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Pressure Pulse Workovers in Heavy Oil

Maurice Dusseault, University of Waterloo, Darrell Shand, Brett Davidson, PRISM Production Technologies Inc.

Abstract

Approximately 100 pressure pulse workovers have been performed on heavy oil wells in Canada since 1998. Analysis of a number of the wells shows varying degrees of success, but in general, the workovers have paid for themselves in almost all recent cases. Although there is insufficient information to fully prove hypotheses using statistical criteria, it appears that pressure pulse workovers have particular application in three situations:

- In cases where the CHOPS well did not initially start producing sand during the primary completion attempts;
- In cases where the well became disconnected from the far-field pressure and gravity driving forces; and,
- In cases when it is desired to place a workover chemical in a well-dispersed fashion around a well.

This article will review the physical mechanisms and drive energy sources that are believed to be responsible for CHOPS production; it will also present the physical processes that we believe occur during aggressive pressure pulse workovers around a heavy oil well.

Introduction

The Canadian heavy oil and oil sand deposits (**Fig 1**) comprise the largest known petroleum accumulation in the world, with over 400×10^9 m^3 OOIP (2.5×10^{12} b). If only 30% of this resource can be economically extracted in the foreseeable future, 100% of Canadian and US oil needs at current rates of consumption (about 20×10^6 b/d) could be met for the next 100 years. Given recent events, pursuit of this resource more aggressively seems eminently reasonable. Furthermore, existing technologies, Steam-Assisted Gravity Drainage (SAGD), Vapor Assisted Petroleum Extraction (VAPEX), Cold Heavy Oil Production with Sand (CHOPS) and pressure pulse flow enhancement can likely achieve this recovery ratio.

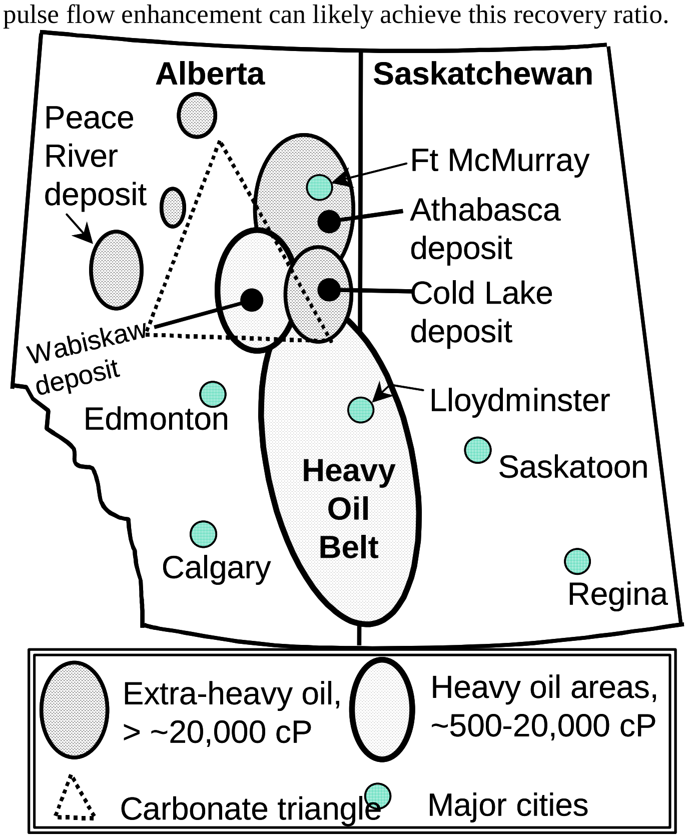

Figure 1: Disposition of Major Heavy Oil and Oil Sands Deposits in Canada (Alberta and Saskatchewan)

CHOPS is now responsible for over 550,000 b/d oil production in the Alberta and Saskatchewan Heavy Oil Belt, over 20% of total Canadian production. The limits on production rate are not related to lack of suitable fields, lack of profitability, or lack of technological capability: limits are because of a lack of heavy oil upgrading capacity in Canada and the mid-west United States. Approximately 850,000 b/d is produced from all sources (thermal, non-thermal, CHOPS, SAGD), and only about 150,000 b/d can be upgraded in Canada: the rest is shipped to upgrading facilities in the United States (Minneapolis, Chicago, Billings…). Because of the shortage of upgrading capacity, the difference between the price offered for heavy oil and that offered for light oil in

Edmonton averaged over US$9.00/b in 2001, rather than US$4.50-5.00/b, which is probably the level at which upgrading costs can be met, along with a profit.

In the right reservoirs, CHOPS has become the favored approach for production of heavy oil[1] because it gives a period of reasonable primary production rate with a modest to low investment. This is because exploitation is through low-cost vertical or slightly inclined wells, and operating expenses have been reduced to about US$4.50/b through the use of progressing cavity pumps and better approaches to sand management.

To execute rational screening for different workover technologies, it is necessary to have a good understanding of the physical mechanisms that may have led to the need for a workover. This requires that a basic understanding of the mechanisms and the sources of drive energy in CHOPS be achieved. This is not straightforward because of the distinctly non-conventional aspects of CHOPS processes and because of the massive changes in reservoir properties that occur over the life of CHOPS wells.

Workovers in CHOPS wells cannot be carried out like workovers in conventional wells; because the reservoir is continuously evolving in terms of rock properties. The reasons for this will be reviewed, and a brief outline of some recent developments will be presented to allow pressure pulse workovers to be assessed in a broader sense.

CHOPS Production Mechanisms

CHOPS entails continuous sand influx into the wellbore along with heavy oil.[2] The sand consists of the "entire formation material", not just fine-grained particles, although only one zone may contribute the majority of the sand being produced. Clearly, this flux of sand has to be brought to the wellbore through some form of drive energy, and the production of hundreds of cubic meters of sand per year from a single well must alter the physical characteristics of the formation surrounding that well.

It has been unequivocally proven, for the Canadian heavy oil deposits and undoubtedly will be for other similar reservoirs,[3,4] that sand influx permits an increase in the oil production rates of vertical wells by a factor up to twenty in some cases.[5] A vertical heavy oil well that produces only 20 b/d of 5000 cP oil through use of a sand exclusion screen may produce from 100 to 400 b/d once the screen is removed and sand encouraged. This oil will be produced along with about 3-5% sand and an amount of solution gas that is proportional to the volume of oil produced, with a constant GOR over time.

