 1—Heavy Crude Blends (Source: Intertek Crude Oil Grades and Types)

Country	Blend	°API
Canada	Albian Heavy	19.6
	Cold Lake	21.2
	Heavy Hardisty	22
	Llyod Blend	20.9
	Western Canadian Select	20.3
Venezuela	Tia Juana Heavy	11
	Laguna	10.9
	Cerro Negro	16
	Boscan	10.1
	Bachaquero 17	17
	BCF-17	16.5
UK	Alba	19.4
	Captain	19.2
	Harding	20.7
Chad	Doba	21.1
Indonesia	Duri	20.8
Australia	Enfield	21.7
	Stag	18.5
Norway	Grane	18.7
Angola	Kuito	19

Country	Blend	°API
Peru	Loreto	18.1
	Mayna	21.5
Brazil	Marlim	19.6
	Peregrino	13.4
Mexico	Maya	21.8
Ecuador	Napo	19
Iran	Nowruz	18
China	Peng lai	21.8

Heavy crude having high API gravity and high viscosity requires special production procedures. The procedure includes changing composition of crude, reducing viscosity and reducing specific gravity amongst others.

Heavy Oil Recovery Methodology

Cyclic Steam Injection

Cyclic steam injection, also called steam soak or the "huff-and-puff" method, is a technique of thermal recovery in which a well is injected with steam for a certain period of time and then turned into a producer. Cyclic steam injection is used widely in heavy-oil reservoirs, tar sands, and in some cases to improve the viscosity of the heavy crude by injecting steam and breaking down complex polymers into light hydrocarbons increasing mobility.

Thermal Recovery by Steam Injection

This concept has traditionally been used worldwide. It includes steam injection into the producing formation. The steam front warms up the hydrocarbon converting it into less complex structures reducing their viscosity. Once the steam is used up, the condensed water phase is used as a front to push the crude towards a producer. This method is referred to as steamflooding. This activity is continued till the well has reached its economic capacity.

In-Situ Combustion

This method is commonly known as Fire Flooding. It is of two types; the first method is dry combustion, in which dry air is injected using an injector well and is ignited. As the fire front advances, the heavy components are broken down to lighter hydrocarbons reducing viscosity. The gas generated from this combustion acts in a similar way to steamflooding pushing oil towards the producer. The second method used is Wet Combustion where water is injected with air. The water captures and spreads heat more efficiently.

Steam Assisted Gravity Drainage (SAGD)

SAGD is a process involving the injection of high-temperature steam underground through a horizontal well to melt the bitumen and crude, allowing it to flow to an adjacent horizontal well. From there, it is pumped to the surface for further processing. SAGD has similar effects on the reservoir as steam injection. Once viscosity of the crude reduces, it flows downwards due to gravity and is collected by the producing well. This method is widely used in the Canadian Tar Sands

Cold Heavy Oil Production with Sand (CHOPS)

CHOPS involves injection and inclusion of sand during completion activity, maintenance of sand inclusion through the life of well and special implementation of sand removal procedures from crude, post production. When production is initiated, the sand influx is up to 40% which dwindles to 5% towards constant production phases. There is usually a timely initiation of sudden increase in sand bursts. This method is mostly performed exclusively in Canada.

Vapor Assisted Petroleum Extraction (VAPEX)

This is a type of non-thermal heavy oil production method. In this process, a solvent vapor is used to reduce the viscosity of the heavy oil, which in concept is similar to SAGD. The injected solvent vapor swells and dilutes the heavy oil by contact. The diluted heavy oil drains by gravity to the lower horizontal well to be produced. This method is used in Venezuela as well as in a limited capacity in Canada.

Toe to Heel Air Injection (THAI)

THAI is a modification of the conventional in-situ combustion technology. Air is injected through a vertical well to the target zone. As the fire front progresses, oil is produced of lower viscosity from a horizontal well of close proximity to the vertical air injector. This method combines the technology from in-situ combustion and SAGD to maximize production, in which the flame front from a vertical well impulses the oil to be produced from another vertical well.

Lost Hills Field

At the western margin of the San Joaquin basin in Kern County, California, is located the Lost Hills oil field. The field is situated at the crest and along the SE plunge of a narrow eight-mile long asymmetrical, doubly-plunging anticline. This reservoir is comprised of diatomaceous mudstone (diatomite) that is about 800 ft in thickness, and has a very low matrix permeability (0.01 to 10 md), high porosity (35-65%), and good oil saturation (50%).

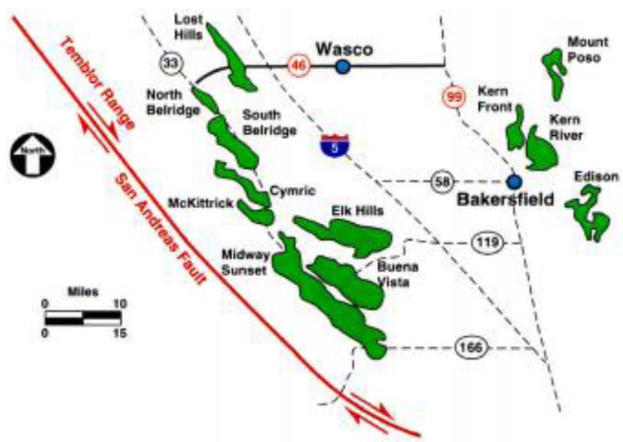

Figure 1—Lost Hills Field

The Upper Etchegoin marine sands are divided into two main units (B and C), separated by a 35-50 ft. thick shale. The B sands are subdivided into three sands, Zones 1, 2, and 3. Zones 2 and 3 are nearly always deposited as high energy, marine delta front sands, with permeabilities of about 3,500 mD and porosity of about 38%. The Lost Hills field has been successfully steam flooded by operators. Texaco began cyclic steaming their Lost Hills property in 1967 and initiated a steam flood project in the Tulare format in in 1977.

Midway Sunset Field

Located in the southwest portion of the San Joaquin Basin in southern California, the Midway Sunset Field is named as a "super giant." Midway Sunset Field has decisive reserves of 2.75 billion barrels. The highly permeable Potter Sand is the reservoir in the northern part of the field and consist of huge unconsolidated sands and sandy conglomerates, interbedded with diatomaceous clays and siltstones. Steam floods were carried out at different times in each of the sand units, initially in the J sands in 1971. A steam flood is planned in the 09-13 sands in 1995. A dead aquifer exists underneath the oil zone.

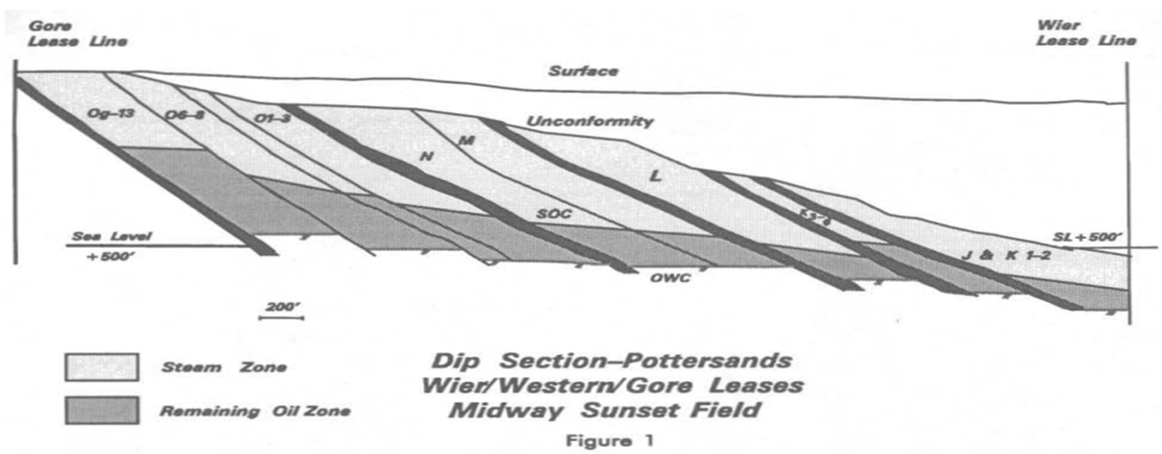

Figure 2—Midway Sunset Field

South Belridge Field

The Belridge diatomite field, located in Southern California, covers a large area and contains light to intermediate oils in a siliceous shallow reservoir of 800-2000 ft reservoir. It has 1200ft thick payzone with very high porosity of upto 65%, but with low permeability rock (0.1-1mD). During deposition, relatively clean diatomite layers have been interbedded with silt and clay in a cyclical manner. The basal zones within cycles are generally clay-rich and exhibit essentially no vertical transmissibility across cycles via the matrix. They are laterally continuous across most of the field. This architecture enables compositional crude variations, and the diatomite reservoir can be considered as a stack of separate volumetric tanks with varying reservoir properties. The field was produced on primary depletion massively since 1977 and was converted to waterflood in 1987 to manage subsidence by maintaining water pressure. Steam injection is currently being pursued to replace waterflooding to arrest the fields declining production by means of controlled pressure support and enhanced thermal recovery. The steam floods are majorly concentrated in Tulare and diatomite formations.

Oil and Heavy Oil Chemistry

Petroleum is the major energy source worldwide. 20-40 % of oil is gained by conventional methods due to the chemistry of oil in the reservoirs. 60-80 % of the oil reservoirs, comprising of heavy and super heavy oils, are the largest portion of the petroleum reserves that are not easy to obtain by primary and secondary recovery. Most of the heavy and super heavy oils are in the shallow reservoirs and tar sands. Temperature, oil size, oil chemical structure, oil components affect the degradation of crude oil. Crude oil contains high amounts of saturated hydrocarbons whereas heavy oil has the least saturated hydrocarbon content. Degradation of saturated hydrocarbons leads to the formation of heavy and super heavy oils. Biodegradation, physical degradation or microbial degradation causes saturated hydrocarbons to form carboxylic acids, polyaromatics, phenols, resins, and asphaltenes. Fig 3 shows ethane degradation to ethylene as an example of saturated hydrocarbon degradation.

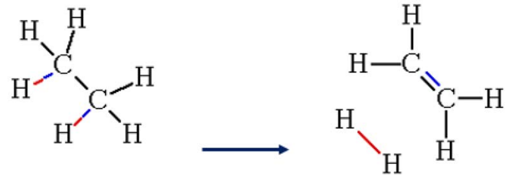

Figure 3—Saturated hydrocarbon degradation

As saturated hydrocarbon content decreases in the oil, density of oil increases. Conventional oil, heavy oil, extra oil and sand bitumen types of oils are grouped based on their API gravity numbers by using,

$$API = \frac{141.5}{\rho} - 131.5 \tag{1}$$

Where,

ρ= density of oil sample at 60 °F/15.6 °C (kg/m^3)

API gravity number decreases as the saturated hydrocarbon reduces and density of oil increases. API gravity of heavy oils is between 10 and 22.3 degrees whereas conventional has 30-40 degrees of API gravity. Oil contents are also analyzed by viscosity, heavy metal content, porosity and permeability of oil. Carbon/Hydrogen (C/H) ratio in the oil chemistry rises as the density of oil increases. C/H ratio increases by 1-1.56 for heavy oils whereas C/H ratio of light oils is around 0.5. Heavy oil, extra heavy oil, and sand bitumen have higher viscosity, density, immobility, C/H ratio, acidity and heavy metal content than conventional oils. Hetero-elements such as sulfur, oxygen, and nitrogen content is also higher in heavy oils. Heavy oil has higher C/H ratio, asphaltene component and high density than light oil; therefore, the viscosity of the heavy oil is higher than conventional oil. The viscosity of the heavy oil is 100-10000 centipoise (cP) while light oil has lower than 100 cP viscosity.

Heavy oils are more acidic than light oils. Total acid number (TAN) is also another parameter to classify heavy and light oils. TAN is the number that quantifies acidity of oil based on how much potassium hydroxide (KOH) is needed to neutralize oil acidity. TAN is calculated as required potassium hydroxide milligrams for 1 gram crude oil. Higher than 0.5 mg, KOH/g shows acidic crude oil. The total acid number is significant especially for purification of oil.

Heavy oils have more hetero-atoms and heavy metal content than light oils. Hetero-elements and heavy metals are removed to purify petroleum. The existence of sulfur comes from thiols, disulfides, benzothiophenes, thiophenols, mercaptans and their derivatives. The weight percentage varies up to six percent. The oxygen sources of oil are organic weak acids and some aromatic compounds. Oxygen weight percentage is generally between 0.1 and 3 %. Nitrogen containing chemical substances are indoles, pyridines, carbazoles, holiness, porphyrins and their derivatives. Nitrogen weight percentage is very low which varies from 0.2 to 1.5 percent; however, it is very hard to remove from petroleum. The most common heavy metals in oil chemistry are Nickel (Ni), Iron (Fe) and Vanadium (V). Refining oil is hardened by the existence of these heavy metals due to adverse effects such as catalyst poisoning.

SARA Analysis of Oils

Hydrocarbon content of oils is analyzed based on the chemical structure of existing hydrocarbons in the crude oil. The purpose of SARA analysis is to characterize oil based on its Saturate, Aromatic, Resin and Asphaltene (SARA) contents. The underlying procedure of SARA analysis is to determine polarity and polarizability of the hydrocarbons.

Saturates content can be as low as two percent to as high as fifty percent. Saturated hydrocarbons are hydrocarbons that have the maximum amount of hydrogen in bonded to their carbon atoms. Degradation of saturates causes the crude oil to become denser or heavier. Saturates are the most valuable part of petroleum. Saturates are nonpolar hydrocarbons that include alkanes, branched alkanes cycloalkanes, saturated carboxylic acids, etc. Fig. 4 represents some examples of saturated hydrocarbons. Methane, ethane, propane, and butane (with chemical formula of (CH_4), (C_2H_6), (C_3H_8) (C_4H_{10}) respectively) are normal paraffin, which is simply saturated hydrocarbons. Isopentane and n-pentane (C_5H_{12}) are the examples of isoparaffins which show branched structure versus long chain structure of the molecular weight hydrocarbon. Four or more than four carbon saturated hydrocarbons may have branched structure as well as long chain structure. Normal and branched paraffin are known by C_nH_{2n+2} formula. Saturated hydrocarbons may have enclosed structures for instance as shown in Fig. 4 cyclohexane and cyclobutane. This enclosed structure of three or more than three carbon saturated hydrocarbons is known as cycloparaffins or cycloalkanes. The formula of cycloalkanes is C_nH_{2n}. Saturated carboxylic acids are weak acids with a formula R-COOH, R: C_nH_{2n+1}. The saturated carboxylic acid in the Fig. 4 contains sixteen carbons as hexadecanoic acid. It is also known as palmitic acid which is commonly seen in palm oil.

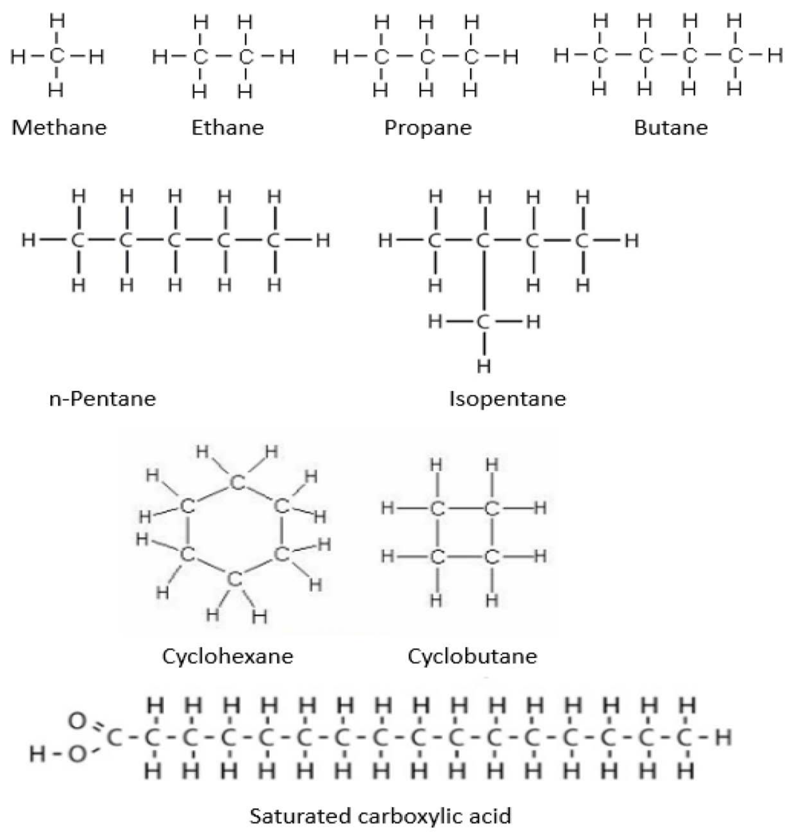

Figure 4—Examples of saturates

Aromatics content of oils varies between fifteen and fifty weight percentage. Aromatics are polarizable hydrocarbons with one or more aromatic rings in their chemical structures. In one ring aromatic hydrocarbon, each carbon atom has one oxygen atom and one double bond with a chemical formula of C_nH_n. Fig. 5 shows common aromatics that are found in crude oil chemistry. Benzene with C_6H_6 formula is the most common aromatic in petroleum. Toluene, xylene, and ethylbenzene are benzene derivatives as seen in the figure. These aromatics have a paraffin attached to benzene. Xylenes are named as ortho-, meta- or para-xylenes based on the place of methyl groups. Benzene, toluene, ethyl-benzene and xylenes are volatile hydrocarbons, and their content in heavy oil is less than light oil. One or more hydrocarbon rings can be attached to benzene ring as shown in the Fig. 5. Naphthalene, anthracene, pyrene and phenanthrene aromatics are mostly found in heavy oil.

