Foamy Oil Production in Trinidad

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The process known as Cold Heavy Oil Production (CHOP) is when heavy oil reservoirs are produced by pumping the reservoir fluids to surface, and no heating of the reservoir is carried out to lower the oil viscosity. Due to the high oil viscosity, recoveries are often less than 5% of the oil in place in the reservoir. However, certain heavy oil reservoirs exhibit higher than expected oil recoveries, more in the range of 5%–25% of oil in place, and higher than expected well productivity. Also, this produced oil shrinks significantly at the surface over a couple of days, maybe by over 70% of the original produced volume. This type of heavy oil fluid behaviour is different to that of 'normal' heavy oil, and is called 'foamy oil' behaviour. Foamy oil behaviour occurs with some heavy oils below their bubble point, and is found in certain Canadian, Venezuelan and Trinidadian heavy oil reservoirs. The peculiar production mechanisms are a result of the evolution of gas from the oil which then remains entrapped in the oil as minute bubbles, less than pore matrix size, within the unconsolidated sand matrix. This paper explores foamy oil production with sanding. After a review of current theory of production mechanisms of foamy oil solution gas drive, a simple, foamy oil model system of wallpaper paste solution (carboxyl-methyl cellulose and water) and antacid mixture is presented. This model system could be used to study a number of the physical processes and properties needed to further understand foamy oil. It does not need high pressure apparatus which otherwise make any experiment slow and expensive, and the equipment difficult to clean. Additionally, sanding is regarded as an essential part of the production of foamy oil and in particular the phenomena of sand dilatancy along with the use of progressive cavity pumps. These topics are then outlined and conclusions are made on directions for the production of Trinidad's heavy foamy oil reserves.

Keywords: Heavy oil, foamy oil, dilatancy, sanding, cold heavy oil production with sanding (CHOPS).

1. Introduction

Heavy oils are crude oils with viscosities greater than 20 cp and densities close to that of water, 940–1000 kg/m^3, (API°<19) [1]. They consist of hydrocarbons heavier than pentane, with the majority of the components being greater than C_{12} and often contain sulphur compounds, asphaltenes and metal compounds. Heavy oils are usually black in appearance, sticky and viscous and have a distinct odour, and as a result they attract less value than conventional lighter oils. Heavy oil reservoirs are often situated in shallow unconsolidated sands.

Heavy oils constitute one of the largest reserves of remaining fossil fuels. Their volumes in place are believed to be greater than those of light oil, with the consensus being that the resources are over six trillion (6000 billion) barrels; the bulk of which is located in Canada (42%), Venezuela (27%) and the Soviet Union (27%) [1]. Trinidad has over one billion barrels (10^9) both onshore and offshore (**Figure 1**) [2],

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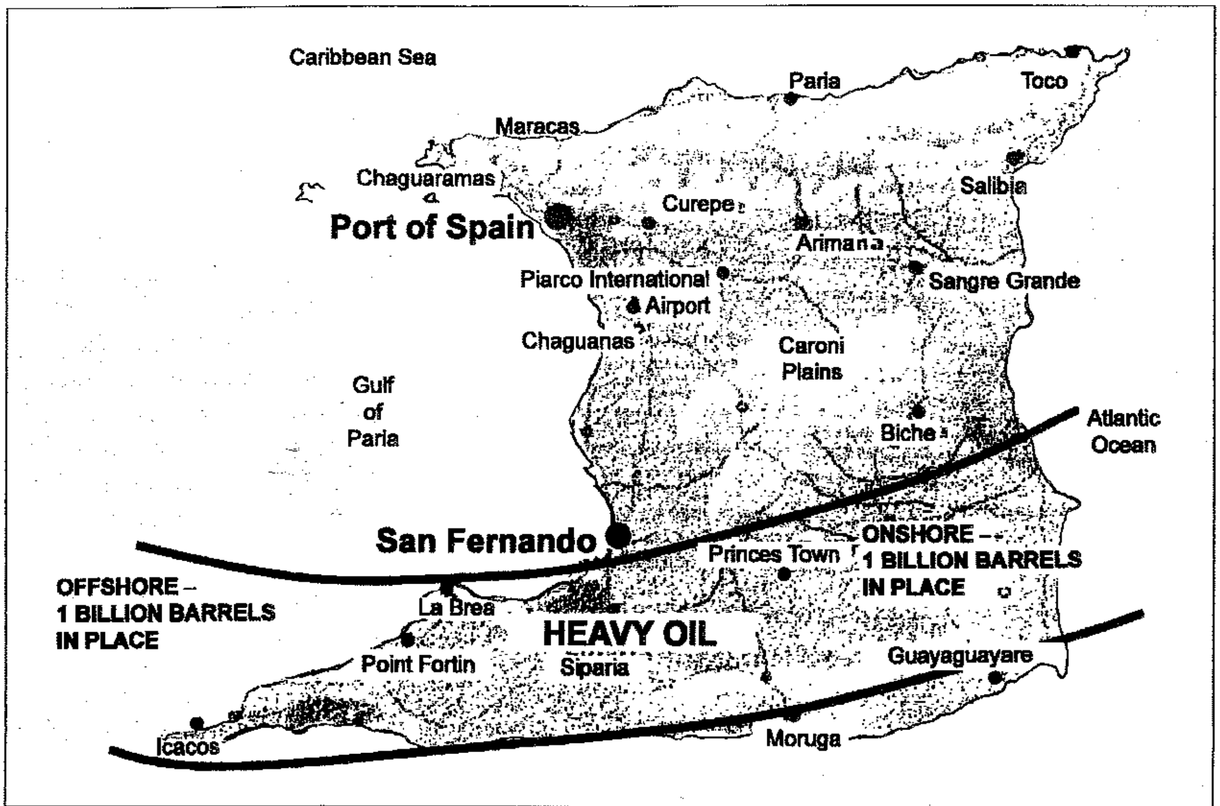