There appear to be five direct production mechanisms associated with oil production using massive sand influx:[6]

- Increased fluid flux associated with the sand flux;
- Growth of a zone of enhanced permeability because of sand withdrawal;
- Accelerated flow toward the wellbore because of expansion of a dispersed bubble phase and greatly retarded solution gas depletion because a continuous gas phase is not formed in the intact reservoir portion;
- Compaction of the weakened and dilated formation formed by the sand production; and,
- Elimination of the formation of near-wellbore mechanical skin through asphaltene precipitation and fines blockage.

General Yield or Piping Channels?

There appear to be two limiting physical structures that can be created through the continuous long-term production of sand: a general dilated zone of higher porosity and permeability but roughly homogeneous; or, a region of "intact" matrix transected by open piping channels from which the sand has been removed by liquefaction at the tip of the channel. Interestingly, the effects on flow rate to the well are similar, and it is not possible to distinguish based on well tests, nor has any technology been proposed that could identify the nature of the altered zone, except perhaps in the immediate wellbore vicinity (i.e. 10-30 cm from the casing).

If the system is a piping network,[7] there are two limiting structures: a self-similar dendritic net with repeated channel bifurcations with distance from the well; or, a number of channels that is fixed or that increases only slowly with distance from the well.

These three "structures" are shown in **Fig 2**. It is likely that the reality in the ground is a combination of these structures at different locations, and perhaps also an evolution of the dominant structures over the life of the well. The writers do not believe that it is possible to propagate small piping channels (20-40 mm diameter) in dense sands (ϕ 28-31%) because of effective sand grain arching in dense sand; rather, we believe that the large overburden stresses that are redistributed during sand production lead to lateral unloading, yield and dilation. This process destroys any fragile cohesion and makes it possible for channels to develop.

Note that in the case of the piping channel hypotheses, oil is "oozing" into the flow system not only from the propagating tips of the channels, but also from the flanks of the channels, so that the high sand content slurry becomes progressively more diluted during transit to the wellbore.

Increased Darcy Flux

If some portion of the solid matrix can flow at velocity v_f, the Darcy velocity, $v_f - v_s$, changes, and the fluid velocity relative to a fixed reference frame increases. During early time, immediately after a CHOPS well is placed on production, the sand cut can be as high as 30-40% sand by volume of the total dead (gas-free) produced materials. At this stage, there is an appreciable enhancement of fluid flux, by as much as a factor of two compared to a static matrix case.

If the nature of the sand producing mechanism is mainly the propagation of piping channels into an "intact" matrix, it is likely that at the tip of the channel the flux of the sand grains reduces flow impedance to the oil. Also, in the channels, the hydraulic diameter is large enough that there is a greatly reduced resistance to flow of the sand-oil-gas slurry toward the wellbore.

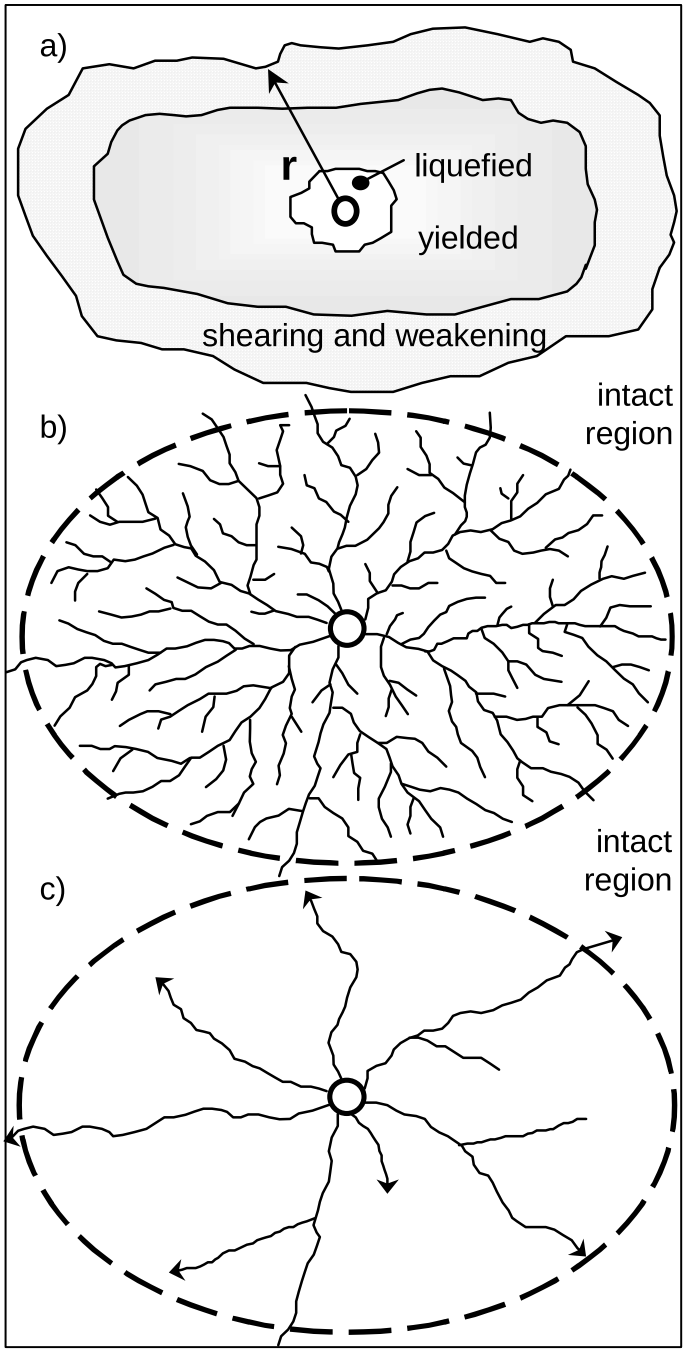

Figure 2: Possible Macroscopic Reservoir fabrics Generated through Massive Sand Production:

- **a. General shear, dilation and yield (homogeneous)**
- **b. Dendritic (self-similar) network of piping channels**
- **c. Constant number of piping channels**

Zone of Enhanced Permeability

Whether the reservoir structure is a network of channels, a disturbed zone of higher porosity and permeability, or some combination of the two, the effect of continuous sand influx is to generate an ever-larger effective wellbore radius, which is beneficial to flow. Only when the effective wellbore radius approaches the interwell scale (i.e. approaches the pattern-fixed drainage radius) will the beneficial effect on flow rates taper off. Various models can be postulated to simulate the enhanced flow rates, and the results depend strongly on the assumptions associated with the nature of the reservoir structures. Testing which permeability enhancement model is likely to be correct through well flow testing and type curve analysis has proven impossible. No well flow software addresses the mechanisms discussed in this section, therefore software packages can give results that are simply irrelevant, but may be seriously misleading to those seeking to understand the process.

