Thermal Recovery of Niger Delta Heavy Crude: A Hot Water Flooding Approach

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Abstract—**Unconventional oil reserve estimate in Nigeria which is at an average of 42 billion barrels of hydrocarbon deposits, surpasses the proven reserve of 37.2 billion barrels of conventional oil reservoirs. With these statistics, the need to evaluate the prospects of production from these unconventional reservoir systems becomes a subject of interest. In this study, a thermal approach towards the recovery of a Niger Delta heavy crude oil was conducted by the viscosity reduction mechanism via hot water injection. Fluid characterization via laboratory tests revealed that the Niger Delta retrieved heavy crude sample had a viscosity 17.80 cp,13.24oAPI and a density of 0.997.6 g/cc. This sample was subjected to a series of recovery processes with hot water temperature ranging from 75 OC to 100 OC at an interval of 5oC, using a locally constructed apparatus. It was used to simulate a reservoir bulk volume of 30 litres and 8.871 liters' pore volume having fluid saturations of 20% formation brine. The heavy crude viscosities were found to be in the magnitude of 1.95cp to 0.87 cp for injected hot water of 75 OC to 100 OC after post recovery tests. Temperature losses to the rock matrix of a heavy crude reservoirs and optimum injection temperatures for a known reservoir bulk volume were also established via experimental processes. The validity of assertion that hot water injection can considerably alter flow properties of heavy oils was experimentally confirmed upon comparing with a convention al water injection process.**

Index Terms—**Hot Water Flooding, Enhanced Oil Recovery, Niger Delta Heavy Crude, Unconsolidated Sand Stone, Viscosity.**

I. INTRODUCTION

With an ever-increasing world demand for fossil energy, engineers have in recent time, perceived the inexorable need to exploit a wide range of sound engineering strategies for the exploration of unconventional oil reservoirs as these accumulations far supersedes that of the conventional. Most unconventional oil reservoirs are characterized by high viscosity of low API gravity and as such lacks the flow dynamics required for natural depletion. Shale oil, Tar sands, Bitumen, and heavy crude oil system all fall under this classification as their production must be accompanied by an enhance recovery technique. Thermal enhanced recovery method proves a potentially viable candidate in the recovery of heavy crude of low to medium API gravity oils, characterized by high viscosity which is usually unfavorable for convectional recovery techniques. The present world's energy balance shows a rapid growth in the demand of crude oil. Developed and highly industrialized countries have a very high consumption rate of the world's energy supply, making unconventional methods of recovery very viable [1]. This research is aimed at altering the thermal properties of Niger delta heavy crude samples via hot water injection for the purpose of production enhancements by means of viscosity reduction.

Thermal Recovery method is one of the most used EOR methods to recover heavy oil and Bitumen worldwide. It accounts for large share of the world production. The primary concept of thermal recovery process is to generate hot fluid on the surface or in-situ and the injection into the reservoir [2]. The hot fluid reduces the viscosity of the hydrocarbon which in turn aids mobility of the hydrocarbon.

Hot water flooding is a process of injecting hot water into the reservoir, reducing the viscosity, residual oil saturation, relative permeability and improves mobility of the oil [2] and [3]. It has been estimated that the world current reserves of heavy oil and Bitumen is at about 4000 billion barrels [4]. Water flooding is an old procedure used by oil industry to improve oil production. This is a method used to boost reservoir pressure. [5]. Water flooding is a technique of injecting water into the reservoir to achieve reservoir pressure maintenance and oil recovery by displacement, [6]. This method is often used in depleting reservoirs. Conventional recovery methods account for only 20% recovery of original oil in place. When the natural energy is depleted, there is a need for secondary recovery by injecting water or gas to increase and maintain reservoir pressure, to enhance production within economic range. After secondary recovery, the remaining oil can be recovered using unconventional methods such as thermal recovery method and non-thermal method [7].