FIGURE 1: *Map of Trinidad showing Areas of Heavy Oil*

which although small compared to the total is still a considerable quantity, because if 20% could be recovered over 20 years, it would be a flowrate of 50,000 barrels/day. The current flow rate (January 2006) of conventional oil from all Trinidad's oilfields is around 150,000 barrels/day.

The production of heavy oils is inefficient with recovery factors usually less than 10%, and often only 1 – 4% [1,3]. This is due to the high oil viscosity. Heavy oil production requires greater reservoir energy for recovery than light oil for the same drawdown (pressure drop) as can be seen from Darcy's Law,

$$Q / A = v = -\frac{k}{\eta}\left(dP^* / dl\right)$$

where, Q is volumetric flow rate of oil, A is cross-sectional area, v is oil velocity, k is reservoir permeability, η is oil viscosity and $\left(dP^* / dl\right)$ is the potential gradient of reservoir, ($P^* = P + z\rho g$, where P is the pressure, and z the distance to a datum level).

The flowrate within the reservoir to the wellbore is inversely proportional to the oil viscosity, thus a 1000 cp oil will flow 1000 times slower than an oil of 1cp, a typical light oil viscosity. As a result, many heavy reservoirs currently cannot be produced at a rate that can be economic, i.e., the production costs are more than the oil can get from the market.[1] This is particularly true where the reservoir fluids are pumped to surface and no heating of the reservoir is carried out – this form of primary production is termed Cold Heavy Oil Production (CHOP). Often, to increase flowrates, heat is added to lower the oil viscosity, but this requires increased energy and equipment costs, which can make the extraction uneconomic both energetically and commercially, as discussed in a companion paper [4].

However, some heavy oil unconsolidated sand reservoirs in Canada and Venezuela with CHOP exhibit higher-than-expected well productivity and oil recovery when exploited with vertical wells under primary depletion conditions and when sand is allowed

[1] As world oil prices rise so heavy oil can become economic.

to freely flow into the wells. These are so-called 'foamy oils'. In Canadian fields, conventional, heavy oil recovery factors range from 1–5%, whereas in foamy oil reservoirs, they range from 5–25% [1,5–8].

In the reservoir, the matrix containing foamy oil is usually composed of uncemented grains (unconsolidated sand) and some of this sand is produced along with the oil. The sand is separated and dispersed in some way [5]. Sanding, discussed in Section 4, appears to increase recovery rates and is a factor that distinguishes foamy oil from conventional heavy oil. In many cases, CHOP involves the intentional production of sand because this is seen to increase the rate of oil production and the process is then known as CHOPS – Cold Heavy Oil Production with Sanding [5].

Foamy oil is often found in shallow reservoirs (depths ranging from 300–1,200 m) although occurrences have been reported in heavy oils offshore Brazil and in China at greater depths [5].

2. Foamy Oil

As foamy oil has some unusual features associated with the gas evolution and which affect the oil's behaviour, both in the reservoir and at surface, a sound understanding of the phenomenon of foamy oil production is needed by engineers to produce foamy oil reservoirs to full advantage.

2.1 Foamy Oil within the Reservoir Matrix

Foamy oil is heavy oil below its bubble point where the gas that has come out of solution and is in the form of small, dispersed bubbles that have not been able to coalese due to the viscous (inelastic) behaviour of the oil [1,5–13]. Foamy oil behaviour is a function of viscosity, diffusion coefficient and the amount of gas dissolved in the oil.

For light oils, when the reservoir pressure drops below the bubble point, gas is released from solution into the oil and when the gas saturation reaches a critical value, (known as the critical saturation), gas begins to flow as a continuous phase. This is part of the solution gas drive process [3]. Essentially, the oil is boiling with the evolving gas phase being mainly methane. Initially, the gas exists in the form of discontinuous bubbles dispersed in the oil. Because the gas does not wet the porous matrix, the bubbles sit in the centre of the pores and significantly reduce the effective permeability of the rock to the oil phase.