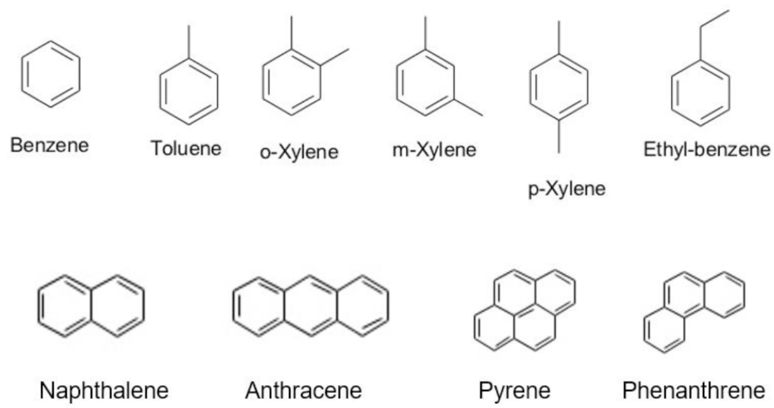

Figure 5—Chemical Structure of Common Aromatics

Resins are the polar parts of petroleum. Resins exist in heavy oils rather than light oil. Resins have a complex chemical structure which contains aromatic rings and branched saturated or unsaturated hydrocarbons. The structure of resins is unique to the reservoir. In other words, resin structures vary from one petroleum reservoir to another. Resins also have more hetero-elements than saturates and aromatics. Resins have a maximum of five aromatic rings in their hydrocarbon chain. The complicated structure of resins is soluble in n-pentane and n-heptane; however, it is not soluble n-propane. Resins have a molecular weight between 500 and 2000 Da. The density of resins is higher than the density of saturates due to the structural differences. Generally, the density of resins is around one gram per cubic centimeters. An increase of resin content leads to the increase of oil viscosity.

Asphaltenes are known as the most polar parts in petroleum chemistry. Asphaltenes have highly complex structures with a very high molecular weight. Asphaltenes have the highest molecular weight of oil with a molecular weight between 500 and 10,000 Da. The density of asphaltene is higher than the other components of oil due to its highly-complicated structure. Petroleum viscosity rises with an increase of asphaltenes' weight percentage. Asphaltenes have one to twenty aromatic rings in their chemical structure. Resins and asphaltenes have both complex structures, and they are separated by their solubility in organic solvents. Asphaltenes are soluble in aromatics (e.g. benzene, toluene) but nevertheless, they are insoluble in n-alkanes (e.g. n-pentane, n-heptane). Asphaltenes have different chemical structures which depend on the reservoir. Asphaltenecontent is extremely high in heavy oil as compared to light oil. Asphaltene has the highest amount of hetero-atom and heavy metal content in oil. Resin has an important role on asphaltene and its molecular interactions. Asphaltenes are solubilized with existing resins in heavy oil. Therefore, stability and mobility/immobility of heavy oils are affected by resin and asphaltene contents. The solubility of asphaltene also depends on various properties such as temperature, pressure, injected solutions, the contents of saturate and aromatics. Minimization of asphaltene solubility causes precipitation of asphaltenes.

Thermal Recovery for Heavy Oil

The main issue surrounding the recovery of bitumen or heavy oil is that bitumen tends to be immobile. For these fluids, the recovery mechanisms should target towards reducing viscosity with the application of heat. Thermal methods depend on various displacement mechanisms for the recovery of oil, but the main focus remains towards the reduction of crude viscosity with increasing temperature.

Steamflooding

The high-temperature steam injected into a reservoir during steamflooding heats the oil and causes it to expand, become less viscous and consequently vaporize so that it can move to the production wells with ease.

For heavy oil reservoirs that contain oil with high viscosity, recovery by steamflooding is a commonly used measure for achieving commercial oil-producing rates. It has also been considered as a method for recovering additional light oil.

As the formation heats up, oil recovery is increased since,

- Oil becomes less viscous due to the rising heat and can move through the formation toward production wells with a lot of ease.
- Oil is easily released from the reservoir rock due to expansion or swelling.
- Once the lighter fractions of oil vaporize, they tend to move ahead into the cooler formation, condense and form a solvent or miscible bank.
- An ordinary waterflood ahead of the heated zone is created by the condensed steam, which cools as it moves through the reservoir.

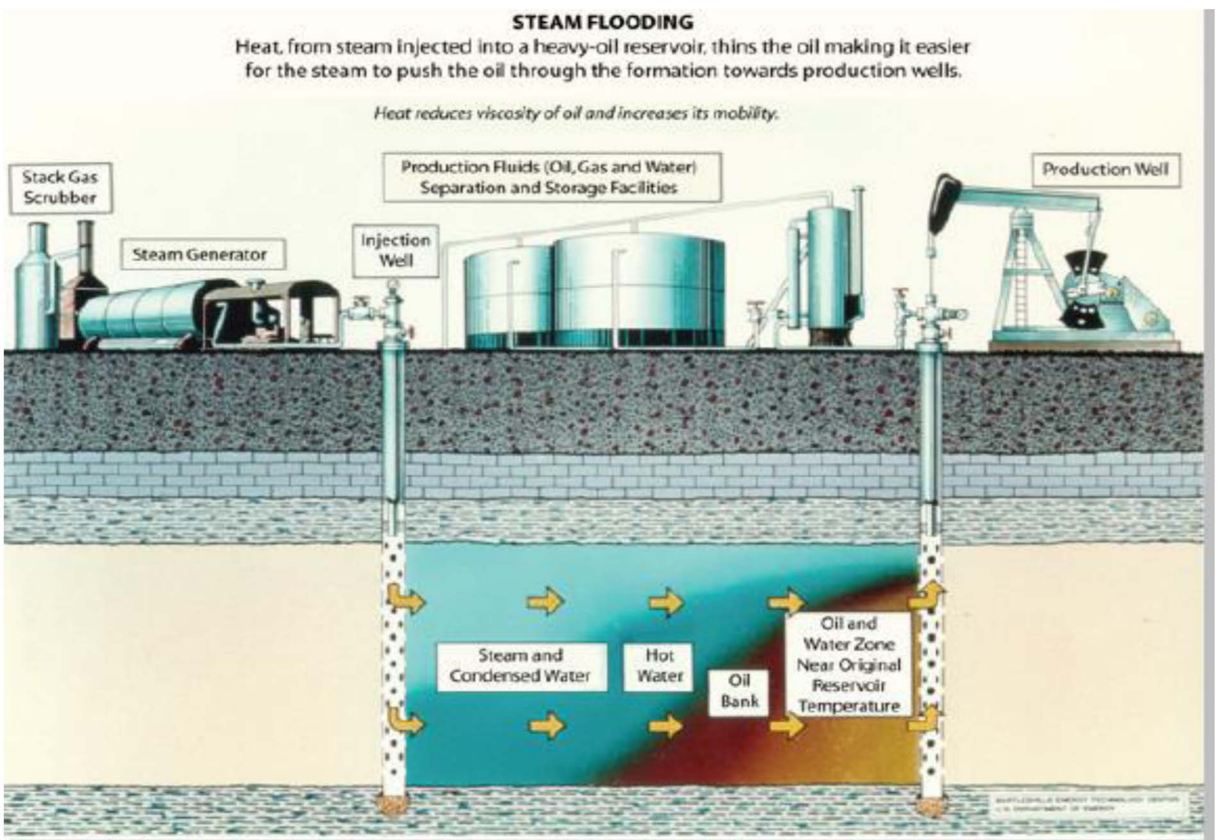

Figure 6—Steamflooding technique (United Energy Group)

Total steam drive for thermal EOR production in California in 1988 was 530,000 BOPD. The non-California (total US.), Thermal EOR (steam flooding) was only 5,000 BOPD more. In-situ combustion, the only other Thermal EOR process contributed another 6,500 BOPD in the US. Also, in 1988 thermal EOR production accounted for 73% of all EOR production in the US. (Blevins, 2010)

The figure below show the contribution of steam flooding for oil recovery and efficiency.

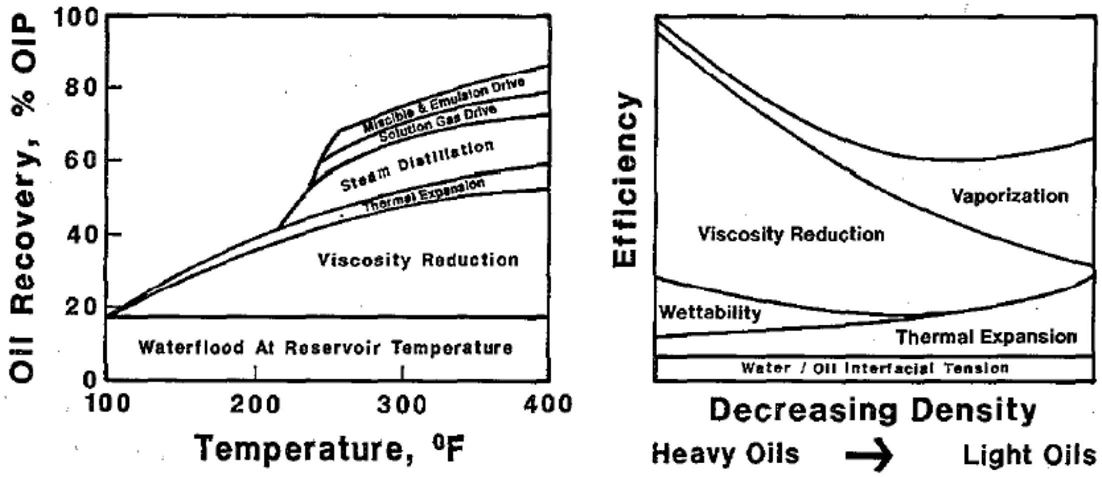

Figure 7—Contribution of steamflooding mechanism to oil recovery (heavy oil, 10 – 20°API) (Blevins, 1990)

Cyclic Steam Stimulation (CSS)

Cyclic steam stimulation, also known as the "huff-and-puff" method, is used to boost production during the primary production phase in heavy oil reservoirs. In this thermal recovery method, a specific amount of steam is injected into wells that have been drilled or converted for injection purposes. In order to allow the steam to heat or 'soak' the producing formation, wells are shut in.

After a required time period, the injection wells are placed back in production until the heat is dissipated with the produced fluids. This cycle may be repeated until the response becomes marginal because of declining natural reservoir pressure and increased water production.

At this stage, a continuous steam flood is usually initiated to continue the heating and thinning of oil and to substitute decreasing reservoir pressure so that production may continue. (UEG, 2012)

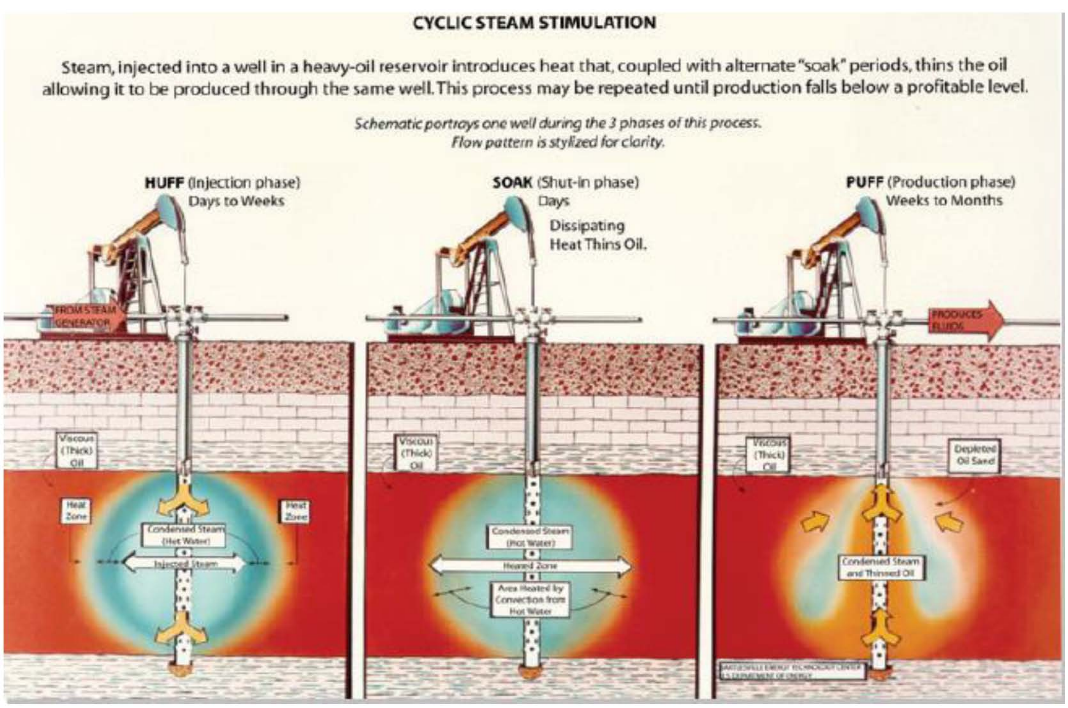

Figure 8—Cyclic Steam Stimulation (CSS) technique (United Energy Group)

Steam-Assisted Gravity Drainage (SAGD)

The SAGD process consists of a top well, which is the steam injector, and a bottom well that is the producer. Displacement efficiency determines the recovery from the steam chamber; the rate of chamber growth greatly affects the rate at which displacement efficiency increases. Increasing the volume of the steam chamber rapidly can result in the increased effectiveness of SAGD. (Termizel et al, 2016) SAGD is commonly used to extract oil sands and extra-heavy crudes in Alberta and Venezuela.

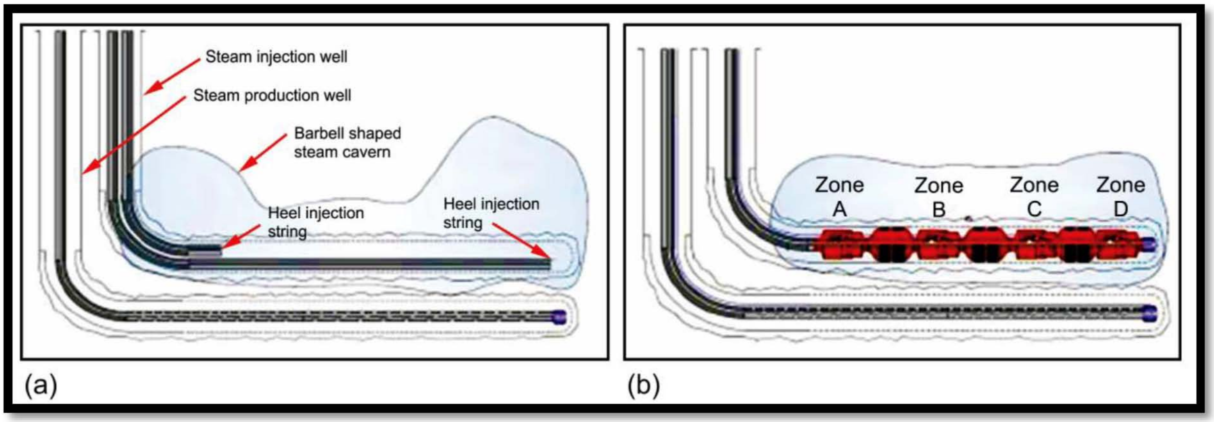

Figure 9—Traditional injector dual string compared to well injector configuration proposed

Current Thermal Simulation Practices

Commercial simulators can be used to simulate a number of thermal recovery processes, for instance, steam injection, cyclic steam injection, steam flood, or steam-assisted gravity drainage (SAGD). Dead oil is used in heavy oil reservoir simulation where the oil phase is shown by a single non-volatile constituent. On the other hand, compositional simulation models presume that normally reservoir fluid properties are dependent on the reservoir temperature, pressure and also the composition of the fluids. Compositional simulation is needed to model reservoir processes, such as depletion, miscible flooding, steam cycling, and gas cycling. (Liu, K., 2001)

Foams

Foams are substances formed by trapping pockets of gas in liquids for solids. Most forms consist of a large volume of gas with thin films of liquid or solid to separate the gas regions. There are several necessary conditions to produce foam – (1) mechanical work, (2) surface active components and (3) formation of foam faster than its breakdown. Mechanical work is required to increase the surface area. Typical mechanical work could be from blowing force (Kuang et al., 2015), and the blowing agent could be gas, liquid or supercritical fluid (Kuang et al., 2016). The surface active components are for reducing the surface tension and thus, to increase the stability of the foam.