Solution Gas Drive

In conventional oil wells in reservoirs drawn down below the gas bubble point ($p_w < p_b$), it is supposed that there is a zone, called the induction zone, where gas bubbles come out of solution, coalesce and form a continuous phase at saturation values of about $S_g \sim 15\text{-}25\%$. ($S_g + S_w + S_o = 1.0$). It is further assumed that the width of the induction zone is small with respect to the characteristic flow path length of the fluids, so that the induction zone can be assumed to have little effect on overall flow behavior. The permeability of the three-phase region is treated using multiphase permeability concepts, and the induction zone width and effects are ignored. Except in the early well life, this gives little error in conventional oil.

In most heavy oil deposits in Canada, the bubble point is fairly close to the pore pressure ($p_b = 0.7 - 1.0 \cdot p_o$), and the Henry solution gas constant appears to be the same for most heavy oils (0.20/bar or 0.20 vol/vol/100 kPa), although of course the total gas content is a function of the initial pressure, and shallower heavy oil deposits thus have less gas in solution. Similar figures for Henry's constant have been determined for the Venezuelan Faja del Orinoco, and in several Chinese heavy oil deposits (Liaohe, Shengli, Jilin).

When the well pressure drops below p_b in heavy oil, bubbles form,[8,9,10,11,12] but the low diffusion rate of CH_4 in the viscous oil,[13] the laminar flow (reduced Brownian motion), and other factors result in a low bubble capture rate or diffusive growth rate, so that the induction zone remains at a scale equal to the characteristic flow path length throughout the life of the well, and the gas phase flows to the well bore as bubbles along with the sand and liquids. Occasionally, a small gas cap will form near the wellbore, but no continuous gas phase develops in the reservoir over the life of the well. Furthermore, the identification of virgin reservoir pressures in the interwell region of 10-acre spaced wells, plus a constant GOR over time, both prove that a critical gas saturation is not reached in the high porosity sands over the life of the well.

This means that as long as the liquefaction front (channels or otherwise) is propagating into new reservoir zones, there will be virgin pressures to help destabilize the sand and cause flow to the well. Because gas bubbles remain discrete, they expand during transit to the wellbore (where p_w is invariably very low, 200-500 kPa) and provide an internal drive force that is absent in conventional oil. This is often referred to as "foamy oil" drive, and the lower the p_w, the better it should be, giving an incentive to operate wells with as low an annular fluid level as possible (BHP gauges are recommended).

Compaction Drive

Fig 3 shows vertical stress distributions in a CHOPS reservoir at early, intermediate and late time. In early time stresses are changing because of near-wellbore sand production, but the strata are successfully carrying the loads. In intermediate time, large stresses are imposed on the intact reservoir, causing it to shear and dilate (if it is a dense sand), but perhaps to compact somewhat (if it is a high porosity sand), generating some induced compaction.

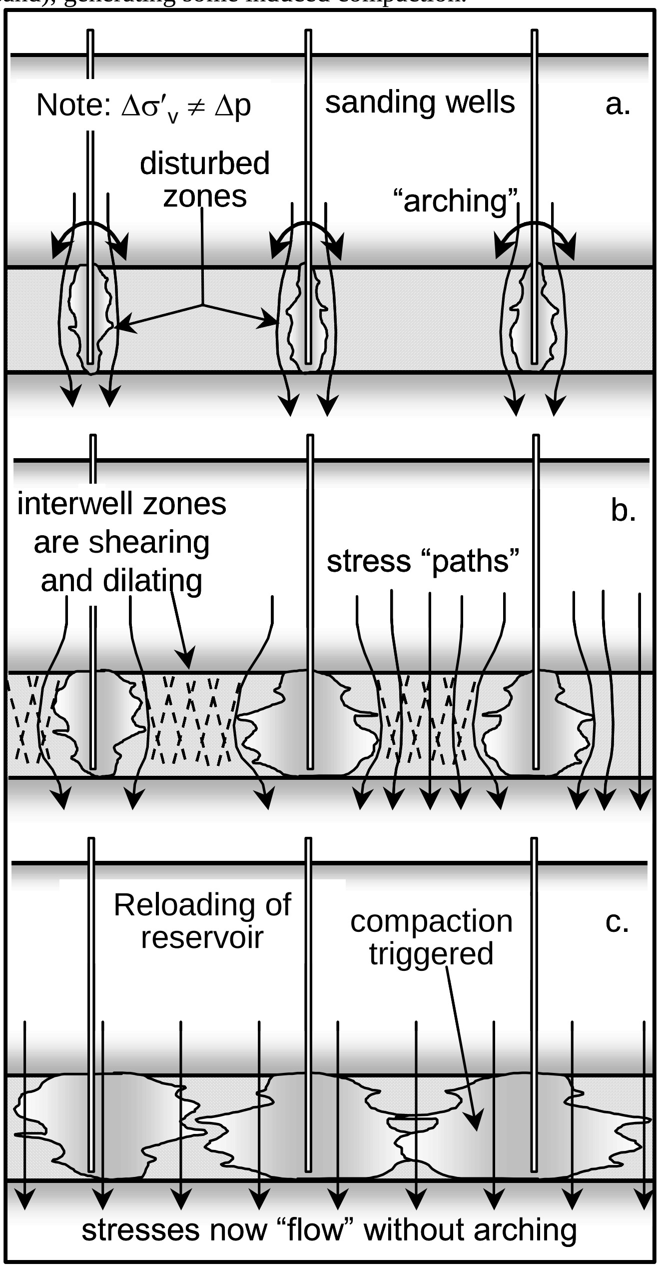

Figure 3: Stress Redistributions around a CHOPS well
- **a. Early time, stress arching, little shear and dilation**
- **b. Intermediate time, shear and dilation**
- **c. Late time, compaction of dilated material**

Frame c of **Fig 3** shows the situation after the disturbed zones have grown to the reservoir scale: stresses are re-imposed on the dilated and loose zones, compacting them from their high porosity to a lower value, and contributing some late-time compaction drive to the process. It is believed that in the Canadian 30% porosity reservoirs, this happens at late time only, and requires that the interwell "pillars" be successfully destabilized.