With foamy oils however, the released gas is entrained in the oil in the form of microscopically, small bubbles (less than 2 μm) and the bubbles are unable to grow because of the oil's high viscosity and non-Newtonian character. The rate of diffusion of gas into the bubble is a function of viscosity, so the bubbles stay small, smaller than the pore size of the reservoir matrix, so can flow within the oil to the production well. The result is an oil-continuous 'foam', whose viscosity may be different to that of the original oil, but whether higher or lower is still not fully certain [11–16]. If lower, it will enhance the mobility of the oil as it flows to the production well.

2.1.1 The Physics of Bubbles within Foamy Oil in the Reservoir

When the pressure of 'live' oil is reduced to below its saturation pressure (bubble point), some degree of supersaturation results. If the supersaturation exceeds a critical supersaturation, micro-bubbles are created on nucleation sites and the bubbles grow [14–19]. Initially, in light oil, this is rapid, but in heavy oil, it is slow due to the higher oil viscosity and lower diffusion and film drainage rates, so these bubbles remain dispersed in the oil phase as tiny bubbles.

Three dynamic processes occur:

- Bubble nucleation;
- Bubble growth; and
- Bubble coalescence

2.1.2 Bubble Nucleation

The first step in the release of solution gas is bubble nucleation. From studies of gas depressurisation, it has been shown that heterogeneous nucleation normally occurs in porous media [16–19]. This nucleation is driven by the supersaturation of dissolved gas in the oil and is believed to occur in the roughness of pore walls or on particles of foreign matter such as fines, clay particles or asphaltine.

The bubble nuclei are created when a sufficient number of gas molecules in solution come together as a result of the random molecular motion and form a cluster of molecules larger than a critical size. Clusters smaller than this critical size are unstable and collapse.

The more viscous the oil, the lower the growth rate so that the supersaturation is not easily relieved and more sites are nucleated. In heavy oil, therefore, probably many microscopic bubbles are formed, depending on the degree of supersaturation and the magnitude of pressure below the bubble point, (P_b-P).

2.1.3 Bubble Growth

Once bubbles have been nucleated, they grow by diffusion of gas molecules from the supersaturated oil across the bubble/liquid interface. The diffusion coefficient has viscosity as a major parameter. Thus, the growth will be restricted by pore geometry, low diffusivity rates and high viscous forces and will be slow in heavy oil.

2.1.4 Bubble Coalescence and Gas Evolution within the Porous Medium

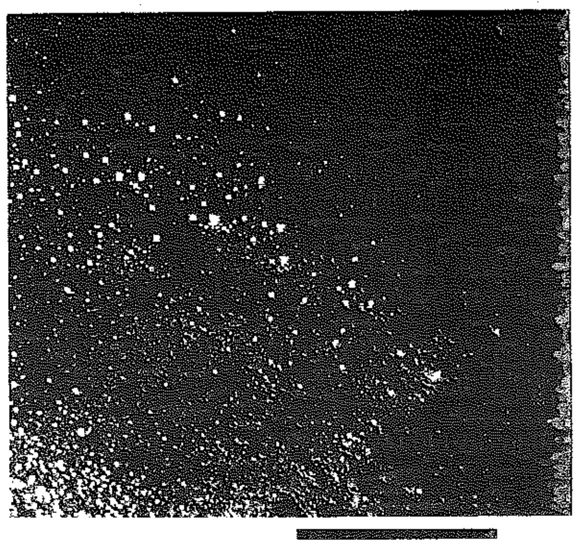
The growing bubbles in the oil are thermodynamically unstable and try to coalesce. The coalescence of bubbles is generally a two-stage process involving the gradual thinning of liquid films followed by breakage of these films [17]. Bubbles break up when the destabilising forces acting on the thin film between the bubbles are larger than the stabilising interfacial forces.

As the drainage time of the liquid film between bubbles is directly proportional to viscosity, this becomes unlikely to readily happen within porous media at reservoir conditions for heavy oil. In fact, it is believed that bubbles continue to grow but are prone to break up into smaller bubbles during fluid motion, so maintaining a dispersed gas flow within the oil rather than forming a separated gas phase [6,14]. As a result, the bubble population in heavy oil fluids will be larger than that in light oil fluids but the volume of the individual bubbles will be smaller.

2.2 Surface Bubble Coalescence

The oil-water-sand-gas mixture is pumped to surface by progressive cavity pumps (Section 5) and produced as a foamy mass, which goes to a stock tank for gravity segregation. The foam collapses over a couple of days and there is a large shrinkage, maybe by a factor of over 3, of th original oil volume at surface. Thus, containers c. .oamy heavy oil that appeared to be initially full, reduce to perhaps much less than half of this volume.

At the surface, just-produced, wellhead oil samples are often described as resembling a chocolate mousse due to the frothy appearance and dark brown, opaque colour (**Figure 2**). At surface, the bubbles of foamy oil expand due to both the pressure drop to atmospheric pressure and the diffusion of molecules into the gas phase from the oil. A viscous foam is produced, which is of poor quality and with large bubbles as shown in **Figure 2**.



