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ARTICLE

ENHANCED HEAVY OIL RECOVERY BY USING THERMAL AND NON-THERMAL METHODS

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ABSTRACT

Many believe that the era of conventional oil will soon come to an end and heavy and nonconventional oil will be replaced by easy producing oils. Compared with conventional oil, heavy oil has reduced mobility; it is termed as heavy oil because it has higher specific gravity and density along with viscosity when compared with the conventional oil. The viscosity is between 100 CP or greater and API gravity less than 20°. API gravity is a specific gravity scale developed by the American petroleum institute to measure the relative density of various petroleum liquids, expressed in degrees. The lower the API number, the heavier the oil and the higher its specific gravity. In this paper introduced thermal and non-thermal methods for heavy oil recovery and investigated some parameters effect on oil recovery, such as: effect of reservoir temperature on oil recovery, effect of temperature of injected fluid on oil recovery, effect of injection pressure on oil recovery, effect of reservoir temperature on gas oil ratio (GOR) and effect of reservoir temperature on water production

KEY WORDS
Conventional Oil , Nonconventional Oil , Non-Thermal Methods , Thermal Methods , Heavy Oil

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INTRODUCTION

Origin of heavy oil according to many authors is the result of biodegradation. Larter et al., (2006) believes that first the oil was expelled from its source rock as light or medium oil , and subsequently migrated to a trap, then it is converted into heavy oil through different processes such as water washing, bacterial degradation (aerobic), and evaporation, provided that the trap is elevated into oxidizing zone. This biodegradation can occur at the depth in a subsurface reservoir. Head et.al, (2003) mentioned the depths of the biodegradation oil up to about 4 Km with most biodegraded reservoirs up to 2.5 Km below the sediment surface.

Goodarzi et al., (2009) define heavy oil in terms of viscosity as the class of oils ranging from 50 cP to 5000 cP. The high viscosity restricts the easy flow of oil at the reservoir temperature and pressure. [Fig. 1] is a graph relating viscosity and API ratings and it can be observed that the heavy oil region lies in the high viscosity range.

Ancheyta and Speight (2007) define heavy oil as a viscous type of petroleum that contains a higher level of sulfur as compared to conventional petroleum that occurs in similar locations. Meyer et al., (2007) explained that the oil becomes heavy as a result of eradication of light fractions through natural processes after evolution from the natural source materials. A high proportion of asphaltic molecules and with substitution in the carbon network of heteroatoms such as nitrogen, sulfur, and oxygen also play an important role in making the oil heavy. Therefore, heavy oil, regardless of source, always contains the heavy fractions of asphaltenes, heavy metal, sulphur, and nitrogen.

The importance of resins and asphaltenes in accumulation, recovery, processing, and utilization of petroleum was highlighted by Raicar and Proctor (1984). They found that most asphaltenes are generated from the kerogen evolution due to the increase in temperature and pressure with the increase in depth. Their opinion is in the light of the fact that asphaltenes are recognized as a soluble chemically altered fragments of kerogen that migrated out of the source rock during oil catagenesis.

Origin of heavy oil according to many authors is the result of biodegradation. Larter et al., (2006) believes that first the oil was expelled from its source rock as light or medium oil , and subsequently migrated to a trap, then it is converted into heavy oil through different processes such as water washing, bacterial degradation (aerobic), and evaporation, provided that the trap is elevated into oxidizing zone. This biodegradation can occur at the depth in a subsurface reservoir. Head et.al, (2003) mentioned the depths of the biodegradation oil up to about 4 Km with most biodegraded reservoirs up to 2.5 Km below the sediment surface.

From the above we can conclude that the heavy oil migrated from the deep source rock or deep reservoirs originally as conventional oil. At these depths, water caused weathering and bacteria fed on the oil causing biological degradation by removing hydrogen and thus increasing its density.

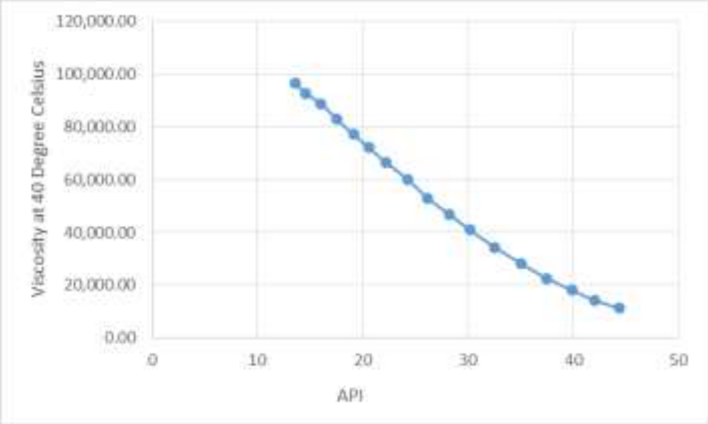


Fig . 1: General Relationship of Viscosity to API Gravity

The recoverable reserves of heavy oil and natural bitumen are equal to the remaining reserves of conventional oil . [Fig. 2]

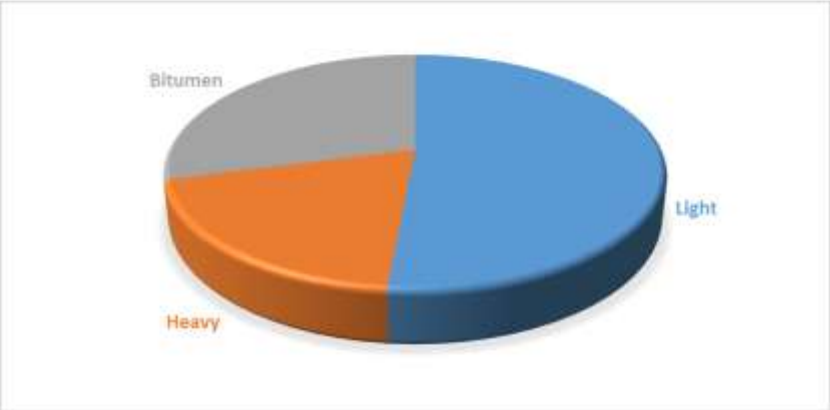


Fig. 2: Distribution of Light , Heavy and Bitumen Resources

Herron in his article "Heavy Oil: A Solution to Dwindling Domestic Oil Supplies" wrote that the total estimate of worldwide deposits of heavy hydrocarbons is around 5½ trillion barrels and western hemisphere contains four-fifths of these deposits. [Fig. 3 , 4 , 5]