Presently there is no universally accepted definition covering all non-convectional oils and gases. Non-convectional oil and gas refers to all hydrocarbons that are difficult to extract with available technology. For liquid hydrocarbons, it includes heavy and extra heavy oils such as tar sands, shale oils and tar shales. Natural gas includes tight gas from compact reservoirs, coal bed, methane bed gas, shale gas and methane hydrates. [7]. For the past decades, there has been rapid growth of non- convectional oils resulting in increase in the global oil reserve. Heavy oil production in Canada and Venezuela has increased from a total heavy oil supply of 1% in the 1990s to 7% in 2011. Unconventional oil is mostly found in unconsolidated sandstone formation with depth less than 1000m deep. Major countries involved in enhanced oil recovery techniques are USA, Mexico, Canada, Indonesia, Venezuela and China [8]

Heavy oil field was first discovered in the Niger Delta in 1968 but was not produced until forty years later when the economics of production had become viable with time. [9]

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This field is located in the south eastern Nigeria in a water depth of 135ft. The wells were drilled in 2008, samples obtained were taken to the laboratory for Pressure, volume and temperature analysis. The result showed heavy oil of about 11-13 API with viscosity of 100 to 200cp [9]. Five wells were drilled of which; three wells show heavy oil with varying API gravity. From a research on thermal recovery, comparing in-situ combustion of Niger delta reservoir and Nelson and Mcneil model on five reservoirs in one field, showed that there is a direct proportion between the maximum oil produced, required compressor horse power and the needed maximum air injection. On air injection via in situ combustion, Niger delta oil recovery far exceeds that of Venezuela heavy crude of similar properties at the same air injection rate [10].

Findings on Cold Heavy Oil Production with Sand(CHOPS) was done on the Niger delta heavy crude oil using software such as PROSPER to model the production performance of the reservoir. From the study, API gravity between 18.07 and 22.14 can be produced normally without using CHOPS. CHOPS improved the production performance of the Niger delta heavy oil well reservoir as the production rate increased rapidly [11]. Spirov and others in 2013 did a research on Bitumen extraction of tar sand using dense carbon dioxide Their experiment involved the use of high pressure carbon dioxide, at low temperature and ethanol for the extraction process. At 75% carbon dioxide in the reactor, the recovery was at 19,47% at 110oC and at 50% carbon dioxide in the reactor gives 15% at 110oC [12].

II. Materials and Methods

A. Fundamental Principle

The basic principle of thermal enhanced oil recovery is the application of heat via hot water flooding into the formation to reduce viscosity and interfacial tension of the crude oil so as to improve its mobility and improving productivity of the well. Hot water flooding entails heat transfers by conduction and convection between the grains and the fluids in the reservoir.

B. Materials for Experimental Investigation

The following materials were used for the experimental demonstration of the viability of the recovery of the Niger Delta Heavy crude;

i. High viscosity crude
ii. sodium chloride
iii. Distilled water
iv. Fine sand
v. 30 Liters capacity rectangular reservoir
vi. The EOR apparatus (A locally designed EOR unit, named HBO unit)
vii. Beakers, Separating funnel & conical flasks
viii. Dean and stack apparatus
ix. Flash point equipment
x. Redwood viscometer
xi. Separating funnel
xii. Pycnometer
xiii. Digital weighing balance

C. Heavy Crude Sample

Heavy crude oil sample was obtained from a Niger delta well.

D. Heavy Crude Sample

Industrial Sodium chloride (NaCl) was used for the brine preparations. This solution was used to mimic a typical formation water composition. Although formation water composition is not limited to the elemental composition of the NaCl, it is proposed that most reservoir formation water resistivity and conductivity analysis are conducted on the assumption of Sodium Chloride dominating the compositional fraction of the formation water.

E. Heavy Crude Sample

30 litre volume of industrially sieved clean sandstone rock sample each of 2.56 g/cc density was obtained to simulate for the Niger Delta sandstone formation in a lab scale. Visual inspection of the sandstone grains confirmed a clean – white, thoroughly sieved fine sand with a smooth textural feel. The sandstone rocks were well sorted and unconsolidated.

F. Heavy Crude Sample

A wide range laboratory equipment was used to ascertain experimental evaluation. The equipment before use, were all confirmed calibrated. this equipment includes; Red wood viscometer for the determination of the kinematic viscosity of the crude oil; A 0 -1000g weighing balance with a digital scale for determining the masses of samples to be used; Dean and stack apparatus for the determination water content of crude oil samples before and after recovery and the EOR apparatus.