Solid foams are widely used as lightweight materials, thermal insulators, flotation devices and so on. Liquid foams can be used in fire retardants, foams used in extinguishing fires (e.g. oil fire), some beverages (e.g. beer, soda beverage et al) and so on. Foam stability is dependent on the physical and chemical properties of surfactant-stabilized films such as capillary suction, gravity drainage, viscosity, surface elasticity, electric double-layer repulsion, steric repulsion and so on (Schramm, L.L. and Wassmuth, F. 1994).

Foams in Petroleum Recovery

Foam was considered to be a promising candidate to improve the mobility control and sweep efficiency of oil-recovery drive fluids, especially gas-drive fluids. Foams used in conformance improvement are dispersions of microgas bubbles of 50-1000 μm. They exist as individual microgas bubbles separated by liquid lamellae forming a liquid partition between gas bubbles.

In steamflooding or CO_2 flooding, foams are used to improve sweep efficiency and improve oil recovery. Mobility-control foam is typically injected from the injection well side. The reduced mobility of foams in porous media is attributed to the flow of dispersed high-pressure steam or CO_2 droplets separated by surfactant-stabilized lamellae within the porous media. Gas-blocking foam is usually placed from the production well.

In CO_2 flooding, CO_2 foams are effective mobility-control agent candidates to improve CO_2 sweep efficiency. In this process, CO_2 could be at a higher density or supercritical. In steamflooding, steam can improve vertical and areal sweep efficiency and reduce steam channeling and override. The effectiveness and economics of both CO_2 flooding and steamflooding are critically dependent on surfactant adsorption and retention. For steamflooding, surfactant thermal stability is also critical.

Surfactants in Foams

All foams used for conformance improvement have surfactants as surface active components dissolved in the liquid phase of the foam to stabilize the gas dispersion. The gas phase of the foam could be common gas or supercritical gas. Surfactants are necessary for the formation of foams and a typical surfactant molecule contains both a polar (hydrophilic) and nonpolar segment (hydrophobic). The surfactant tends to be located on the oil/water or gas/water interface and reduces the interafacial tension. Based on the chemistry of the polar segment of the surfactant molecule, they are classified into four types: anionics, cationics, nonionics and amphoterics (Fig.10). The polar groups of those four types are: an anionic surface in a salt where the polar anionic group is exactly attached to the surfactant molecule, a salt where the polar cationic group is directly attached to the surfacent molecule, non-salt chemical species which promote surfactant properties by imposing electronegativity, and two or more chemical types, respectively.

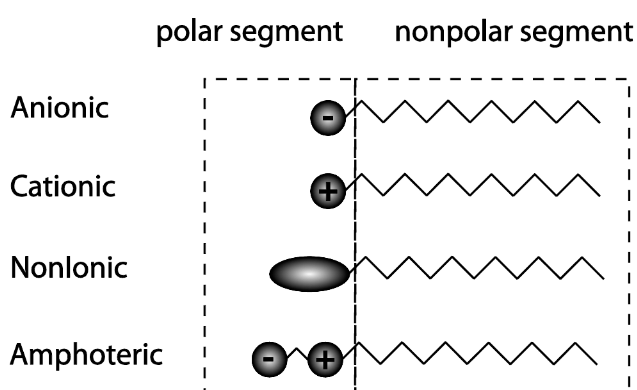

Figure 10—Types of surfactants

Anionic surfactants are commonly used in oilfield foams because they are relatively good surfactants, generally resistant to retention, chemically stable, and available on a commercial scale with a fairly inexpensive price. Cationic surfactants are not used frequently because they could strongly adsorb on to the surfaces of clays and sand. Cationic surfactants are relatively expensive as well. Alph-olefin sulfonates are used in foams because of their good foaming characteristics, good salt tolerance, good thermal stability, and good availability with low cost. Fluorinate surfactants, used with other surfactants, could improve the tolerance of foam to oil. However, they are not widely used in oilfileds mainly because their high cost. For foams in steamflooding, thermal stability of the surfactant should meet the needed life of the foam in the reservoir.

Advantages and Disadvantages

There are many advantages of using foams during oil recovery operations. Foams could reduce permeability and mobility to a greater degree in higher permeability matrix reservoir rock, and improve conformance. Since foams are shear-thinning fluids, they have good injectivity and good effective mobility control in the far-wellbore region. Foams can be exploited when they possess low effective density, helping selectively place foams high in a reservoir and impede problematic gas flow. Additionally, for use in conformance improvement operations, foams are considered to be an environment-friendly material.

There are several disadvantages of using foams as well. It poses a challenge to apply foams successfully in oil recovery operations. Oil could destabilize and deactivate many conformance improvement foams. Additionally, surfactant adsorption or retention has a negative impact on the performance and economics of the mobility-control foams. Meanwhile, gas-block foams, which are used in production-well treatments, have limited strength under high differential pressure conditions. Sometimes, the limited or poor ability to effectively form foams in situ in matrix reservoir rock during co-injection or sequential injection limits the effectiveness and efficiency of foam formation and placement in reservoirs as well.

Steam Foam Process

For extraction of heavy oil from oil sands, methods used commonly involve using steam to heat the formation, liquefy the heavy oil or bitumen, and move it to a production well. Steam-based thermal recovery methods include steam flooding (or steam drive), cyclic steam stimulation (CSS) and steam-assisted gravity drainage (SAGD).

In the steam drive process, steam is usually injected into a vertical injection well. A series of production wells usually surround the injection site. Steam is injected under conditions effective to liquefy the heavy oil or bitumen and drive it toward the production wells. It is known to introduce surfactant compositions into the injection wells in a steam drive process to increase the viscosity of steam and use it more efficiently to recover the heavy oil. For field steam foam injection applications, surfactants were injected as high concentration (10 wt% active) or continuously at a lower concentration (0.1-1.0 wt% active).

Most foam formulations include a small amount of non-condensable gas (at a concentration of 0.5 – 1.0 mol% in the gas phase) or NaCl (1-4% wt% in the aqueous phase) which may be co-injected with the surfactant. The role of this non-condensable gas is to stabilize the collapse of bubbles of steam by condensation. Extra water may be added to the steam to maintain the liquid fraction at the desired value (typically above 0.01).

One issue with steam foam is the maximum applicable temperature. Steam foam has mostly been used below 250 Deg C. Therefore, it is important to select thermally stable surfactants. High-temperature stability of the surfactants restricts the choice of surfactant type to only a few hydrophilic head groups, namely sulfonates, ethoxylates and phosponates. The surfactants must also have good foaming properties; this sets the second constraint on the conceivable molecules. Besides thermal stability and ability to foam, the main other criteria to be fulfilled by steam foam surfactants are good solubility in possibly hard water and limited adsorption on reservoir rock.

CSS involves one well and cycles of steam injection for days or weeks (the "huff" part), a soak period to let the steam to soften the formation over several days, and oil recovery (the "puff" part) for weeks or months. The steam foam was also applied to the steam cyclic process as well as in the steam drive process. Surfactant solutions and steam foams have been used in conjunction with these cyclic steam simulation processes. During a cyclic process, as steam initially flows through high permeability zones, the oil is depleted, and flow resistance is even lower. Thus, the subsequent steam will continue flowing into those depleted zones if the steam foam is not injected. By injecting steam foam, due to its higher resistance, it diverts the subsequently injected steam into the zones of higher oil saturation (less depleted zones).

Performance of Steam Foam Process

The methods for assessing the performance of a steam-foam process are summarized below,

- Improved Vertical Sweep
- Reduced Steam Production
- Enhanced Oil Cut and Oil Recovery
- Increased Oil/Steam Ratio
- Injection Pressure
- Injection Profile
- Pounds Surfactant/Barrel Incremental Oil

Summary of Field Pilot Results

A summary of some of the field pilot results reported in the literature is presented in Table 2. This summary does not include the Steam Assisted Gravity Drainage (SAGD) applications mentioned earlier because we only focus to discuss field test in California, USA. In Table 2, there are 20 examples foam field tests in California, mostly in Kern River and Midway Sunset Field. Two different types of reservoirs are represented in Table 2.

Table 2—List of Steam Foam Field Tests in California, USA

No	Field	Pattern	Company	Location	Year	Reservoir	Thermal Process	Surfactant Injection
1	Midway Sunset		Unocal	California/ USA	1973-1975	Potter	Cyclic Steam	Cyclic
2	Kern River	Mecca	Shell	California/ USA	1976		Steam Flood	Continuous
3	Kern River		Shell	California/ USA			Steam Flood	Continuous
4	Kern River	Green and Whittier	Getty	California/ USA	1978-1979	K1	Steam Flood	Cyclic
5	Midway Sunset	S90-21N	Santa Fe	California/ USA	1980-1981	Spellacy	Steam Flood	Continuous
6	North Kern Front		Petro Lewis	California/ USA	1980-1982	Chanac	Steam Flood	Cyclic
7	Kern River	Mecca	Shell	California/ USA	1980-1985		Steam Flood	Continuous
8	Midway Sunset	Various	Various	California/ USA	1980-1990	Potter	Cyclic Steam	Continuous and Cyclic
9	San Ardo	Rosenberg 85A	Texaco	California/ USA	1981-1982	Aurignac	Steam Flood	Continuous
10	Kern River	McManus	Petro Lewis	California/ USA	1981-1983		Steam Flood	Semi Continuous
11	Kern River	Bishop	Shell	California/ USA	1982-1986		Steam Flood	Continuous
12	Cat Canyon		Conoco	California/ USA		Aurignac	Steam Flood	Continuous
13	Midway Sunset	15A	Chevron	California/ USA	1983	Potter	Steam Flood	Cyclic

No	Field	Pattern	Company	Location	Year	Reservoir	Thermal Process	Surfactant Injection
14	Midway Sunset	26C, 76AW	Chevron	California/ USA	1983	Potter	Steam Flood	Cyclic
IS	Guadalupe		Unocal	California/ USA	1984-1986	Sisquoc	Steam Flood	Continuous
16	Dome Tumbador		Unocal	California/ USA	1985-1988	Potter	Steam Flood	Continuous
17	South Belridge		Mobil	California/ USA	1987	Tulare	Steam Flood	Semi Continuous
18	Midway Sunset	26C, 68W	Chevron	California/ USA	1989	Monarch	Steam Flood	Semi Continuous
19	Cymric	4-10W Section 26W	Chevron	California/ USA	1991	Amnicola	Steam Flood	Continuous
20	Midway Sunset	26C, 52BW	Chevron	California/ USA	1992	Monarch	Steam Flood	Special

The reservoir and fluid characterization for all the published steam foam field tests can be seen in Table 3. Based on the data in Table 3, we can see that the steam drive process was done in thick, high vertical permeability reservoir.

Table 3—Reservoir and Fluid Characteristics from Steam Foam Field Tests in California, USA

No	Field	Pattern	Depth (m)	Thickness (m)	Permeability (md)	Porosity (%)	Oil Viscosity (cp)	Oil Gravity (API)
1	Midway Sunset		425	120	Over 1000	35		
2	Kern River	Mecca						
3	Kern River		200	133	000	23	6400	13
4	Kern River	Green and Whittier		18	1000-5000	31	1780	13.5
5	Midway Sunset	590-21N	305	122	2000	28		11
6	North Kern Front		480	18	2210	33		13
7	Kern River	Mecca	305	22.5		30		13
8	Midway Sunset	Various						
9	San Ardo	Rosenberg 85A	685	36	2200	33	4500-10000	13-14
10	Kern River	McManus	135	24	2000	23		12
11	Kern River	Bishop	185	16		30		13
12	Cat Canyon		965	9			25000	
12	Midway Sunset	15A	335	95	3900	36.5	900	13
14	Midway Sunset	26C, 76AW	365	79	1390	29	1500	14
15	Guadalupe		850	8.5	1550	35	560	9
16	Dome Tumbador		490	134		34		11.2

No	Field	Pattern	Depth (m)	Thickness (m)	Permeability (md)	Porosity (%)	Oil Viscosity (cp)	Oil Gravity (API)
17	South Belridge		175	30	1500-3500	35	1600	12.9
18	Midway Sunset	26C, 68W	425	50	1000-2000	27		
19	Cymric	4-10W Section 26W	305	13.5	500-2000	39	2000	12.6
20	Midway Sunset	26C, 52BW	320	41	700-2000	30		

Summary Technical Challenges of Field Pilot Results

The review of the published field results suggest that steam foams have a proven track record and have been effectively functional in many cases under different reservoir conditions, in particular with the reservoir thickness which varies from less than 9 m (Cat Canyon) to 135 m (Kern River) and oil viscosity also ranges from relatively medium viscosity (560 cp in Guadalupe) to high viscosity (25,000 cp in Cat Canyon). This part will focus on summarizing the technical challenges and lessons learned from field tests in California. The summary is depicted in Table 4.

Table 4—Summary Field Test Results and Challenges

No	Field	Pattern	Pattern Type	Thermal Process	Steam issues	Surfactant Injection	Successful	Incremental Recovery (bbl)	Surfactant Efficiency (bbl/kg)
1	Midway Sunset	Various		Cyclic Steam		Continuous and Cyclic			0.10
2	Midway Sunset		21 IndividualWells	Cyclic Steam	Thief Zones	Cyclic			1.5-6.7
3	Kern River	Mecca	Inv 5 Spot	Steam Flood	Gravity Override	Continuous	Y	196,000	0.30
4	Kern River		Inv 5 Spot	Steam Flood	Gravity Override	Continuous	Y		
5	Midway Sunset	590-21N	Inv 5 Spot/9 Spot	Steam Flood		Continuous			
6	Kern River	Mecca	4 inv 5 spots	Steam Flood		Continuous	Y		
7	San Ardo	Rosenberg 85A	Inv 5 Spot/9 Spot	Steam Flood	Gravity Override	Continuous	No Incremental Oil, Improved comformance		
8	Kern River	Bishop	4 inv 5 spots	Steam Flood	Gravity Override	Continuous	Y	82,000	0.20
9	Cat Canyon		Irregular	Steam Flood	Thief Zones	Continuous	N		
10	Guadalupe		4 inv 5 spots	Steam Flood	Channeling	Continuous	Y	29,400	0.30
11	Dome Tumbador		4 inv 5 spots	Steam Flood	Gravity Override	Continuous	Y	1,234,000	0.40
12	Cymric	4-10W Section 26W	Line Drive	Steam Flood	Channeling, Downdip migration	Continuous	Y		
13	Kem River	Green and Whittier	9 inv 5 spots	Steam Flood	Gravity Override	Cyclic			
14	North Kern Front		2 inv. 9 spots	Steam Flood	Thief Zones	Cyclic	Y	77,970	6.10

No	Field	Pattern	Pattern Type	Thermal Process	Steam issues	Surfactant Injection	Successful	Incremental Recovery (bbl)	Surfactant Efficiency (bbl/kg)
15	Midway Sunset	15A	irr. Inv 9 spot	Steam Flood	Gravity Override due to dip	Cyclic	Y	53,000	8.60
16	Midway Sunset	26C, 76AW	irr. 11/5 spots	Steam Flood	Gravity Override	Cyclic	Y	15,000	2.20
17	Kern River	McManus	Inv. 5 spots	Steam Flood		Semi Continuous	Y	14000-31400	0.4-0.8
18	South Belridge		2 Inv. 5 spots	Steam Flood		Semi Continuous	Y	183,000	2.30
19	Midway Sunset	26C,68W		Steam Flood	Thief Zones	Semi Continuous	Y	27,300	0.50
20	Midway Sunset	26C,52BW		Steam Flood		Special	Y		

One of the key learnings from the field tests is that both continuous and cyclic surfactant injection have been successfully employed. Continuous injection has achieved the highest incremental recovery, but cyclic injection is more efficient and better in terms of incremental bbl per kg of surfactant (Table 4). Cyclic injection is detrimental to maintaining a high resistance factor, however, in several other tests cyclic injection was used when injection pressure was too high (Sander, Clark & Lau 1991). In those cases, surfactant injection was typically stopped when pressure rose to a given value, then resumed once pressure had dropped sufficiently. Another key learning that is indispensable is how to ensure enough surfactant is available to create a strong foam. To maintain the foam stability, the surfactant concentration should be sufficient enough. In general, it is recommended to use at least 0.5% wt. Another parameter that needs to be considered to stabilize the foam is non-condensable gas. Non-condensable gas can be mixed with steam foam to reduce condensation and evaporation, plus increase the foam strength, pressure response and foam stability (Falls, Lawson and Hirasaki, 1988).