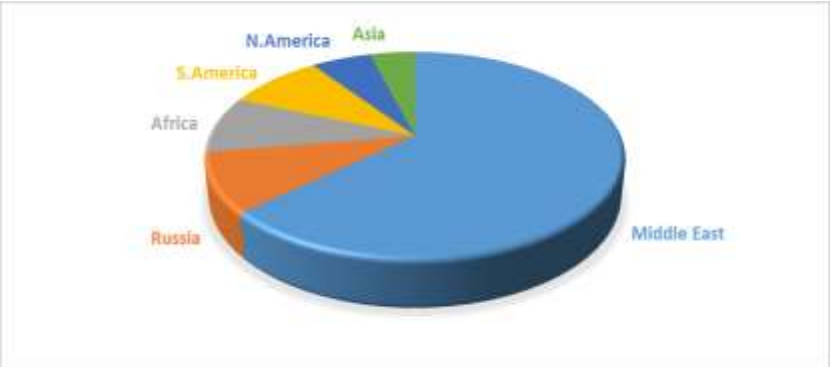


Fig. 3: Conventional reserves by region

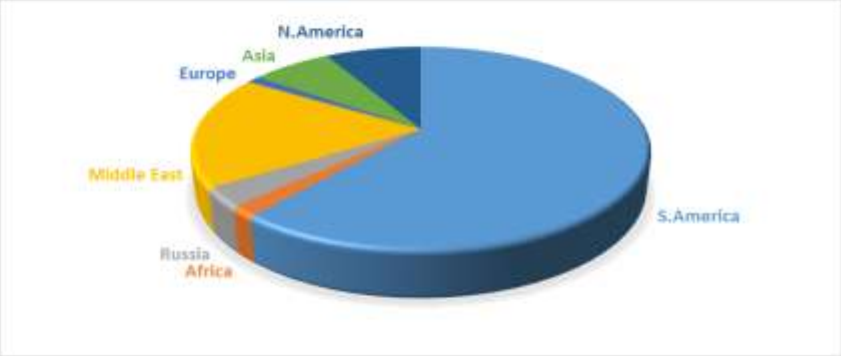


Fig. 4: Heavy oil reserves by region

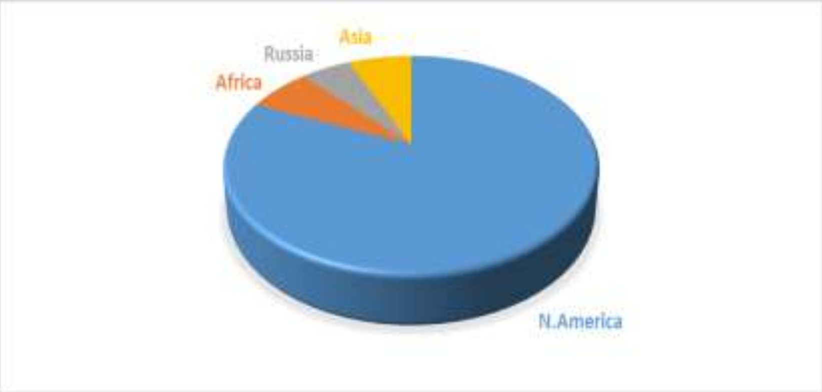
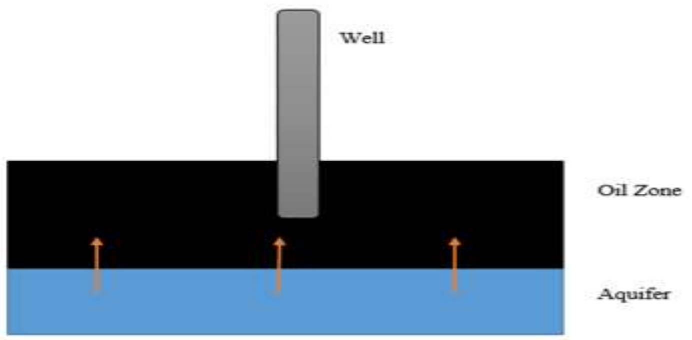


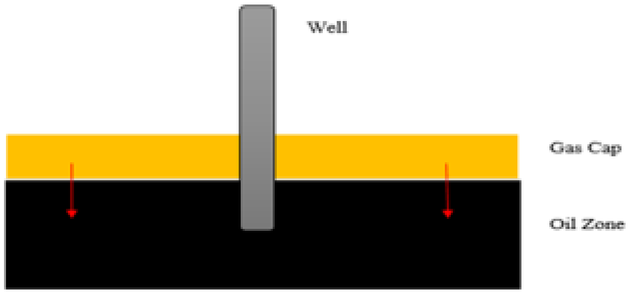
Fig. 5: Bitumen reserves by region

NON- THERMAL PRIMARY RECOVERY METHODS

As discussed earlier, many heavy oil reservoirs contains oil that does not flow easily under reservoir conditions which means successful recovery of this resource is based upon developing a mechanism that displaces the heavy oil in the reservoir. All reservoirs have different lithology and some of them are thin or small and overlying gas or underlying water may cause contraction in them which makes them poor candidate for the thermal methods of oil recovery. That means after the application of primary recovery any additional method should be non-thermal.