G. Heavy Crude Sample

21 ml of water yielded 29.57% porosity of the formation at 100% water saturation for a 50 ml sand, if 20% saturation is desired at same porosity, then water volume must be 5 times less than 21 ml to yield a 20% saturation for the same volume of sand and at same porosity. This means that for every 30litre sand,1.8 litre of water will completely saturate the sand at 29.57% porosity. However, water saturation for same porosity is desired at 20%. Also, at 29.57 % porosity, pore volume is 8.871 litres and volume to be occupied by 20% saturation of water is 1.8 litres. This will be the volume of water that will dilute the salt to be used.

Industrial NaCl was measured and dissolved in distilled water which served as reservoir formation water. The 30 litre sand was then gradually saturated with the brine solution, thoroughly mixed for even saturation and kept for 48 hours.

H. Heavy Crude Sample

Since reservoir volume was determined to be of a 30 litre capacity, it invariably implies that rock matrix volume will occupy a higher volume of the reservoir and since the porosity of the formation was determined to be 29.57%, the pore volume of the reservoir was deduced to be 8.871 litres. This means that the sum of all fluid saturations will occupy a volume of 8.871 litres. A bath of 30 litres containing the brine saturated sand was then saturated with the heavy crude oil sample of 7.1 litres . The model reservoir was closed and kept for 72 hours.

Hot water of 75°C into the reservoir, and fluid injection was terminated after every 1 litre injection of hot water from the bath. Temperature and pressure values upstream and downstream the reservoir were recorded as well as recovered volumes from the producer and time taken in seconds per 1 litre injection. The process was repeated for hot water temperatures of 80°C, 85°C, 90°C, 95°C and 100°C and the respective volumetric recoveries were collected for further analysis including; petro physical analysis after recovery, produced water volume, recovery factor and efficiency and so on.

III. Results and Discussion

A. Petro physical Classification Evaluation of Heavy Crude Sample

The highly viscous crude sample which is a representation of the Niger Delta heavy crude deposit subjected to a series of petro physical evaluations, proved affirmative that substantial accumulations of these deposits can be recovered through thermal recovery processes (Eg. hot water injection). Petro physical characterization involved the evaluation of oil density, oil API gravity, specific gravity of the crude, pour point analysis, flash point, cloud point and oil viscosity investigation.

B. Flow Properties

Oil viscosity, density, API gravity and specific gravity evaluations all initially conducted at standard conditions revealed that flow properties of the crude sample demonstrated a typical black oil behavior as these evaluated parameters were in the magnitude of 0.9976g/cc oil density, 13.42 OAPI oil gravity and a 0.9776 specific gravity. With the sample taking an average drain time of 69.5 seconds for 50 ml of crude, the dynamic viscosity of the crude at standard conditions in the magnitude of 17.80 cp confirms that the oil sample at these conditions is completely free from lighter – ends hydrocarbon and as such, internal flow resistance for the oil is in a high magnitude.
For the representative crude sample, the flash, cloud and pour points recorded 136oC, 3oC and –7oC respectively.

C. Alteration of Thermal Sensitive Properties

Specific Gravity and Oil Viscosity

The variation of this flow properties as a function of temperature also revealed that heavy crude recovery via thermal processes can be economical as recovery efficiency percentages can be increased as a result of the decrease in the inter – molecular attractive forces within the heavy crude molecules, permitting a higher kinetic energy by increasing the force per unit area of the hydrocarbon molecule. These petro physical properties were also evaluated at temperature of 75oC, 80oC, 85oC, 90oC, 95oC and 100oC and the results shown in the figures below;

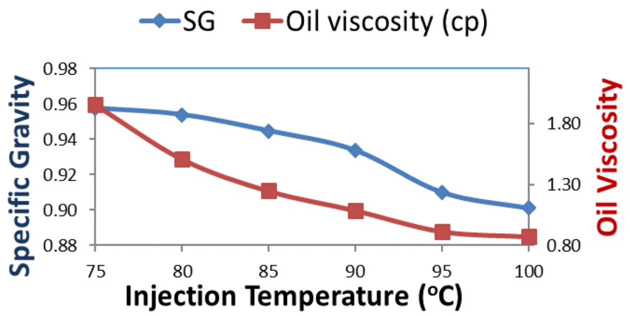

Fig. 1. Variation in SG and Oil Viscosity at Different Test temperatures for Heavy Crude Sample.