Removal of Blockages

If sand is free to move, particularly in the near-wellbore environment, blockages such as precipitated or agglomerated asphaltenes and fine-grained mineral cannot accumulate to block flow paths, and there is no stable substrate for the precipitation of minerals to block pore throats. Thus, as long as sand is moving, the well behaves as if it has a massively negative skin.

Empirically, it is well known that use of any technology that seeks to exclude sand results in massively lowered production that continues to diminish with time. It is believed that a filtration process takes place, with smaller flow channels being progressively more and more blocked with flowing solid materials.

Spatiotemporal Changes of Mechanisms

With the possible exception of the blockage removal, these five mechanisms do not act equally throughout the life of a CHOPS well. For example, at early time when sand cuts approach 30-40%, enhanced Darcy flux is clearly much stronger that late in the well life when the sand flux is only a few percent. On the other hand, compaction is a late-time effect in the quartzose and dense Canadian reservoirs, **Fig 4** is an attempt to qualitatively show the relative effect of the five mechanisms.

The relative weights of the five processes are as yet ill understood, largely because of a lack of detailed monitoring data on CHOPS field from the beginning of production. This is due to the low profit margins traditionally associated with heavy oil, resulting in aggressive cost-cutting to reduce operational costs, which in turn means that careful monitoring and quantification of processes over time is sacrificed.

Sources of Drive Energy in CHOPS

Solution Gas Drive

CHOPS is widely viewed as a solution gas drive process. Empirical evidence in Canada shows that if the reservoir has a low gas content relative to its virgin pore pressure, it is more difficult to sustain CHOPS processes. The nature of this drive energy is worth exploring in a bit more detail.

The low diffusivity of gas in solution in viscous heavy oil means that the mean-free-path length for gas molecule Brownian motion is small, compared to lower molecular weight, less viscous liquids. It appears that there is retardation in gas nucleation so that the formation of bubbles is a slow process and the liquid can remain supersaturated with no free gas bubbles for a long time after the pore pressure is reduced below the bubble point. This can be explained in a straightforward manner.

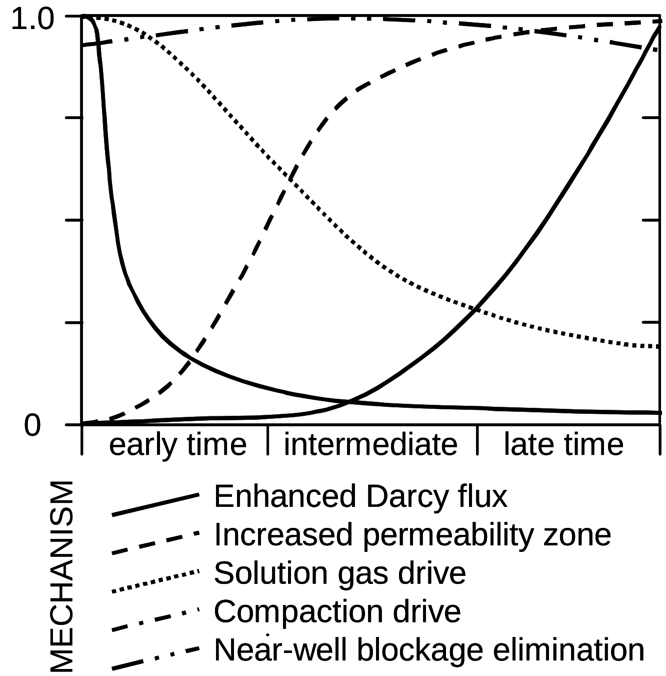

Figure 4: Production Enhancement Mechanisms over Time

Approximately 40-60 CH_4 molecules are required to form a stable bubble that does not spontaneously collapse because of the small radius of curvature. Statistically, in a low viscosity fluid, this number of molecules can be "assembled" through random motion quite easily, so that bubbles nucleate rapidly and then grow by further gas diffusion into the bubbles. In heavy oil, the statistical probability is so low that bubble nucleation is "improbable", and once bubbles form, diffusive growth is slow. Similarly, workover methods attempting to "recharge" the near-wellbore through the injection of CH_4 are doomed to failure because of the extremely slow process of dissolution into the oil.

Bubbles also grow by diffusional capture of smaller bubbles and by the coalescence of two small bubbles into a larger single bubble. These processes are also retarded by the low diffusivity of the gas in the heavy oil, and by the slow laminar flow rates characteristic of CHOPS production.

There has been speculation that bubbles are further stabilized by a coating of polar molecules so that the outside of the bubbles are similarly charged, leading to repulsion, but this has not been demonstrated at this time.

An important aspect of the solution gas drive in CHOPS is that the GOR values tend to be stable over time. This means that only the gas in the oil being mobilized is available, and gas in immobile oil remains undepleted. It appears that the shear distortion of the reservoir leads to dilation, which provides sufficient "free volume" for bubbles to form, and the bubble growth and pore throat blockage help liquefy the sand. Thus, in the absence of sand flux and continued shearing and destabilizing of the sand structure, the solution gas drive is not highly effective. This seems to be confirmed in many cases by the low production rates per metre of well length for long horizontal wells, by the rapid drop in productivity of such wells (limited true radius of influence of the drawdown), and the low recovery factors (generally less than 10% OOIP overall, albeit higher in high k zones).