Primary recovery techniques rely entirely on natural forces within the reservoir that's why it is not the usual approach of recovery. For example the pressure of natural gas dissolved in oil or present above the oil or the natural pressures surrounding the reservoir rocks can help in the flow of oil. [Fig. 6] shows different methods and the basic techniques of primary recovery.





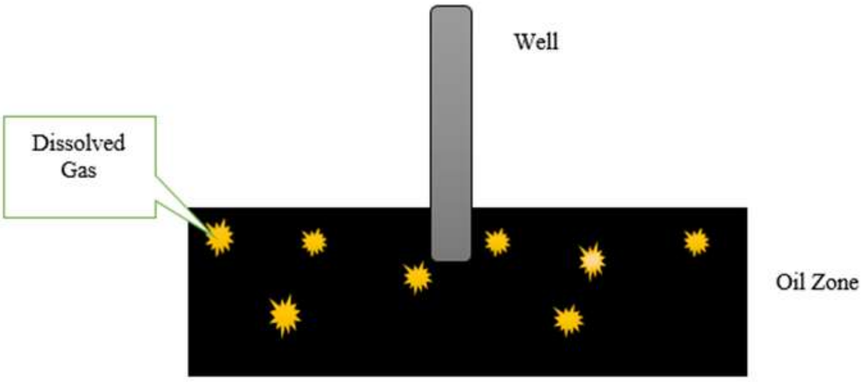


Fig. 6: Three basic natural drives

Water Drive

Water drive is the most efficient naturally driven propulsive force drive, it drives the oil into a well by pressurizing recoverable oil with the help of forces of water . In water drive field it should be taken care that the removal rate should be adjusted, so that water moves up evenly and there is always an available space for it by the removal of hydrocarbons.

This is the most efficient process in driving the oil into a well; it works by pressurizing the light recoverable oil with the help of forces of water in a water drive field. In an anticlinal structure, first the lowest wells around and then the oil-water plane moves upward as they produce until it reaches the top of the anticline. An appreciable decline in bottom-hole pressure is necessary when the well is abandoned as it displaces the oil. This pressure decline provides the pressure gradient to cause water influx. The pressure differential depends upon the permeability, which means less pressure is required for greater permeability to cause the water influx. The recovery from the properly operated drive pools can be as high as 80%. The force behind water drives may be either the expansion of reservoir water or hydrostatic pressure or a combination of both.

Gas Cap Drive

The gas if it lies over the top of the trap with oil beneath it can be utilized to drive the oil into wells at the bottom of the oil bearing zone . The gas (usually methane and other hydrocarbons) is compressed to achieve this condition. This process is known as the gas cap drive. If the oil is produced only from below if the gas cap than it is possible to achieve high gas-oil ration in the reservoir.

In this kind of recovery an undue portion of oil is left behind because the oil deposits are not systematically developed, which causes the bypassing of gas. The gas mixture (methane and other hydrocarbons) may be separated by compressing the gas. Gasoline is an example of the gases that are separated by compression of gases. However, at high pressures retrograde condensates are formed, because in deeper fields the density of oil decreases and the density of gas increases until they form a single phase. The retrograde condensate pools bring condensation in Liquid hydrocarbons because the pressure declines instead of inclination. When this condensate is removed from the reservoir fluid, the pressure is maintained within the gas cap by injecting back the residual gas into the reservoir.

Solution Gas Drive or Dissolved Gas Drive

In Solution gas drive, the propulsive force comes from the gas dissolved in the oil , this force is the result of pressure release at the point of penetration in the well. It means that release of gas expansion from the 'oil in place' fluids, as the reservoir pressure declines, supplies the major reservoir energy for the primary depletion.

Thomas 2008 explained that the Solution gas drive is the mechanism whereby lowering of the reservoir pressure through production in an under-saturated reservoir causes the oil to reach the bubble point where gas starts to evolve from solution.

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The definition from Thomas (2008) is valid when the evolved gas begins to flow only when the critical gas saturation has been reached. Once that condition is achieved, then it will cause an increase in the rate of pressure drop due to the production of the gas phase. All of the evolved gas below the bubble point pressure is kept in the form of small bubbles in the porous media and does not form a continuous free gas phase. Retention of the evolved gas phase in a dispersed form with the oil would lead to maintaining the reservoir energy.

NON- THERMAL SECONDARY RECOVERY METHODS

A lot of oil can be left behind after primary recovery, since the normal reservoir pressure has declined and as a result there is no natural force that can push the oil into the well that's why secondary methods come into play. Secondary oil recovery techniques are applied on depleted or low pressure reservoirs. Some of the techniques are discussed below.

Water Flooding

In water flooding the energy required to drive the oil from the reservoir rock is provided by means of water injection from the surface [Fig. 7]. Water injection boosts the low pressure in the reservoir keeping the production rate and the pressure the same over the long term, hence producing the oil replacing by the water. Water flooding was considered to be a form of enhanced oil recovery but it is essentially an artificial water drive .

The theory of water flooding is quite old in industry and according to Smith (1992) this theory was pioneered by Buckley and Leverett. In their theory, displacement starts with only connate water and oil as incompressible phases. A region divided by the shock front in which only movable oil which is being displaced, from the one with only movable water. Only oil is produced prior to breakthrough and only water after.