10 cm

FIGURE 2: *Wellhead Sample of Foamy Oil showing the Small Bubbles 15 Minutes after Production (from Soldado Field, Trinmar, Trinidad)*

Coalescence processes slowly occur over hours (or days) when the films between the gas bubbles at the gas-liquid surface thin and then rupture, so that the gas can escape from the liquid phase [17]. The interface science of foam-breaking is important but unclear and the high viscous non-Newtonian characterisics of the oil is significant in the gas release.

2.2.1 Interface Science of Surface Foamy Oil

In the stock tank, the dispersed gas bubbles in the produced oil rise to the surface of the oil because of the density difference, but only slowly because of the high viscosity as can be seen from Stokes equation [17].

$$V = \frac{d^2 g(\rho_o - \rho_g)}{18\eta_o}$$

where V is the bubble rise velocity, d the bubble diameter, g the gravitational acceleration, $\rho_o - \rho_g$ is the difference in density between the oil and gas phases and η_o is the dynamic viscosity of the continuous phase (oil).

As the pressure drops to atmospheric, the gas in the bubbles expand according to

$$P = \frac{nRT}{V},$$

where P is the bubble pressure and V its volume, n is the mass in moles of the bubble, T the absolute temperature and R a constant. Molecules are also added by diffusion from the oil to increase n.

The bubbles eventually burst as the surface film of the oil thins and then rupture to release the gas (**Figure 3**) [17]. The separation of the entrapped gas from the oil to form a free gas phase takes time, perhaps up to a few days and the volume of the oil reduces to its final 'dead' value, maybe less than 70% of the original produced (foamy) volume. **Shearer** and **Akers** [20] derived an expression of the time t_g taken for a thick foam suronding a bubble to drain to thickness h_{crit} at which rupure occurs,

$$t_g = \frac{18\eta R_b}{\rho g h_{crit}^2}$$

where R_b is the radius of bubble, ρ and η the density and oil viscosity of the foamy oil. This shows that the

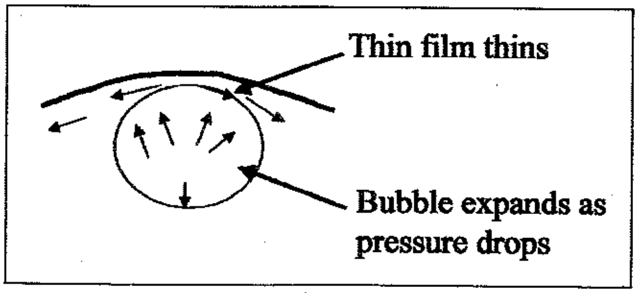


FIGURE 3: *Bubbles Rise to the Surface and Burst*

time t_g is dependent on the oil viscosity (or non-Newtonian equivalent). The non-Newtonian characteristics of the oil may be significant in the gas release, but not much research is reported in the literature on this topic.

3. Foamy Oil Experiments

Researchers have studied foamy oil behaviour in the laboratory in microscopic and macroscopic experiments in order to identify the mechanisms involved [6]. A full understanding could lead to new directions for foamy, heavy oil recovery, particularly optimisation of cold primary production by solution gas drive [9]. Also, there is the fascinating fluid physics of the rheological behaviour of bubbly flow of non-Newtonian fluids, with bubble coalescence, as a research topic in its own right.

Much of the early discussion of foamy oil flow in the literature has been based on the hypothesis of micro-bubbles, i.e., bubbles much smaller than the average pore throat size and therefore free to move with the oil during flow through the rock [6, 9]. This type of dispersion can only be generated by nucleation of a very large number of bubbles and by the presence of a mechanism that prevents these bubbles from growing into much larger bubbles as the reservoir pressure decreases, as discussed in Section 2. An alternate hypothesis is that foamy oil flow involves much larger bubbles migrating with the oil and that the dispersion is created by the break-up of bubbles during their migration with the oil [14].

However, foamy oil is not readily available to all who would wish to carry out studies with real oil samples. The experiments are difficult and expensive. Collecting a foamy oil sample is tiresome and costly and by the time the sample reaches the laboratory, most of the gas has been evolved, i.e., the oil has become 'dead', unless contained in high pressure bombs. Thus, the high-pressure experiments have to be carried out rapidly after obtaining a sample, or the oil has to be resaturated with gas which is a slow and technically difficult process using heavy dedicated equipment [14]. The oil can have a viscosity much greater than 1000 cp and is black, smelly, sticky and difficult to handle, and the cleaning of the equipment is particularly messy.

3.1 *Water-based Foamy Oil Model*

A model system that is cheap, readily available and easy to handle in any laboratory at room temperature and pressure is therefore attractive. A possible suggestion is of wallpaper paste solution (carboxyl-methyl cellulose, CMC, and water) and antacid mixture (citric acid and sodium carbonate) that produces a gas when contacted with water. This could be used to study a number of the physical processes and properties needed to further understand foamy oil. The wallpaper paste solution, when combined with antacid behaves similarly to that of foamy oil but experiments can be conducted at near-atmospheric pressure without the inconvenience of using the oil. Such experimental studies would be easier, low cost and cleaner and could be precursors to experiments on actual foamy oil. A further bonus of our model comes after the experiments have been completed as the apparatus can be rapidly cleaned with tap water in a few minutes, compared to the long process of cleaning the oiled equipment. Also, the effluent can be washed down the drain, whereas special disposal methods are required for the oil. Clearly, our model system is low-cost and it is simple to repeat experiments.