Another big technical challenge with steam foam is the maximum applicable temperature. Steam foam has mostly been used below 250 Deg C. For temperature above 300 Deg C, it is recommended to use high-temperature gas foam with steam rather than steam foam.

Improving conformance is one of the biggest drivers of steam foam. Some field test results in Table 4 show the incremental oil production during the tests as steam is redistributed in layers poorly swept before. The improvements in sweep efficiency were also confirmed in several pilots by the reduction in fluid temperature observed in some producer or observation wells.

Another big uncertainty that we learned from several field tests in California is how far foam can propagate into the reservoir. In Fig.11 (reproduced from Mohammadi and Tenzer, 1990) we can see the evolution of foam volume which may be represented as a function of injected surfactant. According to this interpretation, foam can propagate at large distances into the reservoir provided that enough surfactant is injected.

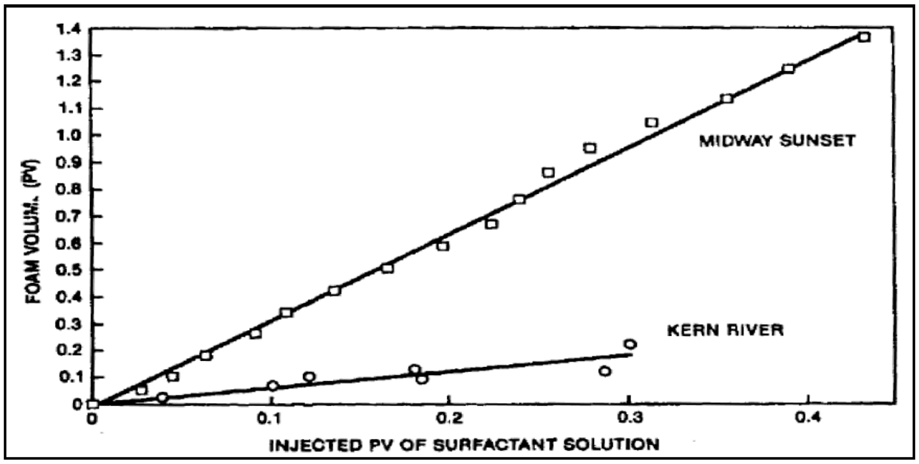

Figure 11—Foam Propagation in Field Tests (Mohammadi & Tenzer, 1990)

Overall, numerous steam foam field tests in California attest to the efficiency of the process to improve steam conformance and increase oil production and recovery. This has been achieved on a variety of reservoir conditions, both for steam flood and cyclic steam injection. This steam foam process has seen very large field applications with years of injection corresponding to very large injection volumes (over 0.4 PV). Cyclic injection of surfactant appears to be more economical than continuous injection. Analysis of the successfully filed cases provides valuable information in order to design the future steam foam field tests.

Reservoir Simulation and Production Optimization

The reservoir is an unbounded one-sixth of a three-spot pattern containing vertical high permeability, high water saturation zones around both injection and production wells. These are in turn connected by a similar horizontal streak at the top of the reservoir. This configuration approximately models the results of a hydraulically fractured Alberta reservoir. A radial cross-section (9 by 3) grid is employed with a highly compressible formation. Significant steam override is observed, and foam treatments are applied to correct this. The test problem describes a field foam run after two years of steam-only injection.

- With the foam mobility reduction treated via modified gas relative permeability curves, an empirical foam modeling approach is employed (which can be region dependent).
- Using the product of factors which can be obtained from experiment, the degree of mobility reduction is interpolated
    - the aqueous surfactant concentration
    - the presence of the oil phase
    - capillary number (equiv to dimensionless velocity)
- With surfactant availability obtained by a combination of surfactant adsorption, surfactant decomposition, and oil partitioning, surfactant transport can be modeled

Foam Modeled as Gas Permeability Reduction

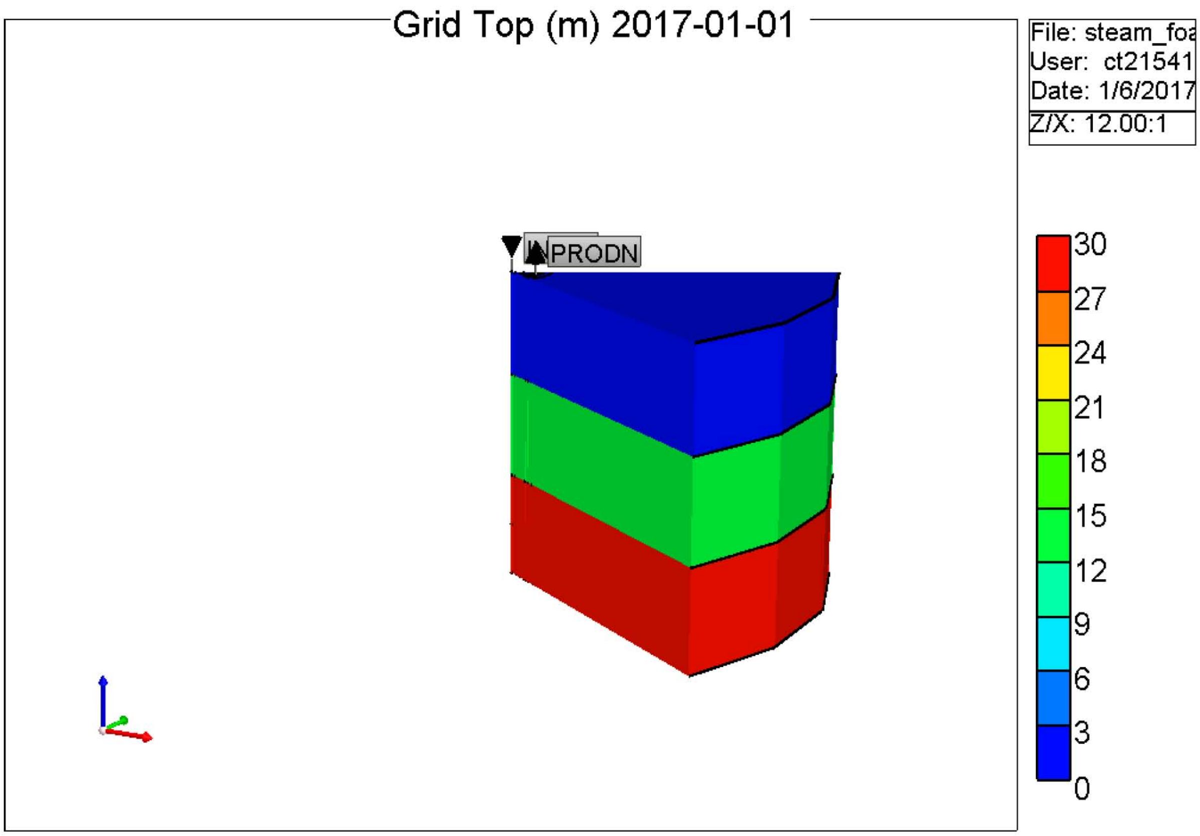

Figure 12—Model Grid

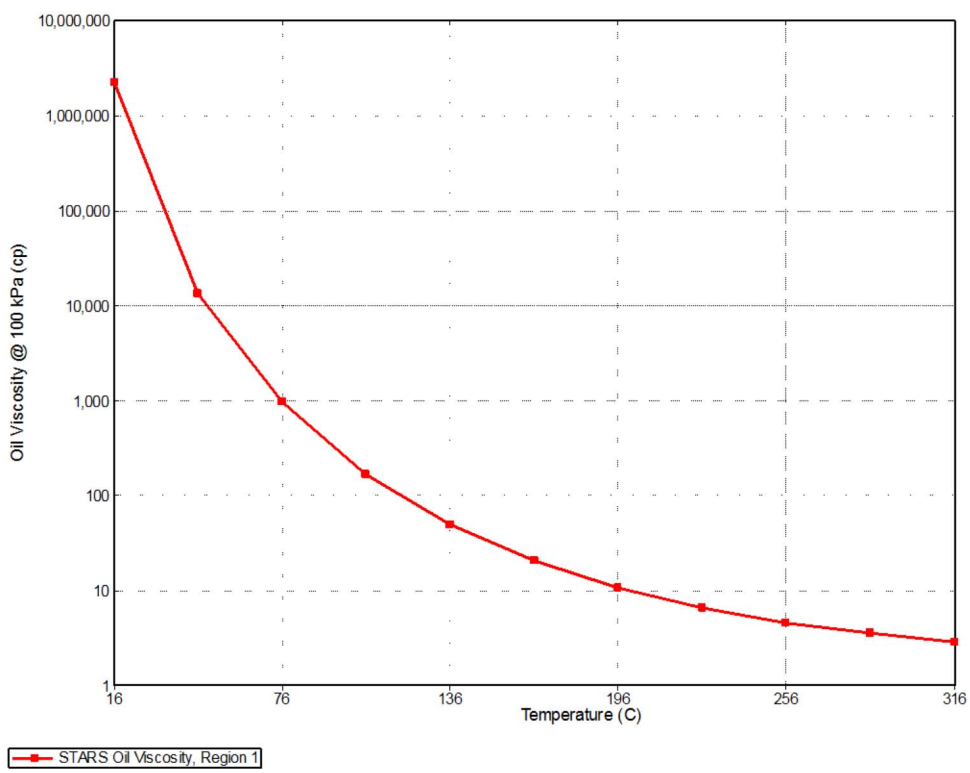

Figure 13—Oil Viscosity vs Temperature

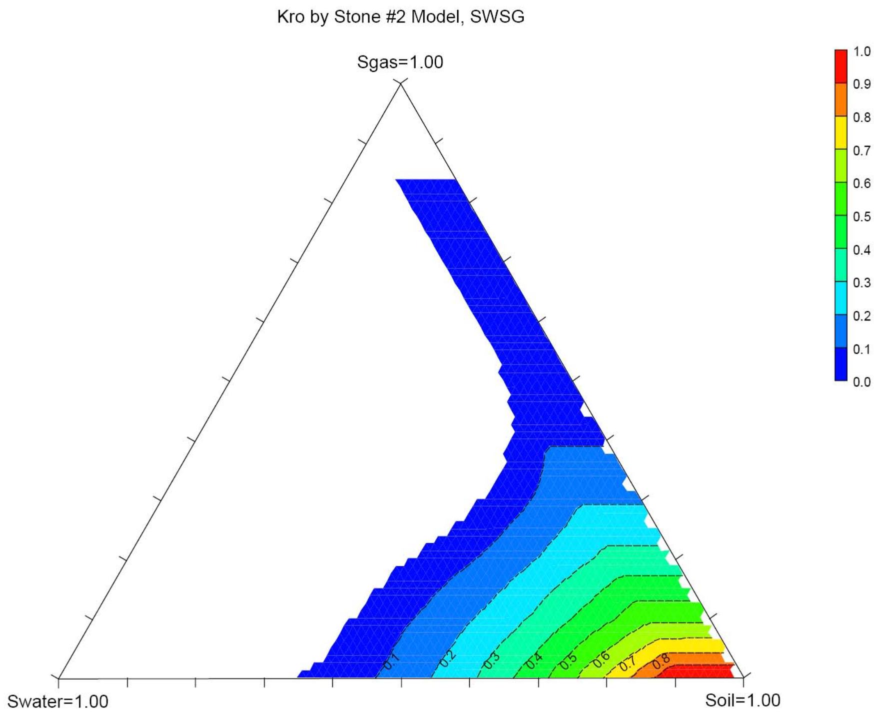

Figure 14—Saturation Distribution

Composition dependence will be taken from phase: water (aqueous) phase

Langmuir isotherm coefficients:

	Temperature	param-1	param-2	param-3	Comment
		gmole/m3	gmole/m3		
1	51.0	5.41e+6	0	2.1e+6	Langmuir concentration coefficients at T=51
2	151.0	1.08e+6	0	9.3e+5	Langmuir concentration coefficients at T=151
3	250.0	2.00e+5	0	5.3e+5	Langmuir concentration coefficients at T=250

Resistance factor applied to phase (ADSPHBLK): default phase

Rock Dependant Parameters: Adsorption Rock Type: 1

Maximum adsorption capacity (ADMAXT)	2.56 gmole/m3
Residual adsorption level (ADRT)	
Accessible pore volume (PORFT)	
Accessible resistance factor (RRFT)	