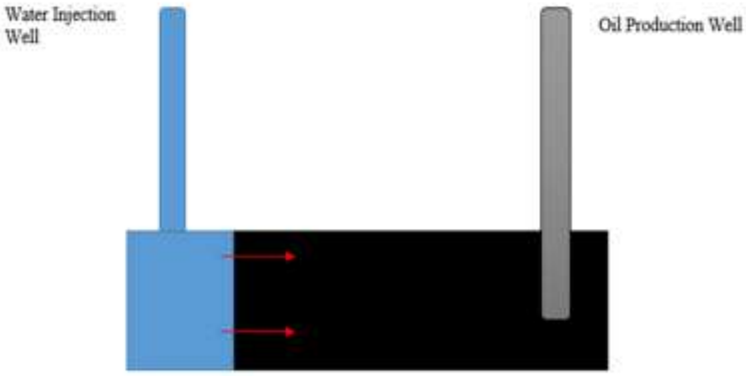

Fig. 7: Water flooding displacing oil

In a completely developed oil field, the wells may be drilled anywhere from 200 to 2,000 feet (60 to 600 meters) from one another, depending on the nature of the reservoir. If water is pumped into alternate wells in such a field consider [Fig. 8], the pressure in the reservoir as a whole can be maintained or even increased. Water flooding may increase the recovery efficiency to as much as 60% or more of the original oil in place. Kumar (2006) reported incremental recovery of approximately 2 to 20% of the original oil in place.

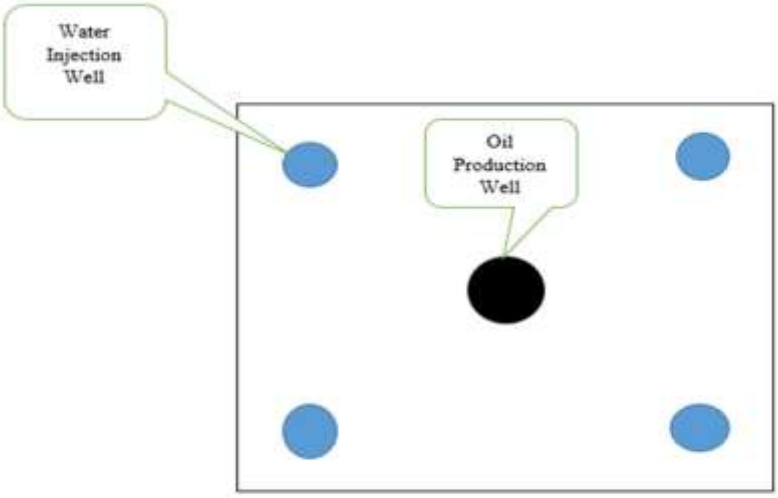

Fig. 8: Concept of water flooding

Cold heavy oil production with sand (CHOPS)

In this method sand is produced aggressively along with the heavy oil without applying heat. The oil production is improved substantially through the regions of increased permeability wormholes. The basis of this process is the oil production and recovery when sand production occurs naturally. The production of the unconsolidated un-cemented reservoir sand results in significantly higher oil production.

Sawatzky et al., (2002) postulated that oil production and sand production are bound together intimately in the process. What these authors means can be described in a three step process :

- The mobile heavy oil flows toward the production well, sharp pressure gradients are generated in the reservoir.
- This results in failure of the unconsolidated sand matrix.
- The failed sand is dragged to the well by the high viscosity oil.

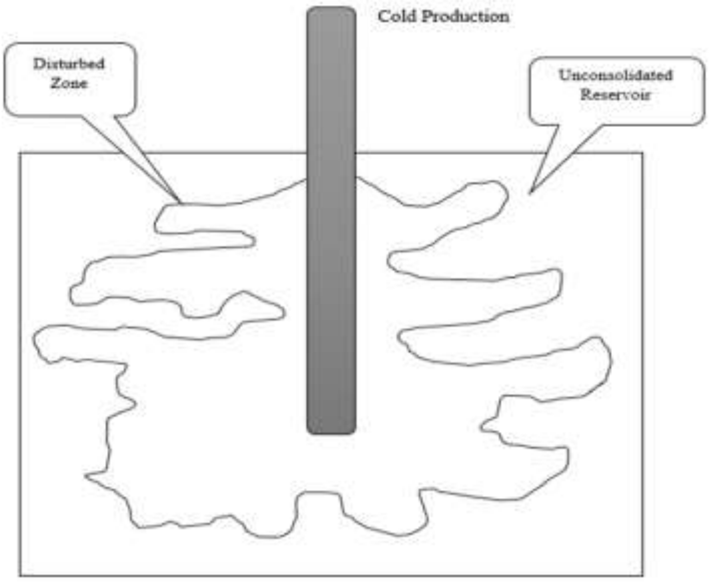

Fig. 9: Schematic of sand production with wormholing

By studying the whole process it can be concluded that the cold production can be summed up succinctly as a process in which the well is transported to the oil rather than the oil transported to the well.

Gas injection

The process also known as reinjection or re-pressurization increases the pressure in the reservoir by gas injection and thus induces the flow of crude oil. The injected gas molecules dissolved in the oil reduce its viscosity and make it mobile which increases the well output. After the crude oil is pumped out, the natural gas is once again recovered. Carbon dioxide is used as the gas for re-pressurization. Inert gases, and natural gas can also be used to pressurize the well, but air is not suitable for that because it causes deterioration of the oil.

NON- THERMAL TERTIARY RECOVERY METHODS

Tertiary recovery of oil begins when it is felt that the production from secondary oil recovery is not enough. Tertiary recovery process like most of the recovery processes reduces the viscosity of oil to increase in production .

But Krumrine and Falcone (1987) believe that there is a renewed interest in chemical enhanced oil recovery because of diminished reserves and advances in surfactant and polymer technology. They also believe that by greater understanding of the chemical reactions involved it is possible to get good results in the field. They suggest that the combination of chemicals should be applied as premixed slugs or in sequence.

The choice of the method and the expected recovery depend on many considerations, economic as well as technological. According to Thomas (2008) only a few recovery methods have been commercially successful, such as steam injection based processes in heavy oils and miscible carbon dioxide, provided that the reservoir offers favorable conditions for implementation of such methods.