The water-based solution can be made to have any viscosity properties from 1 cp to a gel, depending on the quantity of compound (CMC) added. The amount of gas can be controlled by the weight of effervescent mixture added. We used ENOs antacid but any effervescent, salt mixture can be used.

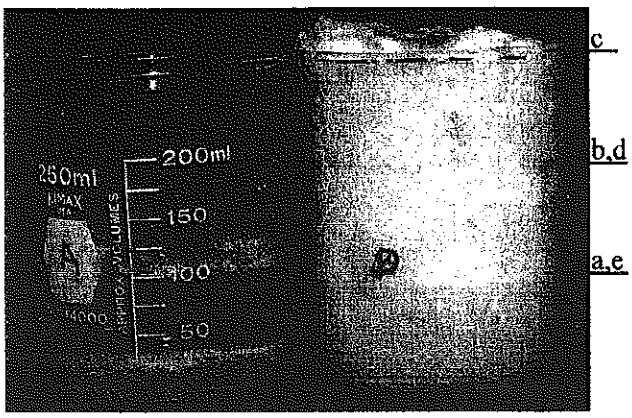


FIGURE 4: *Foamy Oil Model*

Beaker A contains Water. It showed a very Unstable Foam which subsided in under a Minute. Beaker D contains a CMC Solution and Antacid: the Arrows show the Foam Level a, at 0 Hours; Level b, after 0.5 hours; Level c, after 2 hours; Level d, after 4 Hours and Level e, after 6 Hours

Experiments with the foamy solution could include microscale experiments, sand pack, rheological studies of gas suspended in non-Newtonian fluids or film-thinning studies for foam-collapsing.

Figure 4 shows the effect of a CMC solution after various times compared with water. When the solution was placed in an open container at atmospheric pressure, it swelled as the gas bubbles expanded, then over a period of some hours, it shrank to 40% of its swelled volume as the bubbles coalesced and the gas eventually escaped. Foamy oil behaves in the same way. In this experiment, the CMC solution remained 'foamy' for five hours before the foam had fully collapsed, whereas ordinary water gave a very unstable foam that collapsed within a minute.

Clearly, further experiments using different quantities of wallpaper paste granules and antacid could be carried out to quantify the behaviour. Also, if the water-based, foamy oil solution is kept in a container with little air space, perhaps at a pressure slightly higher than atmospheric, the bubbles remain small and flow experiments in bead packs can be performed. Different types of polymer could give different 'foaminess'. This simple model could be the answer for those wanting to identify experimental factors of foamy oil mechanics before moving onto 'live' samples.

4. Sanding Effects

Until recently, the sand produced during heavy oil production was thought of as a nuisance and engineers did their best to eliminate sanding. Thus, the prediction and mitigation of sanding has always been a major challenge in the industry [5].

However, in the late 1980s, it was noticed for heavy foamy oil in unconsolidated sands in cold production that if prevention of sand production was practiced, poor production rates were obtained but, if sanding was allowed, increased production occurred in some instances. Thus, steps were taken to manage sand rather than exclude it. Sanding was encouraged in a controlled fashioned, particularly for vertical wells in unconsolidated sands. This is the basis of CHOPS [5] i.e., oil production and recovery improve when sand production occurs naturally. Unfortunately, oil production from consolidated sands still needs to be produced with horizontal wells and requires sand prevention technologies [5].

Sand production occurs with foamy oil solution gas drive from the unconsolidated sand in the near-wellbore region of the reservoir. This is a result of pressure changes and the high oil viscosity leading to large drag forces on the sand particles, plus destabilising capillary force changes between the sand grains as water ingresses into them during oil and/or gas production. Without sand production, the heavy oil flow rates are usually too low (0.5–3 m per day) to be economical. With sand production, small diameter vertical or inclined wells can maintain steady rates of 7–15 m^3 per day for many years, recovering 5–12 % of the original oil in place [5]. A well may produce several 100 cubic metres or more of sand before a blockage, a pump failure or some other event occurs. This large volume change has massive effects on stresses, compressibilities and permeabilities of the sand remaining in the reservoir as discussed in Section 4.2.

4.1 The Phenomenon of Dilation

The mechanisms that lead to increased productivity with foamy oil have not yet been fully identified, but clearly sand destabilisation by foamy oil creating a permeability increase effect in the near-wellbore region is of importance. The actual behaviour and movement of the affected sand and how the sand particles are dislodged from the rock is not well-understood but there are two plausible models. These are areas of dilation around the well and networks of wormholes [5,21–25].