Figure 15—Maximum Adsorption Capacity

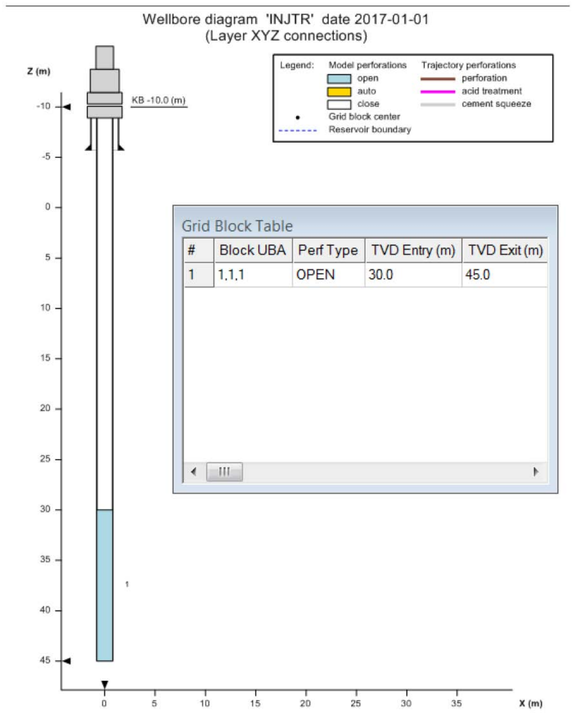

Figure 16—Injector Wellbore Diagram

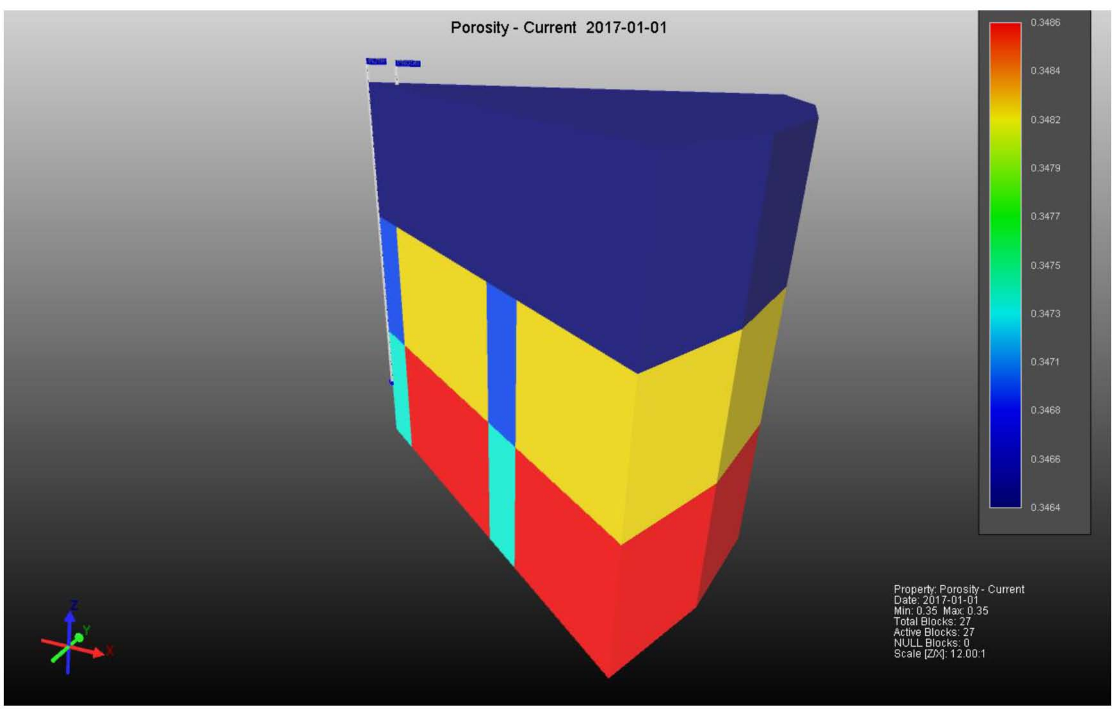

Figure 17—Porosity Distribution

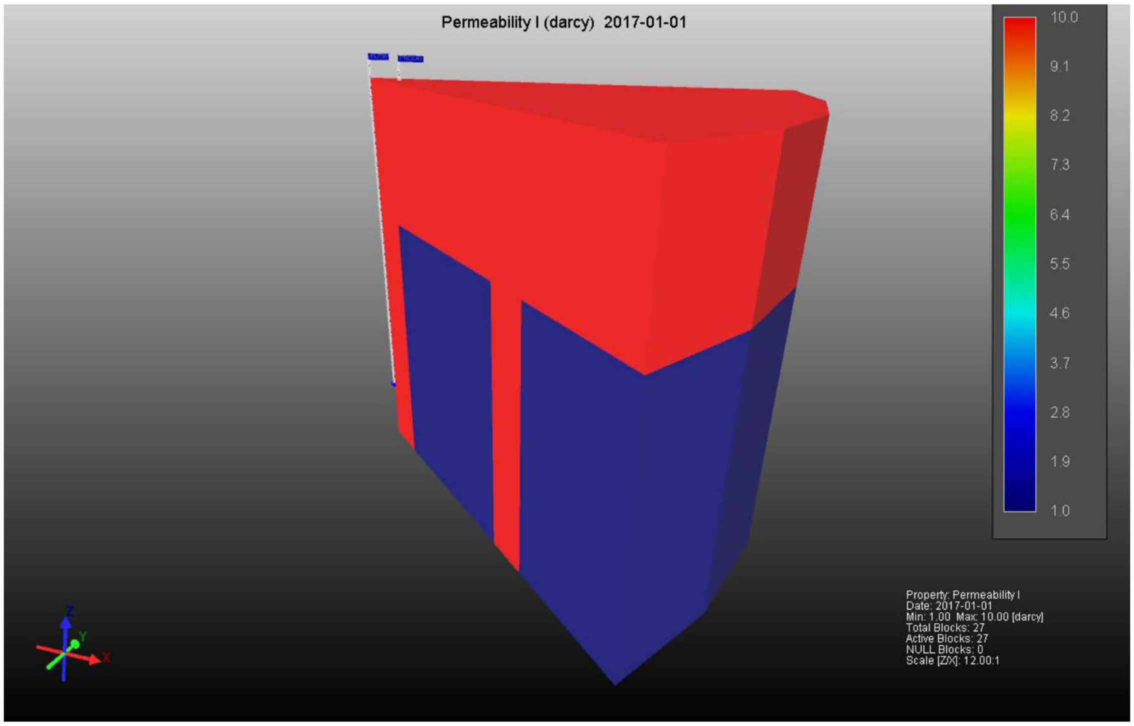

Figure 18—Permeability Distribution

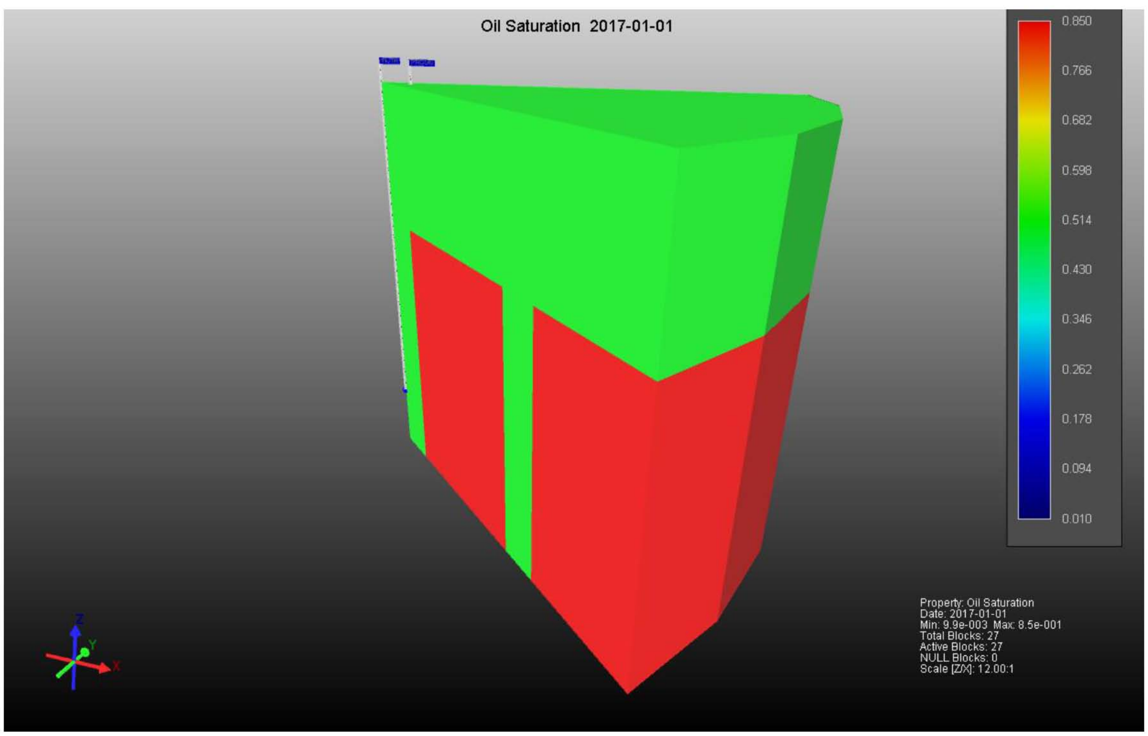

Figure 19—Initial Oil Saturation

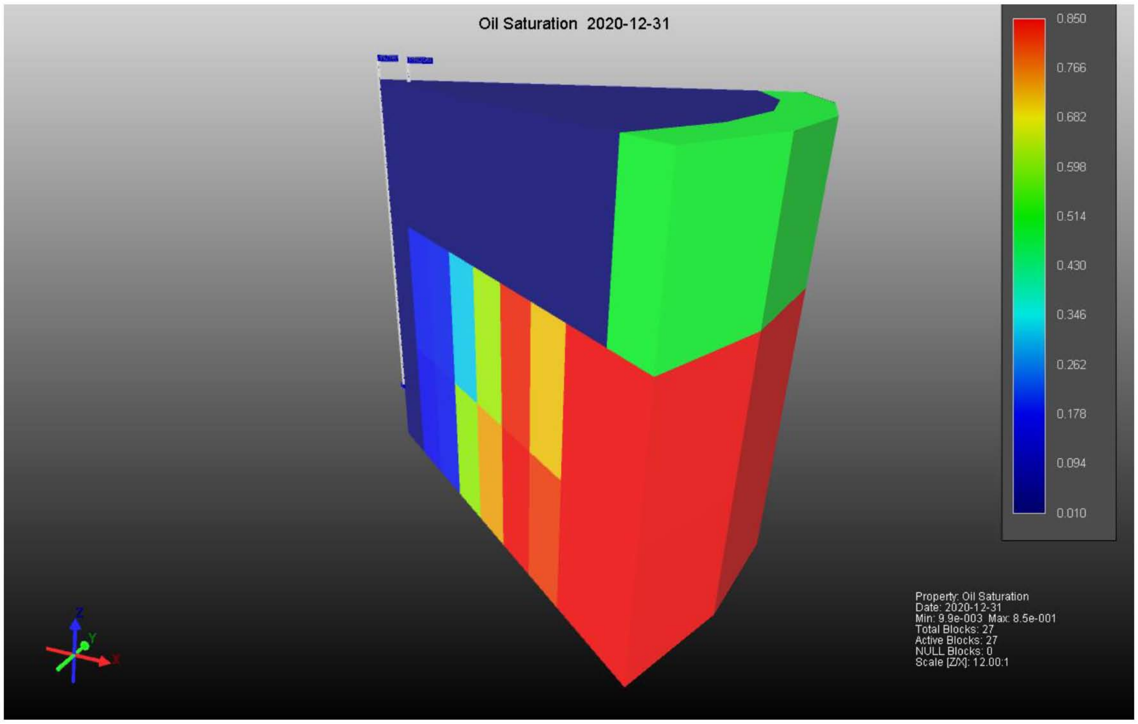

Figure 20—Final Oil Saturation

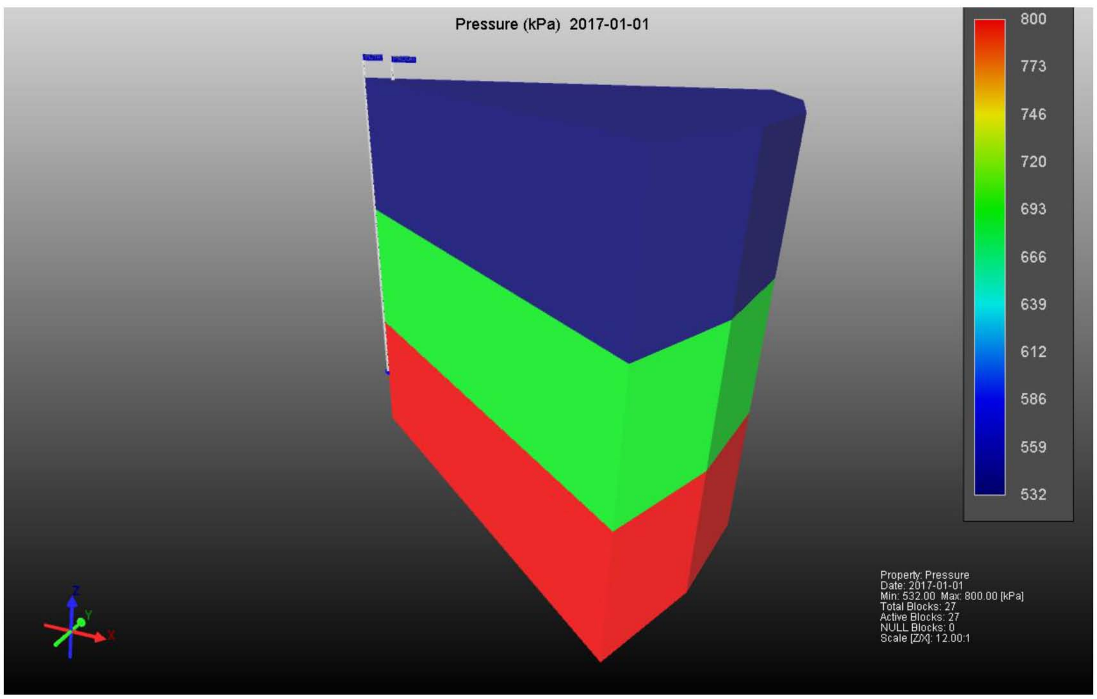

Figure 21—Initial Pressure Distribution

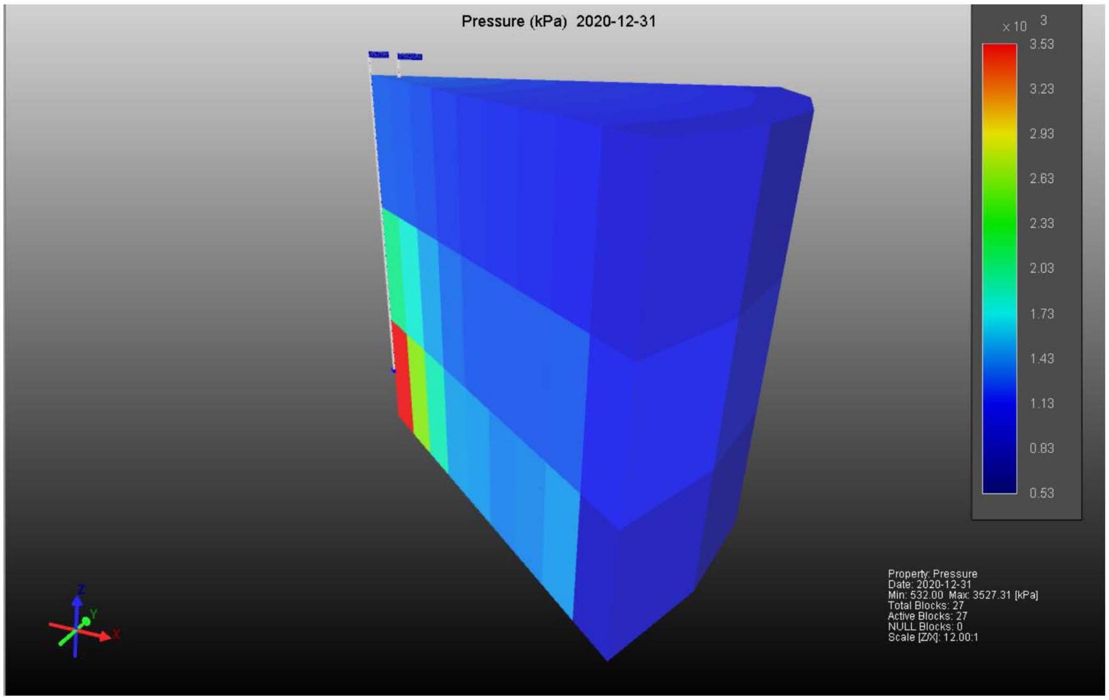

Figure 22—Final Pressure Distribution

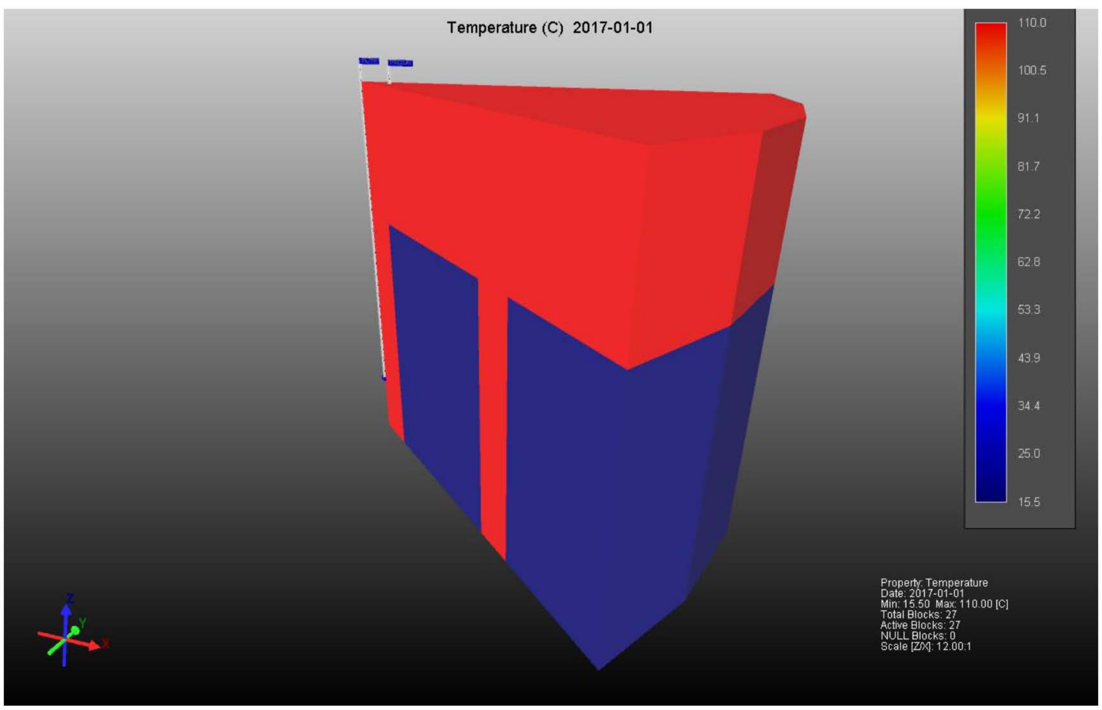

Figure 23—Initial Temperature Distribution

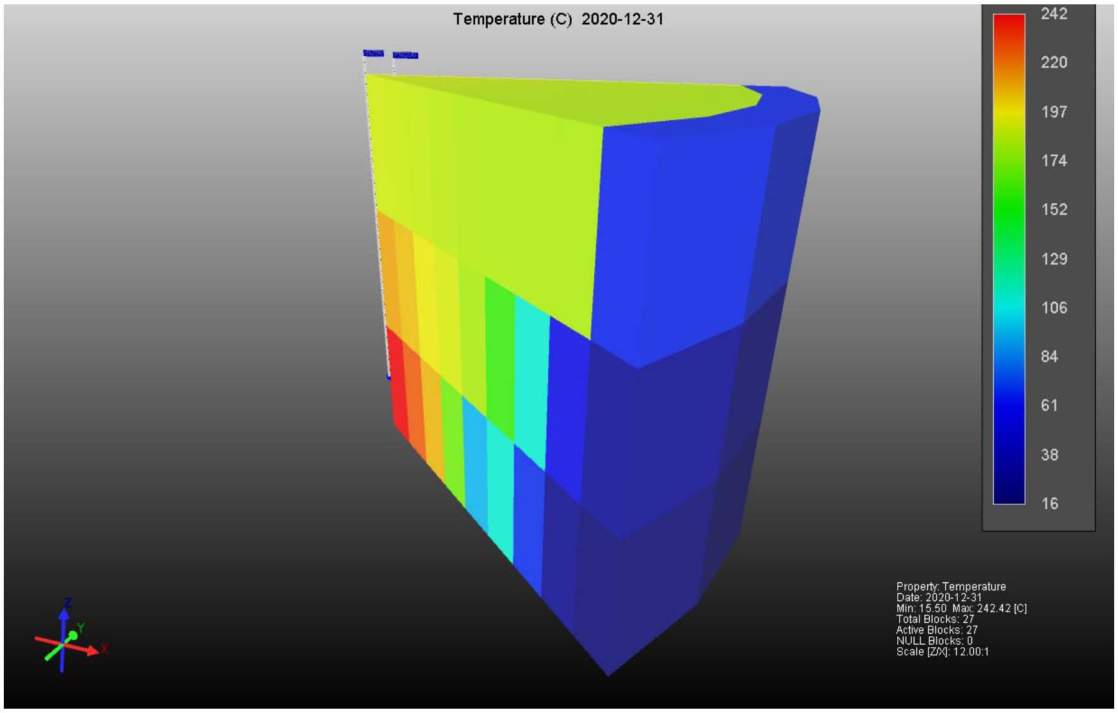

Figure 24—Final Temperature Distribution

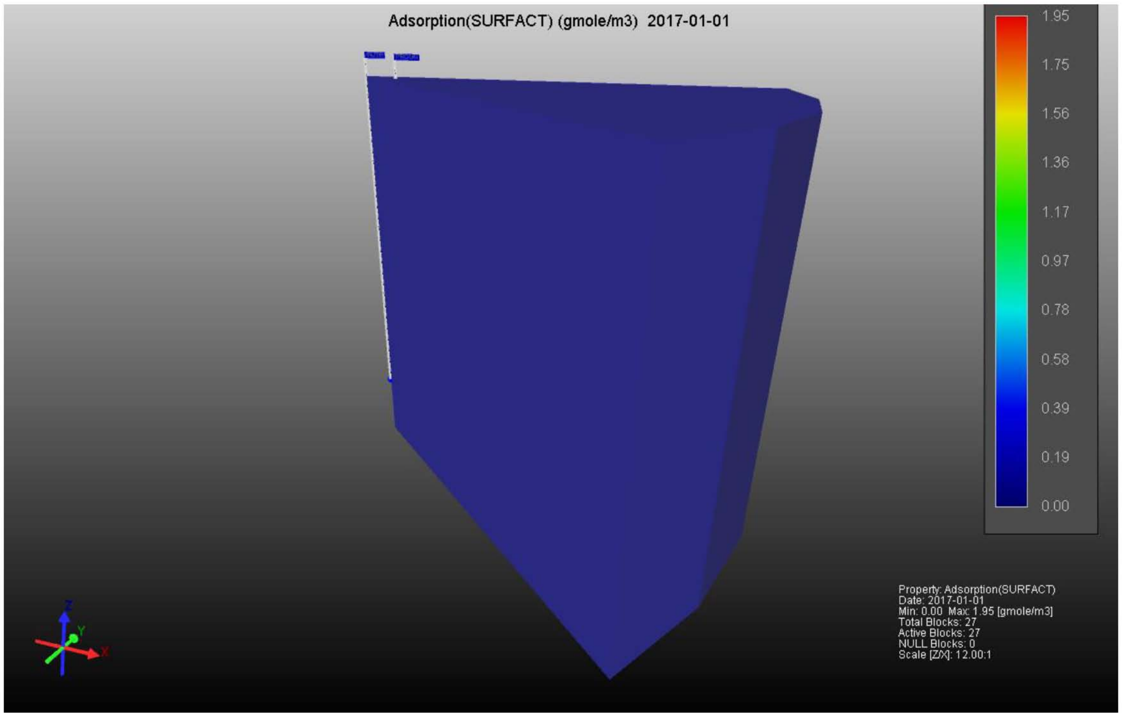

Figure 25—Initial Surfactant Adsorption Distribution

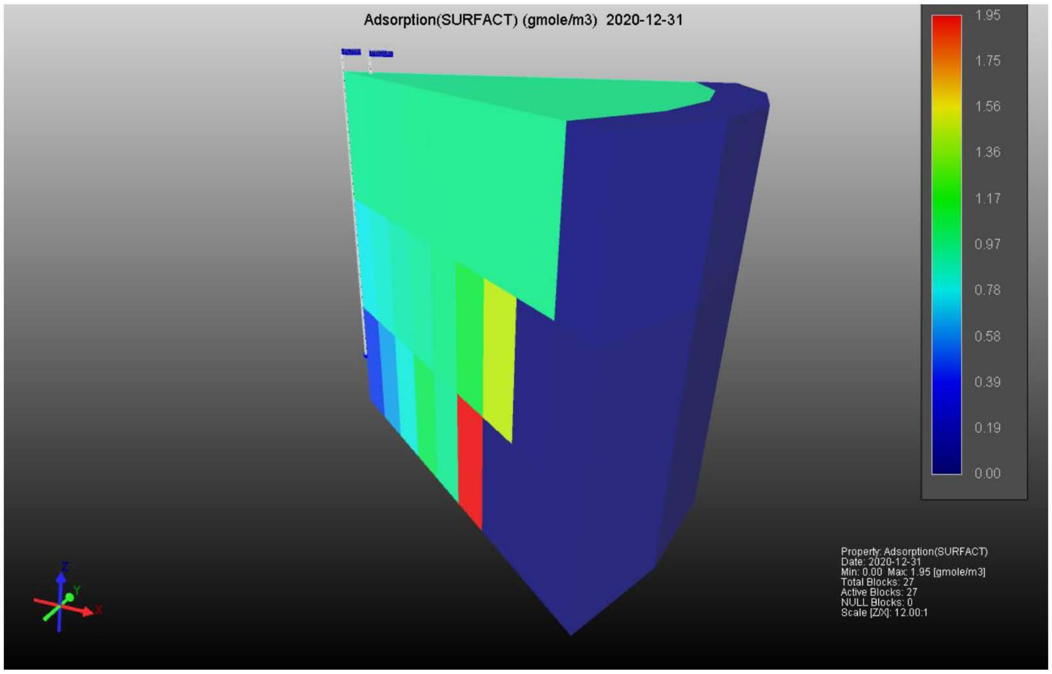

Figure 26—Final Surfactant Adsorption Distribution

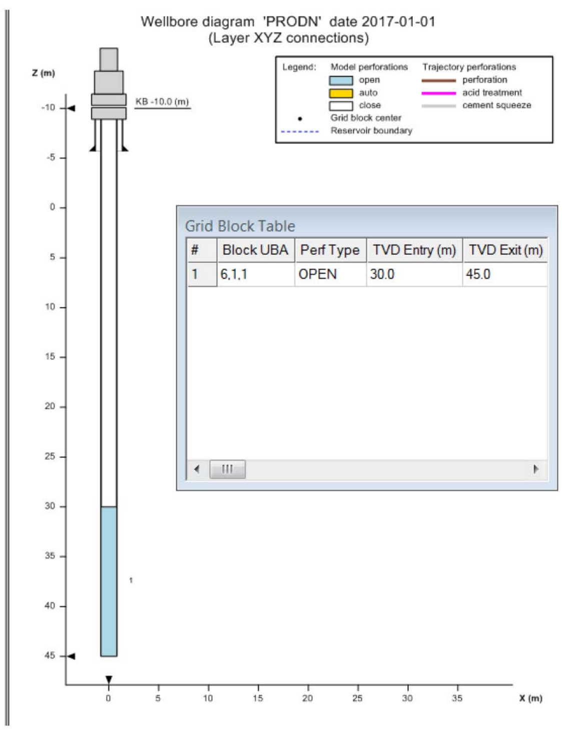