A temperature rises from standard condition of 25°C to about 75°C for the heavy crude sample via heating demonstrated a significant reduction in specific gravity and oil viscosity, initially 0.9776 and 17.80 cp to a magnitude of 0.9576 and 1.95 cp respectively. An average drain time of 11.00 seconds for the 75°C crude sample as compared to the 69.50 seconds at a crude temperature of 25°C both of 50 ml volume reveals that there is a significant increase in kinetic energy and thus, decrease in inter – molecular forces within the crude sample. A stepwise increase of 5oC from 75°C to 100°C as shown in Fig. 1, which presents a graphical relationship for temperature rise with oil viscosity and specific gravity shows that these properties are reduced to higher temperatures. The highest test temperature of 100°C recorded the lowest oil viscosity of 0.87, specific gravity of 0.9011 and drain time for 50 ml crude sample of 8.11 seconds.

D. Oil Density and API Gravity

The higher the temperature, the higher the API gravity. This is because API gravity increases with decreasing specific gravity. For an oil system, flow dynamics will be enhanced for a lower specific gravity fluid than it will for a fluid with a higher specific gravity. However, an inverse relationship exists between temperature and density of a fluid as the densities of fluids at evaluated at specific temperatures.

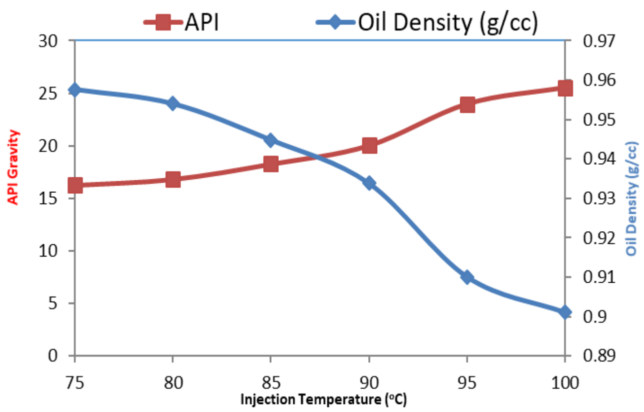

Fig. 2. Variation in API Gravity and oil Density at Different Test temperatures for Heavy Crude Sample.

With the samples initially evaluated at 25°C, having a density of 0.9776 g/cc and a corresponding API gravity of 13.42 °API at same temperature, higher temperatures of 75°C, - 100°C, records a reduction in oil densities and a corresponding increase in calculated API gravities as shown

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in Fig. 2. The highest API gravity of 25.53°API at 100°C as compared to a 16.27°API crude at 75oC reveals that temperature alteration can significantly influence flow quality of these heavy crude samples. At 100°C, the oil density is recorded to be 0.9011 g/cc as compared to a 0.9576 g/cc crude at 75°C. This also implies that the higher the temperature, the lighter the crude.

E. The Thermal Recovery Process -Phase Volumetric Recovery

A series of 1000 ml injection into the reservoir at different injection temperatures was made and the corresponding total volumetric recovery for each 1000 ml injection recorded. Figure 3 shows a summary of total volumetric recoveries per injection and their corresponding injection temperatures.

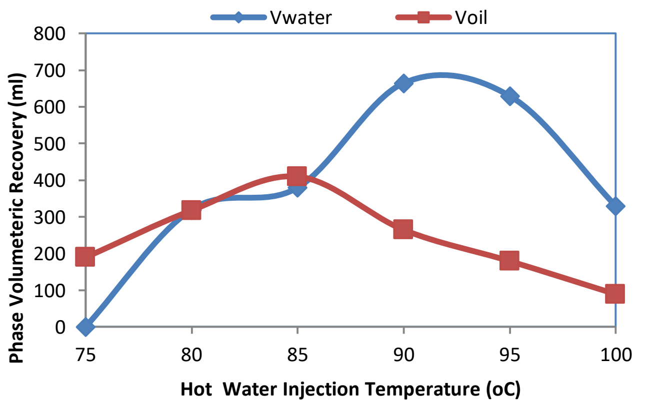

Fig. 3. Phase Volumetric Recovery at Various Injection Fluid Temperatures during Recovery Process