Alkaline flooding

Alkaline flooding also known as caustic flooding appears to be the most attractive among the various non thermal processes. Alkaline flooding (caustic flooding) involves alkaline chemicals, such as sodium hydroxide, sodium carbonate, or sodium orthosilicate, are injected during water flooding or during polymer flooding operations. These Alkaline reagents are quite cheap and abundant. The alkaline reagents react with the surface active materials present in the crude oil and form the in-situ formation of the surfactant soap species. The adsorption of these generated surfactants at the oil/water/sand interfaces reduces the interfacial tension and raises the PH of the injected flood water; as a result the residual oil trapped in the fine pores of the reservoir sand is mobilized.

Carbon dioxide flooding

Carbon dioxide is injected into an oil reservoir in order to increase output when extracting oil. This process can be understood by considering [Fig. 10] which depicts an existing well that has been produced before and has been designated suitable for carbon dioxide flooding; the first action is to restore the pressure within the reservoir to one suitable for production. This is done by injecting water and shutting off the production well. The water serves to increase the sweep efficiency and to minimize the amount of carbon dioxide required for the flood. Then the next step is the injection of carbon dioxide into the same injection well used to restore the pressure; when the carbon dioxide comes in contact with the oil, it creates a miscible zone that can be moved more easily to the production well. As reservoir fluids are produced through production wells, the carbon dioxide reverts to a gaseous state, which provides the "gas lift" similar to the original natural reservoir pressure.

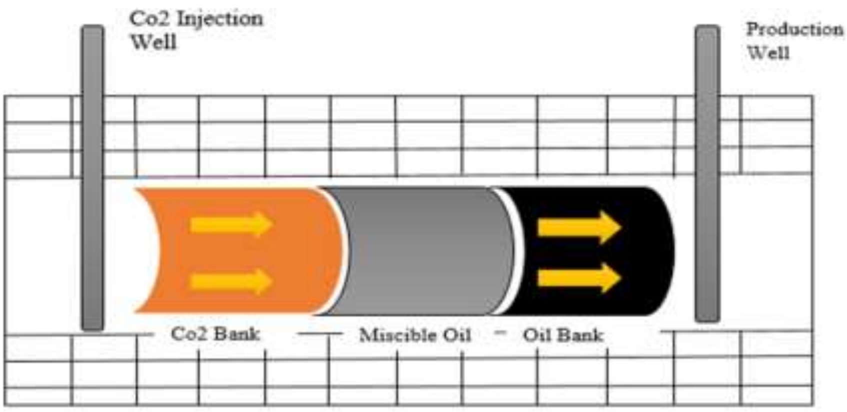

Fig.10: Carbon dioxide flooding

Cyclic carbon dioxide stimulation

This method bears a resemblance to the cyclic steam process . First carbon dioxide is injected into the reservoir, than the well is shut in for a certain amount of time (providing for a soak period), and the well is opened after a certain period, allowing the oil to produce. This is a single well process. Just like the carbon dioxide injection process, the dissolving of the carbon dioxide in the oil reduces the viscosity and causes it to swell, allowing the oil to flow more easily towards the well. Carbon dioxide is injected by high pressure for heavy oil reservoirs. There are two types of carbon dioxide-enhanced oil recovery processes which are miscible and immiscible.

Miscible carbon dioxide enhanced oil recovery process

The miscible carbon dioxide-enhanced oil recovery is a multiple contact process, involving the injected carbon dioxide and the reservoir oil. In this process carbon dioxide vaporizes the lighter oil fraction during the injection phases and then it condenses into the reservoir oil phase. This leads to two reservoir fluids that become miscible and as a result we get more mobile fluid with low viscosity and low interfacial tension. The primary objective of miscible carbon dioxide enhanced oil recovery is to remobilize and dramatically reduce the after-water flooding residual oil saturation in the reservoir's pore space.

Immiscible carbon dioxide enhanced oil recovery process

When insufficient reservoir pressure is available or the reservoir's oil composition is less favorable (heavier), the injected carbon dioxide will not become miscible with the reservoir's oil. Then, another oil displacement mechanism, immiscible carbon dioxide flooding, occurs. The immiscible carbon dioxide flooding process has considerable potential for the recovery of moderately viscous oils, which are unsuited for the application of thermal recovery techniques.

THERMAL RECOVERY METHODS

Generally there are two thermal methods of recovering heavy oil:

- The process in which heat is injected into the reservoir.
- The process in which heat is generated within the reservoir itself.

Steam based process were used before the advancements in the field that introduced new processes such as in situ combustion or fire flooding. Thermal recovery process reduces the viscosity by means of heat and also provides the force to increase the flow rates of the oil to the production well that's why thermal processes are also classified as thermal drives. In the thermal stimulation techniques, only the reservoir near the production well is heated. Stimulation techniques can also be combined with thermal drives, and in this case the driving forces are both natural and imposed.

As shown in [Fig. 11], the fluid is injected continuously through injection wells to displace oil and obtain production from other wells. The same pressure which maintains the injection of the fluid in the well also increases the driving forces in the reservoir, which increases the flow of crude oil. Driving forces present in the reservoir, such as gravity, solution gas, and natural water drive, affects the improved recovery rates once the flow resistance is reduced and overcome by the driving force. Thermal processes use heat in well bores to increase the production rates for heavy crude oils. The drive process can also be applied to recover the residual oil in energy depleted reservoirs that hold conventional oil