Rocks, particularly unconsolidated sands, can expand when squeezed due to dilatancy. Dilatancy is the process of a rock or sand under going an increase in volume due to the application of a shear (i.e., non-hydrostatic) stress. This was first described by **Reynolds** in the 1880s [26]. He found that a porous medium would expand when it is disturbed from its equilibrium state, i.e., pore space increases (**Figure 5**). This can be visualised by imagining an array of round coins on a table. Consider two layers (**Figure 5a**). If one tries to shear the upper layer across the lower one, say to the right, this cannot be done without the upper layer not only moving to the right but also moving up slightly, so as to be able to ride over the lower layer. In doing so, the volume, particularly the pore space, increases.

A second example is shown in **Figure 5b** where we consider a well-shaken box of marbles. The marbles will settle in the close-packed structure, orthorhombic arrangement having minimum pore space (~29%) [27,28]. If the opposite sides of the box

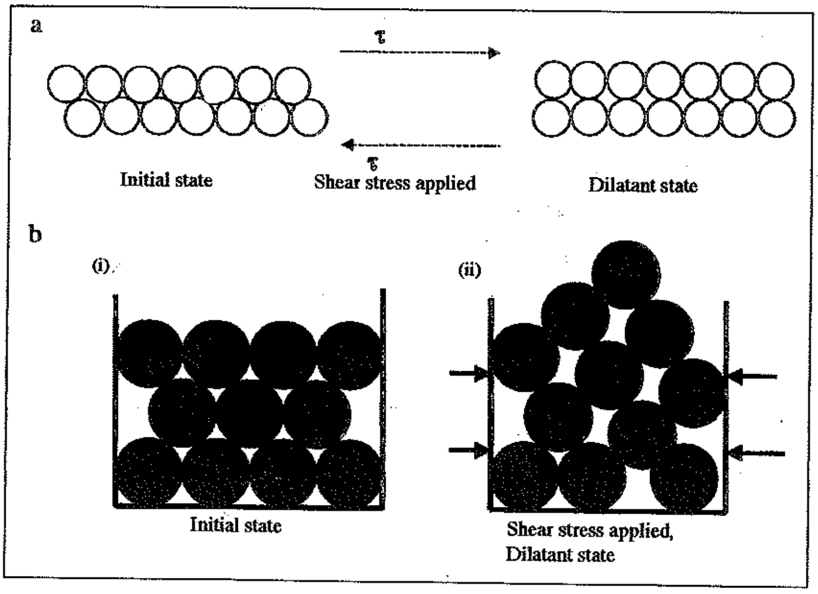


FIGURE 5: *Principle of Dilation*
a. *Two Layers of Circular Coins, Before and After Stress is Applied.*
b. (i) *Box of Well-settled Marbles with Minimum Porespace (29%).*
(ii) *Box Sides are pushed together, the Marbles move, creating a Larger Porespace, therefore Total Volume increases.*

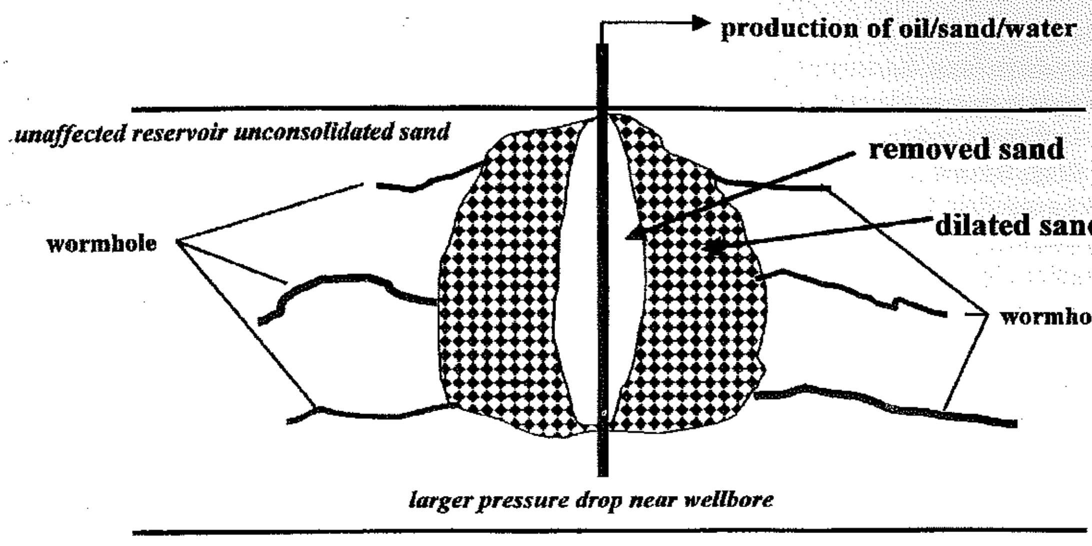


FIGURE 6: *Schematic of Sand Liquefaction and Production from the Near-Wellbore Region of An Unconsolidated Sand Reservoir undergoing CHOPS*

are pushed together, the marbles move and will increase the pore space, thus the porosity increases. Distortion creates a change (increase) in volume from the well-settled state.