The nature of the solution gas drive mechanism is thought to be the reason why thermal stimulation, such as injection of a large slug of steam, has only temporary beneficial effects and often results in a cessation of CHOPS after some time. Also, experience has shown that wells that have previously been steamed in an attempt to generate thermal production are extremely poor candidates for conversion to CHOPS wells. The high temperatures allow the gas to come out of solution rapidly, form a continuous gas phase, and bleed off the gas in adjacent heated zones, to the detriment of the bubble drive mechanism.

Finally, based on field evidence of virgin pressures remaining for long times in the interwell regions, it is believed that for the more viscous cases (~10,000 cP), the oil *in situ* is genuinely immobile in response to the modest gradients that can be generated in a typical shallow heavy oil reservoir. This could be evidence of some gelation structure in the virgin oil because of the high content of polar molecules, and that it takes some initial perturbation (shear) for the Bingham-type gel structure to be broken down so that liquid flow can take place. This *in situ* gelation is generated over geological time; it is disrupted by core damage, and thus will prove extremely difficult to confirm or disprove unequivocally. It is likely not possible to reconstitute such a structure in the laboratory over typically short experimental times, and *in situ* probing using seismic or magnetic resonance methods remains problematical.

Gravitational Drive

The vital role of gravitational forces in sustaining CHOPS has not been widely addressed because it is difficult to simulate in any conventional manner, and because it is not understood. However, understanding this drive force is vital to planning successful workovers in CHOPS wells.

As sand is produced from the near-wellbore region during early CHOPS, the lateral stress that naturally holds back the sand is removed, but the vertical stress is not.[14] This results in shearing of the sand, and because the lateral stress is low, this leads to dilation, and ϕ goes from 30% to 35-40% in the sheared region. This destroys any natural gelation in the oil and provides volume for bubbles to be generated. The sheared and dilated sand is under very low confining stress, and can be more easily diluted, liquefied and carried toward the wellbore.

However, the weakened zone is essentially incapable of supporting vertical stress, so the stress redistribution that must occur (**Fig 3b**) leads to stress concentrations, more shearing, and a self-sustaining process that leads to outward propagation of the dilated and high permeability region.

Is there independent evidence that this takes place? There are three lines of evidence that, taken together, seem to be convincing. First, the few surface subsidence measurements that have been taken show a small (10 cm scale) downwarping, confirming that downward overburden movement is taking place. Second, in an instrumented test in the Morgan Field in Alberta, interwell microseismic shear events were identified, implying episodic (stick-slip) shearing of the strata. Third, surface seismic surveys have identified large low velocity, high impedance zones around good CHOPS wells,[15] and no zones around wells that failed to produce large quantities of sand. This information confirms the existence of shearing and dilation, even in the absence of other mechanisms such as the possible formation of piping channels (which may nonetheless be developing locally).

The energy that this gravitational force can provide is quite large, on the order of several teraJoules for one metre of overburden motion for a 1000 m deep well on 250 m spacing.

Thus, in addition to the more classically understood "compaction drive" that may occur later in the well life when the high porosity zone is fully reloaded (**Fig 3c**), gravity forces appear to be a vital factor in the continued destabilization of the sand, which is essential for successful CHOPS. However, successfully incorporating this drive mechanism into reservoir simulation remains problematic, which is one of the basic reasons that physics-based simulation of CHOPS remains a challenging task, and massive model calibration on empirical data remains the favored means of extrapolation of production histories and prediction of new well performance.

Workover Approaches

This area is in a state of rapid evolution. Some articles have been published,[16,17] but history seems to be continuously overtaken by new methods.

Two general methods are of interest in this article: those that seek to perturb the near-wellbore region (out to perhaps 4-6 m), and those that seek to perturb the reservoir at a great distance (> 10 m), perhaps approaching the interwell scale in the case of pressure pulsing. A brief review is given here.

Why does Production Stop?

Leaving aside mechanical problems, pump wear, and so on, the major "reservoir" reasons for production losses appear to be the following:

- Well perforations become blocked by sand and gravel grains as well as precipitated asphaltenes.
- The near-wellbore region becomes "re-packed" with sand that cannot be destabilized and liquefied by well drawdown during continuous production.
- Access to distant virgin solution gas drive forces is stopped, a process we call well "disconnection" from the far-field.
- The interwell regions (**Fig 3b**) become stabilized, and shearing ceases to be active, eliminating the beneficial effects of gravitational drive forces on the sand.
- Depletion of solution gas at the reservoir scale gradually reduces and eventually eliminates gas expansion drive forces.

Near-Wellbore Methods

These include all methods of injecting limited quantities of fluids (5-20 m^3), aggressive swabbing, chemical placements, foam clean-outs, mechanical sand bailers, and the like. They are intended to unblock the perforations and near-wellbore regions to re-establish sand flow.

Vibrational workovers using frequencies of 10-50 Hz have proven effective in loosening blockages near the well, allowing particles to be re-mobilized and flushed out, but this effect is local because of the high frequencies and the low amplitudes that can be achieved. Furthermore, loose sand with gas bubbles is a highly adsorptive medium.

An issue with all workover methods in CHOPS wells is that, without pump-to-surface methods or foams (low density), it is impossible to obtain returns at the surface. This occurs because sand production reduces the fracture pressure gradient to as low as 8-10 kPa, below the weight of a column of pure water. Thus, liquid addition or flushing attempts generally push sand and other near-wellbore blocking agents farther out into the formation, thereby allowing better local flow.

Reservoir Perturbation Methods

Methods that shock or perturb the reservoir at a larger scale have proven to be effective in CHOPS wells, and perhaps could have a much larger application in conventional wells experiencing flow impairment.

Reperforating serves to install larger diameter flow ports that are less prone to blockage, and the shock associated with explosive discharge creates a shock wave that travels some distance out from the wellbore. Thus, perforation unblocking and near-wellbore perturbation can help re-initiate sand flux to the wellbore. However, the region around the wellbore is extremely soft and there is usually a high gas content, albeit in the form of bubbles. This serves to severely attenuate any shock wave and reduces the efficacy of reperforation. Apparently, this method is best in initiating initial sand production in zones where it proved impossible to generate stable sand influx during the initial completion, or in rehabilitating old wells that were never very productive of sand and hence oil because of small perforations.