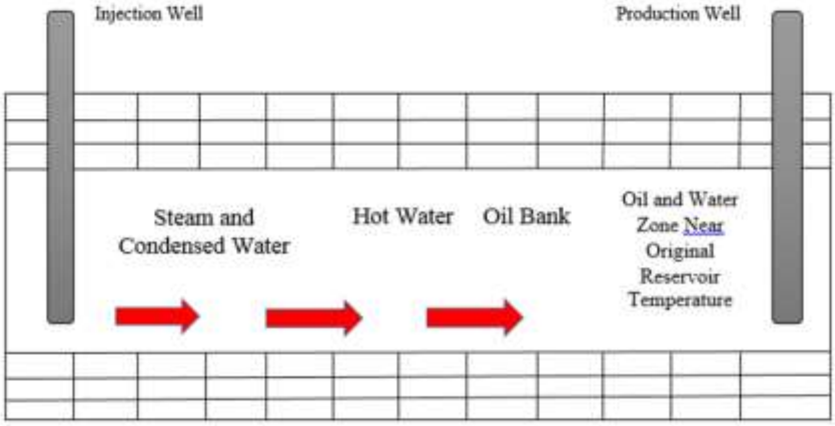

Fig. 11: Oil recovery by thermal methods

Hot fluid injection

In hot fluid injection methods the preheated fluids are injected into the relatively cold reservoir as shown in [Fig. 12]. Injected fluids are usually heated at the surface; although these days well bore heaters which are also known as the down-hole heaters are seeing a wider use. The fluids range from water (both liquid and vapor) and air to others, such as natural gas, carbon dioxide, exhaust gases, and even solvents.

In every hot fluid injection there are heat losses in the well bore from the injection wellbore to the over burden formations as a result of poor insulation of the injected wells and low injected rates. When the heat approaches the formation there is a temperature difference between the well head and the formation as a result of heat loss. In case of condensable fluids such as steam, the heat losses cause the condensation of steam, which then turns into hot water, and oil comes in contact with the hot water rather than steam. To overcome this issue surface lines are insulated.

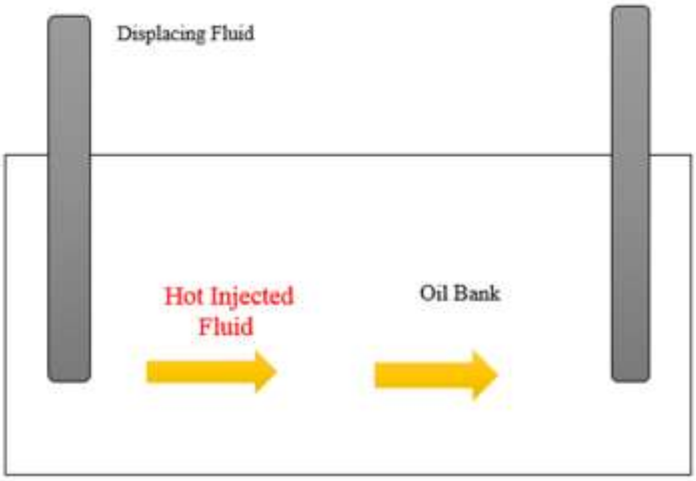

Fig. 12: Hot fluid injection

Hot water drive

Hot Water drive involves the flow of only two phases, water and oil, in which oil is displaced by water. In this process the leading edge of the water comes to the initial reservoir temperature as it loses heat very quickly and increases the mobility of the fluids in the heated zone. This results in better displacement efficiency from the heated zone and would improve the ultimate recovery. Basically the concept is that the thermal expansion of oil facilitates the displacement of oil, because of the pervasive presence of water in all petroleum reservoirs, the displacement by water must occur to some extent in all thermal recovery process. Typically, in hot-water flooding, the water is filtered, treated to control corrosion and scale, heated, and if necessary, treated to minimize the swelling of clays in the reservoir.

Steam based methods

The concept behind the steam-based processes is to reduce the viscosity so that the heavy oil can flow to the production well. In most instances the injection pressure must exceed the formation pressure in order to force the steam into the reservoir and into contact with the oil. When sufficient heating is achieved, the wells are closed and left for a certain period, which is referred to as the soak period. There is no chemical change in the constituents of oil, but there will be favorable changes in the composition, which will result the recovery of the lighter fractions, and the heavier materials will remain in the reservoir.

As the steam condenses, the steam distilled components also condense and form a solvent front that will assist in displacing heavy oil as a mixture of solvent and oil towards the production well. These effects will help to improve the displacement efficiency. Whether or not steam distillation occurs and the role it plays in oil recovery depends on the character of the heavy oil as well as the down-hole conditions. For example, most of the times when dealing with heavy oil, the steam distilled material is composed of aromatic and naphthenic constituents, which are excellent solvents for oil. But when the constituents are predominantly paraffin character result in the deposition of asphaltic material ahead of the steam front, and this deposition will cause the blockade in the reservoir flow channels, which will restrict the oil flow to the production well. Luckily paraffin character is not often found in heavy oil reservoirs.

Steam-assisted gravity drainage (SAGD)

This method involves drilling of two parallel horizontal wells (shown in figure 13), one above the other, along the reservoir itself. Hot steam is introduced from the top well which reduces the viscosity of the heavy oil (like all other thermal methods). The reduction in viscosity of the heavy oil separates it from the sand and it is drained into the lower well by means of gravity. The key to this method is the two parallel and horizontal wells, and this has only become possible due to the directional drilling technology.

The heat of the steam reduces the viscosity of the heavy oil and separates it from the sand. It is drained into the lower well by means of gravity. Even though the injection and the production wells can be close (5-7m), the mechanism causes the steam saturated zone, known as the steam chamber, to rise on the top of the reservoir, expand gradually sideways, and eventually allow the drainage. The distance between the pair of horizontal wells vertically separated by each other is 15-20 feet. These wells are drilled at the bottom of a thick unconsolidated sand stone reservoir. The injected steam reduces the oil viscosity to values as low as 1 -10 cP, depending upon the temperatures and the initial conditions and develops a steam chamber that grows vertically and laterally. The steam and gases rise, the lower well receives oil and condensates due to the density difference. The products are methane, carbon dioxide, and some traces of hydrogen sulfide. The non condensable gases act as a partial insulation blanket by filling up the void space, which helps to reduce the vertical heat losses. Injection pressures are much lower than the fracture gradient, which reduces the chances of breaking into thief zone.