One well-known example of dilatancy is that of wet sand on the sea shore which becomes momentarily firm and apparently dry (shows white) under pressure of a foot, but when the foot is removed, the sand has water sitting on the top for a few minutes. Here, one increases the stress on the sand by stepping on it, the sand shears and dilation occurs and the porosity increases. Initially, the sand is at its well-shaken state (lowest porosity) and the pores are full of water, the dilation of the sand (increase of pressure by the foot) increases the pore space and so requires more water which has to be drawn in through the interstices of the surrounding sand, which takes time. On removing the foot, the sand becomes momentarily waterlogged because the distorting force has been removed, the sand contracts and the pore space reduces and the excess water is expelled momentarily to the surface.

However, dilation cannot occur if the sand grains are not free to move, e.g., when the sand grains are cemented (consolidated), or in the laboratory when confined in a triaxial cell. To stimulate a well by dilation, some sand has to be removed so that the formation can go into shear. Once the overburden stress exceeds the cohesive strength of the rock, then the rock dilates and the porosity increases.

In summary, dilation will occur with any disturbance on the well packed unconsolidated sand grains unless they are rigidly held in place and will increase the bulk volume occupied by the grains, i.e., increase porosity.

4.2 Sand Production Mechanisms and Sanding Management [5]

As the foamy oil moves through the reservoir to the wellbore, the shear stresses cause the near-wellbore unconsolidated sand to dilate. Some of the sand grains get dislodged and sand is produced. Sand grain removal can destabilise the rock structure. As the process continues, more grains are dislodged, moving the destabilised (dilated) volume deeper into the formation. Near the wellbore, many sand grains move and create a zone of removed sand (**Figure 6**). In essence, this massive sand production involves a continuous 'liquefaction' of sand in the reservoir over an increasing distance from the wellbore.

Liquefaction occurs when the stresses caused by the fluid pressure gradients and the overburden in the reservoir acting on the sand causes yield and dilation. The flowing liquids and gas evolution (foamy oil behaviour) then destabilise and suspend the sand in the flowing fluids that then flow to the wellbore. As the sand is continuously removed, it cannot support the sand face that is being destabilised.

The sand in the inner near-wellbore of the reservoir passes from an initial porosity of ~30% to one of the order of >~95%, i.e., this volume, more or less, has no rock matrix [5,11,21–22]. The porosity in the dilated zones may increase from 30 to 35%, which results in large increases in reservoir permeability. Producing 1 m^3 of sand will dilate approximately 12–20 m^3 of the reservoir.

Log data and geomechanical modelling indicate that the sand production does not only form a cavern around the well but creates an outer zone of dilated sand (i.e., where sand has yielded and expanded due to reduced effective stress and liquefaction processes, resulting in higher porosity and permeability) around the well, or a radiating network of tubes (wormholes) extending out from the well, or a combination of both. These greatly increase the contact area between the well and the formation, thus enhancing rate and recovery **(Figure 6)** [23–25].

Thus, sand production generates a growing zone adjacent to the wellbore of greatly enhanced permeability and increased porosity, thereby creating a growing, larger diameter, modified wellbore geometry. This enlarged drainage radius can have several configurations including near no-matrix cavities, dilated zones, sheared zones or piping tubes (wormholes) [11] **(Figure 6)**.

Mobile sand means that any mechanical skin of fines blockage, gas bubble blockage or asphaltene precipitation near the borehole is continuously removed, i.e., the near-wellbore will continually clean itself up. Although, conversely, if sanding ceases, sand recompaction and perforation blockage would create traps for asphaltenes and clays which would almost totally block fluid production paths, so that oil rates would drop precipitously.

Today, in heavy oil, unconsolidated sand reservoirs in Canada and Venezuela, foamy oil flow with sand production enhances oil production. Sand management techniques have led to reduced production costs which will continue to decline as better approaches are developed. No sand exclusion devices (screens, liners, gravel packs) are used [5]. Nevertheless, even with sand production, the drainage area that can be produced with foamy flow is not boundless. The required pressure gradient to create dilation are available only up to a certain radial distance away from the well which gives the engineer ideas of what distances are needed between wells.

5. Progressive Cavity Pump

The oil-water-sand-gas mixture flows into the bottom of the wellbore from the reservoir body as a foamy mass. This can then be lifted to surface by a progressive cavity pump where it goes to a stock tank for gravity segregation of the oil. After the foam has broken as described in Section 2.2, the oil can be exported, but unfortunately, part of the oil forms an emulsion of oil, clay, other fines and water that is very difficult to break and must be further separated from the bulk oil and the residue disposed of in an environmentally-friendly way.

Progressive cavity pumps are now highly reliable and versatile devices capable of pumping slurries with high sand content by means of a cavity which moves along the body of the pump **(Figure 7)** [5,29]. At the heart of the downhole, progressive cavity pump lies the pumping element consisting of a hard steel rotor, usually in the form of a single, external helix of circular section and a stator with the internal form of a double helix. The stator is made from a resilient, abrasion- resistant elastomer bonded inside an alloy steel tube and is selected to be compatible with the specified well fluids. It is essentially an efficient Archimedes' screw pump.