Figure 27—Producer Wellbore Diagram

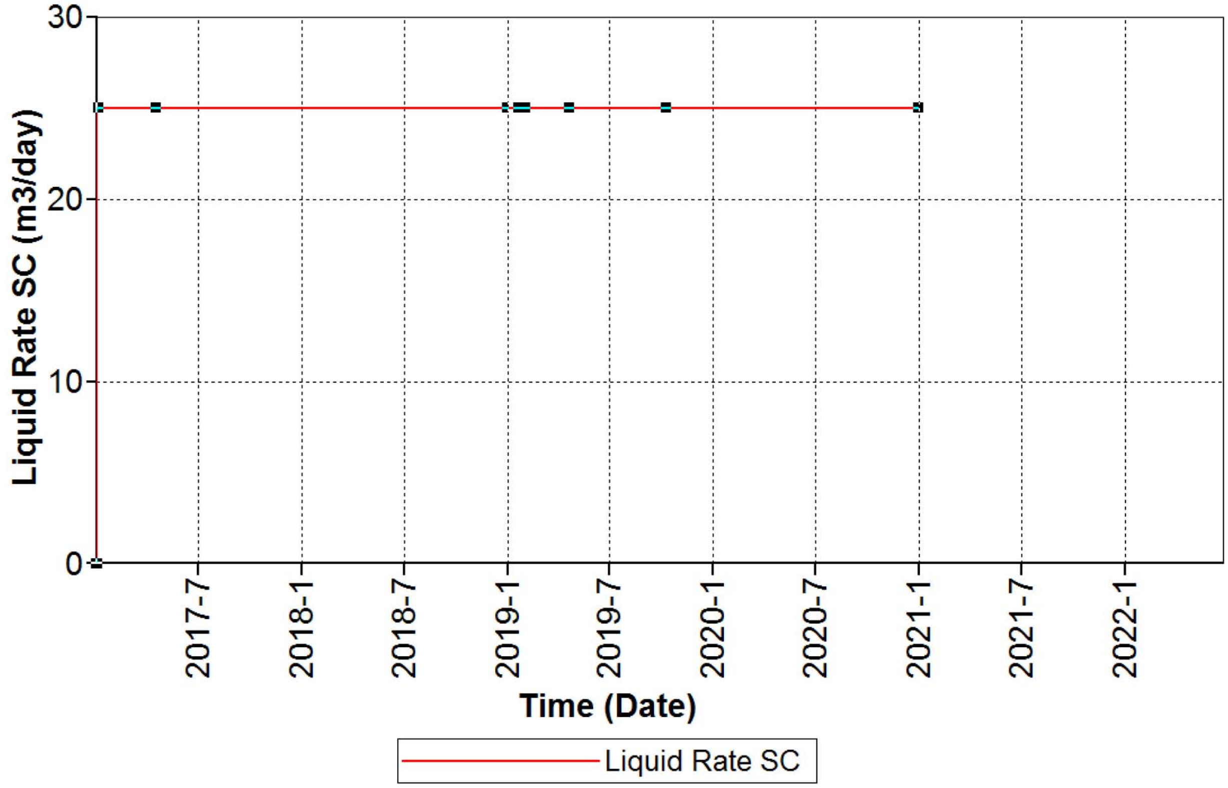

Figure 28—Steam Injection Rate

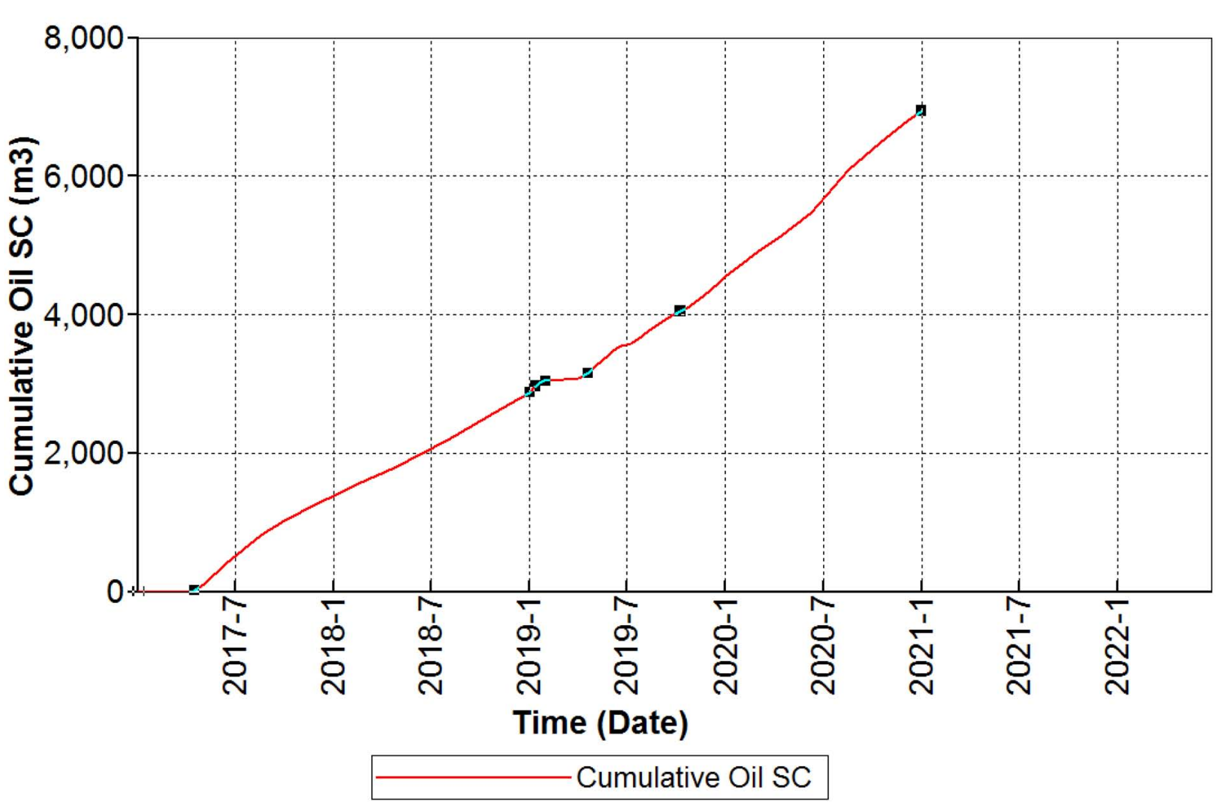

Figure 29—Cumulative Oil Production vs. Time

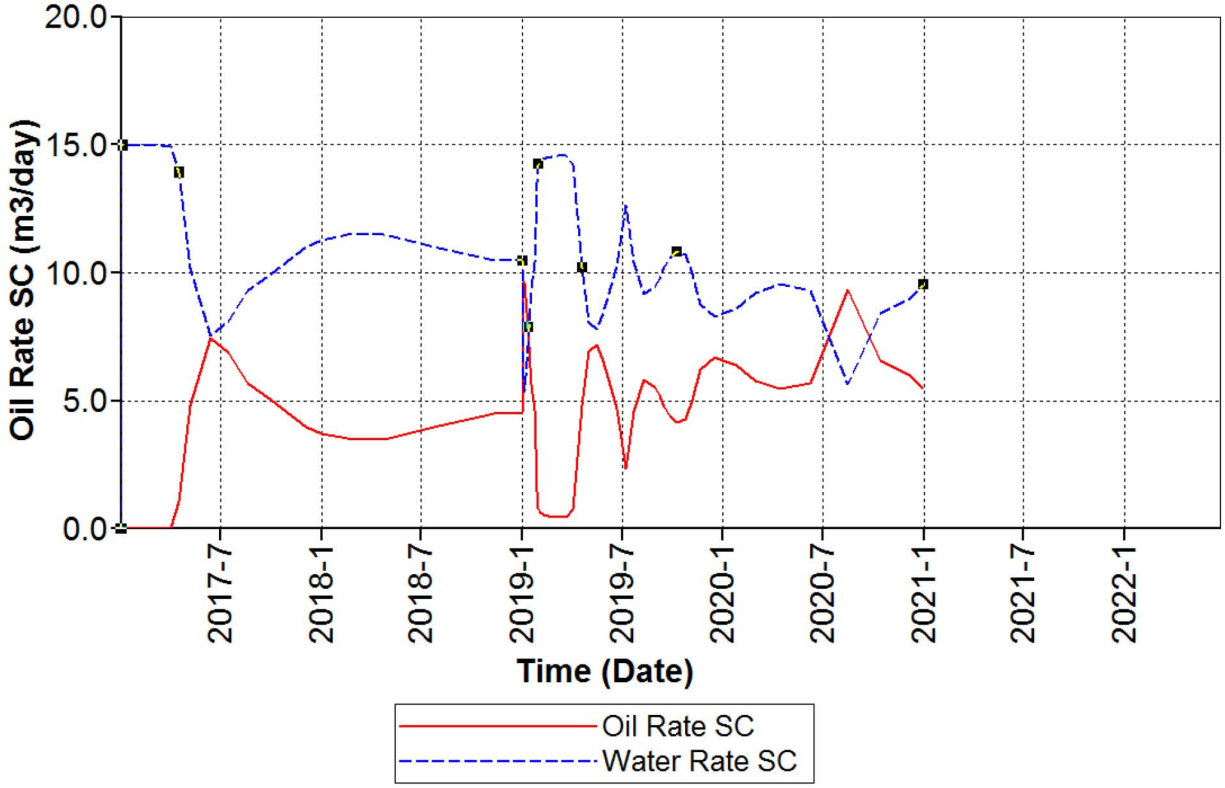

Figure 30—Oil and Water Production Rate

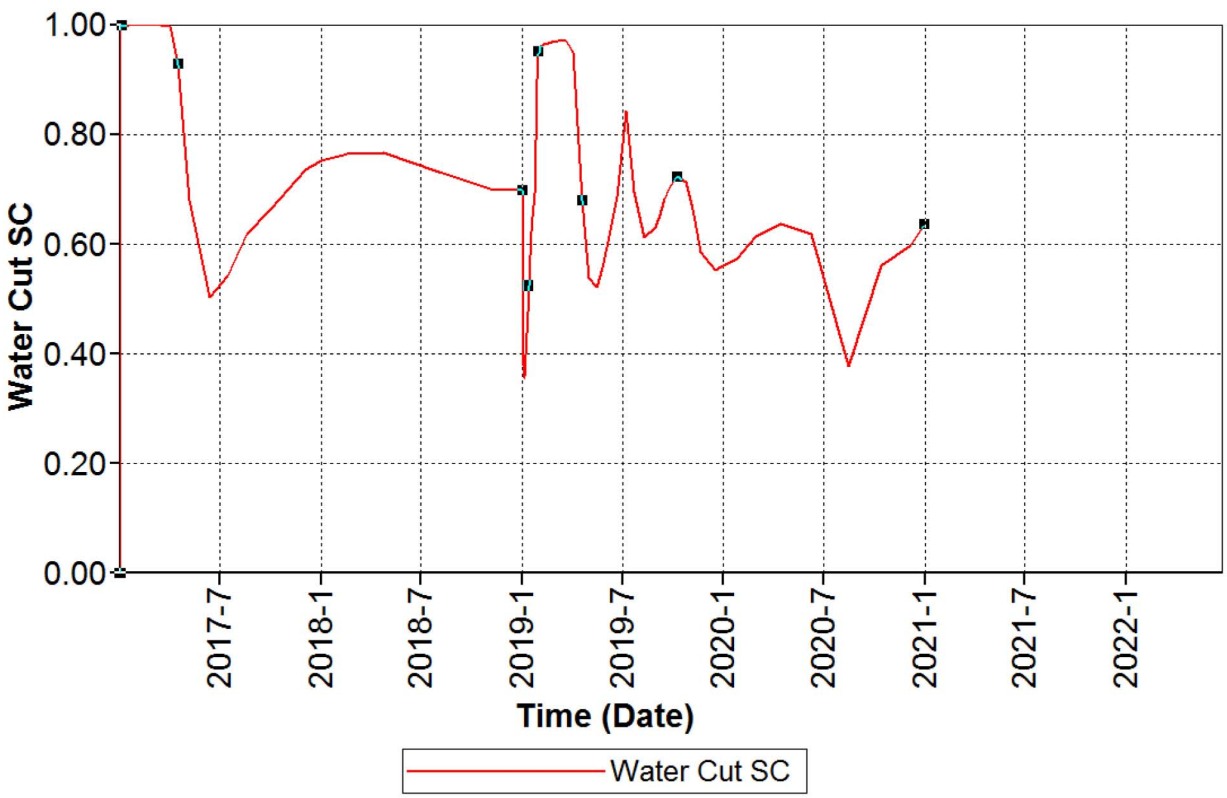

Figure 31—Water Cut

Table 5—Inputs to Reservoir Simulator

Name	Active	Default Value	Source
OVR_THER_COND	Yes	1.495E+5	Continuous Real
OVR_VOL_HT_CAPC	Yes	2.347E+6	Continuous Real
ROCKCP	Yes	2.347E+6	Continuous Real
THCONG	Yes	4.5E+3	Continuous Real
THCONO	Yes	1.15E+4	Continuous Real
THCONR	Yes	1.495E+5	Continuous Real
THCONW	Yes	5.35E+4	Continuous Real
UNDR_THER_COND	Yes	1.495E+5	Continuous Real
UNDR_VOL_HT_CAPC	Yes	2.347E+5	Continuous Real
ADSRP_CAPC	Yes	2.56	Continuous Real
QUAL	Yes	.7	Continuous Real
RATE	Yes	150	Continuous Real
SURFC_FRAC	Yes	1.875E+4	Continuous Real
TINJW	Yes	210	Continuous Real
WTR_FRAC	Yes	.9998125	Continuous Real
PERM_BED	Yes	1	Continuous Real