Rocket propellant discharge down-hole with the wellhead shut-in gives a large impulse to the formation. Because a large amount of gas is generated and liquid is forced through the perforations very aggressively, the magnitude of the shock wave is large enough to propagate effectively into the more remote reservoir regions, although the effect is probably inconsequential beyond perhaps 15-25 m.

Pressure pulsing is now discussed in greater detail.

Pressure Pulse Workovers

The concept of prolonged aggressive liquid phase pulsing[18] arose in part through a gradual appreciation of the production loss mechanisms typical of CHOPS wells, combined with an improved theoretical understanding of incompressible behavior of liquids that lead to the possibility of generating displacement waves that are highly conservative and of low frequency (hence low attenuation). Pulsing from the surface is not possible for several reasons, the major ones being the impossibility of filling the wells with liquid and the issue of the impulse magnitude required to suddenly accelerate a 500-800 m column of liquid. Bottom-hole pulsing is necessary.

There are two basic options for pulse generation: use of the entire tubing string as a drop weight, forcing all the casing liquid below the PPT tool through the perforations; and, use of a bottom hole independent piston driven by mechanical-hydraulic means. The former will be discussed in greater detail (**Fig 5**).

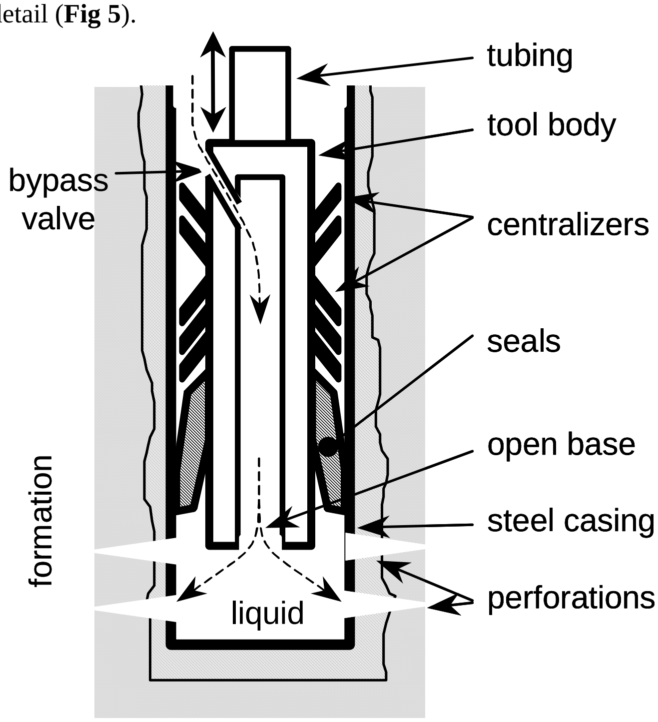

Figure 5: Schematic of a Pulse Workover Tool

In a typical PPT workover, all hardware is removed from the hole, the tool on tubing is located above the perforations, and stroking is carried out by the service rig draw-works. The tool is lifted slowly (15-60 s) to allow fluid to enter the wellbore through the perforations and from the annulus, then dropped and allowed to free-fall for a distance of 4-16 m. Typically, the tool reaches terminal velocity in less than two seconds, and the downstroke takes 2-6 seconds. The process is repeated for 45-90 min, then paused for 15 min, at which point a liquid level in the annulus is taken to guide decisions as to liquid input.

Liquid recharge can be entirely from backflow into the chamber, or the annulus or tubing can be filled or pressurized so that any portion or even 100% of the fluid impelled into the reservoir is fed from surface. This allows slow trickling in of well-mixed workover fluids (e.g. 5% surface feed), or even operation of the PPT tool as a positive displacement impulse pump (100% surface feed).

Pulsing for 4-5 hours was typical for initially workovers, but more recent workovers have generally been for 8 hours, even 24 hours in some cases. At the end of the workover, the tool is withdrawn slowly from the hole, and the well placed back on production.

Bottom-hole pressure responses (**Figs 6, 7**) show high Δp during active pulsing. In the first example the impulse was 300-350 psi for most of the workover in this case. The build-up of Δp in the third pulsing cycle (each cycle consisted of ~ 60 strokes) is thought to be the driving of free gas bubbles back into solution, allowing a higher impulse. The casing was recharged with 2-3 m^3 of somewhat lighter oil at the end of each station stop.

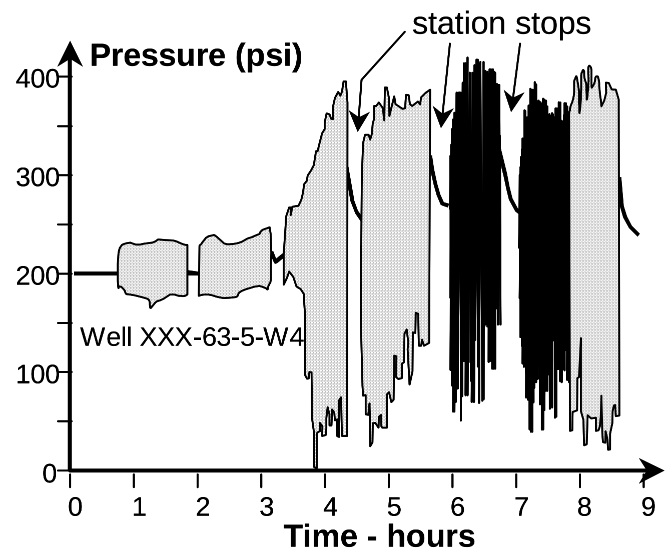

Figure 6: BHP Response for a Pulse Workover (Initial p = 200 psi, final static p = 238 psi, peak p = 400 psi)

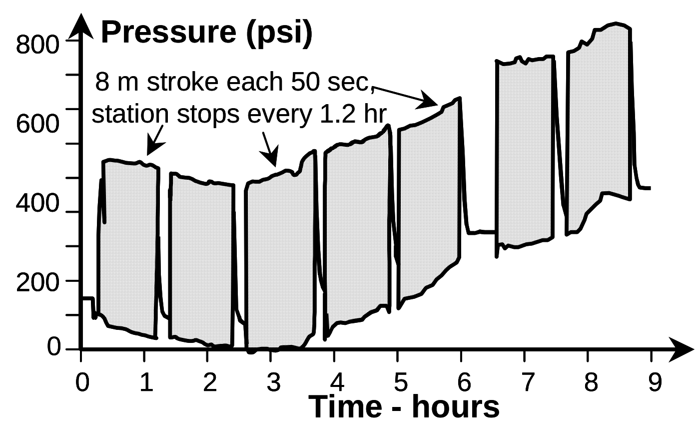

Figure 7: BHP Response (Initial p 145 psi, final static p = 465 psi, peak p ~900 psi)

In the second example, an increase in the static pressure of over 300 psi (2 MPa) was achieved, although the impulse size remained the same, indicating that the resistant to the excitation of the formation remained constant. Both of these wells were economically successful workovers.