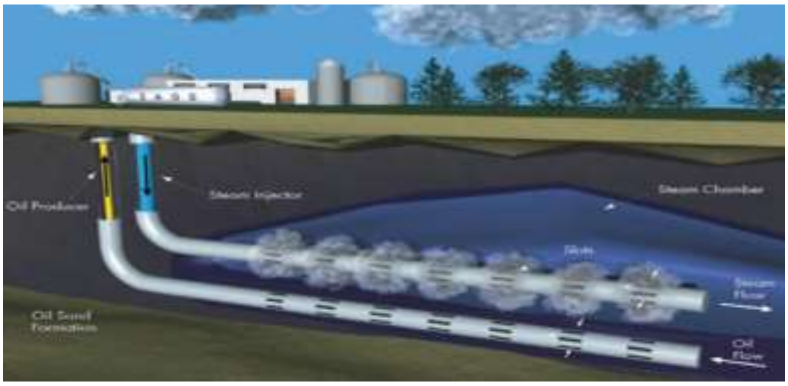

Fig. 13: SAGD process (Source : Canadian Center for Energy Information)

The SAGD process, like all gravity driven processes, is extremely stable because the process zone progresses by means of gravity segregation, and there are no pressure driven instabilities such as conning, fracturing, or channeling. It is vital to maintain a volume balance; it means that each unit volume injected is replaced by each unit volume withdrawn or reduced. If bottom water influx develops, this indicates that the pressure in the water is higher than the pressure in the steam chamber, so this pressure should be balanced. It is obvious that the pressure in the water zone cannot be reduced, so the pressure in the steam chamber and production well must be increased. This increase in pressure is achieved by increasing the operating pressure of the steam chamber through the injection rate of steam or by reducing the production rate from the lower well.

In-situ combustion

In Situ combustion was the center of attention in 1950's when many papers were published on this particular method and until the 1960's most of the projects of thermal oil recovery were connected with this process. In-Situ combustion applies on the reservoirs that contain low gravity oil, which is heated with the help of air injection and the burning part of the crude oil. The oil is then driven out of the reservoir with the help of steam, hot water or gas drive, as it becomes less viscous. Either dry or moist air can be injected. The fire propagates from the air injection well to the producing well, moving oil and the combustion gases to the front. The coke left behind the displaced oil works as a fuel. The temperature reaches hundreds of degrees which is enough to crack heavy oil into low boiling products, below is the summary of different reactants and their products formed as a result of cracking of asphaltenes . The displacement of oil is the result of the combination of hot water, steam and gas drive, vaporization, and light hydrocarbons.

Alexander et al., (1962) define the parameters which determine the design of the in situ combustion process (in addition to the operating cost) which are as follows:

- The fuel concentration per unit reservoir volume burned.
- The composition of the fuel.
- The amount of air required to burn the fuel.
- The volume of reservoir swept by the combustion zone.
- The required air injection rates and pressures.
- The oil production rate.

Simulation

Introducing the reservoir :

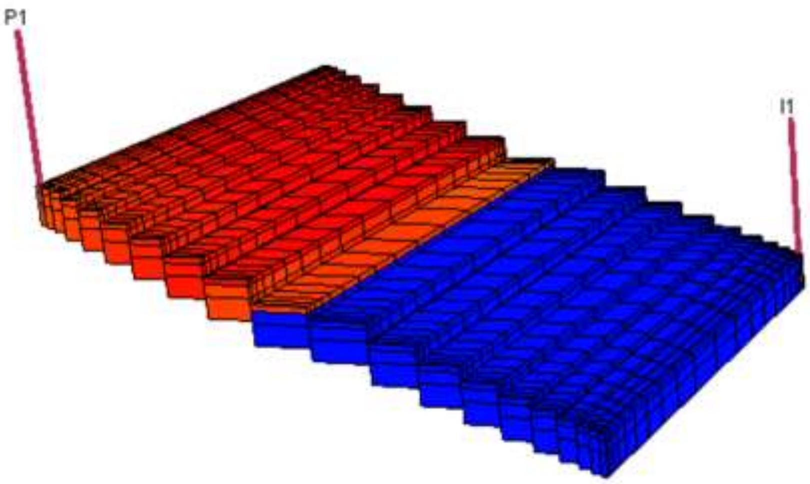

Fig. 14: 3D view of the reservoir

In this simulation investigated some parameters such as :

- Effect of reservoir temperature on oil recovery .
- Effect of temperature of injected fluid (water flooding) on oil recovery .
- Effect of injection (water flooding) pressure on oil recovery .
- Effect of reservoir temperature on gas oil ratio (GOR) .

- Effect of reservoir temperature on water production .

RESULTS

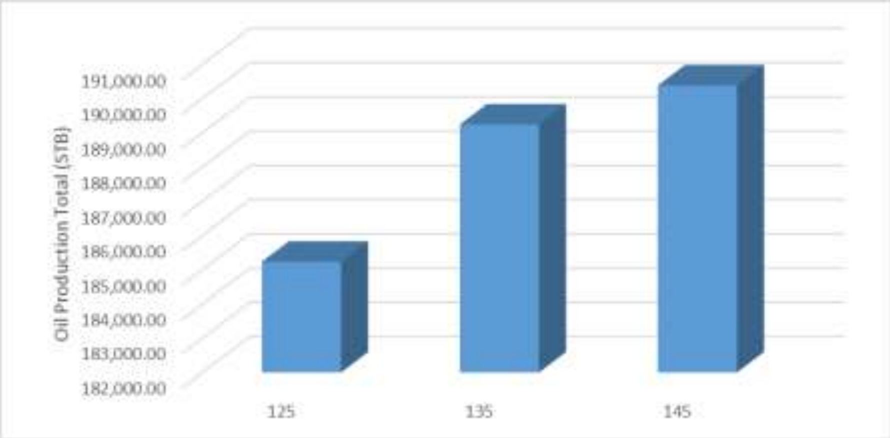

Fig. 15: Effect of reservoir temperature(°F) on oil recovery (stb)