When the rotor is placed inside the stator, a series of sealed cavities are formed so that a 'progressive cavity' is created. Then, as the helical rotor turns eccentrically inside the double-threaded, helical, elastomeric stator, this continuous cavity progresses from the suction end of the pump, up to the discharge end and moves the fluid on thus transporting the well fluid through the pump and up the tubing string to the surface without pulsation.

The fluid flow rate is directly proportional to the speed of rotation, therefore, the pump can be closely matched to the well inflow rate for optimum production. These systems are well-suited for high viscosity fluids and can handle significant amounts of sand because the constantly sweeping seal line between the stator and rotor prevents a build-up of solids within the pump. Entrained gas or suspended solids can also pass through the pump without causing gas locking or pump blockage. However, any settling of sand in the tubing or blockage of the pump intake can cause a blockage, so a field practicality is to ensure continuous production without interruptions.

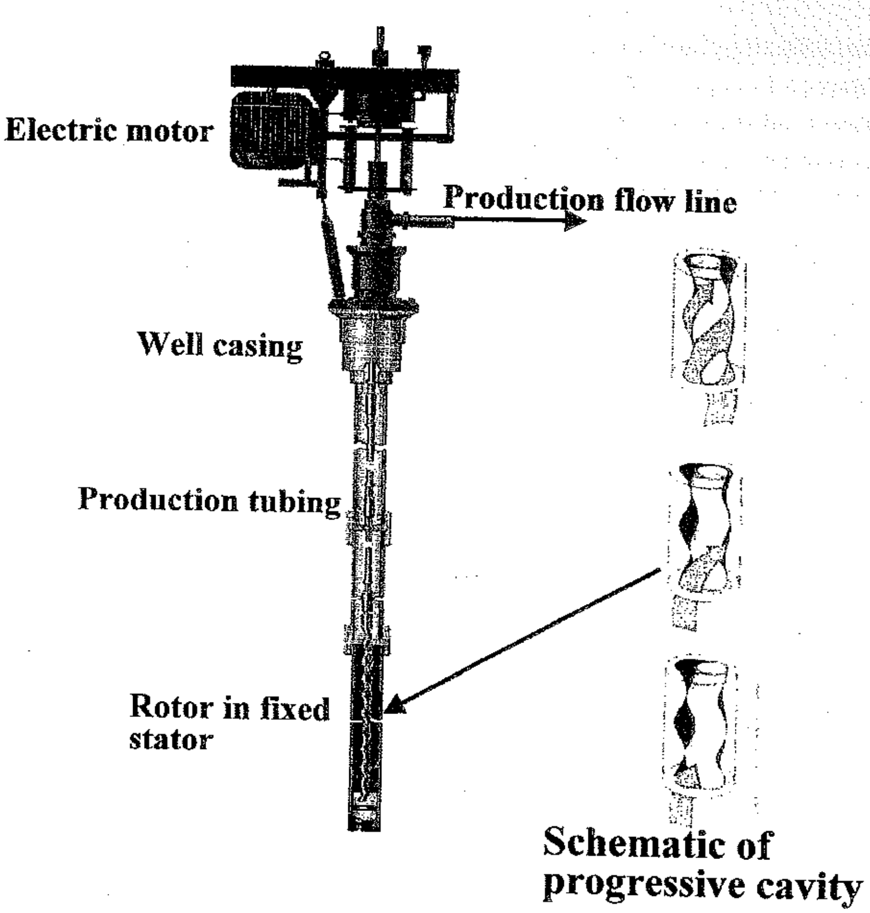


FIGURE 7: *Progressive Cavity Pump [29]*

6. Conclusions

- Foamy oil is heavy oil below its bubble point and the high oil viscosity prevents the evolving, minute gas bubbles, less than pore matrix size, from coalescing within the reservoir. These bubbles may affect the oil mobility but it is not yet sure how. At the surface, the produced oil volume shrinks significantly over a couple of days due to the slow release and escape of gas from the oil.

- Heavy oil producers in Canada have learned from experience that some unconsolidated sand, heavy oil reservoirs exploited with vertical wells under primary depletion conditions, perform better when sand is allowed to freely flow into the wells. Sand production is probably an essential part of the effective production of foamy oil and if it is prevented, less oil is recovered. Sand dilation and stress propagation into the body of the reservoir are essential. The sand/oil mixture can be pumped to surface by progressive cavity pumps.

- The presence of clay (i.e., consolidated sands) stabilises the sand grains and reduces sand movement and is detrimental to enhanced foamy oil production.

- A simple model of wallpaper paste solution (carboxyl-methyl cellulose and water) and antacid mixture could be used to research a number of the physical processes and properties needed to further understand foamy oil. Such experimental studies would be easier, low-cost and cleaner and could be precursors to experiments on actual foamy oil.

- As Trinidad has heavy foamy oil reserves in unconsolidated sand, using horizontal wells and having sand production prevention may not be the best practice. Their economic exploitation might be best carried out without addition of heat, but allowance of sanding using vertical wells.

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