Mechanisms in Pressure Pulsing

If used entirely as a pump, liquid is displaced into the reservoir, and the gas saturation is reduced as pressure increases. This causes a displacement front to propagate from the wellbore, and the impulse is less and less attenuated as the gas saturation drops.

Initiation of Sanding Through Sand Disaggregation

In a well that did not respond to conventional completion approaches to initiate sand influx (for reasons largely unknown this happens in ~10-12% of cases), pulsing develops very sharp pressure spikes at the sand face, enough to reduce the matrix stress to zero, and allow local complete remolding of the sand. The extent of such a remolded zone after 6-20 hr of pulsing is unknown, but probably it is several meters radius around the well.

Blockage Removal

Repeated perturbations in an old well that is blocked have a cumulative effect on the near-wellbore, opening up more and more perforations with time (as shown by the BHP response in many cases), and also remolding and liquefying any sand that has become recompacted over time around the wellbore. Typically, these cases show partially rejuvenated sand (and oil) flux when production is recommenced.

The volume of liquid injected in a single pulse stroke depends on the tool design and the approach taken; for the full-casing displacement option in standard 7″ casing, the volume is 25 liters per metre, or approximately 200 l (~1.3 b) for a stroke of 8 m. Assuming 100 open 25 mm perforations and constant displacement in 4 seconds, the velocities approach 100 m/s, far lower than a rocket propellant surge, but substantially larger than any reasonable workover injection rate from surface that is displacing heavy oil through the perforations.

Workover Chemical Mixing and Dispersion

A serious problem with all attempts to place treatment liquids (surfactants, diluents…) around heavy oil wells is channeling, resulting often in almost pure treatment liquid flowback when the well is placed on production. Channeling can occur because fracturing as well as because of poor mobility ratios (workover fluids are usually far less viscous that the formation oil). Because the sharp pulses tend to suppress fingering and partially overcome capillary blockage at pore throats, treatment chemicals are well-dispersed around the wellbore.

In addition to superior dispersal, if chemical placement is through partial recharge from the surface, and the great majority of the recharge is through backflow through the perforations, chemicals are intimately mixed with formation fluids through the high shear rates of the fluids through the perforation ports. This means that the chemicals are being mixed directly downhole with the virgin reservoir fluids themselves, and potential fluid incompatibility problems and the need for aggressive surface mixing are thereby diminished.

Far-Field Impulse Propagation

Apparently, pulsing is the only way to affect the far-field, inter-well region. At the characteristic frequencies of the impulse phase (< 1 Hz), liquids behave incompressibly, and this leads to the propagation of a displacement wave at a low velocity (~50 m/s).[19,20,21] The incompressible behavior causes short-term but large magnitude liquid accelerations at the pore throats, which serve several purposes, including break-down of any inherent gelation, overcoming of capillary blockages, and triggering of formation shearing in the interwell region.[22]

If the formation is fully liquid saturated (no free gas), the displacement wave attenuates very little (except for geometrical spreading of course), and this allows the effect to propagate to the inter-well scale with time. Observations on offset wells 200-300 m distant during pulse workovers occasionally show associated liquid level responses and even some increases in sand and oil flux, proving that the effects propagate far. If there is a lot of free gas, it has proven expedient to feed in oil during the workover to help resaturate the well region so that the pulse propagates farther with lower amplitude loss. In some cases 25-30 m^3 of oil has been used.

The triggering of shearing in the interwell region, confirmed directly in one case only through microseismic monitoring, can be likened to the cyclic pore pressure perturbations during earthquakes that lead to the liquefaction of shallow, high porosity water-saturated sand. In the case of a CHOPS well, it is re-triggering of the gravitational drive effects that takes place.

Comparative Study of Pulse Workovers

To date, a comprehensive assessment of the efficacy of the various heavy oil well workover alternatives has not been carried out because of the vast data collection effort from a number of companies that would be required. Detailed sand cut analyses and day-to-day production records are seldom kept, and different companies use different metrics to define success. Furthermore, because workover techniques (time of treatment, pump rates, swabbing methods…) are evolving so rapidly, it is almost impossible to collect a sufficient data base on “one static method” among many variants to allow systematic and meaningful comparisons to be made.

Using the standard industry measure of success, 90-day payback of workover costs in terms of increased oil production, the great majority of pulse workovers in the last three years have been successful. However, it should also be pointed out that the workovers are usually executed on problem wells after other approaches have failed, and it is impossible to work miracles, particularly in cases of poor geology and substantial general pressure depletion.

A typical well performance before and after a pulse workover is shown (**Fig 8**). This well had actually been on production for over 20 years before 1998, and had been providing about 50 m^3/mo (~10 b/d) for many years. In the two years before the workover, oil production had declined and water/oil ratios had risen. After the workover, an average production of 50 m^3/mo was re-established for at least a year.