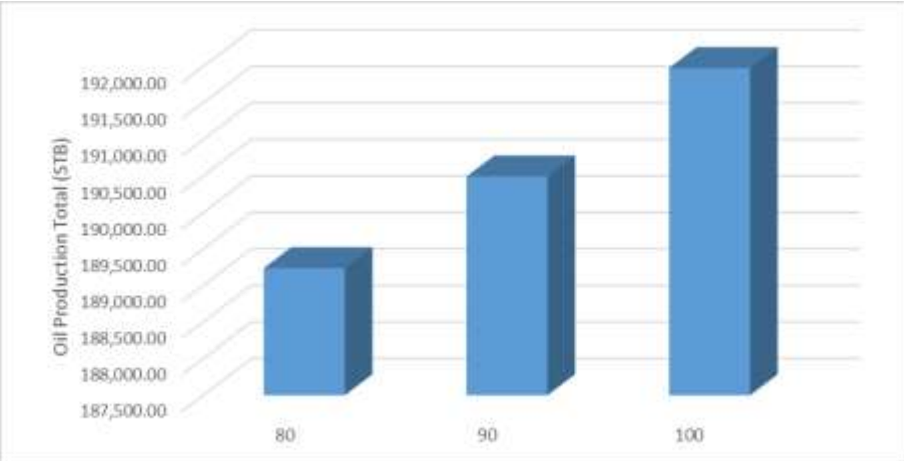

Fig. 16: Effect of temperature of injected fluid (°F) (water flooding) on oil recovery (STB)

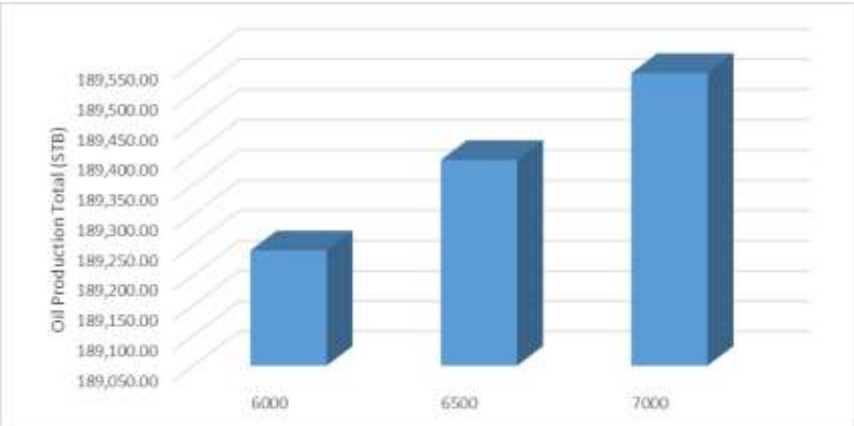

Fig. 17: Effect of injection pressure (Psia) on oil recovery (STB)

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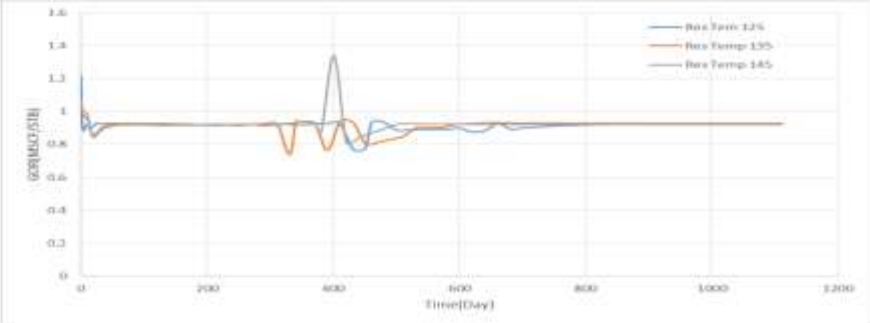

Fig. 18: Effect of reservoir temperature (ºF) on gas oil ratio (GOR)

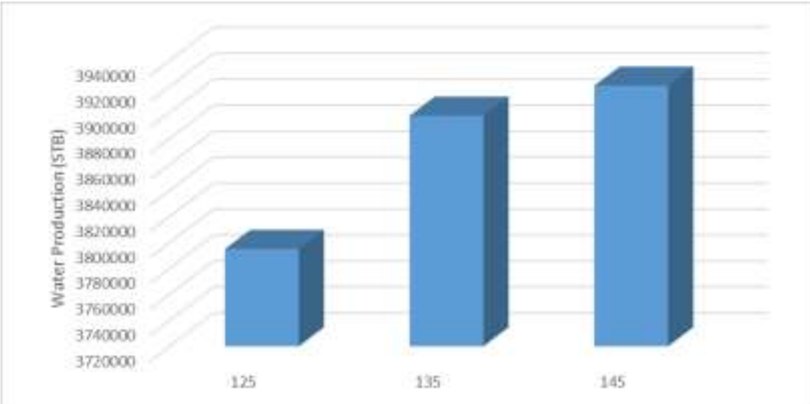

Fig: 19. Effect of reservoir temperature (ºF) on water production (STB)

CONCLUSION

Based on the results of this investigation, the following conclusions could be drawn for this simulation :

- By increasing the reservoir temperature the amount of oil recovery increased .
- By increasing the injected fluid temperature the amount of oil recovery increased .
- By increasing the injection pressure the amount of oil recovery increased .
- The reservoir temperature is not so affected on gas oil ratio (GOR) .
- And finally by increasing the reservoir temperature the amount of water producing increased .

FINANCIAL DISCLOSURE
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