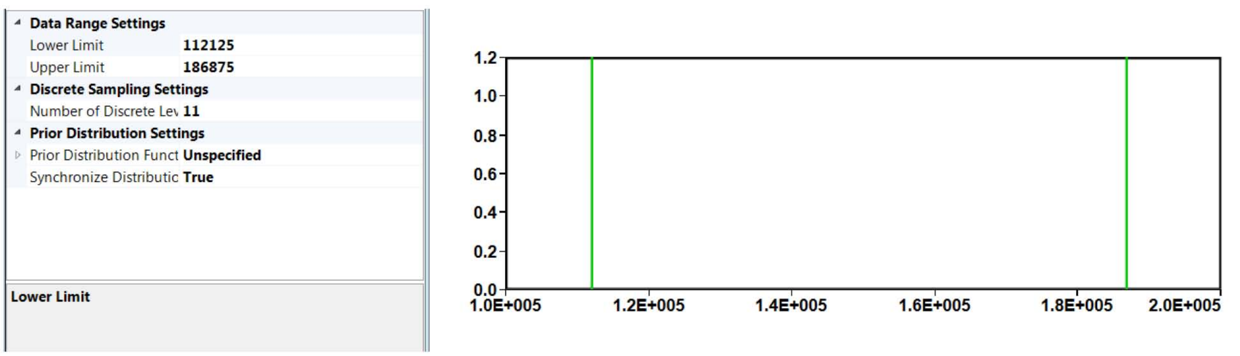

Figure 32—Overburden Thermal Conductivity

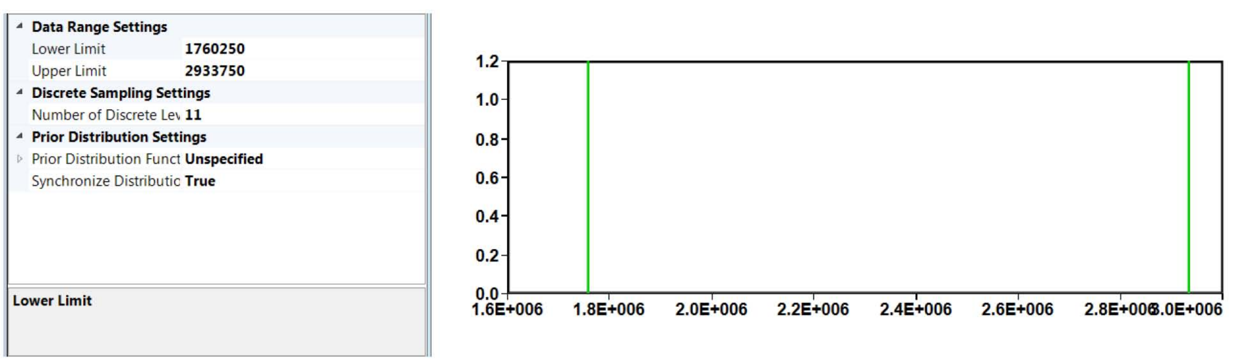

Figure 33—Overburden Volumetric Heat Capacity

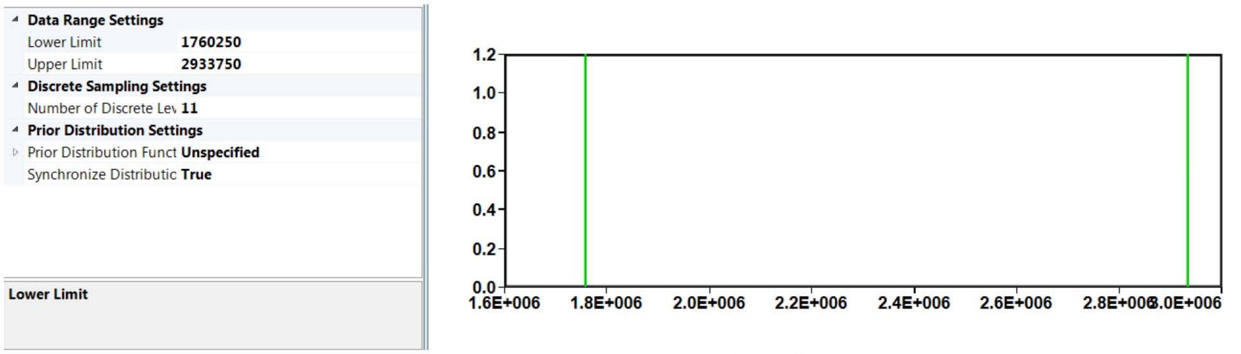

Figure 34—Rock Heat Capacity

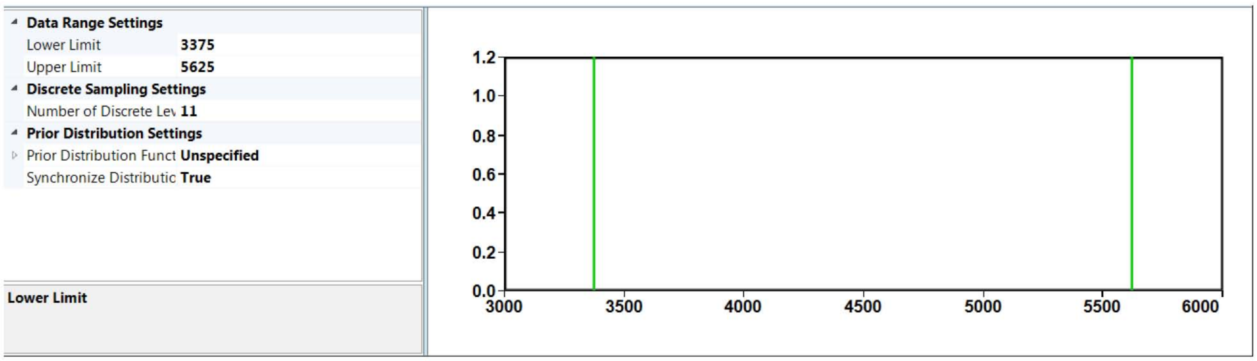

Figure 35—Thermal Conductivity of Gas

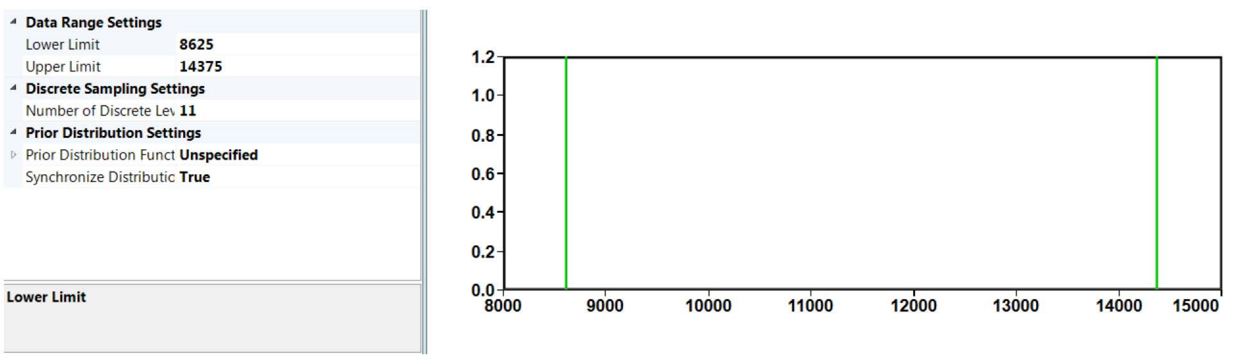

Figure 36—Thermal Conductivity of Oil

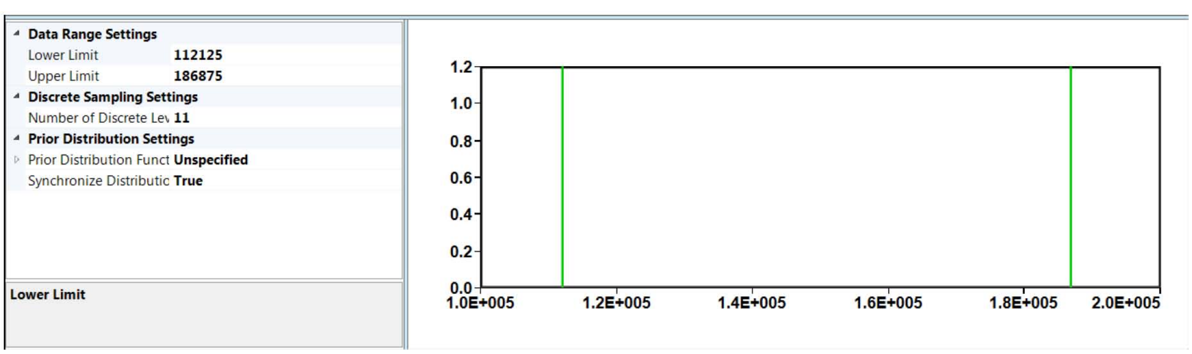

Figure 37—Thermal Conductivity of Rock

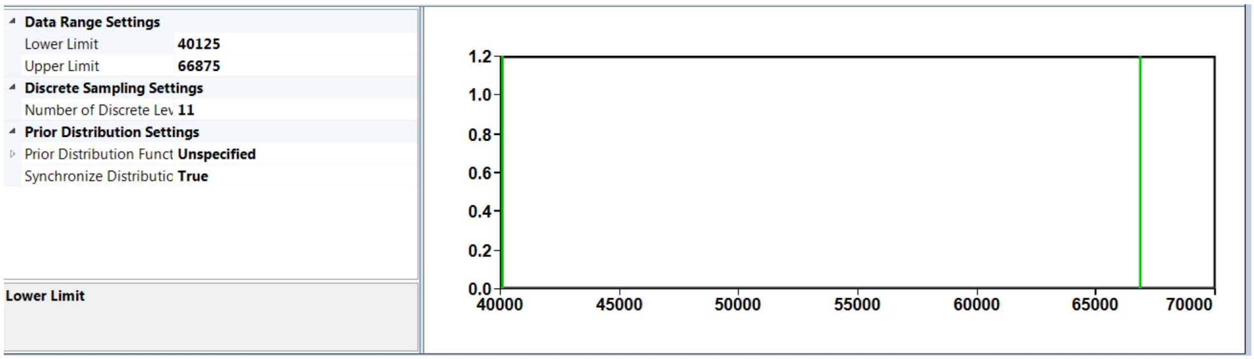

Figure 38—Thermal Conductivity of Water

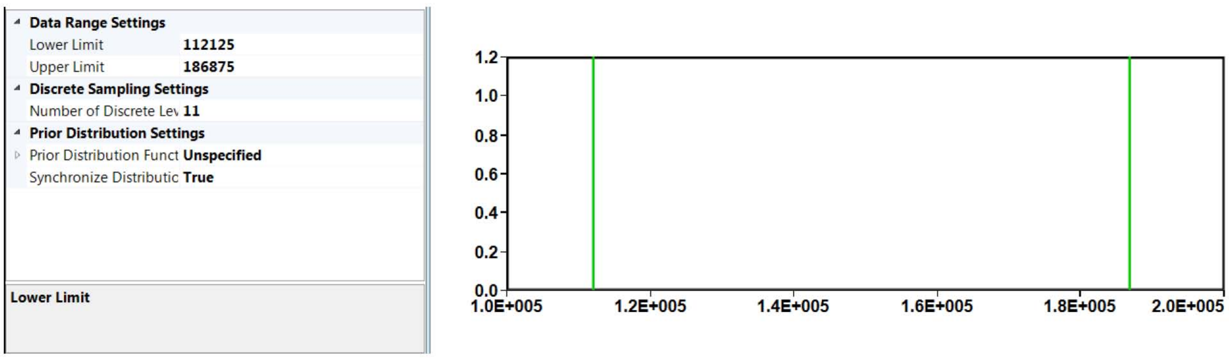

Figure 39—Underburden Thermal Conductivity

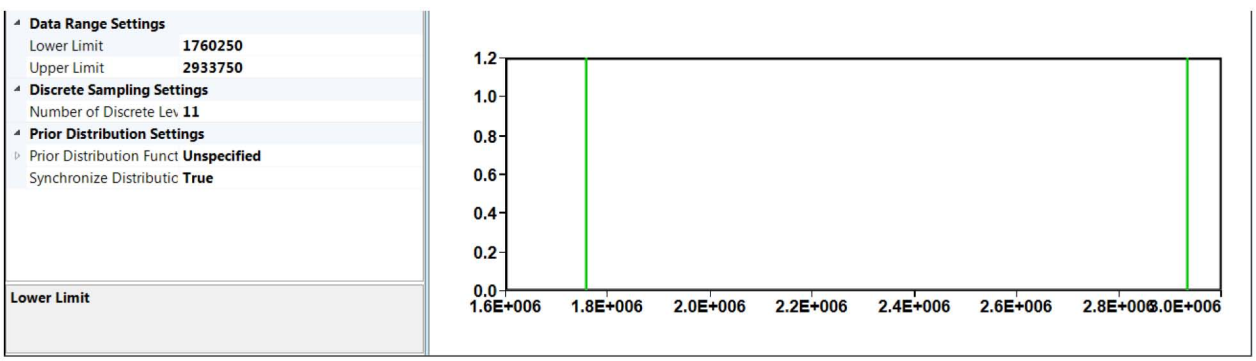

Figure 40—Underburden Volumetric Heat Capacity

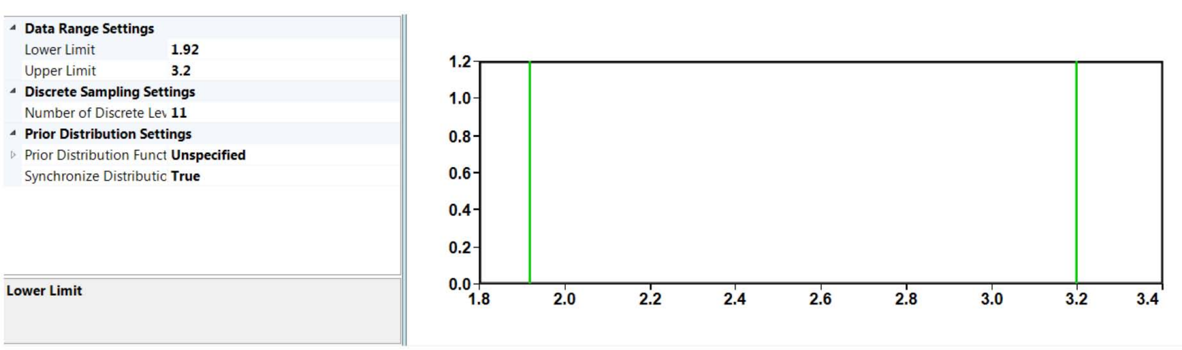

Figure 41—Adsorption Capacity

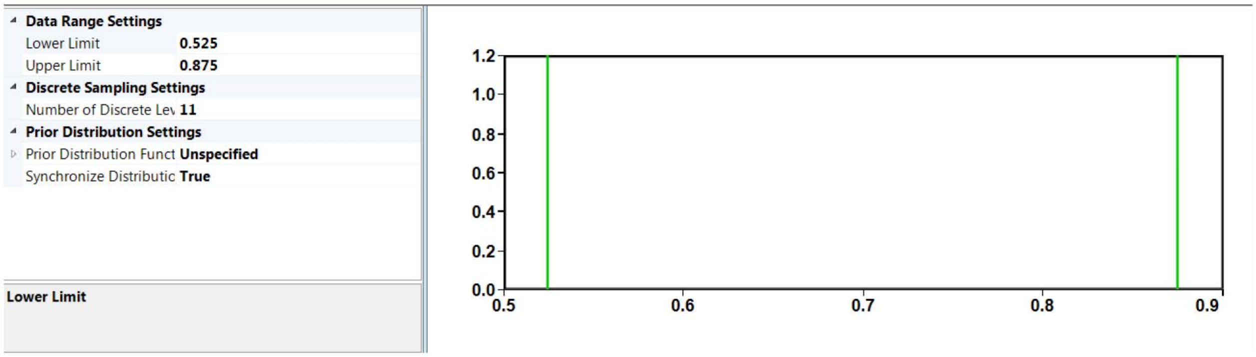

Figure 42—Steam quality

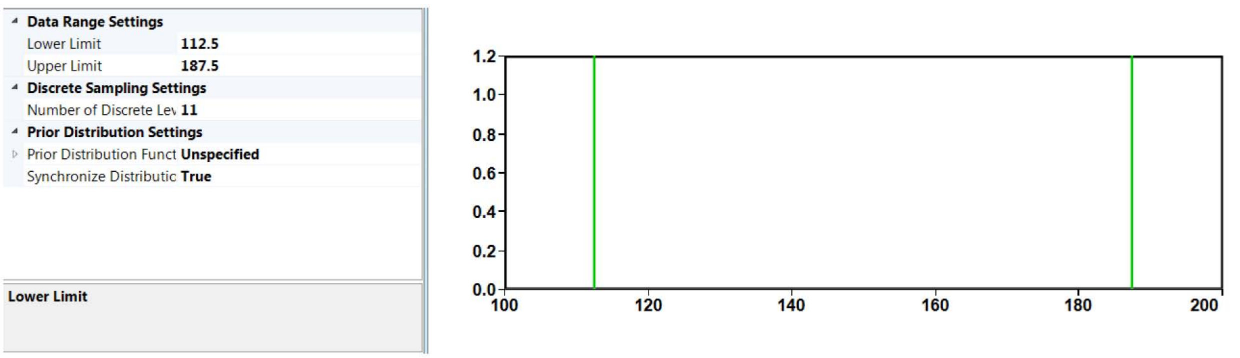

Figure 43—Injection Rate

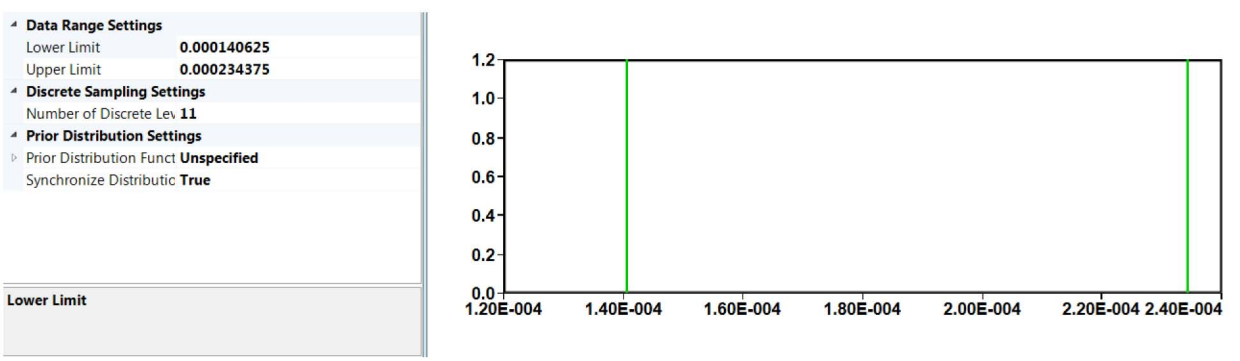

Figure 44—Injected Surfactant Fraction

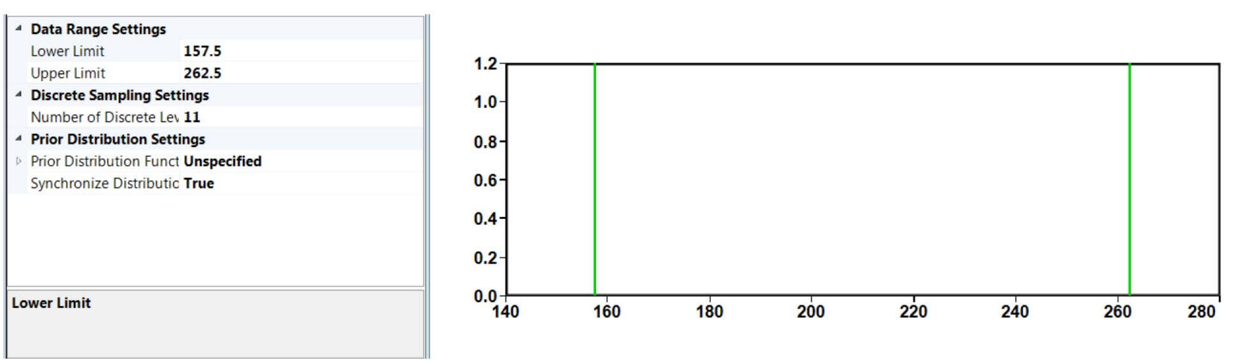

Figure 45—Injection Temperature

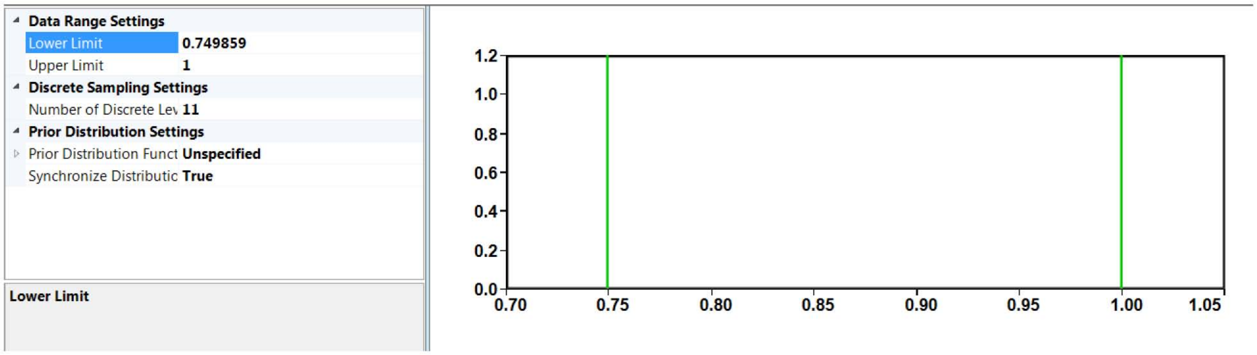

Figure 46—Injected Water fraction

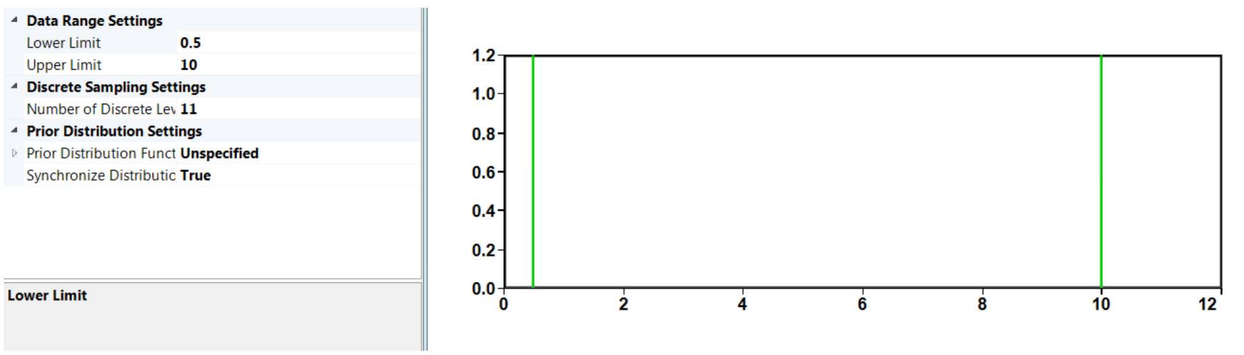

Figure 47—Standard Bed Permeability

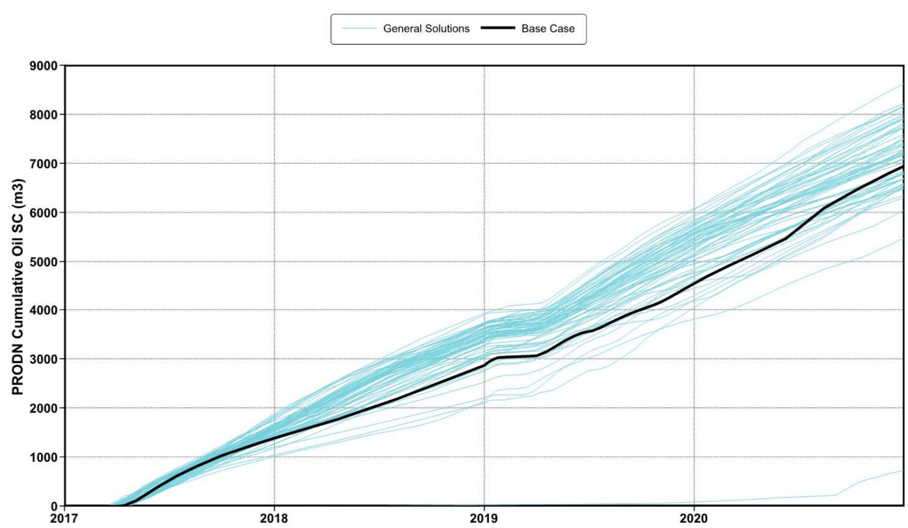

Figure 48—Cumulative Oil vs Time in Different Scenarios

Results & Discussion