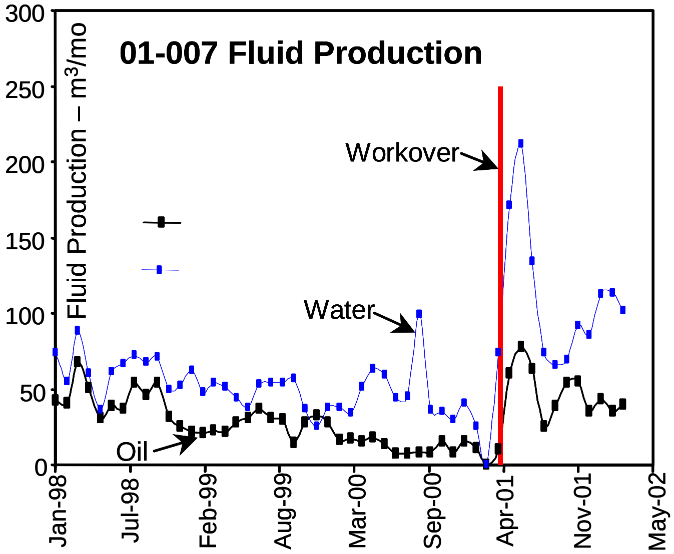

Fig 8: Fluid Production Before and After a Pulse Workover

One approach that serves to illustrate the progress being made is to compare a recent randomly selected pulse workover set to an earlier set. There is only a four-year history, and approximately 100 workovers to date. The first 20 workovers from Jan 1998 were grouped, and the last 20 workovers to date were also grouped. Monthly production of water and oil are plotted (left axis), and the oil production as a ratio of all produced fluids is plotted on the right axis.

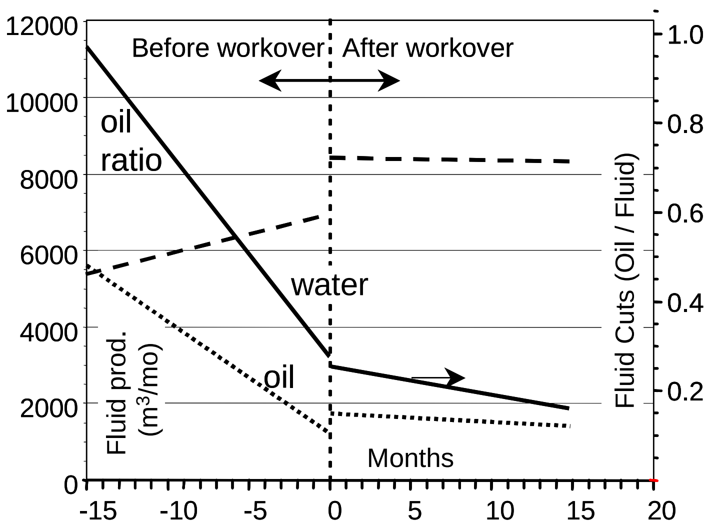

Figure 9: First 20 Workovers (1998)

The first 20 workovers were performed mainly on wells that had been better producers than the last 20 workovers. This makes an absolute comparison impossible. Rather, the relative trends must be examined. In the first set, the dropping oil rates were arrested, and the rising water rate was also arrested, although at a somewhat higher rate than before the workovers. Assuming that the wells would have been all shut in permanently, the pulse workovers resulted in an aggregate 35,000 m^3 additional oil.

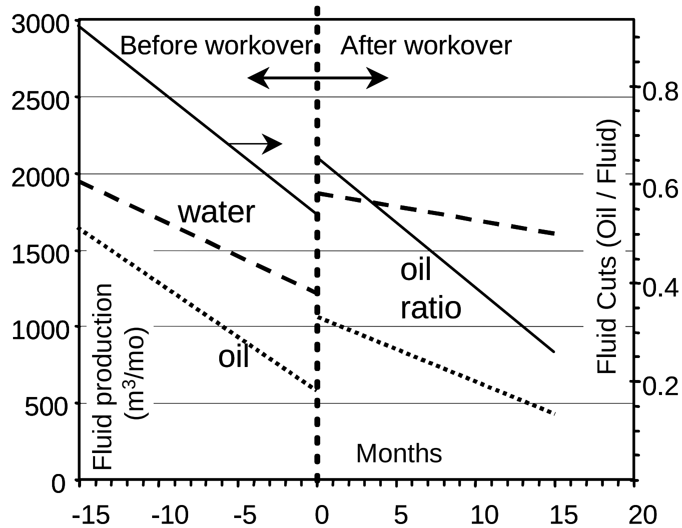

Figure 10: Production From the Last 20 Workovers

For the case of the last 20 workovers, largely attempts to re-establish some production from extremely poor and depleted wells in thinner zones than the first 20 workovers, a higher post-workover oil rate is apparent, but the oil rate declined more rapidly than in the first 20 wells. Incremental oil is about 10,000 m^3.

Discussion

Better screening criteria have evolved for pulse workovers, but the wells that were treated recently were of lower quality. Based on the economic success criterion, a higher ratio of successes now take place, even though the overall oil return rate is not as high for the recent wells. It is difficult to squeeze a little bit of extra value from poor wells that have produced in some cases since 1942 (with long inactive periods), but it appears to be possible to do this profitably.

Pulse workovers are not recommended in cases of massive depletion, nor in cases where it is apparent that a gas cap has developed or there is high gas saturation near the well.

Several additional cases deserve mention. First, in this data base, a few cases where pulsing succeeding in bringing a well on production after the primary completion failed are not included, and these were all successes. Second, a series of chemical placements incorporating pulsing achieved reasonable success,[23] indicating that a combination of the various effects (perforation unblocking, far-field excitation and good placement chemical dispersion) may be particularly useful. Third, only one workover has been executed to date on a consolidated reservoir, including placement of chemicals, and it was an economic success.

Extensive application of pulsing on various reservoir types has not yet happened. Optimistically, we believe that it will prove to be effective in loosening blockages in the pore throats and achieving greater uniform dispersion of chemicals, but this hope will have to wait for the results from appropriate opportunities.

Conclusions

- Pulse workovers in low production heavy oil wells have proven economically successful.
- The evolution of better screening criteria has helped the success ratio.
- Pulsing can bring a great deal of energy to the reservoir through the strong, repeated impulses used; this has benefits in both the near-wellbore and the far-field.
- Pulsing remains a new technology, tried only in Canadian heavy oil, and much remains to be learned.

Acknowledgements

The companies who tried the pulse workovers deserve a great deal of thanks; we hope their attempts result in the development of a new and useful tool for the business of oil extraction.

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