Here, at an initial injection fluid temperature of 75°C, a total of 222ml volumetric recovery was observed to be of the oil phase with a zero-water cut. For fluid injection temperatures of 80°C – 100°C water cut magnitude increased within the temperature range and peaked at about 90°C where the highest water production was observed. For fluid injection temperature of 95°C, a decline in produced water volume was observed and the trend was continuous for the 100°C scenarios. This trend could be traceable to the fact that the temperature increase in the injected water increases the steam quality that is, increases the vapor – liquid ratio and as such, at temperatures of 95 to 100°C, recovery is less influenced by the liquid phase of the injected fluid but primarily influenced by the vapor phase of the injected water. The reduction in net oil production simply indicates reservoir hydrocarbon depletion with time.

F. Thermally Induced Flowrate

For each cumulative recovery, corresponding production rates were recorded by taking cumulative volumetric recovery per time for each temperature interval. For the 75°C injection fluid temperature, a cumulative production of 190 ml with average production time of 40 seconds yielded an oil flow rate of 4.75 ml/sec.

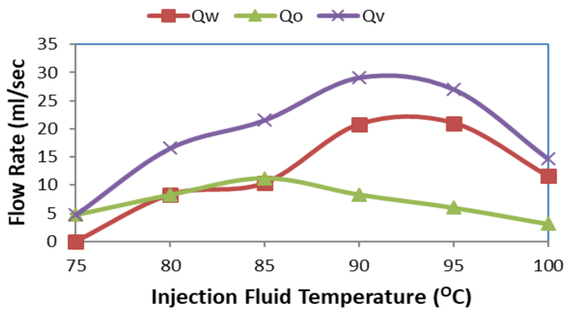

Fig. 4. Fluid Production Rate Profile as a Function of Injection Fluid Temperature.

Fig. 4 shows a peak oil production of 11.17 ml/sec at an 85°C injection fluid temperature and the lowest possible production rate recorded at 100°C, indicating that at longer production periods, hydrocarbon saturation within the reservoir decreases, regardless of the injection fluid temperature. The same trend is observed in the cumulative production rate (oil and water), reason being that production rate is simply the ratio of volume recovered per period, that is to say an increase or a decrease in the volumetric production of either phases will to a large extent influence the cumulative production rate. Production time was a function of injected volumes. At 1000 ml injection, the corresponding time taken for each injection fluid temperature was also recorded. As presented in the graph, time of production / injection duration decreased non – linearly with increasing temperature, possibly as a result of steam quality performance at higher temperatures. The higher the temperature of the injected water, the lower the injection duration.

Fig. 5 shows a peak oil production of 11.17 ml/sec at an 85°C injection fluid temperature and the lowest possible production rate recorded at 100°C, indicating that at longer production periods, hydrocarbon saturation within the reservoir decreases, regardless of the injection fluid temperature. The same trend is observed in the cumulative production rate (oil and water), reason being that production rate is simply the ratio of volume recovered per period, that is to say an increase or a decrease in the volumetric production of either phases will to a large extent influence the cumulative production rate. Production time was a function of injected volumes. At 1000 ml injection, the corresponding time taken for each injection fluid temperature was also recorded, time of production and injection duration decreased non – linearly with increasing temperature, possibly as a result of steam quality performance at higher temperatures. The higher the temperature of the injected water, the lower the injection duration.

G. Effect of Pressure on Overall Recovery

Influence of Injection Pressure on Oil Recovery and Optimum Injection Temperature

Injecting a constant volume of hot water into the reservoir regardless of the injection temperature, it was observed that cumulative recovery was primarily a function of the temperature and not injection pressures. Injection pressures for all temperature ranges were the same. An average injection pressure of 5 psi was observed for temperature ranges from 75°C - 95°C. At 100°C injection fluid temperature, a slight decrease in inlet pressure was observed upstream the reservoir, recording a 3.2 psi inlet pressure. This phenomenon could possibly be traceable to the fact that at higher temperatures of the injected water, the injection pump executes less work as it will require a lesser energy to prime a suction and discharge of 1000 ml hot water of 100ºC.