Through his study we have summarized factors-operational, intensive and extensive that influence performance of a steam flood-foaming operations for heavy oil extraction. Results suggest a strong correlation between thermal properties of rocks and effectiveness of extraction of heavy oil. It is evident from Fig.49 that thermal conductivity of the underburden and the overburden are negatively correlated to recovery. This is attributed to the fact that high conductivity of the formation rocks will cause the heat in the steam to be lost to the rocks and thereby affecting transfer of heat to oil and the resulting mobility. Quality of steam is noted to be positively correlated to heavy oil recovery. Greater the saturation of steam, lower will be the resulting heat conductivity of the system thereby allowing for an effective transfer of heat towards oil. Also, volumetric heat capacity of the underburden is positively correlated to recovery. From Fig.49, we can also safely conclude that rate of injection of steam negatively affects the recovery. It is important to understand that relative importance of these parameters will change with different models but this study serves as an illustration of the absolute significance of the parameters studied and the direction of correlation of these parameters. Furthermore, this study shows the importance of reservoir management strategies in order to maximize the recovery and managing uncertainties of operational parameters.

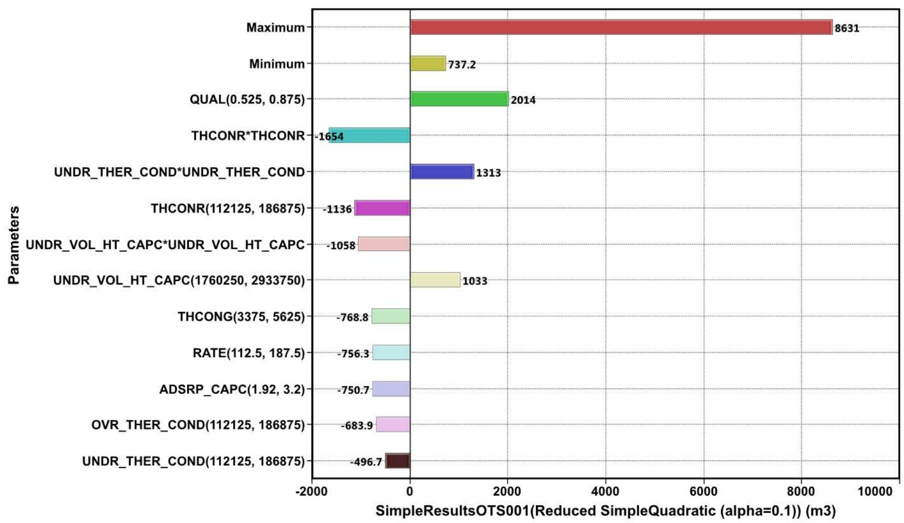

Figure 49—Tornado Chart

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Corresponding author: Cenk Temizel, temizel@alumni.usc.edu

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