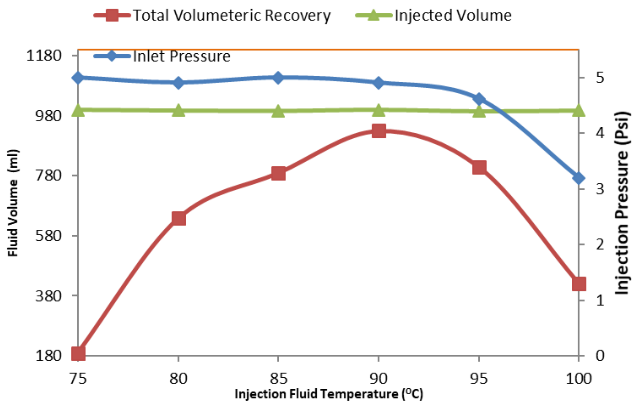

Fig. 5. Injection Pressure Relationship with Cumulative Production and Injected Hot Water Volume.

Though a decline in cumulative volumetric recovery is observed at same temperatures, and time as the pressure profile in Fig. 5, it cannot be inferred that this decline is as a result of injection pressure. This is because at a temperature of 100ºC, water begins to lose its liquid phase to its gaseous equivalent and volumetric recovery at this temperature' only accounts for the liquid phase produced water, which will be of a smaller volume as compared to that injected into the system. The gaseous phase water requires some condensation period in the reservoir and as such cannot be produced within the time of investigation.

Fig. 6, below shows the oil production profile with a peak production rate of 11.17 ml/sec at a hot water injection temperature of 85ºC. It can confidently be asserted that this maximum heavy oil recovery at this mid – ranged temperature is not a function of both injection and production pressures, but primarily a function of the temperature of the hot water. This to a large extent can be used to assert that maximum oil recovery, for the heavy crude reservoir system can be achieved at an optimum water injection temperature of 85ºC.

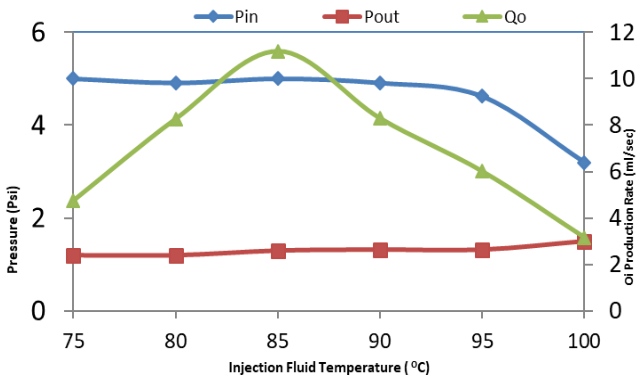

Fig. 6. Pressure – Temperature – Oil Production Relationship Showing Optimum Hot Water Injection Temperature.

H. Comparative Analysis of Heavy Crude Properties Before and After Recovery.

After the EOR recovery process, the produced oil was subjected to same series of petrophysical classification before recovery. Oil density, oil API gravity, specific gravity, water content determination and oil viscosity evaluations were all conducted to ascertain crude property changes after recovery. The first sample recovered at 75ºC injection temperature had no trace of water content but slight percentages were observed for all others from water content experiment using the Dean and stack equipment.

IV. Conclusion

Hot water flooding is an effective method of reducing the viscosity of Niger Delta heavy crude to increase oil production. Laboratory findings showed that substantial volume of heavy crude can be recovered through thermal process (Hot Water Flooding). Result shows that thermal process can be economical because recovery efficiency can be increased as the intermolecular attractive forces within the oil is reduced by temperature alteration. Temperature increase from 75ºC to 100ºC shows significant difference in the density, viscosity, specific gravity and API gravity. Temperature alteration can significantly influence flow quality of heavy crude samples. At initially evaluated temperature of 25°C, the crude density was at 0.9776g/cc and API gravity of 13.42°API compared to crude density of 0. 901.1g/cc and API gravity of 25.5 at 100 C. Pressure effect on oil recovery was observed to be minimal. Optimum oil recovery was obtained at an injection temperature of 85°C, while minimum recovery of oil was obtained at an injection temperature of 100°C. At longer production period, hydrocarbon saturation decreases regardless of the injection temperature.

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